414 Nicollet Mall
Minneapolis, Minnesota 55401

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

March 1, 2022

—VIA ELECTRONIC FILING—

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

RE: ANNUAL TRUE-UP COMPLIANCE REPORT
2021 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES
DOCKET NO. E002/AA-20-417

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 2021 calendar year. This Report also includes compliance items required to be included in the Company's Electric Annual Automatic Adjustment of Charges Reports.

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

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service lists.

If you have any questions regarding this filing, please contact Martha Hoschmiller at (612) 330-5973 or martha.e.hoschmiller@xcelenergy.com or me at 612-330-7681 or lisa.r.peterson@xcelenergy.com.

Sincerely,

/s/

LISA R. PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c: Service List

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2021 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-20-417

ANNUAL TRUE-UP REPORT

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Annual Fuel Forecast True-Up Report which provides a comparison of the approved 2020 fuel forecast to 2021 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 2021 actual fuel expense was $894.1 million, or $144.3 million higher than our approved forecast of $749.7 million. The actual average fuel cost of $31.71 per MWh was 14.1% higher than the authorized rate of $27.78 per MWh. However, actual fuel cost collections, once adjusted for a fuel cost increase of $25 million implemented from October through December and the final 2020 fuel cost true-up implemented in September, resulted in under-collected fuel costs of $81.8 million.

The significant drivers for increased costs between our 2021 forecast and actuals were:

1. higher congestion cost from the MISO market than forecast;
2. increased fuel cost for gas generation due to higher gas prices;
3. increased fuel cost for coal generation in response to higher gas prices and resulting market LMPs

However, higher market LMPs also led to greater than forecast asset-based sales volumes and revenues, which also increased volume of generation from both gas and

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

coal generators. Asset-based sales revenues served to offset some of the increased costs for 2021. We review these drivers and mitigating factors in detail in section II-D.

In this report, we provide details of the variance between forecast and actuals, discuss the prudency of our management of fuel costs in 2021, propose to implement true-up factors by class on September 1, 2022 to collect the $81.8 million of under-collected costs over 12 months, and provide various additional compliance reports.

2021 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 $/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 $/MWh fuel costs in each month by fuel type (including identification of costs from specific power purchase agreements) and compare the annual revenue based on the fuel rates set by the Commission with annual revenues based on actual costs for the year. Each utility will refund any over-collections and show prudence of costs before allowing recovery of under-collections. If annual revenues collected ($/MWh) are higher than total actual costs, the utility must refund the over-collection through a true-up mechanism. If annual revenues collected are lower than total actual costs), the utility must show why it is reasonable to charge the higher costs (under-collections) to ratepayers through a true-up mechanism. In this true-up report, the Company reports that the 2020 annual revenues collected were lower than total actual costs, and therefore we show why it is reasonable to charge the higher costs.

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 12 Order) in the same docket set forth a procedural schedule for the various filings, reviews, approvals, and implementation of the various components 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.[2]

The Commission's December 20, 2020 Order in Docket No. E002/AA-20-417 approved the Company's fuel forecast and resulting monthly rate factors by customer class for calendar year 2021. The Commission's June 6, 2021 Order in Docket No. E002/AA-19-293 approved a 2020 true-up factor by customer class which adjusted the approved rates for the month of September 2021. No party objected to the Company's August 27, 2021 adjustment proposal filed in Docket No. E002/AA-20-417, therefore we implemented a $25 million increase to fuel costs which increased the rate factors by customer class for the months of October, November and December 2021.

B. Procedural Schedule

Under the procedural schedule detailed in Appendix A of the June 12 Order, Comments on the true-up reports are due on April 15, Reply Comments are due on May 2, and Response Comments are due on May 15. A Commission Order is expected by August 2 to allow utilities to provide customers notice of true-up rate factors 30 days before implementation on September 1.

II. 2021 FORECAST VERSUS ACTUALS COMPARISON

A. Summary

The Company's approved 2021 FCA forecast included $749.7 million in fuel costs, and an average rate of $27.78 per MWh. Actual costs for 2021 were $894.1 million, or 19.3 percent higher than forecast. The actual cost per MWh was $31.71 per MWh, or 14.1 percent higher than authorized. One of the primary drivers to the difference between our forecasted fuel costs and actual fuel costs was a major increase in natural

[2] See Part F, Attachment 5 of this Report for a compliance matrix detailing the various compliance items included in this report.

gas prices due to last year's Winter Storm Uri. Because this storm had a large and wide impact, the price of natural gas remained relatively high for the remainder of the year. Another significant driver was higher transmission system congestion cost due to the increased development of wind generation across the Midwest.

Fuel revenue collections for 2021 were 5.0% higher than forecasted, which reduces the year's under-recovered costs. Table 1 below summarizes the 2021 forecast to actuals comparison.

Table 1: 2021 Fuel Cost and Revenue Comparison Summary MN Jurisdiction

	Actual (000s)	Forecast (000s)	Variance (000s)	Variance (%)
Total FCA Costs	$894,089	$749,743	$144,345	19.3%
MWh Sales	28,195,869	26,988,067	1,207,802	4.5%
FCA Cost in $/MWh	$31.71	$27.78	$3.93	14.1%
Fuel Collections	$787,064	$749,743	$37,321	5.0%
Mid-Year Adjustment Collections	$25,135			
Over-recovery of 2020 True-Up	$124			
(Over) Under Recovery	$81,766			

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 2021 Fuel Costs and Prudency of True-Up Proposal

2021 proved to be a challenging year for fuel recovery under the new fuel recovery mechanism. Beginning with Winter Storm Uri in February, and continuing throughout the year, pressures arose that led to significantly higher costs than forecast, and material under-recovery of fuel costs. The diverse NSP system generation fleet allowed the Company to reliably navigate the Winter Storm Uri event, which in fact resulted in lower costs than forecast for electric generation in February, through off-setting asset-based sales into MISO when LMPs were significantly elevated as a result of the storm. However; following Uri, natural gas prices stayed higher than forecast throughout most of the year, leading to higher fuel costs than forecast for the year. As a result of high gas prices, coal generation ran more than forecast, and resulted in higher than forecast costs for coal generation. In addition, late season coal prices began to rise significantly in response to high natural gas prices.

Another pressure that drove costs much higher than forecast was increasing costs from congestion. Recall that Locational Marginal Prices consist of three components: system energy cost (which varies for each market interval but is constant across the MISO footprint for that interval), congestion costs, and losses. Put simply, congestion costs are a signal that transmission capacity in the market is constrained. Congestion costs saw a step increase in April 2021, remained high through the summer of 2021, and saw another step increase in September 2021 when gas prices rose to their highest level of the year. The in-servicing of the new Huntley-Wilmarth transmission line provided some relief in December 2021, but costs still remained much higher than forecast in our July 2020 Reply Comments, the forecast approved in this docket. Congestion was high in MISO due to substantial additions of renewable energy, concentrated in certain wind-rich regions of MISO. Additions of generation have outpaced transmission capacity, limiting the ability to transport lower-cost wind generation to load zones in MISO, instead leaving higher priced resources to set marginal market prices. On-going transmission work in MISO to bring new lines, such as Huntley-Wilmarth, into service and actions such as reconfigurations and dynamic line ratings may help mitigate some of the congestion in the near term. However, additional investment in transmission will likely be necessary to address congestion over the longer term.

Throughout all these events, we were able to manage our generation fleet successfully and reliably, with outstanding nuclear plant performance evidenced by a lower nuclear forced outage rate than forecast. This led to substantial revenues from asset-based sales to MISO that contributed a significant offset to higher fuel and congestion costs. Obviously Winter Storm Uri and the subsequent rise in natural gas prices, in addition to rising congestion in MISO, were events the Company could not have forecast in July 2020 when our Reply Comments established rates for 2021 fuel recovery.

Although the Company's year-end results reveal under-collection of $81.8 million, this reflects $25.1 million in additional fuel surcharges implemented as a mid-year adjustment to fuel rates for under-recovery through June 2021. At that time, the Company projected that year-end under-recovery would be as much as $70 million. Subsequently, gas prices rose substantially for September through December 2021, and congestion costs saw another step increase in September 2021 that led to actual year-end costs coming in over $30 million higher than the estimate provided in August 2021.

Because our under-recovery is driven by the factors listed above that are outside of the Company's control, and because the Company managed our diverse generation fleet through very challenging circumstances to provide high availability that led to significant offsets to higher costs, we believe our proposal to recover the under-collected 2021 fuel costs is reasonable, and we request the Commission approve a true-up for that amount.

C. Proposed True-Up Rate Factors

We propose to collect the $81.8 million over 12 months, beginning September 1, 2022. The proposed monthly true-up factors are shown in Part A, Attachment 3 and Part A, Attachment 5.

To determine the proposed true-up factors by customer class, we compare the 2021 forecasted Minnesota cost to the actual cost, which includes the mid-year rate adjustment as well as the over-recovered 2020 final true-up. The resulting amount, divided by 12 that yields the average monthly recovery amount. This monthly amount further divided by the forecasted 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 true up factors will be added to the monthly fuel cost charges for each of 12 months beginning September 1, 2022. We provide the proposed tariff sheet reflecting the proposed true-up rates as Part A, Attachment 9. Because the tariff sheet presents calendar year 2022 rates, only the September through December 2022 rates are updated in the tariff to reflect our proposed true-up factors. In our May 2, 2022 Fuel Forecast Filing to propose 2023 fuel factors, the proposed tariff sheet will include the January through August 2023 proposed true-up factors.

We propose to update the Company web site with the true-up factors by August 1, 2022, or upon issuance of the Commission's Order, to provide customers 30 days' notice of the rate change. Monthly fuel rates are presented at the following link: https://www.xcelenergy.com/company/rates_and_regulations/rates/rate_riders.

D. 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 fuel price input for hydro generation in the model because hydro generation does not require any fuel purchases.

Figure 1: Hydro Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Hydro	0	0	0	861	922	(61)	$0.00	$0.00	$0.00

Company-owned hydro facilities experienced lower than normal water flows in 2021, 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

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Owned Wind	0	0	0	7,264	8,125	(861)	$0.00	$0.00	$0.00

Actual 2021 Company-owned wind production was less than forecast primarily due to increased curtailment, which accounts for approximately 60 percent of the decline. Post-PTC eligible facilities, Grand Meadow and Nobles, accounted for the majority of the curtailments. Also, in-service dates for Mower County and Freeborn wind facilities were later than forecast. There is no fuel price input for wind generation in the forecast model because wind generation does not require any fuel purchases. Less actual wind generation than forecast increased generation from other fuel types.

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 discuss detailed outage data in more detail later in this report.

Figure 3: Company-Owned Coal Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Coal	$197,754	$149,944	$47,810	9,265	7,022	2,243	$21.34	$21.35	-$0.01

The 2021 actual coal generation was greater than forecast. This was due to higher gas prices that lead to stronger LMP and greater market sales.

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 discuss detailed outage data in more detail later in this report.

Figure 4: Company-Owned Wood/RDF Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Wood/ RDF	9,155	10,472	(1,318)	534	454	80	$17.15	$23.07	-$5.92

Actual 2021 Company-owned wood/RDF cost was less than forecast due to lower realized fuel prices at Bayfront and French Island.

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 forecasted natural gas rates. For peaking plants, the model uses the MISO calculation of each unit's Equivalent Forced Outage Rate – Demand (eFORd) based on three-years of history. We discuss detailed outage data in more detail later in this report.

Natural gas fuel prices are forecast based on New York Mercantile Exchange (NYMEX) futures prices for natural gas at the Ventura hub. Costs for transport of natural gas to each specific plant are based on the Company's transport and delivery contracts in place at the time we made our forecast filing.

Figure 5: Company-Owned Natural Gas Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Owned Gas (CC)	195,504	120,865	74,640	6,101	4,325	1,776	$32.05	$27.94	$4.10
Owned Gas (CT)	49,824	13,851	35,973	843	218	624	$59.13	$63.48	-$4.35

Actual 2021 Company-owned natural gas generation was higher than forecast due to stronger LMP and greater market sales, even though gas prices were higher than forecast. Gas prices stayed elevated throughout most of the year, influenced by Winter Storm Uri in February. The fixed gas demand costs were spread over greater volumes, which lowered the average $/MWh for the owned CTs, as seen in Figure 5.

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

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Nuclear	111,253	111,986	(732)	14,069	13,744	324	$7.91	$8.15	-$0.24

Actual Company-owned nuclear generation experienced better-than-forecast performance in 2021 due to a lower than forecast outage rate. The investments we have made in our nuclear plants over the past several years have provided benefit. Since January 2018 (through August 2021), Monticello has operated at an average capability factor of 94.2 percent, including 99.3 percent in 2018 and 98.6 percent in 2020, both non-refueling years. In that same timeframe, Prairie Island achieved a combined average capacity factor of more than 95 percent, including a 99.9 percent on Unit 2 in 2018; 99.4 percent on Unit 1 in 2019; and 99.3 percent on Unit 2 in 2020, all non-refueling years. Part C, Attachments 4 and 5 provide details on actual outages in 2021, including a comparison of forecast to actual outage costs by unit.

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 forecasted purchased natural gas rates.

Figure 7: Purchased Natural Gas Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Gas PPAs	146,232	83,784	62,448	4,032	3,402	630	$36.27	$24.63	$11.64

Actual 2021 purchased natural gas generation was higher than forecast due to stronger LMP and greater market sales, even though gas prices were higher than 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

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	Forecast	Variance	Actual	Forecast	Variance	Actual	Forecast	Variance
Solar PPAs	42,905	40,172	2,733	609	624	(15)	$70.47	$64.36	$6.10

Actual 2021 purchased solar production volumes were lower than forecast due to higher curtailment at the Marshall facility. Purchase solar costs were higher due to greater generation than forecast for the Aurora and North Star facilities. See Part C, Attachment 7 for actual solar PPA production and cost by month and by contract.

ix. Purchased Solar Generation (Community Solar Gardens)

The community solar gardens (CSG) program forecast includes expectations of future growth based on current applications for gardens seeking to participate in the program. 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 2021.

The market cost of energy from the solar gardens generation is determined based on the assumed Locational Marginal Price (LMP) in the simulation. This cost is shared with all jurisdictions in the NSP system. The cost of the program above market is direct assigned to Minnesota customers.

Figure 9: Community Solar Gardens Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
CSG Market	73,006	32,674	40,332						
CSG Above Market	110,646	157,160	(46,514)						
Total CSG	183,652	189,834	(6,182)	1,456	1,467	(12)	$126.17	$129.36	-$3.19

The 2021 actual CSG production and cost were slightly lower than forecast. The CSG forecast is based on assumptions of when community solar projects are completed (or receive permission to operate) and assumptions of how many under which rate vintages will operational during the forecast year. Completion dates can be impacted by weather, construction, and scheduling. All of these factors have an impact on the actual production and bill credits.

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, using a 5-year historical average for curtailment costs. Those for which curtailment is not allowed are modeled as non-curtailable projects.

Figure 10: Wind PPAs Forecast to Actuals

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Wind PPAs	194,087	194,502	(415)	5,008	5,934	(926)	$38.76	$32.78	$5.98

Actual purchased wind generation was less than forecast due to higher wind curtailments, which account for 93 percent of the of the overall decline. Non-PTC eligible farms, such as Fenton and Minn Dakota, accounted for the majority of the actual wind curtailment. Actual costs compared favorably to forecast.

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

	2021 ($000)			2021 GWh			2021 $/MWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Other PPAs	176,450	178,659	(2,209)	2,139	2,341	(202)	$82.51	$76.33	$6.18

Actual 2021 other purchased generation costs were lower than forecast due to lower generation volumes from a mix of small PPA contracts including KODA, Rapidan, SAF and City of St. Cloud.

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. The simulation can make this decision hourly within the constraints of the modeled system. In addition, the model forecasts monthly intersystem sales opportunities of excess generation after system native requirements are fulfilled. This is done through an hourly dispatch simulation based on projected hourly market prices designed to represent LMP for the NSP system. The sum of these quantities represent the equivalent MISO Day 2 and Day 3 costs for the Forecast.

Figure 12: Net MISO Costs and Revenues

	2021 ($000)			2021 GWh		
	Actual	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Net MISO	($122,173)	($126,997)	$4,823	(10,574)	(7,267)	(3,307)

Due to congestion, net MISO revenue was lower than projected, despite higher than forecast asset-based sales into MISO. Higher than forecast LMPs led to greater volume and revenue from asset-based sales, but these sales were made from higher cost generation due to higher fuel prices and limited ability to transport energy from the Company's renewable resources. In addition, higher market LMPs resulted in greater costs for market purchases from MISO than forecast.

Table 3 below compares the 2021 forecast to actuals by primary MISO charge type.

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

Category	Actual	Forecast	Variance
Congestion	$230,065	$33,187	$196,878
FTR	($59,818)	($30,339)	($29,479)
Incremental Transmission losses	$4,368	($7,087)	$11,455
RSG/RNU	$10,430	$5,588	$4,842
ASM	($2,203)	($1,110)	($1,092)
MISO Charges TOTAL	$182,842	$239	$182,603

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.

xiii. Retail Sales

The Minnesota sales forecast used in the Fuel Clause Adjustment filing was developed in July 2020. Actual Minnesota retail sales in 2021 were 28,814,203 MWh, compared with the 2021 sales forecast of 27,384,049 MWh, resulting in a sales-to-forecast variance of 1,430,154 MWh.[3] As summarized in the table below, contributing factors to the forecast variance include greater than anticipated residential class COVID pandemic impacts from continued social distancing and work-from-home measures, the 2021 weather impact on sales, lower than expected Combined Heat and Power (CHP) generation, and other non-specified factors. These were in part offset by

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

greater commercial and industrial (C&I) COVID pandemic impacts from reduced economic and business activity, lower than expected C&I load additions/reductions, and lower solar generation than forecasted. In summary, the combined residential and C&I COVID pandemic impacts, weather impacts, and other non-specified factors were the largest contributors to the forecast variance.

Table 3: Sales-to-Forecast Variance in 2021 (MWh)

	2021 Minnesota Juris.
Jul 2020 Cal Mth Sales Forecast	27,384,049
Actual 2021 Cal Mth Sales	28,814,203
Actual Sales Variance from Forecast	1,430,154
Contribution to Forecast Variance:	
DSM Forecast Variance	2,755
	[PROTECTED DATA BEGINS
C&I Load additions/reductions	
	PROTECTED DATA ENDS]
2021 Weather Impact	504,928
Residential COVID Impacts	45,397
C&I COVID Impacts	607,323
	[PROTECTED DATA BEGINS
CHP Forecast Variance	
	PROTECTED DATA ENDS]
Solar Forecast Variance	(14,551)
Other Factors	287,757
Total	1,430,154

E. Other Items Impacting Total Fuel Cost

i. Costs Excluded from Fuel Costs

Part A, Attachment 3 provides monthly details of the direct assigned WindSource and Renewable*Connect amounts for 2021, which are excluded from total fuel costs.

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.[4] The 2020 annual FCA recovery of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** is shown in Part A, Attachment 2, line 47, the month the excluded customers were issued their bill credit.[5] 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

The Saver's Switch discount is applied during the months of June through September, and therefore our 2021 true-up shows these amounts for those months in our detailed monthly actuals report shown in Part A, Attachment 2, line 48. 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 amounts after they are known.

iv. Asset Based Margins

Table 5 below provides a comparison of the forecasted asset-based margins to the actual asset-based margins for 2021.

Table 4: Actual 2021 Asset-Based Margins
($ millions)

	Revenue	Cost	Margin
Forecast	136.3	95.1	41.2
Actuals	437.2	308.9	128.3
Variance	300.9	213.8	87.1

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

---

[4] The Fuel Clause Adjustment (FCA) and Renewable Development Fund (RDF) Riders.
[5] The Company provided this amount in the May 27, 2021 SES Exclusion Annual Report filed in Docket No. E002/M-17-425.

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 12, 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 12, 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 has included in our 2022 test year rate case application a demonstration that the proposed base rates exclude Fuel Clause-Adjustment-related costs.[6]

2. Monthly Fuel Cost Charges

See Part A, Attachment 8 for the monthly fuel cost charges implemented in 2021.

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 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 2022-2026 was provided as part of the Company's May 1, 2021 fuel forecast for calendar year 2022. The monthly five-year projection of fuel cost by energy source for the period of 2023-2026 will be provided as part of the Company's May 1, 2022 fuel forecast for calendar year 2023.

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

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 2015 and 2021 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 2021 Annual True-Up Report, our proposal to recover $81.8 million in under-recovered fuel costs for the 2021 calendar year, and the Electric AAA reporting requirements included in this report.

Dated: March 1, 2022

Northern States Power Company

TABLE OF CONTENTS

Part D: Policies and Actions – MN Rule 7825.2800

Part E: Annual Auditor's Report – MN Rule 7825.2820

Part F: Miscellaneous Compliance Reports

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

		2021 ($000)				2021 GWh			2021 $/MWh		
	MN Jurisdiction Fuel Collections			$787,064							
	MN Jurisdiction Fuel Costs			$894,089							
	(Over)/Under Recovery (Deferred to Balance Sheet)			**$107,025**	**Receivable** 12%						
	Surcharge to collect YTD June Under Recovery			$25,135							
	Over Recovery via 2020 Surcharge			$124							
1	**Net (Over)/Under Recovery**			**$81,766**	**Net Receivable**						
2											
3		Actual	Forecast (1)	Variance		Actual	Forecast (1)	Variance	Actual	Forecast (1)	Variance
4	Coal	$197,754	$149,944	$47,810		9,265	7,022	2,243	$21.34	$21.35	-$0.01
5	Wood/RDF	$9,155	10,472	(1,318)		534	454	80	$17.15	$23.07	-$5.92
6	Natural Gas CC	$195,504	120,865	74,640		6,101	4,325	1,776	$32.05	$27.94	$4.10
	Natural Gas & Oil CT	$49,824	13,851	35,973		843	218	624	$59.13	$63.48	-$4.35
7	Nuclear Fuel	$111,253	111,986	(732)		14,069	13,744	324	$7.91	$8.15	-$0.24
8	Total Fuel	$563,490	$407,117	$156,373		30,811	25,763	5,047	$18.29	$15.80	$2.49
9	Hydro	$0	0	0		861	922	(61)	$0.00	$0.00	$0.00
10	Wind	$0	0	0		7,264	8,125	(861)	$0.00	$0.00	$0.00
11											
12	LT Purchased Energy (Gas)	$146,232	83,784	62,448		4,032	3,402	630	$36.27	$24.63	$11.64
13	LT Purchased Energy (Solar)	$42,905	40,172	2,733		609	624	(15)	$70.47	$64.36	$6.10
14	Community Solar*Gardens	$183,652	189,834	(6,182)		1,456	1,467	(12)	$126.17	$129.36	-$3.19
	LT Purchased Energy (Wind)	$194,087	194,502	(415)		5,008	5,934	(926)	$38.76	$32.78	$5.98
15	LT Purchased Energy (Other)	$176,450	178,659	(2,209)		2,139	2,341	(202)	$82.51	$76.33	$6.18
	Total Purchased Power	$743,326	$686,952	$56,374		13,243	13,768	(525)	$56.13	$49.90	$6.24
16											
	Net MISO Day 2 and Day 3	($122,173)	($126,997)	$4,823		(10,574)	(7,267)	(3,307)			
17	Less Costs Direct Assigned (2)	($129,104)	(169,450)	40,346							
18	**Net System Costs**	**$1,055,539**	**$797,623**	**$257,916**		**41,605**	**41,311**	**293**	**$25.37**	**$19.31**	**$6.06**
19	**Net System Mwh Sales**	**39,305,604**	**37,819,056**	**1,486,548**							
	System Cost in $/Mwh	**$26.85**	**$21.09**	**$5.76**							
20											
	MN Jurisdictional Fuel Cost	***$758,124***	***$569,448***	***$188,676***							
21	Direct Assigned Costs:										
22	Solar Gardens - Above Market Cost	110,646	157,160	(46,514)							
23	Biomass Termination Costs	23,442	23,136	307							
	Recovery Adjustment		0	0							
24	**Net Direct Assigned Costs**	**$134,088**	**$180,296**	**($46,207)**							
25	**MN Jurisdiction Mwh Sales**	**28,195,869**	**26,988,067**	**1,207,802**							
26	**MN Jurisdiction Cost in $/Mwh**	**$4.76**	**$6.68**	**($1.92)**							
	MN Direct Assigned	**$134,131**	**$180,296**	**($46,164)**							
	Other Adjustments	**1,834**		**1,834**							
	Total MN Jurisdiction FCA Costs	**$894,089**	**$749,743**	**$144,345**	**19.3%**						
	MN Jurisdiction Mwh Sales	**28,195,869**	**26,988,067**	**1,207,802**	**4.5%**						
	MN Jurisdiction FCA Cost in $/MWh	**$31.71**	**$27.78**	**$3.93**	**14.1%**						

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
2021 Fuel, Purchased Power and Other Costs

	($000)	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021 Total
	Own Generation													
	Fossil Fuel													
1	Coal	$16,302	$24,661	$9,459	$9,429	$6,236	$21,048	$25,705	$25,972	$15,833	$14,024	$8,610	$20,478	$197,754
2	Wood/RDF	$885	$822	$572	$785	$728	$880	$774	$723	$436	$909	$724	$916	$9,155
3	Natural Gas CC	$13,178	$13,023	$7,770	$7,923	$10,935	$12,182	$22,399	$20,633	$15,727	$33,284	$23,161	$15,289	$195,504
4	Natural Gas & Oil CT	$1,217	$8,077	$2,758	$1,665	$4,249	$8,071	$3,795	$4,595	$3,417	$4,563	$2,417	$4,999	$49,824
5	Total Fossil Fuel 1+2+3+4	$31,582	$46,584	$20,559	$19,802	$22,148	$42,181	$52,674	$51,923	$35,412	$52,780	$34,911	$41,681	$452,237
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	$10,157	$9,197	$9,877	$7,920	$7,788	$9,772	$10,084	$9,968	$9,242	$7,031	$9,928	$10,290	$111,253
9	Total Fuel 5+6+7+8	$41,739	$55,781	$30,436	$27,722	$29,936	$51,954	$62,757	$61,891	$44,654	$59,811	$44,839	$51,971	$563,490
	Purchased Energy													
10	LT Purchased Energy (Gas)	$8,319	$10,723	$9,849	$6,643	$8,486	$11,404	$17,246	$13,893	$10,953	$14,497	$18,037	$16,181	$146,232
11	LT Purchased Energy (Solar)	$1,261	$2,197	$3,991	$3,991	$5,132	$6,044	$5,344	$4,874	$4,342	$2,860	$1,819	$1,049	$42,905
12	Community Solar*Gardens	$9,648	$8,841	$18,833	$12,324	$19,713	$28,940	$20,111	$19,321	$17,957	$11,549	$10,928	$5,487	$183,652
13	LT Purchased Energy (Wind)	$14,855	$12,073	$19,924	$15,139	$16,697	$12,114	$9,633	$13,318	$16,300	$18,741	$22,729	$22,564	$194,087
14	LT Purchased Energy (Other)	$9,849	$9,688	$3,818	$14,261	$18,214	$18,658	$19,437	$19,580	$18,046	$16,882	$15,464	$12,554	$176,450
15	Total Purchased Energy 10+11+12+13+14	$43,932	$43,523	$56,414	$52,358	$68,242	$77,160	$71,770	$70,986	$67,599	$64,529	$68,978	$57,836	$743,326
16	ST Market Purchase	$5,330	$6,423	$5,337	$3,657	$5,210	$13,933	$5,495	$5,879	$4,775	$9,482	$10,000	$9,619	$85,141
17	Market Sales	($20,398)	($62,825)	($14,427)	($14,551)	($19,155)	($32,821)	($36,397)	($47,767)	($34,826)	($53,364)	($52,930)	($47,738)	($437,200)
18	Net Market Cost 16+17	($15,069)	($56,402)	($9,090)	($10,894)	($13,945)	($18,887)	($30,902)	($41,888)	($30,051)	($43,882)	($42,930)	($38,119)	($352,059)
19	MISO Cost	$7,198	($3,801)	$20,730	$17,791	$14,474	$22,716	$14,180	$17,977	$26,918	$32,546	$31,350	$27,808	$229,886
20	Net MISO D2 and ASM Cost 18+19	($7,871)	($60,203)	$11,640	$6,896	$529	$3,829	($16,722)	($23,912)	($3,133)	($11,336)	($11,580)	($10,311)	($122,173)
21	**Total System Cost 9+15+20**	$77,801	$39,101	$98,491	$86,976	$98,706	$132,942	$117,805	$108,965	$109,119	$113,004	$102,237	$99,496	$1,184,644
22	Less Solar Gardens - Above Market Cost	($5,944)	($5,640)	($7,653)	($6,063)	($15,288)	($13,710)	($12,981)	($13,641)	($10,499)	($7,187)	($6,493)	($5,644)	($110,745)
23	Less WindSource	($670)	($611)	($947)	($1,026)	($1,395)	($460)	($1,458)	($1,375)	($1,103)	($1,078)	($1,130)	($917)	($12,169)
24	Less Renewable*Connect	($474)	($445)	($554)	($483)	($511)	($461)	($545)	($636)	($525)	($613)	($411)	($532)	($6,190)
25	Total Costs Direct Assigned 22+23+24	($7,088)	($6,696)	($9,154)	($7,573)	($17,195)	($14,631)	($14,984)	($15,652)	($12,127)	($8,878)	($8,034)	($7,093)	($129,104)
26	**Net System Costs 21+25**	$70,713	$32,405	$89,337	$79,403	$81,512	$118,311	$102,821	$93,313	$96,992	$104,126	$94,203	$92,403	$1,055,539
	Calendar Month MWh Sales													
27	Total NSP-MN and NSP-WI Retail Sales	3,304,074	3,058,003	3,150,513	2,784,929	3,117,434	3,784,180	3,971,178	3,958,514	3,201,709	3,195,672	3,081,785	3,315,948	39,923,939
28	Less Minnesota WindSource	(34,791)	(32,040)	(35,241)	(32,267)	(19,363)	(51,525)	(42,232)	(44,056)	(40,978)	(36,733)	(32,781)	(38,549)	(440,556)
29	Less Minnesota Renewable*Connect	(13,038)	(13,894)	(15,739)	(13,672)	(14,601)	(13,850)	(16,197)	(17,262)	(15,774)	(17,048)	(11,791)	(14,913)	(177,779)
30	**Total System MWh Sales 27+28+29**	3,256,245	3,012,069	3,099,533	2,738,990	3,083,470	3,718,805	3,912,749	3,897,196	3,144,957	3,141,891	3,037,213	3,262,486	39,305,604
31	Minnesota Jurisdictional Retail Sales	2,350,241	2,157,274	2,238,900	1,989,702	2,260,185	2,778,228	2,909,376	2,909,329	2,339,033	2,319,167	2,211,492	2,351,277	28,814,204
32	Less Minnesota WindSource	(34,791)	(32,040)	(35,241)	(32,267)	(19,363)	(51,525)	(42,232)	(44,056)	(40,978)	(36,733)	(32,781)	(38,549)	(440,556)
33	Less Minnesota Renewable*Connect	(13,038)	(13,894)	(15,739)	(13,672)	(14,601)	(13,850)	(16,197)	(17,262)	(15,774)	(17,048)	(11,791)	(14,913)	(177,779)
34	**Total Minnesota Retail Sales 31+32+33**	2,302,412	2,111,340	2,187,920	1,943,763	2,226,221	2,712,853	2,850,947	2,848,011	2,282,281	2,265,386	2,166,920	2,297,815	28,195,869
35	**System Fuel Costs in cents/kWh 26/30x100**	2.172¢	1.076¢	2.882¢	2.899¢	2.643¢	3.181¢	2.628¢	2.394¢	3.084¢	3.314¢	3.102¢	2.832¢	2.685¢
	Minnesota Jurisdictional Energy Costs													
36	System Fuel Costs in cents/kWh 35	2.172¢	1.076¢	2.882¢	2.899¢	2.643¢	3.181¢	2.628¢	2.394¢	3.084¢	3.314¢	3.102¢	2.832¢	
37	Total Minnesota Retail Sales Subject to FCA 34	2,302,412	2,111,340	2,187,920	1,943,763	2,226,221	2,712,853	2,850,947	2,848,011	2,282,281	2,265,386	2,166,920	2,297,815	28,195,869
38	Minnesota Costs Subject to FCA 36x37/100	$50,008	$22,718	$63,056	$56,350	$58,839	$86,296	$74,923	$68,181	$70,386	$75,075	$67,218	$65,074	$758,124
	MN Direct Assigned Cost (Solar Gardens & Biomass PPA Buyout)													
39	Solar Garden Above Market Direct Recovery	$5,940	$5,633	$7,637	$6,050	$15,273	$13,700	$12,971	$13,635	$10,491	$7,184	$6,491	$5,641	$110,646
40	Laurentian Payment	$0	$0	$0	$0	$0	$13,192	$0	$0	$0	$0	$0	$0	$13,192
41	Pine Bend Payment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	Benson Buyout costs	$872	$868	$865	$862	$857	$855	$852	$849	$846	$842	$841	$840	$10,249
43	MN Direct Assigned Total	$6,811	$6,502	$8,502	$6,911	$16,130	$27,747	$13,823	$14,484	$11,336	$8,026	$7,332	$6,481	$134,086
44	Minnesota Direct Assigned Cost in cents/kWh 43/34*100	0.296¢	0.308¢	0.389¢	0.356¢	0.725¢	1.023¢	0.485¢	0.509¢	0.497¢	0.354¢	0.338¢	0.282¢	0.476¢
45	Minnesota Fuel Costs in cents/kWh 35+44	2.468¢	1.384¢	3.271¢	3.255¢	3.368¢	4.204¢	3.113¢	2.903¢	3.581¢	3.668¢	3.440¢	3.114¢	3.161¢
46	**Minnesota Fuel Costs Subtotal 45*34/100**	$56,824	$29,221	$71,567	$63,269	$74,979	$114,048	$88,750	$82,678	$81,728	$83,094	$74,542	$71,554	$892,255
47	**Other Adjustments**	$0	$0	$786	$0	$0	$478	$207	$201	$161	$0	$0	$0	$1,834
48	**Minnesota Fuel Costs 46+47**	$56,824	$29,221	$72,353	$63,269	$74,979	$114,526	$88,957	$82,879	$81,890	$83,094	$74,542	$71,554	$894,089
49	**Minnesota Fuel Costs in cents/kWh 48/34x100**	2.468¢	1.384¢	3.307¢	3.255¢	3.368¢	4.222¢	3.120¢	2.910¢	3.588¢	3.668¢	3.440¢	3.114¢	3.171¢
50	**Minnesota Fuel Costs in $/MWh 49x10**	$24.68	$13.84	$33.07	$32.55	$33.68	$42.22	$31.20	$29.10	$35.88	$36.68	$34.40	$31.14	$31.71

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota

2022 Monthly Fuel Clause Charges with Proposed 2021 True-up ($/KWh)

	Residential	Commercial & Industrial				Outdoor Lighting
		Non-Demand	Demand			
			Non-TOD	On-Peak	Off-Peak	
January	$0.02597	$0.02630	$0.02548	$0.03184	$0.02086	$0.02038
February	$0.03066	$0.03104	$0.03008	$0.03761	$0.02460	$0.02403
March	$0.03268	$0.03309	$0.03206	$0.04009	$0.02623	$0.02562
April	$0.03256	$0.03297	$0.03194	$0.03992	$0.02614	$0.02554
May	$0.03453	$0.03496	$0.03387	$0.04234	$0.02772	$0.02708
June	$0.03979	$0.04029	$0.03903	$0.04880	$0.03194	$0.03119
July	$0.03392	$0.03435	$0.03328	$0.04161	$0.02722	$0.02658
August	$0.03386	$0.03428	$0.03321	$0.04154	$0.02716	$0.02653
September						
2022 Forecast	$0.03328	$0.03369	$0.03265	$0.04081	$0.02671	$0.02609
2021 True Up	$0.00325	$0.00329	$0.00318	$0.00398	$0.00260	$0.00254
Total	$0.03653	$0.03698	$0.03583	$0.04479	$0.02931	$0.02863
October						
2022 Forecast	$0.03116	$0.03155	$0.03057	$0.03822	$0.02501	$0.02443
2021 True Up	$0.00333	$0.00337	$0.00326	$0.00408	$0.00267	$0.00261
Total	$0.03449	$0.03492	$0.03383	$0.04230	$0.02768	$0.02704
November						
2022 Forecast	$0.02891	$0.02927	$0.02836	$0.03546	$0.02320	$0.02266
2021 True Up	$0.00340	$0.00344	$0.00333	$0.00417	$0.00273	$0.00266
Total	$0.03231	$0.03271	$0.03169	$0.03963	$0.02593	$0.02532
December						
2022 Forecast	$0.02662	$0.02696	$0.02612	$0.03265	$0.02138	$0.02088
2021 True Up	$0.00309	$0.00313	$0.00304	$0.00380	$0.00248	$0.00242
Total	$0.02971	$0.03009	$0.02916	$0.03645	$0.02386	$0.02330
January 2023						
2023 Forecast*						
2021 True Up	$0.00304	$0.00308	$0.00299	$0.00373	$0.00244	$0.00238
Total						
February 2023						
2023 Forecast*						
2021 True Up	$0.00352	$0.00357	$0.00345	$0.00432	$0.00283	$0.00276
Total						
March 2023						
2023 Forecast*						
2021 True Up	$0.00310	$0.00314	$0.00305	$0.00381	$0.00249	$0.00243
Total						
April 2023						
2023 Forecast*						
2021 True Up	$0.00357	$0.00362	$0.00350	$0.00438	$0.00287	$0.00280
Total						
May 2023						
2023 Forecast*						
2021 True Up	$0.00335	$0.00339	$0.00328	$0.00411	$0.00269	$0.00262
Total						
June 2023						
2023 Forecast*						
2021 True Up	$0.00306	$0.00310	$0.00301	$0.00376	$0.00246	$0.00240
Total						
July 2023						
2023 Forecast*						
2021 True Up	$0.00266	$0.00269	$0.00261	$0.00326	$0.00213	$0.00208
Total						
August 2023						
2023 Forecast*						
2021 True Up	$0.00273	$0.00276	$0.00268	$0.00335	$0.00219	$0.00214
Total						

* 2023 forecast is not available at time of this 2021 true up filing.

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
2021 Under (+)/Over(-) Recovered Expense

	($000)	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021 Total
	2021 FCA Factors Excluding 2020 True Up													
	From Docket No. E002/AA-20-417, July 31, 2020 Reply Comments Filing (Att D page 2). Approved in December 22, 2020 Order													
1	Residential	2.315¢	2.613¢	2.716¢	2.854¢	3.236¢	3.617¢	3.086¢	3.012¢	2.890¢	2.743¢	2.474¢	2.310¢	
2	C&I Non-Demand	2.344¢	2.646¢	2.750¢	2.890¢	3.277¢	3.663¢	3.125¢	3.049¢	2.927¢	2.777¢	2.505¢	2.339¢	
3	C&I Demand Non-TOD	2.271¢	2.564¢	2.665¢	2.800¢	3.175¢	3.548¢	3.027¢	2.954¢	2.836¢	2.691¢	2.427¢	2.266¢	
4	C&I Demand On-Peak	2.839¢	3.206¢	3.332¢	3.500¢	3.970¢	4.438¢	3.786¢	3.696¢	3.546¢	3.364¢	3.035¢	2.834¢	
5	C&I Demand Off-Peak	1.859¢	2.097¢	2.180¢	2.292¢	2.597¢	2.902¢	2.476¢	2.416¢	2.320¢	2.201¢	1.985¢	1.854¢	
6	Outdoor Lighting	1.816¢	2.048¢	2.129¢	2.239¢	2.537¢	2.834¢	2.418¢	2.359¢	2.266¢	2.150¢	1.938¢	1.811¢	
	Minnesota Calendar Month Retail Sales													
	Minnesota Retail Sales:													
7	Residential	799,783	721,255	695,892	588,091	653,150	1,013,974	1,021,964	1,030,874	677,911	640,969	662,542	764,055	9,270,460
8	C&I Non-Demand	72,416	69,382	69,935	57,686	64,968	72,336	77,934	75,004	63,152	60,689	60,026	68,208	811,736
9	C&I Demand Non-TOD	685,015	639,616	671,199	594,366	702,931	805,701	863,401	844,400	715,602	729,376	662,421	706,830	8,620,858
10	C&I Demand On-Peak	279,842	267,038	301,251	283,855	317,429	328,532	362,413	369,542	338,269	339,854	313,416	298,603	3,800,044
11	C&I Demand Off-Peak	495,976	453,443	488,166	460,506	512,768	550,571	576,374	581,780	534,560	538,382	500,731	500,976	6,194,233
12	Outdoor Lighting	17,209	6,540	12,457	5,198	8,939	7,114	7,290	7,729	9,539	9,897	12,356	12,605	116,873
13	Total 7+8+9+10+11+12	2,350,241	2,157,274	2,238,900	1,989,702	2,260,185	2,778,228	2,909,376	2,909,329	2,339,033	2,319,167	2,211,492	2,351,277	28,814,204
	Less WindSource & Renewable*Connect													
14	Residential	19,374	17,215	20,612	16,947	15,507	21,829	23,073	24,297	20,472	17,523	16,332	18,983	232,164
15	C&I Non-Demand	301	261	288	228	234	267	337	338	282	246	248	273	3,303
16	C&I Demand Non-TOD	4,942	4,620	5,212	4,805	4,715	19,258	6,950	21,589	6,556	6,308	5,476	6,112	96,543
17	C&I Demand On-Peak	9,437	9,694	10,122	9,779	5,464	9,785	11,438	6,146	11,998	12,101	9,165	11,439	116,568
18	C&I Demand Off-Peak	13,675	14,050	14,669	14,172	7,918	14,180	16,577	8,907	17,389	17,536	13,282	16,578	168,933
19	Outdoor Lighting	100	94	77	8	126	56	54	41	55	67	69	77	824
20	Total 14+15+16+17+18+19	47,829	45,934	50,980	45,939	33,964	65,375	58,429	61,318	56,752	53,781	44,572	53,462	618,335
	Minnesota FCA Calendar Month Sales:													
21	Residential 7-14	780,409	704,040	675,280	571,144	637,643	992,145	998,891	1,006,577	657,439	623,446	646,210	745,072	9,038,296
22	C&I Non-Demand 8-15	72,115	69,121	69,647	57,458	64,734	72,069	77,597	74,666	62,870	60,443	59,778	67,935	808,433
23	C&I Demand Non-TOD 9-16	680,073	634,996	665,987	589,561	698,216	786,443	856,451	822,811	709,046	723,068	656,945	700,718	8,524,315
24	C&I Demand On-Peak 10-17	270,405	257,344	291,129	274,076	311,965	318,747	350,975	363,396	326,271	327,753	304,251	287,164	3,683,476
25	C&I Demand Off-Peak 11-18	482,301	439,393	473,497	446,334	504,850	536,391	559,797	572,873	517,171	520,846	487,449	484,398	6,025,300
26	Outdoor Lighting 12-19	17,109	6,446	12,380	5,190	8,813	7,058	7,236	7,688	9,484	9,830	12,287	12,528	116,049
27	Total 21+22+23+24+25+26	2,302,412	2,111,340	2,187,920	1,943,763	2,226,221	2,712,853	2,850,947	2,848,011	2,282,281	2,265,386	2,166,920	2,297,815	28,195,869
	Recovery Based on Forecast Factors													
28	Residential 1x21/100	$18,066	$18,397	$18,341	$16,300	$20,634	$35,886	$30,826	$30,318	$19,000	$17,101	$15,987	$17,211	$258,067
29	C&I Non-Demand 2x22/100	$1,690	$1,829	$1,915	$1,661	$2,121	$2,640	$2,425	$2,277	$1,840	$1,679	$1,497	$1,589	$23,163
30	C&I Demand Non-TOD 3x23/100	$15,444	$16,281	$17,749	$16,508	$22,168	$27,903	$25,925	$24,306	$20,109	$19,458	$15,944	$15,878	$237,673
31	C&I Demand On-Peak 4x24/100	$7,677	$8,250	$9,700	$9,593	$12,385	$14,146	$13,288	$13,431	$11,570	$11,026	$9,234	$8,138	$128,438
32	C&I Demand Off-Peak 5x25/100	$8,966	$9,214	$10,322	$10,230	$13,111	$15,566	$13,861	$13,841	$11,998	$11,464	$9,676	$8,981	$137,229
33	Outdoor Lighting 6x26/100	$311	$132	$264	$116	$224	$200	$175	$181	$215	$211	$238	$227	$2,494
34	MN Fuel Recoveries excluding True Up 28+29+30+31+32+33	$52,155	$54,103	$58,291	$54,408	$70,643	$96,341	$86,499	$84,354	$64,732	$60,938	$52,577	$52,024	$787,064
	2021 Under (+)/Over(-) Recovered Expense													
35	Minnesota Actual Fuel Costs (Pt A Att 2) Line 48	$56,824	$29,221	$72,353	$63,269	$74,979	$114,526	$88,957	$82,879	$81,890	$83,094	$74,542	$71,554	$894,089
36	Minnesota Actual Recovery 34	$52,155	$54,103	$58,291	$54,408	$70,643	$96,341	$86,499	$84,354	$64,732	$60,938	$52,577	$52,024	$787,064
37	**2021 Total Under (+)/Over(-) Recovered Exp**	**$4,669**	**($24,882)**	**$14,062**	**$8,862**	**$4,336**	**$18,185**	**$2,458**	**($1,475)**	**$17,158**	**$22,156**	**$21,965**	**$19,530**	**$107,025**

Northern States Power Company (Minnesota)
Electric Utility - State of Minnesota
2020 True-up and 2021 Proposed True-up Factors

	($000)	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021 Total
1a	2020 Under Recovery True Up From Docket No. E002/AA-19-293, January 31, 2020 True-up Filing									$3,842				**$3,842**
1b	2021 Mid-Year True Up From Docket No. E002/AA-20-417, September 28, 2021 True-up Filing										$8,398	$8,398	**$8,398**	**$25,194**
	Recovery Factors ($/kWh)													
1	Residential									0.177¢	0.387¢	0.395¢	0.362¢	
2	C&I Non-Demand									0.179¢	0.392¢	0.400¢	0.367¢	
3	C&I Demand Non-TOD									0.174¢	0.379¢	0.387¢	0.355¢	
4	C&I Demand On-Peak									0.217¢	0.474¢	0.484¢	0.445¢	
5	C&I Demand Off-Peak									0.142¢	0.310¢	0.317¢	0.291¢	
6	Outdoor Lighting									0.139¢	0.303¢	0.309¢	0.284¢	
	Minnesota FCA Calendar Month Sales													
7	Residential									657,439	623,446	646,210	745,072	2,672,167
8	C&I Non-Demand									62,870	60,443	59,778	67,935	251,026
9	C&I Demand Non-TOD									709,046	723,068	656,945	700,718	2,789,777
10	C&I Demand On-Peak									326,271	327,753	304,251	287,164	1,245,439
11	C&I Demand Off-Peak									517,171	520,846	487,449	484,398	2,009,864
12	Outdoor Lighting									9,484	9,830	12,287	12,528	44,129
13	Total 7+8+9+10+11+12									2,282,281	2,265,386	2,166,920	2,297,815	**9,012,402**
	Actual Recovered Amount													
14	Residential 2x8/1000									$1,164	$2,413	$2,553	$2,697	$8,826
15	C&I Non-Demand 3x9/1000									$113	$237	$239	$249	$838
16	C&I Demand Non-TOD 4x10/1000									$1,234	$2,740	$2,542	$2,488	$9,004
17	C&I Demand On-Peak 5x11/1000									$708	$1,554	$1,473	$1,278	$5,012
18	C&I Demand Off-Peak 6x12/1000									$734	$1,615	$1,545	$1,410	$5,304
19	Outdoor Lighting 7x13/1000									$13	$30	$38	$36	$117
20	Total 14+15+16+17+18+19									$3,966	$8,588	$8,390	$8,157	**$29,100**
21	**2021 Under (+)/Over(-) Recovered Expense**									$124	$8,588	$8,390	$8,157	**$25,259**

	2021 Net Under (+)/Over (-) Recovery	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021 Total
22	2021 Total Under (+)/Over(-) Recovery (Pt A Att 4) Line 37	$4,669	($24,882)	$14,062	$8,862	$4,336	$18,185	$2,458	($1,475)	$17,158	$22,156	$21,965	$19,530	$107,025
23	2021 Total Recovered Under (+)/Over(-) Recovery 21	$0	$0	$0	$0	$0	$0	$0	$0	$124	$8,588	$8,390	$8,157	$25,259
24	**2021 Net Under (+)/Over (-) Recovery 22+23**	**$4,669**	**($24,882)**	**$14,062**	**$8,862**	**$4,336**	**$18,185**	**$2,458**	**($1,475)**	**$17,034**	**$13,568**	**$13,576**	**$11,373**	**$81,766**

	Proposed True Up Recovery to be Included in September 2022 - August 2023 FCA Factors	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Total
25	Recovery Amount ($000)	$6,814	$6,814	$6,814	$6,814	$6,814	$6,814	$6,814	$6,814	$6,814	$6,814	$6,814	$6,814	**$81,766**
26	Forecasted 2022/2023 MN Retail MWh Sales Subject to FCA	2,139,085	2,085,175	2,037,664	2,241,107	2,279,951	1,969,493	2,232,053	1,943,844	2,072,168	2,264,038	2,608,556	2,539,021	
27	Proposed True Up Factor ($/kWh)	**$0.00319**	**$0.00327**	**$0.00334**	**$0.00304**	**$0.00299**	**$0.00346**	**$0.00305**	**$0.00351**	**$0.00329**	**$0.00301**	**$0.00261**	**$0.00268**	
	FAF Ratio													
28	Residential	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	
29	C&I Non-Demand	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	
30	C&I Demand Non-TOD	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	
31	C&I Demand On-Peak	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	
32	C&I Demand Off-Peak	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	
33	Outdoor Lighting	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	
	Proposed True Up Factor by Class Category													
34	Residential	**$0.00325**	**$0.00333**	**$0.00340**	**$0.00309**	**$0.00304**	**$0.00352**	**$0.00310**	**$0.00357**	**$0.00335**	**$0.00306**	**$0.00266**	**$0.00273**	
35	C&I Non-Demand	**$0.00329**	**$0.00337**	**$0.00344**	**$0.00313**	**$0.00308**	**$0.00357**	**$0.00314**	**$0.00362**	**$0.00339**	**$0.00310**	**$0.00269**	**$0.00276**	
36	C&I Demand Non-TOD	**$0.00318**	**$0.00326**	**$0.00333**	**$0.00304**	**$0.00299**	**$0.00345**	**$0.00305**	**$0.00350**	**$0.00328**	**$0.00301**	**$0.00261**	**$0.00268**	
37	C&I Demand On-Peak	**$0.00398**	**$0.00408**	**$0.00417**	**$0.00380**	**$0.00373**	**$0.00432**	**$0.00381**	**$0.00438**	**$0.00411**	**$0.00376**	**$0.00326**	**$0.00335**	
38	C&I Demand Off-Peak	**$0.00260**	**$0.00267**	**$0.00273**	**$0.00248**	**$0.00244**	**$0.00283**	**$0.00249**	**$0.00287**	**$0.00269**	**$0.00246**	**$0.00213**	**$0.00219**	
39	Outdoor Lighting	**$0.00254**	**$0.00261**	**$0.00266**	**$0.00242**	**$0.00238**	**$0.00276**	**$0.00243**	**$0.00280**	**$0.00262**	**$0.00240**	**$0.00208**	**$0.00214**	
	Forecast Fuel Cost Factors													
40	Residential	$0.03328	$0.03116	$0.02891	$0.02662									
41	C&I Non-Demand	$0.03369	$0.03155	$0.02927	$0.02696									
42	C&I Demand Non-TOD	$0.03265	$0.03057	$0.02836	$0.02612									
43	C&I Demand On-Peak	$0.04081	$0.03822	$0.03546	$0.03265									
44	C&I Demand Off-Peak	$0.02671	$0.02501	$0.02320	$0.02138									
45	Outdoor Lighting	$0.02609	$0.02443	$0.02266	$0.02088									
	Forecast Fuel Cost Factors With 2021 True Up													
46	Residential	**$0.03653**	**$0.03449**	**$0.03231**	**$0.02971**									
47	C&I Non-Demand	**$0.03698**	**$0.03492**	**$0.03271**	**$0.03009**									
48	C&I Demand Non-TOD	**$0.03583**	**$0.03383**	**$0.03169**	**$0.02916**									
49	C&I Demand On-Peak	**$0.04479**	**$0.04230**	**$0.03963**	**$0.03645**									
50	C&I Demand Off-Peak	**$0.02931**	**$0.02768**	**$0.02593**	**$0.02386**									
51	Outdoor Lighting	**$0.02863**	**$0.02704**	**$0.02532**	**$0.02330**									

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

		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021 Total
	Own Generation													
	Fossil Fuel													
1	Coal	782.0	1,273.4	436.3	294.0	404.7	1,045.6	1,209.1	1,315.8	724.9	635.6	350.8	792.8	9,265.0
2	Wood/RDF	47.4	35.1	34.5	42.1	50.7	47.2	49.2	47.3	36.6	47.4	49.7	46.7	533.8
3	Natural Gas CC	569.2	348.6	223.8	271.0	451.3	528.2	683.6	656.5	432.9	730.3	601.9	603.3	6,100.6
4	Natural Gas & Oil CT	2.9	55.1	26.4	81.1	84.3	153.8	125.2	124.5	46.7	102.7	25.9	14.0	842.6
5	Subtotal	1,401.5	1,712.2	720.9	688.2	990.9	1,774.8	2,067.1	2,144.1	1,241.1	1,516.0	1,028.3	1,456.8	16,742.1
6	Hydro	62.1	47.3	128.3	129.4	101.3	61.2	55.3	55.7	45.5	51.1	64.7	59.1	861.1
7	Wind	508.5	440.2	652.8	706.9	599.4	481.0	398.1	545.6	620.8	713.1	815.4	782.6	7,264.3
8	Nuclear Fuel	1,308.8	1,183.8	1,266.5	991.9	949.5	1,213.3	1,252.0	1,242.5	1,168.8	899.6	1,276.1	1,315.8	14,068.5
9	Total Fuel 5+6+7+8	3,280.9	3,383.5	2,768.5	2,516.3	2,641.2	3,530.3	3,772.6	3,987.9	3,076.1	3,179.7	3,184.5	3,614.4	38,936.0
	Purchased Energy													
10	LT Purchased Energy (Gas)	315.9	261.2	357.1	257.4	307.4	375.7	448.1	374.5	236.1	285.7	406.4	406.3	4,032.0
11	LT Purchased Energy (Solar)	23.4	33.8	56.3	54.4	69.7	81.9	74.6	68.0	59.6	40.9	27.2	19.1	608.9
12	Community Solar*Gardens	74.1	73.7	150.4	97.3	156.4	225.2	160.6	153.4	139.8	95.9	85.7	43.0	1,455.6
13	LT Purchased Energy (Wind)	416.2	323.2	507.4	488.1	410.4	301.8	270.9	357.7	394.8	436.6	551.9	548.6	5,007.6
14	LT Purchased Energy (Other)	130.7	120.2	128.6	119.3	206.3	227.0	228.8	219.9	220.5	200.1	165.4	171.7	2,138.6
15	Total Purchased Energy 10+11+12+13+14	960.3	812.1	1,199.8	1,016.5	1,150.2	1,211.7	1,183.0	1,173.6	1,050.9	1,059.2	1,236.6	1,188.6	13,242.6
16	ST Market Purchase	236.1	125.4	128.8	193.9	254.6	312.7	180.9	140.7	95.5	139.3	145.5	132.4	2,085.8
17	Market Sales	(985.0)	(998.2)	(910.6)	(751.9)	(846.6)	(923.2)	(971.5)	(1,294.3)	(897.0)	(1,125.1)	(1,412.3)	(1,544.1)	(12,659.8)
18	Net Market Cost 16+17	(748.9)	(872.8)	(781.9)	(558.0)	(592.0)	(610.6)	(790.5)	(1,153.6)	(801.5)	(985.8)	(1,266.8)	(1,411.7)	(10,574.0)
19	MISO Cost													
20	Net MISO D2 and ASM Cost 18+19	(748.9)	(872.8)	(781.9)	(558.0)	(592.0)	(610.6)	(790.5)	(1,153.6)	(801.5)	(985.8)	(1,266.8)	(1,411.7)	(10,574.0)
21	**Total System GWh (At Generator) 9+15+20**	3,492.4	3,322.8	3,186.5	2,974.8	3,199.3	4,131.4	4,165.1	4,007.8	3,325.5	3,253.2	3,154.3	3,391.3	41,604.5
22	Less Solar Gardens - Above Market													
23	Less WindSource	(34.8)	(32.0)	(35.2)	(32.3)	(19.4)	(51.5)	(42.2)	(44.1)	(41.0)	(36.7)	(32.8)	(38.5)	(440.6)
24	Less Renewable*Connect	(13.0)	(13.9)	(15.7)	(13.7)	(14.6)	(13.9)	(16.2)	(17.3)	(15.8)	(17.0)	(11.8)	(14.9)	(177.8)
25	Total Costs Direct Assigned 22+23+24	(47.8)	(45.9)	(51.0)	(45.9)	(34.0)	(65.4)	(58.4)	(61.3)	(56.8)	(53.8)	(44.6)	(53.5)	(618.3)
26	**Net System GWh (At Generator) 21+25**	3,444.5	3,276.9	3,135.5	2,928.9	3,165.4	4,066.1	4,106.7	3,946.5	3,268.8	3,199.4	3,109.7	3,337.8	40,986.2

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

		Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021 Total
	Own Generation													
	Fossil Fuel													
1	Coal	$20.85	$19.37	$21.68	$32.08	$15.41	$20.13	$21.26	$19.74	$21.84	$22.06	$24.54	$25.83	$21.34
2	Wood/RDF	$18.67	$23.44	$16.58	$18.67	$14.37	$18.65	$15.73	$15.29	$11.93	$19.19	$14.57	$19.59	$17.15
3	Natural Gas CC	$23.15	$37.36	$34.72	$29.23	$24.23	$23.06	$32.77	$31.43	$36.33	$45.58	$38.48	$25.34	$32.05
4	Natural Gas & Oil CT	$422.56	$146.53	$104.37	$20.53	$50.41	$52.46	$30.31	$36.91	$73.10	$44.44	$93.40	$357.50	$59.13
5	Subtotal	$22.54	$27.21	$28.52	$28.77	$22.35	$23.77	$25.48	$24.22	$28.53	$34.82	$33.95	$28.61	$27.01
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	$7.76	$7.77	$7.80	$7.98	$8.20	$8.05	$8.05	$8.02	$7.91	$7.82	$7.78	$7.82	$7.91
9	Total Fuel	$12.72	$16.49	$10.99	$11.02	$11.33	$14.72	$16.63	$15.52	$14.52	$18.81	$14.08	$14.38	$14.47
	Purchased Energy													
10	LT Purchased Energy (Gas)	$26.33	$41.05	$27.58	$25.80	$27.61	$30.35	$38.49	$37.09	$46.39	$50.73	$44.38	$39.83	$36.27
11	LT Purchased Energy (Solar)	$53.98	$65.06	$70.83	$73.39	$73.61	$73.80	$71.66	$71.65	$72.86	$69.90	$66.94	$54.96	$70.47
12	Community Solar*Gardens	$130.14	$119.90	$125.22	$126.70	$126.05	$128.50	$125.23	$125.97	$128.42	$120.40	$127.46	$127.68	$126.17
13	LT Purchased Energy (Wind)	$35.70	$37.35	$39.26	$31.02	$40.69	$40.13	$35.56	$37.23	$41.29	$42.93	$41.19	$41.13	$38.76
14	LT Purchased Energy (Other)	$75.33	$80.63	$29.69	$119.50	$88.29	$82.20	$84.94	$89.04	$81.83	$84.37	$93.48	$73.11	$82.51
15	Total Purchased Energy	$45.75	$53.59	$47.02	$51.51	$59.33	$63.68	$60.67	$60.49	$64.33	$60.92	$55.78	$48.66	$56.13
16	ST Market Purchase	$22.57	$51.22	$41.45	$18.85	$20.46	$44.56	$30.37	$41.79	$50.00	$68.08	$68.72	$72.68	$40.82
17	Market Sales	$20.71	$62.94	$15.84	$19.35	$22.63	$35.55	$37.47	$36.91	$38.83	$47.43	$37.48	$30.92	$34.53
18	Net Market Cost	$20.12	$64.62	$11.63	$19.52	$23.56	$30.93	$39.09	$36.31	$37.50	$44.51	$33.89	$27.00	$33.29
19	MISO Cost													
20	Net MISO D2 and ASM Cost	$10.51	$68.97	($14.89)	($12.36)	($0.89)	($6.27)	$21.15	$20.73	$3.91	$11.50	$9.14	$7.30	$11.55
21	**Total System $/MWh**	$22.28	$11.77	$30.91	$29.24	$30.85	$32.18	$28.28	$27.19	$32.81	$34.74	$32.41	$29.34	$28.47
22	Less Solar Gardens - Above Market													
23	Less WindSource	$19.25	$19.07	$26.86	$31.81	$72.05	$8.92	$34.51	$31.20	$26.92	$29.35	$34.48	$23.78	$27.62
24	Less Renewable* Connect	$36.38	$32.03	$35.17	$35.36	$35.00	$33.30	$33.68	$36.83	$33.29	$35.96	$34.81	$35.65	$34.82
25	Total Costs Direct Assigned	$148.20	$145.77	$179.56	$164.85	$506.26	$223.80	$256.45	$255.26	$213.68	$165.08	$180.25	$132.67	$208.79
26	**Net System $/MWh**	$20.53	$9.89	$28.49	$27.11	$25.75	$29.10	$25.04	$23.64	$29.67	$32.55	$30.29	$27.68	$25.75

Northern States Power Company
Electric Utility - State of Minnesota
Minnesota Retail Electric 2021 Fuel Cost Charges

	FUEL COST CHARGE ($/kWh)					
	Residential	C&I Non-Demand	C&I Demand			Outdoor Lighting
			Non-TOD	TOD		
				On-Peak	Off-Peak	
2021 Factors						
FAF Ratio *	1.0177	1.0305	0.9984	1.2486	0.8166	0.7976
January	$0.02315	$0.02344	$0.02271	$0.02839	$0.01859	$0.01816
February	$0.02613	$0.02646	$0.02564	$0.03206	$0.02097	$0.02048
March	$0.02716	$0.02750	$0.02665	$0.03332	$0.02180	$0.02129
April	$0.02854	$0.02890	$0.02800	$0.03500	$0.02292	$0.02239
May	$0.03236	$0.03277	$0.03175	$0.03970	$0.02597	$0.02537
June	$0.03617	$0.03663	$0.03548	$0.04438	$0.02902	$0.02834
July	$0.03086	$0.03125	$0.03027	$0.03786	$0.02476	$0.02418
August	$0.03012	$0.03049	$0.02954	$0.03696	$0.02416	$0.02359
September						
Forecast	$0.02890	$0.02927	$0.02836	$0.03546	$0.02320	$0.02266
2020 True Up	$0.00177	$0.00179	$0.00174	$0.00217	$0.00142	$0.00139
Total	$0.03067	$0.03106	$0.03010	$0.03763	$0.02462	$0.02405
October						
Forecast	$0.02743	$0.02777	$0.02691	$0.03364	$0.02201	$0.02150
2021 True Up**	$0.00387	$0.00392	$0.00379	$0.00474	$0.00310	$0.00303
Total	$0.03130	$0.03169	$0.03070	$0.03838	$0.02511	$0.02453
November						
Forecast	$0.02474	$0.02505	$0.02427	$0.03035	$0.01985	$0.01938
2021 True Up**	$0.00395	$0.00400	$0.00387	$0.00484	$0.00317	$0.00309
Total	$0.02869	$0.02905	$0.02814	$0.03519	$0.02302	$0.02247
December						
Forecast	$0.02310	$0.02339	$0.02266	$0.02834	$0.01854	$0.01811
2021 True Up**	$0.00362	$0.00367	$0.00355	$0.00445	$0.00291	$0.00284
Total	$0.02672	$0.02706	$0.02621	$0.03279	$0.02145	$0.02095
YTD Average	**$0.02932**	**$0.02969**	**$0.02877**	**$0.03597**	**$0.02353**	**$0.02298**

* FAF Ratio effective since October 1, 2017. ** 2021 Mid-Year True Up

Redline

FUEL COST FACTORS (2022)

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Demand Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Demand Off-Peak	Outdoor Lighting	
January	$0.02597	$0.02630	$0.02548	$0.03184	$0.02086	$0.02038	~~R~~
February	$0.03066	$0.03104	$0.03008	$0.03761	$0.02460	$0.02403	~~R~~
March	$0.03268	$0.03309	$0.03206	$0.04009	$0.02623	$0.02562	~~R~~
April	$0.03256	$0.03297	$0.03194	$0.03992	$0.02614	$0.02554	~~R~~
May	$0.03453	$0.03496	$0.03387	$0.04234	$0.02772	$0.02708	~~R~~
June	$0.03979	$0.04029	$0.03903	$0.04880	$0.03194	$0.03119	~~R~~
July	$0.03392	$0.03435	$0.03328	$0.04161	$0.02722	$0.02658	~~R~~
August	$0.03386	$0.03428	$0.03321	$0.04154	$0.02716	$0.02653	~~R~~
September	~~$0.03328~~ $0.03653	~~$0.03369~~ $0.03698	~~$0.03265~~ $0.03583	~~$0.04081~~ $0.04479	~~$0.02671~~ $0.02931	~~$0.02609~~ $0.02863	R
October	~~$0.03116~~ $0.03449	~~$0.03155~~ $0.03492	~~$0.03057~~ $0.03383	~~$0.03822~~ $0.04230	~~$0.02501~~ $0.02768	~~$0.02443~~ $0.02704	R
November	~~$0.02891~~ $0.03231	~~$0.02927~~ $0.03271	~~$0.02836~~ $0.03169	~~$0.03546~~ $0.03963	~~$0.02320~~ $0.02593	~~$0.02266~~ $0.02532	R
December	~~$0.02662~~ $0.02971	~~$0.02696~~ $0.03009	~~$0.02612~~ $0.02916	~~$0.03265~~ $0.03645	~~$0.02138~~ $0.02386	~~$0.02088~~ $0.02330	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 and Windsource® Program kWh sales. Qualifying costs are the sum of the following:

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.

2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. All Midwest ISO (MISO) costs and revenues authorized by the Commission to flow through this Fuel Clause Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.

(Continued on Sheet No. 5-91.2)

Clean

FUEL COST FACTORS (2022)

Month	Residential	Commercial & Industrial Non-Demand	Commercial & Industrial Demand Non-TOD	Commercial & Industrial Demand On-Peak	Commercial & Industrial Demand Off-Peak	Outdoor Lighting	
January	$0.02597	$0.02630	$0.02548	$0.03184	$0.02086	$0.02038	
February	$0.03066	$0.03104	$0.03008	$0.03761	$0.02460	$0.02403	
March	$0.03268	$0.03309	$0.03206	$0.04009	$0.02623	$0.02562	
April	$0.03256	$0.03297	$0.03194	$0.03992	$0.02614	$0.02554	
May	$0.03453	$0.03496	$0.03387	$0.04234	$0.02772	$0.02708	
June	$0.03979	$0.04029	$0.03903	$0.04880	$0.03194	$0.03119	
July	$0.03392	$0.03435	$0.03328	$0.04161	$0.02722	$0.02658	
August	$0.03386	$0.03428	$0.03321	$0.04154	$0.02716	$0.02653	
September	$0.03653	$0.03698	$0.03583	$0.04479	$0.02931	$0.02863	R
October	$0.03449	$0.03492	$0.03383	$0.04230	$0.02768	$0.02704	R
November	$0.03231	$0.03271	$0.03169	$0.03963	$0.02593	$0.02532	R
December	$0.02971	$0.03009	$0.02916	$0.03645	$0.02386	$0.02330	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 and Windsource® Program kWh sales. Qualifying costs are the sum of the following:

1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518.

2. The cost of energy purchases as recorded in FERC Account 555, exclusive of capacity or demand charges, irrespective of the designation assigned to such transaction, when such energy is purchased on an economic dispatch basis.

3. All Midwest ISO (MISO) costs and revenues authorized by the Commission to flow through this Fuel Clause Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.

4. All fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expenses recovered in base rates or other riders.

(Continued on Sheet No. 5-91.2)

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 2021 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 2021 AAA 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, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, stated the following: 2021 began with extremely cold weather. The coldest days from February 14-17 were 15 to 35 degrees below normal. Prolonged cold weather led to unusually large outages and derates in the Midwest and the South, with roughly half of the outages and derates categorized as forced outages and fuel supply shortages. Natural gas prices were greatly affected by this cold weather, and gas prices in the Midwest soared from less than $3 per MMBTU to hundreds of dollars at some locations. Spring saw energy

[1] We have reduced the number of detailed MISO reporting formats 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.

price increases of 40 percent relative to spring 2020, attributable to continued high natural gas prices along with average and peak load growth of 4 and 7 percent, respectively. Higher gas prices led to changes in the generation mix; the share of energy produced from coal grew from 27 to 36 percent this year, while the share produced from natural gas resources fell from 37 to 28 percent. A new record wind peak output of 20.7 GW occurred on March 30. The summer months saw hotter than normal temperatures, leading to several Hot Weather Alerts, Capacity Advisories, Conservative Operations and Maximum Generation Alerts. Energy prices for the summer rose 58 percent compared to summer of 2020, as fuel prices and load increased. On June 10, MISO declared a Midwest Maximum Generation Event Step 2 (EEA2). In the fall, average hourly wind output continued to grow, rising by 6 percent compared to last year, and set a new output record of 21.7 GW on November 12. Finally, despite some challenging operational hazards presented by much higher fuel prices and higher than anticipated summer temperatures, throughout the report period, MISO performed market functions well.[2]

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 2021 AAA reporting period and are provided in the following table.

---

[2] MISO Independent Market Monitor (misoenergy.org)

	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Other Market Charge Types	ASM Admin Fees	Net Savings
Jan '21	(50,613,846)	(50,775,638)	161,792	22,393	26,998	112,400
Feb '21	(394,376,477)	(394,663,942)	287,465	15,809	30,011	241,645
Mar '21	(17,675,345)	(18,040,222)	364,877	7,621	15,532	341,724
Apr '21	(19,792,973)	(20,249,212)	456,239	13,327	22,618	420,294
May '21	(39,282,444)	(39,672,826)	390,382	38,461	24,649	327,271
Jun '21	(62,560,687)	(62,912,369)	351,682	(30,528)	27,811	354,400
Jul '21	(76,787,280)	(77,244,383)	457,103	25,580	25,835	405,688
Aug '21	(68,496,418)	(68,709,747)	213,329	83,511	28,095	101,722
Sep '21	(42,330,540)	(42,539,168)	208,628	43,037	22,252	143,339
Oct '21	(54,068,062)	(54,486,136)	418,074	136,770	23,049	258,255
Nov '21	(49,505,031)	(49,801,223)	296,192	237,061	24,222	34,910
Dec '21	(59,341,135)	(59,477,494)	136,359	112,377	31,510	(7,528)

The Company estimates the ASM resulted in total NSP System savings of approximately $2.734 million for the 2021 reporting period. Part B, Attachment 12 provides the ASM daily activity and net savings. The Minnesota jurisdictional allocation of the savings is approximately 75 percent, or $2.05 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 Excessive Deficient Energy Deployment charges 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 MWs and a maximum capability of 400 MWs might be able to operate to 300 MWs with one coal pulverizer in operation, while a generator with a capability between 300 MWs and 400 MWs would require two coal pulverizers to be in operation. The unit might be able to ramp at a rate of 10 MWs/min up to 300 MWs, then slow to 3 MWs/min while the second pulverizer is starting, and then ramp at 5 MWs/min up to 400 MWs. The Company could offer only 3 MWs/min of ramp capability to MISO for dispatch, which would ensure that the unit would be able to follow its dispatch instruction close to 100% 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 MWs/min 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 2021 AAA reporting period, the net benefit for the Company was approximately $2.734 million[3] while the amount incurred in EDEDCs was $0.76 million. The $3.5 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.

[3] The ASM benefits calculated by the Company for 2021 do not include all 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 $61,934 in CRDFC during the 2021 AAA 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% 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
2021 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
January	$ 978,970.85	87.3699%	83.6786%	$ 715,724.70
February	$ 877,945.09	87.3699%	83.6786%	$ 641,864.86
March	$ 1,041,223.26	87.3699%	83.6786%	$ 761,237.38
April	$ 963,635.84	87.3699%	83.6786%	$ 704,513.29
May	$ 1,120,017.08	87.3699%	83.6786%	$ 818,843.47
June	$ 1,356,719.97	87.3699%	83.6786%	$ 991,896.74
July	$ 1,066,565.26	87.3699%	83.6786%	$ 779,764.89
August	$ 1,254,029.07	87.3699%	83.6786%	$ 916,819.51
September	$ 1,169,610.12	87.3699%	83.6786%	$ 855,100.90
October	$ 1,195,345.57	87.3699%	83.6786%	$ 873,916.06
November	$ 905,693.14	87.3699%	83.6786%	$ 662,151.43
December	$ 1,247,487.85	87.3699%	83.6786%	$ 912,037.23
Total	**$ 13,177,243.10**			**$ 9,633,870.46**

*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.

For comparison purposes, we also provide the data for calendar year 2020, below.

Schedule 10 Administrative Charges Paid to MISO Under MISO Tariff
Calendar Year 2020

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
January	$ 772,810.86	87.3247%	83.8543%	$ 565,894.74
February	$ 979,664.29	87.3247%	83.8543%	$ 717,364.23
March	$ 726,909.90	87.3247%	83.8543%	$ 532,283.52
April	$ 990,418.00	87.3247%	83.8543%	$ 725,238.69
May	$ 986,164.65	87.3247%	83.8543%	$ 722,124.15
June	$ 935,744.42	87.3247%	83.8543%	$ 685,203.68
July	$ 984,804.62	87.3247%	83.8543%	$ 721,128.26
August	$ 1,138,434.58	87.3247%	83.8543%	$ 833,624.59
September	$ 856,111.99	87.3247%	83.8543%	$ 626,892.42
October	$ 892,354.51	87.3247%	83.8543%	$ 653,431.19
November	$ 965,488.28	87.3247%	83.8543%	$ 706,983.77
December	$ 1,124,282.02	87.3247%	83.8543%	$ 823,261.31
Total	**$ 11,353,188.12**			**$ 8,313,430.57**

*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) decreased the NSP System allocation to the Company effective January 1, 2021, pursuant to the annual update to the Interchange Agreement allocation factors accepted by FERC in Docket No. ER21-1401-000, letter order dated June 22, 2021.

The State of Minnesota jurisdictional demand allocator (12 month coincident peak demand) increased effective January 1, 2021 based on State of Minnesota demands. The net impact of the decrease in the 2021 Interchange Agreement demand allocator and the increase in the 2021 State of Minnesota jurisdictional demand allocator is an increase in the 2021 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 $1.8 million or approximately 16 percent from 2020 to 2021. The increase is due to (1) the execution of MISO's Market System Enhancement design and implementation; (2) workforce evolution, streamlining, and development; and (3) Customer Experience Program to improve customer service and increase data sharing. In addition, NSP network transmission load increased approximately 4.1 percent from 2020 to 2021.

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 2010-21	
[PROTECTED DATA BEGINS		**Peak**	**Peak Off**
			PROTECTED DATA ENDS]

Generation Node	Load Node	Spring 2021	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Summer 2021	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Fall 2021	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Winter 2021-22	
[PROTECTED DATA BEGINS		Peak	Peak Off
			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

		System	Intersystem	System Retail	Minnesota Retail
	January 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,016,637.64)	$ 18,255,451.21	$ 4,238,813.57	$ 2,997,162.45
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,792,177.16	$ -	$ 2,792,177.16	$ 1,974,280.87
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 458.16	$ -	$ 458.16	$ 323.95
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,764,083.84)	$ -	$ (2,764,083.84)	$ (1,954,416.76)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 166,930.13	$ -	$ 166,930.13	$ 118,032.25
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (458.16)	$ -	$ (458.16)	$ (323.95)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 45,568.97	$ 1,910,806.91	$ 1,956,375.88	$ 1,383,306.02
13 c	Real-Time Asset Energy Amount - Loss Component	$ 7,486.61	$ -	$ 7,486.61	$ 5,293.60
14	Real-Time Distribution of Losses Amount	$ (833,743.05)	$ -	$ (833,743.05)	$ (589,519.52)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 4,466.68	$ -	$ 4,466.68	$ 3,158.28
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 5,450.84	$ -	$ 5,450.84	$ 3,854.16
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (26.14)	$ -	$ (26.14)	$ (18.48)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 5,846,674.82	$ -	$ 5,846,674.82	$ 4,134,042.21
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,011.32	$ -	$ 1,011.32	$ 715.08
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 167,831.77	$ -	$ 167,831.77	$ 118,669.78
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,011.32)	$ -	$ (1,011.32)	$ (715.08)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 53,682.64	$ -	$ 53,682.64	$ 37,957.69
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	$ (61.89)	$ -	$ (61.89)	$ (43.76)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,295,128.45)	$ -	$ (1,295,128.45)	$ (915,753.97)
30	Financial Transmission Rights Monthly Allocation Amount	$ (45,031.42)	$ -	$ (45,031.42)	$ (31,840.63)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (324,720.42)	$ -	$ (324,720.42)	$ (229,601.95)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 178,365.73	$ -	$ 178,365.73	$ 126,118.09
37	Financial Transmission Guarantee Uplift Amount	$ (158,348.63)	$ -	$ (158,348.63)	$ (111,964.48)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 698,709.55	$ -	$ 698,709.55	$ 494,040.61
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 40,571.55	$ -	$ 40,571.55	$ 28,687.16
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (184,241.08)	$ 30,608.18	$ (153,632.90)	$ (108,630.10)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 37,396.59	$ -	$ 37,396.59	$ 26,442.22
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (68,735.05)	$ 24,870.26	$ (43,864.79)	$ (31,015.73)
43	Real Time Price Volatility Make Whole Payment	$ (50,758.60)	$ 24,323.61	$ (26,434.99)	$ (18,691.54)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 615,120.24	$ (68,914.04)	$ 546,206.20	$ 386,209.18
19	Real-Time Market Administration Amount	$ 62,254.43	$ (8,896.95)	$ 53,357.48	$ 37,727.78
29	Financial Transmission Rights Market Administration Amount	$ 24,952.66	$ -	$ 24,952.66	$ 17,643.42
33	Day-Ahead Schedule 24 Allocation Amount	$ 95,570.45	$ (10,669.99)	$ 84,900.46	$ 60,031.06
34	Real -Time Schedule 24 Allocation Amount	$ (86,200.61)	$ 103,694.39	$ 17,493.78	$ 12,369.43
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	$ (5,706.32)	$ 1,486.76	$ (4,219.56)	$ (2,983.55)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,635,397.07	$ -	$ 1,635,397.07	$ 1,156,349.67
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,639,395.05)	$ 33,879.14	$ (1,605,515.91)	$ (1,135,221.43)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (202,829.18)	$ -	$ (202,829.18)	$ (143,415.60)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 22,539.98	$ -	$ 22,539.98	$ 15,937.47
	TOTAL MISO CHARGES	**$ (9,174,499.50)**	**$ 20,296,639.48**	**$ 11,122,139.98**	**$ 7,864,195.89**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 624,516.34**	**$ 441,580.38**
	SCHEDULE 24 (FOR RETAIL)			**$ 102,394.24**	**$ 72,400.49**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 10,395,229.40**	**$ 7,350,215.02**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	February 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (44,980,191.08)	$ 55,500,818.15	$ 10,520,627.07	$ 7,374,539.15
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 7,255,728.08	$ -	$ 7,255,728.08	$ 5,085,975.43
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 17,560.74	$ -	$ 17,560.74	$ 12,309.38
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (7,734,983.00)	$ -	$ (7,734,983.00)	$ (5,421,913.98)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ (506,890.56)	$ -	$ (506,890.56)	$ (355,310.03)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (17,560.74)	$ -	$ (17,560.74)	$ (12,309.38)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (2,825,330.36)	$ 5,776,103.00	$ 2,950,772.64	$ 2,068,373.70
13 c	Real-Time Asset Energy Amount - Loss Component	$ 10,206.24	$ -	$ 10,206.24	$ 7,154.17
14	Real-Time Distribution of Losses Amount	$ (3,687,207.29)	$ -	$ (3,687,207.29)	$ (2,584,584.96)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 1.68	$ -	$ 1.68	$ 1.18
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (1.68)	$ -	$ (1.68)	$ (1.18)
21	Real-time Net inadvertent Distribution	$ 30,397.26	$ -	$ 30,397.26	$ 21,307.26
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 37,210.46	$ -	$ 37,210.46	$ 26,083.05
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (9.64)	$ -	$ (9.64)	$ (6.76)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 7,175,800.61	$ -	$ 7,175,800.61	$ 5,029,949.47
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (35,521.91)	$ -	$ (35,521.91)	$ (24,899.44)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (1,233,557.34)	$ -	$ (1,233,557.34)	$ (864,674.40)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 35,521.91	$ -	$ 35,521.91	$ 24,899.44
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (485,257.36)	$ -	$ (485,257.36)	$ (340,146.02)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 388.71	$ -	$ 388.71	$ 272.47
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (388.71)	$ -	$ (388.71)	$ (272.47)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (22.42)	$ -	$ (22.42)	$ (15.72)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ 62,560.31	$ -	$ 62,560.31	$ 43,852.28
30	Financial Transmission Rights Monthly Allocation Amount	$ (87,106.47)	$ -	$ (87,106.47)	$ (61,058.15)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (8,272.26)	$ -	$ (8,272.26)	$ (5,798.52)
37	Financial Transmission Guarantee Uplift Amount	$ 27,483.00	$ -	$ 27,483.00	$ 19,264.48
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ (3,535,925.54)	$ -	$ (3,535,925.54)	$ (2,478,542.50)
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 581,708.22	$ -	$ 581,708.22	$ 407,754.22
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (100,861.42)	$ 85,820.46	$ (15,040.96)	$ (10,543.11)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 2,297,660.28	$ -	$ 2,297,660.28	$ 1,610,568.04
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (12,024,549.38)	$ 7,593,052.77	$ (4,431,496.61)	$ (3,106,302.03)
43	Real Time Price Volatility Make Whole Payment	$ (523,280.24)	$ 43,637.09	$ (479,643.15)	$ (336,210.68)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 641,194.54	$ (71,803.87)	$ 569,390.67	$ 399,120.11
19	Real-Time Market Administration Amount	$ 64,581.44	$ (13,290.51)	$ 51,290.93	$ 35,952.89
29	Financial Transmission Rights Market Administration Amount	$ 22,576.00	$ -	$ 22,576.00	$ 15,824.87
33	Day-Ahead Schedule 24 Allocation Amount	$ 98,206.73	$ (10,990.28)	$ 87,216.45	$ 61,135.25
34	Real -Time Schedule 24 Allocation Amount	$ (95,126.55)	$ 93,255.69	$ (1,870.86)	$ (1,311.40)
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	$ 2,927.30	$ 1,342.88	$ 4,270.18	$ 2,993.23
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,635,397.07	$ -	$ 1,635,397.07	$ 1,146,347.99
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,639,395.05)	$ 33,896.28	$ (1,605,498.77)	$ (1,125,390.48)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (202,828.97)	$ -	$ (202,828.97)	$ (142,175.00)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 22,539.50	$ -	$ 22,539.50	$ 15,799.29
	TOTAL MISO CHARGES	**$ (59,704,617.89)**	**$ 69,031,841.66**	**$ 9,327,223.77**	**$ 6,538,011.13**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 643,257.60**	**$ 450,897.87**
	SCHEDULE 24 (FOR RETAIL)			**$ 85,345.59**	**$ 59,823.85**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 8,598,620.58**	**$ 6,027,289.41**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	March 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (7,825,350.74)	$ 12,974,811.65	$ 5,149,460.91	$ 3,634,937.43
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,449,937.58	$ -	$ 2,449,937.58	$ 1,729,379.05
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (4,571.15)	$ -	$ (4,571.15)	$ (3,226.72)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,649,740.75)	$ -	$ (2,649,740.75)	$ (1,870,417.51)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 160,574.46	$ -	$ 160,574.46	$ 113,347.42
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 4,571.15	$ -	$ 4,571.15	$ 3,226.72
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 202,708.94	$ 1,340,934.37	$ 1,543,643.31	$ 1,089,637.72
13 c	Real-Time Asset Energy Amount - Loss Component	$ 7,405.16	$ -	$ 7,405.16	$ 5,227.21
14	Real-Time Distribution of Losses Amount	$ 473,842.13	$ -	$ 473,842.13	$ 334,478.99
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 5,138.96	$ -	$ 5,138.96	$ 3,627.52
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 36,491.00	$ -	$ 36,491.00	$ 25,758.52
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (14.85)	$ -	$ (14.85)	$ (10.48)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 9,532,761.15	$ -	$ 9,532,761.15	$ 6,729,052.01
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 558.65	$ -	$ 558.65	$ 394.34
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 255,620.82	$ -	$ 255,620.82	$ 180,439.41
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (558.65)	$ -	$ (558.65)	$ (394.34)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 235,091.59	$ -	$ 235,091.59	$ 165,948.09
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (0.00)	$ -	$ (0.00)	$ (0.00)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 0.00	$ -	$ 0.00	$ 0.00
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (112.19)	$ -	$ (112.19)	$ (79.19)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,564,911.22)	$ -	$ (4,564,911.22)	$ (3,222,311.41)
30	Financial Transmission Rights Monthly Allocation Amount	$ (172,381.16)	$ -	$ (172,381.16)	$ (121,681.62)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (99,092.25)	$ -	$ (99,092.25)	$ (69,947.93)
37	Financial Transmission Guarantee Uplift Amount	$ 93,724.42	$ -	$ 93,724.42	$ 66,158.85
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 2,893,264.89	$ -	$ 2,893,264.89	$ 2,042,318.03
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ (188,545.40)	$ -	$ (188,545.40)	$ (133,091.74)
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (172,381.16)	$ (6,649,907.88)	$ (6,822,289.04)	$ (4,815,765.03)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (376,273.57)	$ -	$ (376,273.57)	$ (265,606.62)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 10,785,612.14	$ 24,170.57	$ 10,809,782.71	$ 7,630,484.91
43	Real Time Price Volatility Make Whole Payment	$ (144,989.30)	$ 37,596.26	$ (107,393.04)	$ (75,807.35)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 435,010.14	$ (49,420.59)	$ 385,589.55	$ 272,182.64
19	Real-Time Market Administration Amount	$ 44,833.83	$ (8,729.40)	$ 36,104.43	$ 25,485.65
29	Financial Transmission Rights Market Administration Amount	$ 22,508.92	$ -	$ 22,508.92	$ 15,888.75
33	Day-Ahead Schedule 24 Allocation Amount	$ 89,402.63	$ (9,904.17)	$ 79,498.46	$ 56,116.93
34	Real -Time Schedule 24 Allocation Amount	$ (78,930.48)	$ 98,587.68	$ 19,657.20	$ 13,875.76
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	$ (14,126.40)	$ 14,641.50	$ 515.10	$ 363.60
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,379,554.71	$ -	$ 2,379,554.71	$ 1,679,696.70
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,379,799.01)	$ 25,880.42	$ (2,353,918.59)	$ (1,661,600.49)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (134,061.22)	$ -	$ (134,061.22)	$ (94,632.07)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 5,619.74	$ -	$ 5,619.74	$ 3,966.90
	TOTAL MISO CHARGES	**$ 11,308,393.51**	**$ 7,798,660.41**	**$ 19,107,053.92**	**$ 13,487,420.66**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 444,202.90**	**$ 313,557.05**
	SCHEDULE 24 (FOR RETAIL)			**$ 99,155.66**	**$ 69,992.69**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 18,563,695.36**	**$ 13,103,870.92**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	April 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (8,516,416.75)	$ 12,134,639.65	$ 3,618,222.90	$ 2,567,723.07
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,745,921.79	$ -	$ 2,745,921.79	$ 1,948,682.24
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 962.40	$ -	$ 962.40	$ 682.98
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,865,209.65)	$ -	$ (2,865,209.65)	$ (2,033,336.56)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 223,005.42	$ -	$ 223,005.42	$ 158,258.95
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 621.35	$ -	$ 621.35	$ 440.95
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (192,337.12)	$ 2,190,168.37	$ 1,997,831.25	$ 1,417,789.21
13 c	Real-Time Asset Energy Amount - Loss Component	$ 4,320.33	$ -	$ 4,320.33	$ 3,065.98
14	Real-Time Distribution of Losses Amount	$ (629,706.81)	$ -	$ (629,706.81)	$ (446,880.35)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (6,260.99)	$ -	$ (6,260.99)	$ (4,443.20)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 32,087.87	$ -	$ 32,087.87	$ 22,771.61
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (4.04)	$ -	$ (4.04)	$ (2.87)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 18,870,742.35	$ -	$ 18,870,742.35	$ 13,391,889.26
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 22,736.97	$ -	$ 22,736.97	$ 16,135.61
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 280,902.29	$ -	$ 280,902.29	$ 199,346.28
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (11,600.84)	$ -	$ (11,600.84)	$ (8,232.70)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (27,979.73)	$ -	$ (27,979.73)	$ (19,856.21)
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	$ (29.47)	$ -	$ (29.47)	$ (20.91)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,442,331.44)	$ -	$ (4,442,331.44)	$ (3,152,563.35)
30	Financial Transmission Rights Monthly Allocation Amount	$ (305,351.77)	$ -	$ (305,351.77)	$ (216,697.20)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (167,653.17)	$ -	$ (167,653.17)	$ (118,977.44)
37	Financial Transmission Guarantee Uplift Amount	$ 171,940.98	$ -	$ 171,940.98	$ 122,020.35
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 999,614.34	$ -	$ 999,614.34	$ 709,390.46
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 81,298.83	$ -	$ 81,298.83	$ 57,694.86
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (155,118.81)	$ 78,107.50	$ (77,011.31)	$ (54,652.17)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 323,706.30	$ -	$ 323,706.30	$ 229,722.76
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (172,649.25)	$ 93,187.04	$ (79,462.21)	$ (56,391.48)
43	Real Time Price Volatility Make Whole Payment	$ (210,202.18)	$ 20,891.46	$ (189,310.72)	$ (134,347.03)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 682,827.56	$ (70,198.64)	$ 612,628.92	$ 434,760.78
19	Real-Time Market Administration Amount	$ 83,621.11	$ (9,397.25)	$ 74,223.86	$ 52,674.01
29	Financial Transmission Rights Market Administration Amount	$ 31,323.66	$ -	$ 31,323.66	$ 22,229.28
33	Day-Ahead Schedule 24 Allocation Amount	$ 91,079.32	$ (9,602.34)	$ 81,476.98	$ 57,821.29
34	Real -Time Schedule 24 Allocation Amount	$ (84,063.93)	$ 81,861.36	$ (2,202.57)	$ (1,563.08)
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	$ (6,336.61)	$ (7,240.36)	$ (13,576.97)	$ (9,635.09)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,379,554.71	$ -	$ 2,379,554.71	$ 1,688,684.66
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,379,799.01)	$ 27,025.80	$ (2,352,773.21)	$ (1,669,678.79)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (134,061.22)	$ -	$ (134,061.22)	$ (95,138.44)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 5,619.74	$ -	$ 5,619.74	$ 3,988.13
	TOTAL MISO CHARGES	**$ 6,724,774.53**	**$ 14,529,442.59**	**$ 21,254,217.12**	**$ 15,083,355.85**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 718,176.44**	**$ 509,664.07**
	SCHEDULE 24 (FOR RETAIL)			**$ 79,274.41**	**$ 56,258.21**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 20,456,766.27**	**$ 14,517,433.57**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	May 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (8,727,304.46)	$ 16,763,601.00	$ 8,036,296.54	$ 5,802,090.54
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,753,105.15	$ -	$ 2,753,105.15	$ 1,987,702.33
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 123.68	$ -	$ 123.68	$ 89.30
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,451,791.77)	$ -	$ (6,451,791.77)	$ (4,658,100.88)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 441,581.15	$ -	$ 441,581.15	$ 318,815.24
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 60.49	$ -	$ 60.49	$ 43.67
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 271,055.48	$ 1,769,481.15	$ 2,040,536.63	$ 1,473,238.10
13 c	Real-Time Asset Energy Amount - Loss Component	$ 31,061.23	$ -	$ 31,061.23	$ 22,425.76
14	Real-Time Distribution of Losses Amount	$ (702,423.16)	$ -	$ (702,423.16)	$ (507,139.42)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 4,934.44	$ -	$ 4,934.44	$ 3,562.59
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 24,583.64	$ -	$ 24,583.64	$ 17,749.03
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 14,961,422.39	$ -	$ 14,961,422.39	$ 10,801,931.82
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 5,290.87	$ -	$ 5,290.87	$ 3,819.93
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 698,253.61	$ -	$ 698,253.61	$ 504,129.07
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (5,310.68)	$ -	$ (5,310.68)	$ (3,834.23)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 17,282.05	$ -	$ 17,282.05	$ 12,477.39
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	$ (3,584,911.84)	$ -	$ (3,584,911.84)	$ (2,588,254.80)
30	Financial Transmission Rights Monthly Allocation Amount	$ (151,677.06)	$ -	$ (151,677.06)	$ (109,508.66)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 130,721.60	$ -	$ 130,721.60	$ 94,379.12
37	Financial Transmission Guarantee Uplift Amount	$ (123,728.78)	$ -	$ (123,728.78)	$ (89,330.40)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 694,539.47	$ -	$ 694,539.47	$ 501,447.51
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 98,289.44	$ -	$ 98,289.44	$ 70,963.56
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (165,172.58)	$ 90,122.35	$ (75,050.23)	$ (54,185.19)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 269,064.79	$ -	$ 269,064.79	$ 194,260.91
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (255,493.70)	$ 124,591.35	$ (130,902.35)	$ (94,509.61)
43	Real Time Price Volatility Make Whole Payment	$ (185,940.71)	$ 23,566.47	$ (162,374.24)	$ (117,231.87)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 548,421.51	$ (75,909.05)	$ 472,512.46	$ 341,147.20
19	Real-Time Market Administration Amount	$ 61,652.66	$ (7,708.54)	$ 53,944.12	$ 38,946.88
29	Financial Transmission Rights Market Administration Amount	$ 18,574.12	$ -	$ 18,574.12	$ 13,410.25
33	Day-Ahead Schedule 24 Allocation Amount	$ 74,939.60	$ (10,350.04)	$ 64,589.56	$ 46,632.73
34	Real -Time Schedule 24 Allocation Amount	$ (90,117.19)	$ 100,007.69	$ 9,890.50	$ 7,140.80
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	$ 15,656.44	$ 29,850.68	$ 45,507.12	$ 32,855.49
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,379,554.71	$ -	$ 2,379,554.71	$ 1,718,004.28
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,379,799.01)	$ 26,300.09	$ (2,353,498.92)	$ (1,699,192.38)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (134,061.22)	$ -	$ (134,061.22)	$ (96,790.27)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 5,619.74	$ -	$ 5,619.74	$ 4,057.37
	TOTAL MISO CHARGES	**$ 548,056.10**	**$ 18,833,553.15**	**$ 19,381,609.25**	**$ 13,993,243.17**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 545,030.70**	**$ 393,504.33**
	SCHEDULE 24 (FOR RETAIL)			**$ 74,480.06**	**$ 53,773.53**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 18,762,098.49**	**$ 13,545,965.31**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	June 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (15,818,710.09)	$ 29,004,008.11	$ 13,185,298.02	$ 9,618,620.84
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,012,658.47	$ -	$ 5,012,658.47	$ 3,656,713.80
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,807.89	$ -	$ 1,807.89	$ 1,318.85
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (10,086,538.85)	$ -	$ (10,086,538.85)	$ (7,358,088.74)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 460,429.13	$ -	$ 460,429.13	$ 335,881.16
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,694.94)	$ -	$ (1,694.94)	$ (1,236.45)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 55,399.89	$ 3,458,040.43	$ 3,513,440.32	$ 2,563,040.31
13 c	Real-Time Asset Energy Amount - Loss Component	$ 15,907.81	$ -	$ 15,907.81	$ 11,604.68
14	Real-Time Distribution of Losses Amount	$ (1,535,171.17)	$ -	$ (1,535,171.17)	$ (1,119,901.07)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (73,797.39)	$ -	$ (73,797.39)	$ (53,834.89)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 22,727.38	$ -	$ 22,727.38	$ 16,579.53
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 190.31	$ -	$ 190.31	$ 138.83
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 25,718,062.67	$ -	$ 25,718,062.67	$ 18,761,221.27
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 94,891.49	$ -	$ 94,891.49	$ 69,222.95
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (474,626.75)	$ -	$ (474,626.75)	$ (346,238.27)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (95,535.43)	$ -	$ (95,535.43)	$ (69,692.70)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (183,852.66)	$ -	$ (183,852.66)	$ (134,119.76)
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	$ (4,022.77)	$ -	$ (4,022.77)	$ (2,934.59)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (5,703,649.41)	$ -	$ (5,703,649.41)	$ (4,160,788.86)
30	Financial Transmission Rights Monthly Allocation Amount	$ (135,194.21)	$ -	$ (135,194.21)	$ (98,623.62)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 36,507.45	$ -	$ 36,507.45	$ 26,632.04
37	Financial Transmission Guarantee Uplift Amount	$ (34,476.93)	$ -	$ (34,476.93)	$ (25,150.78)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,521,239.08	$ -	$ 1,521,239.08	$ 1,109,737.67
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 82,260.14	$ -	$ 82,260.14	$ 60,008.43
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (70,707.96)	$ 6,757,245.81	$ 6,686,537.85	$ 4,877,801.95
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 351,452.58	$ -	$ 351,452.58	$ 256,383.22
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (736,358.10)	$ (6,430,712.15)	$ (7,167,070.25)	$ (5,228,348.36)
43	Real Time Price Volatility Make Whole Payment	$ (203,569.64)	$ 13,259.53	$ (190,310.11)	$ (138,830.44)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 825,853.41	$ (65,034.06)	$ 760,819.35	$ 555,014.60
19	Real-Time Market Administration Amount	$ 75,529.22	$ (8,480.31)	$ 67,048.91	$ 48,911.90
29	Financial Transmission Rights Market Administration Amount	$ 24,870.79	$ -	$ 24,870.79	$ 18,143.14
33	Day-Ahead Schedule 24 Allocation Amount	$ 119,194.58	$ (9,516.39)	$ 109,678.19	$ 80,009.79
34	Real -Time Schedule 24 Allocation Amount	$ (91,217.54)	$ 100,419.05	$ 9,201.51	$ 6,712.46
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	$ (31,440.54)	$ 17,846.19	$ (13,594.35)	$ (9,917.02)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,869,718.20	$ -	$ 2,869,718.20	$ 2,093,447.66
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,879,303.56)	$ 5,702.12	$ (2,873,601.44)	$ (2,096,280.47)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (721,099.72)	$ -	$ (721,099.72)	$ (526,039.29)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 176,935.83	$ -	$ 176,935.83	$ 129,073.96
	TOTAL MISO CHARGES	**$ (1,415,331.34)**	**$ 32,842,778.33**	**$ 31,427,446.99**	**$ 22,926,193.72**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 852,739.05**	**$ 622,069.64**
	SCHEDULE 24 (FOR RETAIL)			**$ 118,879.70**	**$ 86,722.25**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 30,455,828.24**	**$ 22,217,401.83**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System		Intersystem		System Retail		Minnesota Retail
	July 2021 Actual							
	Energy and Loss Charges							
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	(25,052,895.44)	$ 34,397,124.48	$	9,344,229.04	$	6,808,487.27
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	5,382,354.02	$ -	$	5,382,354.02	$	3,921,745.57
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	3,626.01	$ -	$	3,626.01	$	2,642.02
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(10,455,186.11)	$ -	$	(10,455,186.11)	$	(7,617,964.12)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	523,568.11	$ -	$	523,568.11	$	381,487.53
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	(3,660.69)	$ -	$	(3,660.69)	$	(2,667.29)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$ -	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	(2,643,141.11)	$ 1,316,113.51	$	(1,327,027.60)	$	(966,912.36)
13 c	Real-Time Asset Energy Amount - Loss Component	$	68,185.10	$ -	$	68,185.10	$	49,681.72
14	Real-Time Distribution of Losses Amount	$	(2,035,691.96)	$ -	$	(2,035,691.96)	$	(1,483,266.59)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$ -	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$ -	$	-	$	-
21	Real-time Net inadvertent Distribution	$	(89,110.53)	$ -	$	(89,110.53)	$	(64,928.62)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	117,473.37	$ -	$	117,473.37	$	85,594.64
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	-	$ -	$	-	$	-
	Congestion Related Charges							
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	14,026,509.30	$ -	$	14,026,509.30	$	10,220,137.97
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	12,385.35	$ -	$	12,385.35	$	9,024.34
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	31,443.04	$ -	$	31,443.04	$	22,910.35
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(12,234.20)	$ -	$	(12,234.20)	$	(8,914.21)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$ -	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	(56,984.93)	$ -	$	(56,984.93)	$	(41,520.94)
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	$	(3,783,139.82)	$ -	$	(3,783,139.82)	$	(2,756,509.84)
30	Financial Transmission Rights Monthly Allocation Amount	$	(26,444.18)	$ -	$	(26,444.18)	$	(19,268.03)
31	Financial Transmission Rights Transaction Amount	$	-	$ -	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$ -	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	96,332.85	$ -	$	96,332.85	$	70,191.02
37	Financial Transmission Guarantee Uplift Amount	$	(95,905.39)	$ -	$	(95,905.39)	$	(69,879.56)
38	Financial Transmission Rights Monthly Transaction Amount	$	-	$ -	$	-	$	-
	Uplift (RNU) Charges							
23	Real-Time Revenue Neutrality Uplift Amount	$	404,740.51	$ -	$	404,740.51	$	294,906.15
	Revenue Sufficiency Guarantee (RSG) Charges							
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	114,720.83	$ -	$	114,720.83	$	83,589.06
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(34,898.02)	$ 19,837.41	$	(15,060.61)	$	(10,973.61)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	914,878.30	$ -	$	914,878.30	$	666,607.94
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(875,997.76)	$ 257,786.73	$	(618,211.03)	$	(450,447.21)
43	Real Time Price Volatility Make Whole Payment	$	(119,396.10)	$ 28,649.70	$	(90,746.40)	$	(66,120.57)
	Market Administration Charges							
4	Day-Ahead Market Administration Amount	$	618,549.28	$ (62,088.37)	$	556,460.91	$	405,454.21
19	Real-Time Market Administration Amount	$	53,545.13	$ (3,275.79)	$	50,269.34	$	36,627.76
29	Financial Transmission Rights Market Administration Amount	$	24,301.05	$ -	$	24,301.05	$	17,706.48
33	Day-Ahead Schedule 24 Allocation Amount	$	98,264.69	$ (9,792.42)	$	88,472.27	$	64,463.57
34	Real -Time Schedule 24 Allocation Amount	$	(87,176.37)	$ 108,375.86	$	21,199.49	$	15,446.59
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	$	(24,737.82)	$ 137,494.30	$	112,756.48	$	82,157.77
26	Real-Time Uninstructed Deviation Amount	$	-	$ -	$	-	$	-
	Auction Revenue Rights (ARR)							
39	Auction Revenue Rights - FTR Auction Transactions	$	2,869,718.20	$ -	$	2,869,718.20	$	2,090,963.28
40	Auction Revenue Rights - Monthly ARR Revenue	$	(2,879,303.56)	$ 7,409.67	$	(2,871,893.89)	$	(2,092,548.56)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(721,099.72)	$ -	$	(721,099.72)	$	(525,415.02)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	176,935.83	$ -	$	176,935.83	$	128,920.79
	TOTAL MISO CHARGES	$	(23,459,472.74)	$ 36,197,635.08	$	12,738,162.34	$	9,281,409.49
	SCHEDULE 16 & 17 (FOR RETAIL)				$	631,031.30	$	459,788.45
	SCHEDULE 24 (FOR RETAIL)				$	109,671.76	$	79,910.15
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)				$	11,997,459.28	$	8,741,710.89

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	August 2021 Actual				
	Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (33,991,443.64)	$ 43,529,255.15	$ 9,537,811.51	$ 6,970,086.21
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,680,287.48	$ -	$ 5,680,287.48	$ 4,151,066.88
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 0.11	$ -	$ 0.11	$ 0.08
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (9,390,677.14)	$ -	$ (9,390,677.14)	$ (6,862,562.67)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 578,793.92	$ -	$ 578,793.92	$ 422,973.71
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (0.11)	$ -	$ (0.11)	$ (0.08)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,098,316.40)	$ 3,602,996.67	$ 2,504,680.27	$ 1,830,381.88
13 c	Real-Time Asset Energy Amount - Loss Component	$ 97,756.32	$ -	$ 97,756.32	$ 71,438.82
14	Real-Time Distribution of Losses Amount	$ (1,864,583.13)	$ -	$ (1,864,583.13)	$ (1,362,608.72)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 33,797.24	$ -	$ 33,797.24	$ 24,698.50
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 122,125.33	$ -	$ 122,125.33	$ 89,247.32
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
	Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 18,961,792.24	$ -	$ 18,961,792.24	$ 13,856,986.63
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 32,084.57	$ -	$ 32,084.57	$ 23,446.91
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 822,214.97	$ -	$ 822,214.97	$ 600,862.08
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (32,084.57)	$ -	$ (32,084.57)	$ (23,446.91)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 43,140.44	$ -	$ 43,140.44	$ 31,526.37
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	$ (6,092,957.45)	$ -	$ (6,092,957.45)	$ (4,452,639.75)
30	Financial Transmission Rights Monthly Allocation Amount	$ (219,011.77)	$ -	$ (219,011.77)	$ (160,050.44)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (187,062.85)	$ -	$ (187,062.85)	$ (136,702.66)
37	Financial Transmission Guarantee Uplift Amount	$ 182,528.91	$ -	$ 182,528.91	$ 133,389.32
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
	Uplift (RNU) Charges				
23	Real-Time Revenue Neutrality Uplift Amount	$ 241,134.07	$ -	$ 241,134.07	$ 176,217.08
	Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 120,212.82	$ -	$ 120,212.82	$ 87,849.68
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (168,497.95)	$ 35,420.25	$ (133,077.70)	$ (97,251.14)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 539,923.33	$ -	$ 539,923.33	$ 394,567.68
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (736,535.44)	$ 255,242.07	$ (481,293.37)	$ (351,721.81)
43	Real Time Price Volatility Make Whole Payment	$ (518,669.17)	$ 59,701.86	$ (458,967.31)	$ (335,406.26)
	Market Administration Charges				
4	Day-Ahead Market Administration Amount	$ 666,323.60	$ (86,721.87)	$ 579,601.73	$ 423,564.05
19	Real-Time Market Administration Amount	$ 62,387.12	$ (7,331.92)	$ 55,055.20	$ 40,233.49
29	Financial Transmission Rights Market Administration Amount	$ 21,061.38	$ -	$ 21,061.38	$ 15,391.33
33	Day-Ahead Schedule 24 Allocation Amount	$ 106,826.41	$ (13,963.27)	$ 92,863.14	$ 67,862.96
34	Real -Time Schedule 24 Allocation Amount	$ (96,079.67)	$ 89,302.94	$ (6,776.73)	$ (4,952.33)
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	$ (17,342.07)	$ 138,552.66	$ 121,210.59	$ 88,578.84
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
	Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,869,718.20	$ -	$ 2,869,718.20	$ 2,097,146.00
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,879,303.56)	$ 7,650.24	$ (2,871,653.32)	$ (2,098,560.16)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (721,099.72)	$ -	$ (721,099.72)	$ (526,968.60)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 176,935.83	$ -	$ 176,935.83	$ 129,301.99
	TOTAL MISO CHARGES	**$ (26,654,620.35)**	**$ 47,610,104.78**	**$ 20,955,484.43**	**$ 15,313,946.27**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 655,718.31**	**$ 479,188.87**
	SCHEDULE 24 (FOR RETAIL)			**$ 86,086.41**	**$ 62,910.63**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 20,213,679.71**	**$ 14,771,846.78**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	September 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (20,289,009.82)	$ 31,597,807.10	$ 11,308,797.28	$ 8,206,742.78
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,200,423.73	$ -	$ 5,200,423.73	$ 3,773,923.86
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (3,033.09)	$ -	$ (3,033.09)	$ (2,201.10)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ -	$ -	$ -	$ -
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 499,932.63	$ -	$ 499,932.63	$ 362,798.84
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 3,033.09	$ -	$ 3,033.09	$ 2,201.10
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (492,178.41)	$ 2,729,530.87	$ 2,237,352.46	$ 1,623,636.51
13 c	Real-Time Asset Energy Amount - Loss Component	$ 61,941.35	$ -	$ 61,941.35	$ 44,950.56
14	Real-Time Distribution of Losses Amount	$ (1,487,885.67)	$ -	$ (1,487,885.67)	$ (1,079,751.87)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (28,545.77)	$ -	$ (28,545.77)	$ (20,715.54)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 160,254.87	$ -	$ 160,254.87	$ 116,296.23
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 35,440,477.72	$ -	$ 35,440,477.72	$ 25,718,993.59
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 41,854.26	$ -	$ 41,854.26	$ 30,373.45
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 361,652.20	$ -	$ 361,652.20	$ 262,449.36
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (41,854.26)	$ -	$ (41,854.26)	$ (30,373.45)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 79,762.24	$ -	$ 79,762.24	$ 57,883.10
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	$ (13,375,718.57)	$ -	$ (13,375,718.57)	$ (9,706,698.17)
30	Financial Transmission Rights Monthly Allocation Amount	$ (303,401.68)	$ -	$ (303,401.68)	$ (220,177.22)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (860,405.56)	$ -	$ (860,405.56)	$ (624,392.40)
37	Financial Transmission Guarantee Uplift Amount	$ 857,294.93	$ -	$ 857,294.93	$ 622,135.03
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,820,760.18	$ -	$ 1,820,760.18	$ 1,321,317.39
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 118,572.21	$ -	$ 118,572.21	$ 86,047.31
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (288,323.00)	$ 211,269.03	$ (77,053.97)	$ (55,917.72)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 283,126.26	$ -	$ 283,126.26	$ 205,463.44
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (618,442.68)	$ 234,261.12	$ (384,181.56)	$ (278,798.81)
43	Real Time Price Volatility Make Whole Payment	$ (66,200.40)	$ 47,537.15	$ (18,663.25)	$ (13,543.84)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 601,019.33	$ (64,436.86)	$ 536,582.47	$ 389,395.46
19	Real-Time Market Administration Amount	$ 58,202.58	$ (8,945.86)	$ 49,256.72	$ 35,745.38
29	Financial Transmission Rights Market Administration Amount	$ 17,803.32	$ -	$ 17,803.32	$ 12,919.79
33	Day-Ahead Schedule 24 Allocation Amount	$ 99,757.00	$ (10,324.42)	$ 89,432.58	$ 64,900.82
34	Real -Time Schedule 24 Allocation Amount	$ (93,675.82)	$ 111,636.38	$ 17,960.56	$ 13,033.90
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ (8,792,421.66)	$ -	$ (8,792,421.66)	$ (6,380,620.43)
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (22,249.82)	$ 140,286.16	$ 118,036.34	$ 85,658.44
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,988,864.08	$ -	$ 3,988,864.08	$ 2,894,700.53
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,133,122.02)	$ 8,845.89	$ (4,124,276.13)	$ (2,992,968.44)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,039,833.53)	$ -	$ (1,039,833.53)	$ (754,602.47)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 185,508.32	$ -	$ 185,508.32	$ 134,622.54
	TOTAL MISO CHARGES	**$ (2,056,061.46)**	**$ 34,997,466.56**	**$ 32,941,405.10**	**$ 23,905,427.95**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 603,642.51**	**$ 438,060.63**
	SCHEDULE 24 (FOR RETAIL)			**$ 107,393.14**	**$ 77,934.71**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 32,230,369.45**	**$ 23,389,432.61**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	October 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (35,330,735.86)	$ 48,205,048.10	$ 12,874,312.24	$ 9,282,717.54
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,954,389.86	$ -	$ 5,954,389.86	$ 4,293,271.61
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 4,800.20	$ -	$ 4,800.20	$ 3,461.07
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ 317,365.59	$ -	$ 317,365.59	$ 228,828.93
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 384,276.00	$ -	$ 384,276.00	$ 277,073.10
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (4,800.20)	$ -	$ (4,800.20)	$ (3,461.07)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 736,883.44	$ 4,312,786.05	$ 5,049,669.49	$ 3,640,944.44
13 c	Real-Time Asset Energy Amount - Loss Component	$ 30,752.37	$ -	$ 30,752.37	$ 22,173.27
14	Real-Time Distribution of Losses Amount	$ (1,329,827.33)	$ -	$ (1,329,827.33)	$ (958,840.46)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 4.02	$ -	$ 4.02	$ 2.90
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (4.02)	$ -	$ (4.02)	$ (2.90)
21	Real-time Net inadvertent Distribution	$ (108,991.15)	$ -	$ (108,991.15)	$ (78,585.48)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 441,625.34	$ -	$ 441,625.34	$ 318,423.48
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (48.14)	$ -	$ (48.14)	$ (34.71)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 26,498,931.80	$ -	$ 26,498,931.80	$ 19,106,426.39
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 28,735.99	$ -	$ 28,735.99	$ 20,719.40
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ -	$ -	$ -	$ -
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (28,735.99)	$ -	$ (28,735.99)	$ (20,719.40)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 64,250.18	$ -	$ 64,250.18	$ 46,326.07
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (10.78)	$ -	$ (10.78)	$ (7.77)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 10.78	$ -	$ 10.78	$ 7.77
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 119.05	$ -	$ 119.05	$ 85.84
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,732,219.29)	$ -	$ (2,732,219.29)	$ (1,970,001.93)
30	Financial Transmission Rights Monthly Allocation Amount	$ (226,867.25)	$ -	$ (226,867.25)	$ (163,577.25)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (157,972.70)	$ -	$ (157,972.70)	$ (113,902.47)
37	Financial Transmission Guarantee Uplift Amount	$ 124,594.63	$ -	$ 124,594.63	$ 89,836.00
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,294,349.60	$ -	$ 1,294,349.60	$ 933,260.09
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 161,165.12	$ -	$ 161,165.12	$ 116,204.29
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (160,287.50)	$ 91,878.19	$ (68,409.31)	$ (49,324.91)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 636,609.31	$ -	$ 636,609.31	$ 459,012.05
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (476,951.36)	$ 306,140.98	$ (170,810.38)	$ (123,158.77)
43	Real Time Price Volatility Make Whole Payment	$ (198,525.68)	$ 42,105.45	$ (156,420.23)	$ (112,783.10)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 607,995.69	$ (83,311.03)	$ 524,684.66	$ 378,311.43
19	Real-Time Market Administration Amount	$ 65,360.10	$ (8,811.41)	$ 56,548.69	$ 40,773.09
29	Financial Transmission Rights Market Administration Amount	$ 15,946.98	$ -	$ 15,946.98	$ 11,498.19
33	Day-Ahead Schedule 24 Allocation Amount	$ 100,152.23	$ (13,909.05)	$ 86,243.18	$ 62,183.60
34	Real -Time Schedule 24 Allocation Amount	$ (91,346.08)	$ 98,152.34	$ 6,806.26	$ 4,907.49
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ (10,916,122.41)	$ -	$ (10,916,122.41)	$ (7,870,811.20)
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (25,897.00)	$ 85,151.73	$ 59,254.73	$ 42,724.22
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,988,864.08	$ -	$ 3,988,864.08	$ 2,876,075.85
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,133,122.02)	$ 8,833.64	$ (4,124,288.38)	$ (2,973,720.33)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,039,834.13)	$ -	$ (1,039,834.13)	$ (749,747.74)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 185,508.31	$ -	$ 185,508.31	$ 133,756.37
	TOTAL MISO CHARGES	**$ (15,319,608.22)**	**$ 53,044,064.99**	**$ 37,724,456.77**	**$ 27,200,324.97**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 597,180.33**	**$ 430,582.72**
	SCHEDULE 24 (FOR RETAIL)			**$ 93,049.44**	**$ 67,091.09**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 37,034,227.00**	**$ 26,702,651.16**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

Docket No. E002/AA-20-417
True-up Report
Part B, Attachment 2

		System	Intersystem	System Retail	Minnesota Retail
	November 2021 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (36,292,846.86)	$ 47,929,519.11	$ 11,636,672.25	$ 8,302,261.92
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 6,484,772.92	$ -	$ 6,484,772.92	$ 4,626,604.76
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,114.67	$ -	$ 2,114.67	$ 1,508.73
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ 2,279,918.56	$ -	$ 2,279,918.56	$ 1,626,623.20
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (5,453.73)	$ -	$ (5,453.73)	$ (3,891.00)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 669,162.93	$ 4,440,943.70	$ 5,110,106.63	$ 3,645,839.87
13 c	Real-Time Asset Energy Amount - Loss Component	$ 8,159.54	$ -	$ 8,159.54	$ 5,821.48
14	Real-Time Distribution of Losses Amount	$ (1,620,162.77)	$ -	$ (1,620,162.77)	$ (1,155,916.00)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (255,986.51)	$ -	$ (255,986.51)	$ (182,635.29)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 256,632.68	$ -	$ 256,632.68	$ 183,096.31
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (2.68)	$ -	$ (2.68)	$ (1.91)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 25,618,822.24	$ -	$ 25,618,822.24	$ 18,277,920.68
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 28,615.04	$ -	$ 28,615.04	$ 20,415.59
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 518,435.46	$ -	$ 518,435.46	$ 369,881.26
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (26,282.22)	$ -	$ (26,282.22)	$ (18,751.23)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 99,996.41	$ -	$ 99,996.41	$ 71,343.11
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	$ (2.94)	$ -	$ (2.94)	$ (2.10)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (6,585,836.73)	$ -	$ (6,585,836.73)	$ (4,698,709.42)
30	Financial Transmission Rights Monthly Allocation Amount	$ (374,418.97)	$ -	$ (374,418.97)	$ (267,131.73)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (551,313.90)	$ -	$ (551,313.90)	$ (393,338.60)
37	Financial Transmission Guarantee Uplift Amount	$ 485,738.92	$ -	$ 485,738.92	$ 346,553.69
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 3,701,232.91	$ -	$ 3,701,232.91	$ 2,640,669.46
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 177,219.10	$ -	$ 177,219.10	$ 126,438.16
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (434,734.60)	$ 96,481.64	$ (338,252.96)	$ (241,328.84)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 143,002.62	$ -	$ 143,002.62	$ 102,026.18
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (173,483.62)	$ 107,905.60	$ (65,578.02)	$ (46,787.08)
43	Real Time Price Volatility Make Whole Payment	$ (265,501.95)	$ 10,457.94	$ (255,044.01)	$ (181,962.86)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 629,622.76	$ (104,735.48)	$ 524,887.28	$ 374,484.35
19	Real-Time Market Administration Amount	$ 70,215.42	$ (14,153.31)	$ 56,062.11	$ 39,997.89
29	Financial Transmission Rights Market Administration Amount	$ 13,648.58	$ -	$ 13,648.58	$ 9,737.67
33	Day-Ahead Schedule 24 Allocation Amount	$ 95,400.02	$ (16,004.06)	$ 79,395.96	$ 56,645.58
34	Real -Time Schedule 24 Allocation Amount	$ (86,994.08)	$ 100,949.19	$ 13,955.11	$ 9,956.37
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ (8,651,226.24)	$ -	$ (8,651,226.24)	$ (6,172,275.43)
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (28,235.58)	$ 85,151.73	$ 56,916.15	$ 40,607.21
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,988,864.08	$ -	$ 3,988,864.08	$ 2,845,881.85
40	Auction Revenue Rights - Monthly ARR Revenue	$ (4,133,122.02)	$ 9,149.01	$ (4,123,973.01)	$ (2,942,276.22)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (1,039,834.13)	$ -	$ (1,039,834.13)	$ (741,876.64)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 185,508.31	$ -	$ 185,508.31	$ 132,352.15
	TOTAL MISO CHARGES	**$ (15,068,356.36)**	**$ 52,645,665.07**	**$ 37,577,308.71**	**$ 26,809,783.11**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 594,597.97**	**$ 424,219.91**
	SCHEDULE 24 (FOR RETAIL)			**$ 93,351.07**	**$ 66,601.95**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 36,889,359.67**	**$ 26,318,961.25**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	December 2021 Actual				
	Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (40,963,290.42)	$ 44,010,043.28	$ 3,046,752.86	$ 2,145,871.10
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,389,699.33	$ -	$ 5,389,699.33	$ 3,796,041.41
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (130,248.86)	$ -	$ (130,248.86)	$ (91,736.11)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ 775,113.57	$ -	$ 775,113.57	$ 545,923.44
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ (159,088.47)	$ -	$ (159,088.47)	$ (112,048.26)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (7,368.05)	$ -	$ (7,368.05)	$ (5,189.42)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 925,712.24	$ 3,366,475.64	$ 4,292,187.88	$ 3,023,048.59
13 c	Real-Time Asset Energy Amount - Loss Component	$ 6,254.07	$ -	$ 6,254.07	$ 4,404.83
14	Real-Time Distribution of Losses Amount	$ (1,401,227.79)	$ -	$ (1,401,227.79)	$ (986,904.54)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 45,497.88	$ -	$ 45,497.88	$ 32,044.80
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 246,301.24	$ -	$ 246,301.24	$ 173,473.44
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ -	$ -	$ -
	Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 16,498,296.03	$ -	$ 16,498,296.03	$ 11,619,983.07
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (419,258.53)	$ -	$ (419,258.53)	$ (295,289.71)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 119,130.99	$ -	$ 119,130.99	$ 83,905.64
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (89,235.75)	$ -	$ (89,235.75)	$ (62,850.00)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (103,180.01)	$ -	$ (103,180.01)	$ (72,671.14)
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	$ 582,597.95	$ -	$ 582,597.95	$ 410,331.97
30	Financial Transmission Rights Monthly Allocation Amount	$ (180,970.98)	$ -	$ (180,970.98)	$ (127,460.42)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 69,868.59	$ -	$ 69,868.59	$ 49,209.44
37	Financial Transmission Guarantee Uplift Amount	$ (143,064.56)	$ -	$ (143,064.56)	$ (100,762.39)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
	Uplift (RNU) Charges				
23	Real-Time Revenue Neutrality Uplift Amount	$ 356,815.07	$ -	$ 356,815.07	$ 251,309.90
	Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 108,523.40	$ -	$ 108,523.40	$ 76,434.56
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (303,123.52)	$ 110,140.52	$ (192,983.00)	$ (135,920.65)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 135,029.10	$ -	$ 135,029.10	$ 95,102.90
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (110,987.19)	$ 50,412.29	$ (60,574.90)	$ (42,663.76)
43	Real Time Price Volatility Make Whole Payment	$ (94,731.54)	$ 53,129.22	$ (41,602.32)	$ (29,301.10)
	Market Administration Charges				
4	Day-Ahead Market Administration Amount	$ 736,890.70	$ (124,835.94)	$ 612,054.76	$ 431,078.82
19	Real-Time Market Administration Amount	$ 85,186.32	$ (11,106.79)	$ 74,079.53	$ 52,175.26
29	Financial Transmission Rights Market Administration Amount	$ 30,794.15	$ -	$ 30,794.15	$ 21,688.76
33	Day-Ahead Schedule 24 Allocation Amount	$ 104,239.89	$ (17,756.11)	$ 86,483.78	$ 60,911.75
34	Real -Time Schedule 24 Allocation Amount	$ (88,648.71)	$ 90,789.28	$ 2,140.57	$ 1,507.63
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
	Virtual Energy Charges				
12	Day-Ahead Virtual Energy Amount	$ (2,156,036.98)	$ -	$ (2,156,036.98)	$ (1,518,527.32)
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
	Other MISO Charges				
20	Real-Time Miscellaneous Amount	$ 717,303.73	$ 85,151.73	$ 802,455.46	$ 565,180.72
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
	Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,409,766.32	$ -	$ 6,409,766.32	$ 4,514,489.01
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,456,472.05)	$ 19,572.62	$ (6,436,899.43)	$ (4,533,599.24)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (235,898.85)	$ -	$ (235,898.85)	$ (166,146.89)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 76,750.07	$ -	$ 76,750.07	$ 54,056.16
	TOTAL MISO CHARGES	**$ (19,623,061.62)**	**$ 47,632,015.74**	**$ 28,008,954.12**	**$ 19,727,102.25**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 716,928.44**	**$ 504,942.83**
	SCHEDULE 24 (FOR RETAIL)			**$ 88,624.35**	**$ 62,419.38**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 27,203,401.33**	**$ 19,159,740.03**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

January - December 2021 Actual

		System	Intersystem	System Retail	Minnesota Retail
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (291,804,832.80)	$ 394,302,126.99	$ 102,497,294.19	$ 73,526,418.26
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 57,101,455.57	$ -	$ 57,101,455.57	$ 40,961,720.39
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (106,399.24)	$ -	$ (106,399.24)	$ (76,325.48)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (49,025,813.39)	$ -	$ (49,025,813.39)	$ (35,168,659.71)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 2,773,111.92	$ -	$ 2,773,111.92	$ 1,989,291.41
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (32,710.54)	$ -	$ (32,710.54)	$ (23,464.90)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (4,344,811.51)	$ 36,214,380.67	$ 31,869,569.16	$ 22,861,630.55
13 c	Real-Time Asset Energy Amount - Loss Component	$ 349,436.13	$ -	$ 349,436.13	$ 250,667.95
14	Real-Time Distribution of Losses Amount	$ (16,653,788.00)	$ -	$ (16,653,788.00)	$ (11,946,592.27)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 5.70	$ -	$ 5.70	$ 4.09
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (5.70)	$ -	$ (5.70)	$ (4.09)
21	Real-time Net inadvertent Distribution	$ (438,459.88)	$ -	$ (438,459.88)	$ (314,529.13)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 1,502,964.02	$ -	$ 1,502,964.02	$ 1,078,151.01
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 84.82	$ -	$ 84.82	$ 60.85
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 219,150,293.32	$ -	$ 219,150,293.32	$ 157,207,429.30
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (186,615.93)	$ -	$ (186,615.93)	$ (133,868.91)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,547,301.06	$ -	$ 1,547,301.06	$ 1,109,956.18
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (308,922.00)	$ -	$ (308,922.00)	$ (221,605.15)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (264,049.14)	$ -	$ (264,049.14)	$ (189,415.61)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 377.93	$ -	$ 377.93	$ 271.11
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (377.93)	$ -	$ (377.93)	$ (271.11)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (4,132.63)	$ -	$ (4,132.63)	$ (2,964.54)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (51,515,645.96)	$ -	$ (51,515,645.96)	$ (36,954,740.73)
30	Financial Transmission Rights Monthly Allocation Amount	$ (2,227,856.92)	$ -	$ (2,227,856.92)	$ (1,598,152.82)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (324,720.42)	$ -	$ (324,720.42)	$ (232,938.14)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (1,519,976.47)	$ -	$ (1,519,976.47)	$ (1,090,354.89)
37	Financial Transmission Guarantee Uplift Amount	$ 1,387,781.50	$ -	$ 1,387,781.50	$ 995,524.85
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 11,090,474.13	$ -	$ 11,090,474.13	$ 7,955,749.92
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 1,495,996.26	$ -	$ 1,495,996.26	$ 1,073,152.69
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (2,238,347.60)	$ 957,023.46	$ (1,281,324.14)	$ (919,157.68)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 5,555,575.89	$ -	$ 5,555,575.89	$ 3,985,291.51
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (5,464,571.39)	$ 2,640,908.63	$ (2,823,662.76)	$ (2,025,554.05)
43	Real Time Price Volatility Make Whole Payment	$ (2,581,765.51)	$ 404,855.74	$ (2,176,909.77)	$ (1,561,605.89)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 7,608,828.76	$ (927,409.80)	$ 6,681,418.96	$ 4,792,914.87
19	Real-Time Market Administration Amount	$ 787,369.36	$ (110,128.04)	$ 677,241.32	$ 485,818.96
29	Financial Transmission Rights Market Administration Amount	$ 268,361.61	$ -	$ 268,361.61	$ 192,509.16
33	Day-Ahead Schedule 24 Allocation Amount	$ 1,173,033.55	$ (142,782.54)	$ 1,030,251.01	$ 739,050.40
34	Real -Time Schedule 24 Allocation Amount	$ (1,069,577.03)	$ 1,177,031.85	$ 107,454.82	$ 77,082.70
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ (30,515,807.29)	$ -	$ (30,515,807.29)	$ (21,890,509.68)
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 559,815.31	$ 729,715.96	$ 1,289,531.27	$ 925,045.06
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 37,394,971.43	$ -	$ 37,394,971.43	$ 26,825,277.02
40	Auction Revenue Rights - Monthly ARR Revenue	$ (37,911,935.92)	$ 214,144.92	$ (37,697,791.00)	$ (27,042,504.59)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (6,326,541.61)	$ -	$ (6,326,541.61)	$ (4,538,343.65)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 1,226,021.20	$ -	$ 1,226,021.20	$ 879,486.12
	TOTAL MISO CHARGES	**$ (153,894,405.34)**	**$ 435,459,867.84**	**$ 281,565,462.50**	**$ 201,980,941.33**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 7,627,021.89**	**$ 5,471,242.98**
	SCHEDULE 24 (FOR RETAIL)			**$ 1,137,705.83**	**$ 816,133.10**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 272,800,734.78**	**$ 195,693,565.25**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

January 2021	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	(703,460)	$ (5,377,785.68)	161,621	$ 12,877,665.53	(865,081)	$ (18,255,451.21)	-	$ -
5a Day Ahead Non Asset Energy	(106,875)	$ (2,429,321.93)	(106,875)	$ (2,429,321.93)	-	$ -	11,688	$ 255,736.87
13a Real Time Asset Energy	(3,352)	$ 106,738.21	109,253	$ 2,017,545.12	(112,605)	$ (1,910,806.91)	-	$ -
22a Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	(813,687)	$ (7,700,369.40)	163,999	$ 12,465,888.72	(977,686)	$ (20,166,258.12)	11,688	$ 255,736.87
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 458.16	-	$ 458.16	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (833,743.05)	-	$ (833,743.05)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (833,284.89)	-	$ (833,284.89)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 615,120.24	-	$ 546,206.20	-	$ 68,914.04	-	$ 924.19
19 Real Time Market Administration (Schedule 17)	-	$ 62,254.43	-	$ 53,357.48	-	$ 8,896.95	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 24,952.66	-	$ 24,952.66	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 95,570.45	-	$ 84,900.46	-	$ 10,669.99	-	$ 142.56
34 Real -Time Schedule 24 Allocation Amount	-	$ (86,200.61)	-	$ 17,493.78	-	$ (103,694.39)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 711,697.17	-	$ 726,910.58	-	$ (15,213.41)	-	$ 1,066.75
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	-	$ 1,011.32	-	$ 1,011.32	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (1,295,128.45)	-	$ (1,295,128.45)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (45,031.42)	-	$ (45,031.42)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ (324,720.42)	-	$ (324,720.42)	-	$ -	-	$ (11.82)
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ 178,365.73	-	$ 178,365.73	-	$ -	-	$ 11.82
37 Financial Transmission Guarantee Uplift Amount	-	$ (158,348.63)	-	$ (158,348.63)	-	$ -	-	$ 177.01
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (1,643,851.87)	-	$ (1,643,851.87)	-	$ -	-	$ 177.01
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 40,571.55	-	$ 40,571.55	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (184,241.08)	-	$ (153,632.90)	-	$ (30,608.18)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 37,396.59	-	$ 37,396.59	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (68,735.05)	-	$ (43,864.79)	-	$ (24,870.26)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (50,758.60)	-	$ (26,434.99)	-	$ (24,323.61)	-	$ -
SUBTOTAL	-	$ (225,766.59)	-	$ (145,964.54)	-	$ (79,802.05)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ (343.49)	-	$ 1,143.27	-	$ (1,486.76)	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ 4,466.68	-	$ 4,466.68	-	$ -	-	$ 3.09
23 Real Time Revenue Neutrality Uplift Amount	-	$ 698,709.55	-	$ 698,709.55	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 702,832.74	-	$ 704,319.50	-	$ (1,486.76)	-	$ 3.09
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 1,635,397.07	-	$ 1,635,397.07	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (1,639,395.05)	-	$ (1,605,515.91)	-	$ (33,879.14)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (202,829.18)	-	$ (202,829.18)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 22,539.98	-	$ 22,539.98	-	$ -	-	$ -
SUBTOTAL	-	$ (184,287.18)	-	$ (150,408.04)	-	$ (33,879.14)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (1,011.32)	-	$ (1,011.32)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (458.16)	-	$ (458.16)	-	$ -	-	$ -
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	-	$ (1,469.48)	-	$ (1,469.48)	-	$ -	-	$ -
Total MISO Day 2 Charges	(813,687)	$ (9,174,499.50)	163,999	$ 11,122,139.98	(977,686)	$ (20,296,639.48)	11,688	$ 256,983.72
x Net Congestion Amount	-	$ 6,068,127.34	-	$ 6,068,127.34	-	$ -	-	$ -
y Net Loss Amount	-	$ 2,966,567.76	-	$ 2,966,567.76	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (9,034,695.10)	-	$ (9,034,695.10)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(813,687)	$ (9,174,499.50)	163,999	$ 11,122,139.98	(977,686)	$ (20,296,639.48)	11,688	$ 256,983.72

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

February 2021	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	(722,420)	$ (30,548,662.37)	113,575	$ 24,952,155.78	(835,995)	$ (55,500,818.15)	-	$ -
5a Day Ahead Non Asset Energy	(92,097)	$ (9,475,430.91)	(92,097)	$ (9,475,430.91)	-	$ -	10,344	$ 806,634.91
13a Real Time Asset Energy	(32,269)	$ (3,300,381.50)	121,721	$ 2,475,721.50	(153,990)	$ (5,776,103.00)	-	$ -
22a Real Time Non Asset Energy	2	$ 77.72	2	$ 77.72	-	$ -	-	$ -
SUBTOTAL	(846,784)	$ (43,324,397.06)	143,201	$ 17,952,524.09	(989,985)	$ (61,276,921.15)	10,344	$ 806,634.91
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 17,560.74	-	$ 17,560.74	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (3,687,207.29)	-	$ (3,687,207.29)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (3,669,646.55)	-	$ (3,669,646.55)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 641,194.54	-	$ 569,390.67	-	$ 71,803.87	-	$ 891.72
19 Real Time Market Administration (Schedule 17)	-	$ 64,581.44	-	$ 51,290.93	-	$ 13,290.51	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 22,576.00	-	$ 22,576.00	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 98,206.73	-	$ 87,216.45	-	$ 10,990.28	-	$ 135.76
34 Real -Time Schedule 24 Allocation Amount	-	$ (95,126.55)	-	$ (1,870.86)	-	$ (93,255.69)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 731,432.16	-	$ 728,603.19	-	$ 2,828.97	-	$ 1,027.48
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	-	$ (35,521.91)	-	$ (35,521.91)	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ 62,560.31	-	$ 62,560.31	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (87,106.47)	-	$ (87,106.47)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (8,272.26)	-	$ (8,272.26)	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ 27,483.00	-	$ 27,483.00	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (40,857.33)	-	$ (40,857.33)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 581,708.22	-	$ 581,708.22	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (100,861.42)	-	$ (15,040.96)	-	$ (85,820.46)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 2,297,660.28	-	$ 2,297,660.28	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (12,024,549.38)	-	$ (4,431,496.61)	-	$ (7,593,052.77)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (523,280.24)	-	$ (479,643.15)	-	$ (43,637.09)	-	$ -
SUBTOTAL	-	$ (9,769,322.54)	-	$ (2,046,812.22)	-	$ (7,722,510.32)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 40,027.98	-	$ 41,370.86	-	$ (1,342.88)	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ 30,397.26	-	$ 30,397.26	-	$ -	-	$ 38.35
23 Real Time Revenue Neutrality Uplift Amount	-	$ (3,535,925.54)	-	$ (3,535,925.54)	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (3,465,500.30)	-	$ (3,464,157.42)	-	$ (1,342.88)	-	$ 38.35
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 1,635,397.07	-	$ 1,635,397.07	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (1,639,395.05)	-	$ (1,605,498.77)	-	$ (33,896.28)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (202,828.97)	-	$ (202,828.97)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 22,539.50	-	$ 22,539.50	-	$ -	-	$ -
SUBTOTAL	-	$ (184,287.45)	-	$ (150,391.17)	-	$ (33,896.28)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ 35,521.91	-	$ 35,521.91	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (17,560.74)	-	$ (17,560.74)	-	$ -	-	$ -
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	-	$ 17,961.17	-	$ 17,961.17	-	$ -	-	$ -
Total MISO Day 2 Charges	(846,784)	$ (59,704,617.90)	143,201	$ 9,327,223.76	(989,985)	$ (69,031,841.66)	10,344	$ 807,700.74
x Net Congestion Amount	-	$ 5,456,963.49	-	$ 5,456,963.49	-	$ -	-	$ -
y Net Loss Amount	-	$ 6,759,034.12	-	$ 6,759,034.12	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (12,215,997.61)	-	$ (12,215,997.61)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(846,784)	$ (59,704,617.90)	143,201	$ 9,327,223.76	(989,985)	$ (69,031,841.66)	10,344	$ 807,700.74

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

March 2021		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	(683,676)	$ 4,157,347.96	82,878	$ 17,132,159.61	(766,554)	$ (12,974,811.65)	-	$ -
5a	Day Ahead Non Asset Energy	(103,614)	$ (2,233,545.46)	(103,614)	$ (2,233,545.46)	-	$ -	12,845	$ 238,051.42
13a	Real Time Asset Energy	10,393	$ 445,205.69	154,091	$ 1,786,140.06	(143,698)	$ (1,340,934.37)	-	$ -
22a	Real Time Non Asset Energy	(9)	$ (4.01)	(9)	$ (4.01)	-	$ -	-	$ -
	SUBTOTAL	(776,906)	$ 2,369,004.18	133,346	$ 16,684,750.20	(910,252)	$ (14,315,746.02)	12,845	$ 238,051.42
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c	Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (4,571.15)	-	$ (4,571.15)	-	$ -	-	$ -
13c	Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c	Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14	Real Time Distribution Losses	-	$ 473,842.13	-	$ 473,842.13	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 469,270.98	-	$ 469,270.98	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 435,010.14	-	$ 385,589.55	-	$ 49,420.59	-	$ 814.09
19	Real Time Market Administration (Schedule 17)	-	$ 44,833.83	-	$ 36,104.43	-	$ 8,729.40	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 22,508.92	-	$ 22,508.92	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 89,402.63	-	$ 79,498.46	-	$ 9,904.17	-	$ 168.09
34	Real -Time Schedule 24 Allocation Amount	-	$ (78,930.48)	-	$ 19,657.20	-	$ (98,587.68)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 512,825.04	-	$ 543,358.56	-	$ (30,533.52)	-	$ 982.18
	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	-	$ 558.65	-	$ 558.65	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ (4,564,911.22)	-	$ (4,564,911.22)	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (172,381.16)	-	$ (172,381.16)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ (99,092.25)	-	$ (99,092.25)	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ 93,724.42	-	$ 93,724.42	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (4,742,101.56)	-	$ (4,742,101.56)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ (188,545.40)	-	$ (202,657.39)	-	$ 14,111.99	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (172,381.16)	-	$ (6,822,289.04)	-	$ 6,649,907.88	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ (376,273.57)	-	$ (384,742.59)	-	$ 8,469.02	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ 10,785,612.14	-	$ 10,809,782.71	-	$ (24,170.57)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (144,989.30)	-	$ (107,393.04)	-	$ (37,596.26)	-	$ -
	SUBTOTAL	-	$ 9,903,422.71	-	$ 3,292,700.65	-	$ 6,610,722.06	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 22,241.59	-	$ 36,883.09	-	$ (14,641.50)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 5,138.96	-	$ 5,138.96	-	$ -	-	$ 13.69
23	Real Time Revenue Neutrality Uplift Amount	-	$ 2,893,264.89	-	$ 2,821,273.77	-	$ 71,991.12	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 2,920,645.44	-	$ 2,863,295.82	-	$ 57,349.62	-	$ 13.69
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 2,379,554.71	-	$ 2,379,554.71	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (2,379,799.01)	-	$ (2,353,918.59)	-	$ (25,880.42)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (134,061.22)	-	$ (134,061.22)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 5,619.74	-	$ 5,619.74	-	$ -	-	$ -
	SUBTOTAL	-	$ (128,685.78)	-	$ (102,805.36)	-	$ (25,880.42)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (558.65)	-	$ (558.65)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 4,571.15	-	$ 4,571.15	-	$ -	-	$ -
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	-	$ 4,012.50	-	$ 4,012.50	-	$ -	-	$ -
	Total MISO Day 2 Charges	(776,906)	$ 11,308,393.51	133,346	$ 19,012,481.80	(910,252)	$ (7,704,088.29)	12,845	$ 239,047.29
x	Net Congestion Amount	-	$ 10,023,361.37	-	$ 9,695,736.41	-	$ 327,624.96	-	$ -
y	Net Loss Amount	-	$ 2,617,902.35	-	$ 2,098,891.94	-	$ 519,010.41	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (12,641,263.72)	-	$ (12,641,263.72)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ (846,635.37)	-	$ 846,635.37	-	$ -
	Total MISO Day 2 Charges	(776,906)	$ 11,308,393.51	133,346	$ 18,165,846.43	(910,252)	$ (6,857,452.92)	12,845	$ 239,047.29

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

April 2021	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	(596,130)	$ 13,100,247.42	89,286	$ 25,234,887.07	(685,416)	$ (12,134,639.65)	-	$ -
5a Day Ahead Non Asset Energy	(97,940)	$ (2,361,301.93)	(97,940)	$ (2,361,301.93)	-	$ -	14,268	$ 370,289.90
13a Real Time Asset Energy	(5,486)	$ (215,996.53)	74,222	$ 1,974,171.84	(79,707)	$ (2,190,168.37)	-	$ -
22a Real Time Non Asset Energy	18	$ 4.69	18	$ 4.69	-	$ -	-	$ -
SUBTOTAL	(699,537)	$ 10,522,953.65	65,586	$ 24,847,761.67	(765,123)	$ (14,324,808.02)	14,268	$ 370,289.90
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 962.40	-	$ 962.40	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (629,706.81)	-	$ (629,706.81)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (628,744.41)	-	$ (628,744.41)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 682,827.56	-	$ 612,628.92	-	$ 70,198.64	-	$ 1,498.28
19 Real Time Market Administration (Schedule 17)	-	$ 83,621.11	-	$ 74,223.86	-	$ 9,397.25	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 31,323.66	-	$ 31,323.66	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 91,079.32	-	$ 81,476.98	-	$ 9,602.34	-	$ 201.08
34 Real -Time Schedule 24 Allocation Amount	-	$ (84,063.93)	-	$ (2,202.57)	-	$ (81,861.36)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 804,787.72	-	$ 797,450.85	-	$ 7,336.87	-	$ 1,699.36
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	-	$ 22,736.97	-	$ 22,736.97	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (4,442,331.44)	-	$ (4,442,331.44)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (305,351.77)	-	$ (305,351.77)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (167,653.17)	-	$ (167,653.17)	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ 171,940.98	-	$ 171,940.98	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (4,720,658.43)	-	$ (4,720,658.43)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 81,298.83	-	$ 81,298.83	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (155,118.81)	-	$ (77,011.31)	-	$ (78,107.50)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 323,706.30	-	$ 323,706.30	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (172,649.25)	-	$ (79,462.21)	-	$ (93,187.04)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (210,202.18)	-	$ (189,310.72)	-	$ (20,891.46)	-	$ -
SUBTOTAL	-	$ (132,965.11)	-	$ 59,220.89	-	$ (192,186.00)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 25,713.05	-	$ 18,472.69	-	$ 7,240.36	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ (6,260.99)	-	$ (6,260.99)	-	$ -	-	$ (10.61)
23 Real Time Revenue Neutrality Uplift Amount	-	$ 999,614.34	-	$ 999,614.34	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 1,019,066.40	-	$ 1,011,826.04	-	$ 7,240.36	-	$ (10.61)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 2,379,554.71	-	$ 2,379,554.71	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (2,379,799.01)	-	$ (2,352,773.21)	-	$ (27,025.80)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (134,061.22)	-	$ (134,061.22)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 5,619.74	-	$ 5,619.74	-	$ -	-	$ -
SUBTOTAL	-	$ (128,685.78)	-	$ (101,659.98)	-	$ (27,025.80)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (11,600.84)	-	$ (11,600.84)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 621.35	-	$ 621.35	-	$ -	-	$ -
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	-	$ (10,979.49)	-	$ (10,979.49)	-	$ -	-	$ -
Total MISO Day 2 Charges	(699,537)	$ 6,724,774.55	65,586	$ 21,254,217.14	(765,123)	$ (14,529,442.59)	14,268	$ 371,978.65
x Net Congestion Amount	-	$ 19,123,635.44	-	$ 19,123,635.44	-	$ -	-	$ -
y Net Loss Amount	-	$ 2,973,243.50	-	$ 2,973,243.50	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (22,096,878.94)	-	$ (22,096,878.94)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(699,537)	$ 6,724,774.55	65,586	$ 21,254,217.14	(765,123)	$ (14,529,442.59)	14,268	$ 371,978.65

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-20-417
True-Up Report
Part B, Attachment 3

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

May 2021	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	(545,336)	$ 8,987,223.10	221,441	$ 25,750,824.10	(766,777)	$ (16,763,601.00)	-	$ -
5a Day Ahead Non Asset Energy	(210,539)	$ (5,311,957.02)	(210,539)	$ (5,311,957.02)	-	$ -	13,735	$ 352,895.27
13a Real Time Asset Energy	16,701	$ 319,398.75	95,222	$ 2,088,879.90	(78,521)	$ (1,769,481.15)	-	$ -
22a Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	(739,173)	$ 3,994,664.83	106,125	$ 22,527,746.98	(845,298)	$ (18,533,082.15)	13,735	$ 352,895.27
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 123.68	-	$ 123.68	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (702,423.16)	-	$ (702,423.16)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (702,299.48)	-	$ (702,299.48)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 548,421.51	-	$ 472,512.46	-	$ 75,909.05	-	$ 1,096.59
19 Real Time Market Administration (Schedule 17)	-	$ 61,652.66	-	$ 53,944.12	-	$ 7,708.54	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 18,574.12	-	$ 18,574.12	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 74,939.60	-	$ 64,589.56	-	$ 10,350.04	-	$ 149.77
34 Real -Time Schedule 24 Allocation Amount	-	$ (90,117.19)	-	$ 9,890.50	-	$ (100,007.69)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 613,470.70	-	$ 619,510.76	-	$ (6,040.06)	-	$ 1,246.36
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	-	$ 5,290.87	-	$ 5,290.87	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (3,584,911.84)	-	$ (3,584,911.84)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (151,677.06)	-	$ (151,677.06)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ 130,721.60	-	$ 130,721.60	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ (123,728.78)	-	$ (123,728.78)	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (3,724,305.21)	-	$ (3,724,305.21)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 98,289.44	-	$ 98,289.44	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (165,172.58)	-	$ (75,050.23)	-	$ (90,122.35)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 269,064.79	-	$ 269,064.79	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (255,493.70)	-	$ (130,902.35)	-	$ (124,591.35)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (185,940.71)	-	$ (162,374.24)	-	$ (23,566.47)	-	$ -
SUBTOTAL	-	$ (239,252.76)	-	$ (972.59)	-	$ (238,280.17)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 40,240.08	-	$ 70,090.76	-	$ (29,850.68)	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ 4,934.44	-	$ 4,934.44	-	$ -	-	$ 1.61
23 Real Time Revenue Neutrality Uplift Amount	-	$ 694,539.47	-	$ 694,539.47	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 739,713.99	-	$ 769,564.67	-	$ (29,850.68)	-	$ 1.61
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 2,379,554.71	-	$ 2,379,554.71	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (2,379,799.01)	-	$ (2,353,498.92)	-	$ (26,300.09)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (134,061.22)	-	$ (134,061.22)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 5,619.74	-	$ 5,619.74	-	$ -	-	$ -
SUBTOTAL	-	$ (128,685.78)	-	$ (102,385.69)	-	$ (26,300.09)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (5,310.68)	-	$ (5,310.68)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 60.49	-	$ 60.49	-	$ -	-	$ -
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	-	$ (5,250.19)	-	$ (5,250.19)	-	$ -	-	$ -
Total MISO Day 2 Charges	(739,173)	$ 548,056.10	106,125	$ 19,381,609.25	(845,298)	$ (18,833,553.15)	13,735	$ 354,143.24
x Net Congestion Amount	-	$ 15,676,958.05	-	$ 15,676,958.05	-	$ -	-	$ -
y Net Loss Amount	-	$ 3,225,747.53	-	$ 3,225,747.53	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (18,902,705.58)	-	$ (18,902,705.58)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(739,173)	$ 548,056.10	106,125	$ 19,381,609.25	(845,298)	$ (18,833,553.15)	13,735	$ 354,143.24

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

June 2021	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	(533,235)	$ 14,912,011.09	273,792	$ 43,916,019.20	(807,027)	$ (29,004,008.11)	-	$ -
5a Day Ahead Non Asset Energy	(232,118)	$ (10,100,736.46)	(232,118)	$ (10,100,736.46)	-	$ -	14,369	$ 581,359.38
13a Real Time Asset Energy	(13,295)	$ (112,544.99)	97,696	$ 3,345,495.44	(110,991)	$ (3,458,040.43)	-	$ -
22a Real Time Non Asset Energy	(469)	$ (33,537.83)	(469)	$ (33,537.83)	-	$ -	-	$ -
SUBTOTAL	(779,117)	$ 4,665,191.81	138,901	$ 37,127,240.35	(918,018)	$ (32,462,048.54)	14,369	$ 581,359.38
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 1,807.89	-	$ 1,807.89	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (1,535,171.17)	-	$ (1,535,171.17)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (1,533,363.28)	-	$ (1,533,363.28)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 825,853.41	-	$ 760,819.35	-	$ 65,034.06	-	$ 1,402.85
19 Real Time Market Administration (Schedule 17)	-	$ 75,529.22	-	$ 67,048.91	-	$ 8,480.31	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 24,870.79	-	$ 24,870.79	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 119,194.58	-	$ 109,678.19	-	$ 9,516.39	-	$ 203.62
34 Real -Time Schedule 24 Allocation Amount	-	$ (91,217.54)	-	$ 9,201.51	-	$ (100,419.05)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 954,230.46	-	$ 971,618.75	-	$ (17,388.29)	-	$ 1,606.47
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	-	$ 94,891.49	-	$ 94,891.49	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (5,703,649.41)	-	$ (5,703,649.41)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (135,194.21)	-	$ (135,194.21)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ 36,507.45	-	$ 36,507.45	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ (34,476.93)	-	$ (34,476.93)	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (5,741,921.61)	-	$ (5,741,921.61)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 82,260.14	-	$ 82,260.14	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (70,707.96)	-	$ 6,686,537.85	-	$ (6,757,245.81)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 351,452.58	-	$ 351,452.58	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (736,358.10)	-	$ (7,167,070.25)	-	$ 6,430,712.15	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (203,569.64)	-	$ (190,310.11)	-	$ (13,259.53)	-	$ -
SUBTOTAL	-	$ (576,922.98)	-	$ (237,129.79)	-	$ (339,793.19)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 20,992.20	-	$ 38,838.39	-	$ (17,846.19)	-	$ (14.01)
21 Real Time Net Inadvertent Distribution	-	$ (73,797.39)	-	$ (73,797.39)	-	$ -	-	$ (105.49)
23 Real Time Revenue Neutrality Uplift Amount	-	$ 1,521,239.08	-	$ 1,521,239.08	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 1,468,433.89	-	$ 1,486,280.08	-	$ (17,846.19)	-	$ (119.50)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 2,869,718.20	-	$ 2,869,718.20	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (2,879,303.56)	-	$ (2,873,601.44)	-	$ (5,702.12)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (721,099.72)	-	$ (721,099.72)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 176,935.83	-	$ 176,935.83	-	$ -	-	$ -
SUBTOTAL	-	$ (553,749.25)	-	$ (548,047.13)	-	$ (5,702.12)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (95,535.43)	-	$ (95,535.43)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (1,694.94)	-	$ (1,694.94)	-	$ -	-	$ -
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	-	$ (97,230.37)	-	$ (97,230.37)	-	$ -	-	$ -
Total MISO Day 2 Charges	(779,117)	$ (1,415,331.33)	138,901	$ 31,427,447.00	(918,018)	$ (32,842,778.33)	14,369	$ 582,846.35
x Net Congestion Amount	-	$ 25,055,560.49	-	$ 25,055,560.49	-	$ -	-	$ -
y Net Loss Amount	-	$ 5,489,185.72	-	$ 5,489,185.72	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (30,544,746.21)	-	$ (30,544,746.21)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(779,117)	$ (1,415,331.33)	138,901	$ 31,427,447.00	(918,018)	$ (32,842,778.33)	14,369	$ 582,846.35

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-20-417
True-Up Report
Part B, Attachment 3

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

July 2021	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	(730,275)	$ (5,644,032.14)	183,637	$ 28,753,092.34	(913,911)	$ (34,397,124.48)	-	$ -
5a Day Ahead Non Asset Energy	(220,957)	$ (9,900,174.95)	(220,957)	$ (9,900,174.95)	-	$ -	16,135	$ 647,796.48
13a Real Time Asset Energy	(75,437)	$ (2,631,940.94)	(21,216)	$ (1,315,827.43)	(54,221)	$ (1,316,113.51)	-	$ -
22a Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	(1,026,669)	$ (18,176,148.03)	(58,537)	$ 17,537,089.96	(968,132)	$ (35,713,237.99)	16,135	$ 647,796.48
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 3,626.01	-	$ 3,626.01	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (2,035,691.96)	-	$ (2,035,691.96)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (2,032,065.95)	-	$ (2,032,065.95)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 618,549.28	-	$ 556,460.91	-	$ 62,088.37	-	$ 1,087.81
19 Real Time Market Administration (Schedule 17)	-	$ 53,545.13	-	$ 50,269.34	-	$ 3,275.79	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 24,301.05	-	$ 24,301.05	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 98,264.69	-	$ 88,472.27	-	$ 9,792.42	-	$ 172.35
34 Real -Time Schedule 24 Allocation Amount	-	$ (87,176.37)	-	$ 21,199.49	-	$ (108,375.86)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 707,483.78	-	$ 740,703.06	-	$ (33,219.28)	-	$ 1,260.16
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	-	$ 12,385.35	-	$ 12,385.35	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (3,783,139.82)	-	$ (3,783,139.82)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (26,444.18)	-	$ (26,444.18)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ 96,332.85	-	$ 96,332.85	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ (95,905.39)	-	$ (95,905.39)	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (3,796,771.19)	-	$ (3,796,771.19)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 114,720.83	-	$ 114,720.83	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (34,898.02)	-	$ (15,060.61)	-	$ (19,837.41)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 914,878.30	-	$ 914,878.30	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (875,997.76)	-	$ (618,211.03)	-	$ (257,786.73)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (119,396.10)	-	$ (90,746.40)	-	$ (28,649.70)	-	$ -
SUBTOTAL	-	$ (692.75)	-	$ 305,581.09	-	$ (306,273.84)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 92,735.55	-	$ 230,229.85	-	$ (137,494.30)	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ (89,110.53)	-	$ (89,110.53)	-	$ -	-	$ (138.86)
23 Real Time Revenue Neutrality Uplift Amount	-	$ 404,740.51	-	$ 404,740.51	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 408,365.53	-	$ 545,859.83	-	$ (137,494.30)	-	$ (138.86)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 2,869,718.20	-	$ 2,869,718.20	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (2,879,303.56)	-	$ (2,871,893.89)	-	$ (7,409.67)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (721,099.72)	-	$ (721,099.72)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 176,935.83	-	$ 176,935.83	-	$ -	-	$ -
SUBTOTAL	-	$ (553,749.25)	-	$ (546,339.58)	-	$ (7,409.67)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (12,234.20)	-	$ (12,234.20)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (3,660.69)	-	$ (3,660.69)	-	$ -	-	$ -
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	-	$ (15,894.89)	-	$ (15,894.89)	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,026,669)	$ (23,459,472.75)	(58,537)	$ 12,738,162.33	(968,132)	$ (36,197,635.08)	16,135	$ 648,917.78
x Net Congestion Amount	-	$ 14,000,967.41	-	$ 14,000,967.41	-	$ -	-	$ -
y Net Loss Amount	-	$ 5,974,107.23	-	$ 5,974,107.23	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (19,975,074.64)	-	$ (19,975,074.64)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,026,669)	$ (23,459,472.75)	(58,537)	$ 12,738,162.33	(968,132)	$ (36,197,635.08)	16,135	$ 648,917.78

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 Docket No. E002/AA-20-417

Electric Operations - State of Minnesota True-Up Report

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES Part B, Attachment 3

August 2021	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	(1,041,859)	$ (9,349,363.88)	150,327	$ 34,179,891.27	(1,192,186)	$ (43,529,255.15)	-	$ -
5a Day Ahead Non Asset Energy	(184,413)	$ (7,989,668.25)	(184,413)	$ (7,989,668.25)	-	$ -	16,956	$ 659,813.67
13a Real Time Asset Energy	(19,778)	$ (957,419.67)	80,220	$ 2,645,577.00	(99,998)	$ (3,602,996.67)	-	$ -
22a Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	(1,246,050)	$ (18,296,451.80)	46,134	$ 28,835,800.02	(1,292,184)	$ (47,132,251.82)	16,956	$ 659,813.67
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 0.11	-	$ 0.11	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (1,864,583.13)	-	$ (1,864,583.13)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (1,864,583.02)	-	$ (1,864,583.02)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 666,323.60	-	$ 579,601.73	-	$ 86,721.87	-	$ 1,234.44
19 Real Time Market Administration (Schedule 17)	-	$ 62,387.12	-	$ 55,055.20	-	$ 7,331.92	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 21,061.38	-	$ 21,061.38	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 106,826.41	-	$ 92,863.14	-	$ 13,963.27	-	$ 196.97
34 Real -Time Schedule 24 Allocation Amount	-	$ (96,079.67)	-	$ (6,776.73)	-	$ (89,302.94)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 760,518.84	-	$ 741,804.72	-	$ 18,714.12	-	$ 1,431.41
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	-	$ 32,084.57	-	$ 32,084.57	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (6,092,957.45)	-	$ (6,092,957.45)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (219,011.77)	-	$ (219,011.77)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (187,062.85)	-	$ (187,062.85)	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ 182,528.91	-	$ 182,528.91	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (6,284,418.59)	-	$ (6,284,418.59)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 120,212.82	-	$ 120,212.82	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (168,497.95)	-	$ (133,077.70)	-	$ (35,420.25)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 539,923.33	-	$ 539,923.33	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (736,535.44)	-	$ (481,293.37)	-	$ (255,242.07)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (518,669.17)	-	$ (458,967.31)	-	$ (59,701.86)	-	$ -
SUBTOTAL	-	$ (763,566.41)	-	$ (413,202.23)	-	$ (350,364.18)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 104,783.26	-	$ 243,335.92	-	$ (138,552.66)	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ 33,797.24	-	$ 33,797.24	-	$ -	-	$ 41.22
23 Real Time Revenue Neutrality Uplift Amount	-	$ 241,134.07	-	$ 241,134.07	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 379,714.57	-	$ 518,267.23	-	$ (138,552.66)	-	$ 41.22
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 2,869,718.20	-	$ 2,869,718.20	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (2,879,303.56)	-	$ (2,871,653.32)	-	$ (7,650.24)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (721,099.72)	-	$ (721,099.72)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 176,935.83	-	$ 176,935.83	-	$ -	-	$ -
SUBTOTAL	-	$ (553,749.25)	-	$ (546,099.01)	-	$ (7,650.24)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (32,084.57)	-	$ (32,084.57)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (0.11)	-	$ (0.11)	-	$ -	-	$ -
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	-	$ (32,084.68)	-	$ (32,084.68)	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,246,050)	$ (26,654,620.34)	46,134	$ 20,955,484.44	(1,292,184)	$ (47,610,104.78)	16,956	$ 661,286.30
x Net Congestion Amount	-	$ 19,827,147.65	-	$ 19,827,147.65	-	$ -	-	$ -
y Net Loss Amount	-	$ 6,356,837.72	-	$ 6,356,837.72	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (26,183,985.37)	-	$ (26,183,985.37)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,246,050)	$ (26,654,620.34)	46,134	$ 20,955,484.44	(1,292,184)	$ (47,610,104.78)	16,956	$ 661,286.30

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

September 2021	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	(620,968)	$ 20,351,891.64	167,276	$ 51,949,698.74	(788,244)	$ (31,597,807.10)	-	$ -
5a Day Ahead Non Asset Energy	(179,332)	$ (7,930,836.84)	(179,332)	$ (7,930,836.84)	-	$ -	14,048	$ 573,779.21
13a Real Time Asset Energy	(11,717)	$ (350,474.82)	95,844	$ 2,379,056.05	(107,561)	$ (2,729,530.87)	-	$ -
22a Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	(812,017)	$ 12,070,579.98	83,788	$ 46,397,917.95	(895,805)	$ (34,327,337.97)	14,048	$ 573,779.21
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ (3,033.09)	-	$ (3,033.09)	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (1,487,885.67)	-	$ (1,487,885.67)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (1,490,918.76)	-	$ (1,490,918.76)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 601,019.33	-	$ 536,582.47	-	$ 64,436.86	-	$ 1,153.56
19 Real Time Market Administration (Schedule 17)	-	$ 58,202.58	-	$ 49,256.72	-	$ 8,945.86	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 17,803.32	-	$ 17,803.32	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 99,757.00	-	$ 89,432.58	-	$ 10,324.42	-	$ 191.11
34 Real -Time Schedule 24 Allocation Amount	-	$ (93,675.82)	-	$ 17,960.56	-	$ (111,636.38)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 683,106.41	-	$ 711,035.65	-	$ (27,929.24)	-	$ 1,344.67
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	-	$ 41,854.26	-	$ 41,854.26	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (13,375,718.57)	-	$ (13,375,718.57)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (303,401.68)	-	$ (303,401.68)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (860,405.56)	-	$ (860,405.56)	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ 857,294.93	-	$ 857,294.93	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (13,640,376.62)	-	$ (13,640,376.62)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 118,572.21	-	$ 118,572.21	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (288,323.00)	-	$ (77,053.97)	-	$ (211,269.03)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 283,126.26	-	$ 283,126.26	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (618,442.68)	-	$ (384,181.56)	-	$ (234,261.12)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (66,200.40)	-	$ (18,663.25)	-	$ (47,537.15)	-	$ -
SUBTOTAL	-	$ (571,267.61)	-	$ (78,200.31)	-	$ (493,067.30)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 138,005.05	-	$ 278,291.21	-	$ (140,286.16)	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ (28,545.77)	-	$ (28,545.77)	-	$ -	-	$ (51.87)
23 Real Time Revenue Neutrality Uplift Amount	-	$ 1,820,760.18	-	$ 1,820,760.18	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 1,930,219.46	-	$ 2,070,505.62	-	$ (140,286.16)	-	$ (51.87)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 3,988,864.08	-	$ 3,988,864.08	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,133,122.02)	-	$ (4,124,276.13)	-	$ (8,845.89)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,039,833.53)	-	$ (1,039,833.53)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 185,508.32	-	$ 185,508.32	-	$ -	-	$ -
SUBTOTAL	-	$ (998,583.15)	-	$ (989,737.26)	-	$ (8,845.89)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (41,854.26)	-	$ (41,854.26)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 3,033.09	-	$ 3,033.09	-	$ -	-	$ -
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	-	$ (38,821.17)	-	$ (38,821.17)	-	$ -	-	$ -
Total MISO Day 2 Charges	(812,017)	$ (2,056,061.46)	83,788	$ 32,941,405.10	(895,805)	$ (34,997,466.56)	14,048	$ 575,072.01
x Net Congestion Amount	-	$ 35,881,892.16	-	$ 35,881,892.16	-	$ -	-	$ -
y Net Loss Amount	-	$ 5,762,297.71	-	$ 5,762,297.71	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (41,644,189.87)	-	$ (41,644,189.87)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(812,017)	$ (2,056,061.46)	83,788	$ 32,941,405.10	(895,805)	$ (34,997,466.56)	14,048	$ 575,072.01

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

October 2021	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	(879,145)	$ (2,877,414.15)	136,822	$ 45,327,633.95	(1,015,967)	$ (48,205,048.10)	-	$ -
5a Day Ahead Non Asset Energy	(200,823)	$ (10,214,480.83)	(200,823)	$ (10,214,480.83)	-	$ -	14,437	$ 786,232.02
13a Real Time Asset Energy	6,857	$ 831,885.96	114,375	$ 5,144,672.01	(107,518)	$ (4,312,786.05)	-	$ -
22a Real Time Non Asset Energy	38	$ 2,351.55	38	$ 2,351.55	-	$ -	-	$ -
SUBTOTAL	(1,073,073)	$ (12,257,657.47)	50,413	$ 40,260,176.68	(1,123,485)	$ (52,517,834.15)	14,437	$ 786,232.02
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 4,800.20	-	$ 4,800.20	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (1,329,827.33)	-	$ (1,329,827.33)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (1,325,027.13)	-	$ (1,325,027.13)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 607,995.69	-	$ 524,684.66	-	$ 83,311.03	-	$ 1,184.14
19 Real Time Market Administration (Schedule 17)	-	$ 65,360.10	-	$ 56,548.69	-	$ 8,811.41	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 15,946.98	-	$ 15,946.98	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 100,152.23	-	$ 86,243.18	-	$ 13,909.05	-	$ 194.97
34 Real -Time Schedule 24 Allocation Amount	-	$ (91,346.08)	-	$ 6,806.26	-	$ (98,152.34)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 698,108.92	-	$ 690,229.77	-	$ 7,879.15	-	$ 1,379.11
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	-	$ 28,735.99	-	$ 28,735.99	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (2,732,219.29)	-	$ (2,732,219.29)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (226,867.25)	-	$ (226,867.25)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (157,972.70)	-	$ (157,972.70)	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ 124,594.63	-	$ 124,594.63	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (2,963,728.62)	-	$ (2,963,728.62)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 161,165.12	-	$ 161,165.12	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (160,287.50)	-	$ (68,409.31)	-	$ (91,878.19)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 636,609.31	-	$ 636,609.31	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (476,951.36)	-	$ (170,810.38)	-	$ (306,140.98)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (198,525.68)	-	$ (156,420.23)	-	$ (42,105.45)	-	$ -
SUBTOTAL	-	$ (37,990.11)	-	$ 402,134.51	-	$ (440,124.62)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 413,447.69	-	$ 498,599.42	-	$ (85,151.73)	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ (108,991.15)	-	$ (108,991.15)	-	$ -	-	$ (184.55)
23 Real Time Revenue Neutrality Uplift Amount	-	$ 1,294,349.60	-	$ 1,294,349.60	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 1,598,806.14	-	$ 1,683,957.87	-	$ (85,151.73)	-	$ (184.55)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 3,988,864.08	-	$ 3,988,864.08	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,133,122.02)	-	$ (4,124,288.38)	-	$ (8,833.64)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,039,834.13)	-	$ (1,039,834.13)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 185,508.31	-	$ 185,508.31	-	$ -	-	$ -
SUBTOTAL	-	$ (998,583.76)	-	$ (989,750.12)	-	$ (8,833.64)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (28,735.99)	-	$ (28,735.99)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (4,800.20)	-	$ (4,800.20)	-	$ -	-	$ -
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	-	$ (33,536.19)	-	$ (33,536.19)	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,073,073)	$ (15,319,608.22)	50,413	$ 37,724,456.77	(1,123,485)	$ (53,044,064.99)	14,437	$ 787,426.58
x Net Congestion Amount	-	$ 26,880,666.62	-	$ 26,880,666.62	-	$ -	-	$ -
y Net Loss Amount	-	$ 6,369,370.09	-	$ 6,369,370.09	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (33,250,036.71)	-	$ (33,250,036.71)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,073,073)	$ (15,319,608.22)	50,413	$ 37,724,456.77	(1,123,485)	$ (53,044,064.99)	14,437	$ 787,426.58

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-20-417
True-Up Report
Part B, Attachment 3

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

November 2021	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	(1,146,141)	$ (4,189,251.70)	97,872	$ 43,740,267.41	(1,244,012)	$ (47,929,519.11)	-	$ -
5a Day Ahead Non Asset Energy	(139,777)	$ (5,852,872.22)	(139,777)	$ (5,852,872.22)	-	$ -	15,485	$ 707,851.55
13a Real Time Asset Energy	17,677	$ 777,318.88	184,936	$ 5,218,262.58	(167,259)	$ (4,440,943.70)	-	$ -
22a Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	(1,268,240)	$ (9,264,805.04)	143,031	$ 43,105,657.77	(1,411,271)	$ (52,370,462.81)	15,485	$ 707,851.55
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ 2,114.67	-	$ 2,114.67	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (1,620,162.77)	-	$ (1,620,162.77)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (1,618,048.10)	-	$ (1,618,048.10)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 629,622.76	-	$ 524,887.28	-	$ 104,735.48	-	$ 1,307.06
19 Real Time Market Administration (Schedule 17)	-	$ 70,215.42	-	$ 56,062.11	-	$ 14,153.31	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 13,648.58	-	$ 13,648.58	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 95,400.02	-	$ 79,395.96	-	$ 16,004.06	-	$ 198.30
34 Real -Time Schedule 24 Allocation Amount	-	$ (86,994.08)	-	$ 13,955.11	-	$ (100,949.19)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 721,892.70	-	$ 687,949.04	-	$ 33,943.66	-	$ 1,505.36
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	-	$ 28,615.04	-	$ 28,615.04	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (6,585,836.73)	-	$ (6,585,836.73)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (374,418.97)	-	$ (374,418.97)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (551,313.90)	-	$ (551,313.90)	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ 485,738.92	-	$ 485,738.92	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (6,997,215.64)	-	$ (6,997,215.64)	-	$ -	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 177,219.10	-	$ 177,219.10	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (434,734.60)	-	$ (338,252.96)	-	$ (96,481.64)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 143,002.62	-	$ 143,002.62	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (173,483.62)	-	$ (65,578.02)	-	$ (107,905.60)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (265,501.95)	-	$ (255,044.01)	-	$ (10,457.94)	-	$ -
SUBTOTAL	-	$ (553,498.45)	-	$ (338,653.27)	-	$ (214,845.18)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 228,391.49	-	$ 313,543.22	-	$ (85,151.73)	-	$ -
21 Real Time Net Inadvertent Distribution	-	$ (255,986.51)	-	$ (255,986.51)	-	$ -	-	$ (473.59)
23 Real Time Revenue Neutrality Uplift Amount	-	$ 3,701,232.91	-	$ 3,701,232.91	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 3,673,637.89	-	$ 3,758,789.62	-	$ (85,151.73)	-	$ (473.59)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 3,988,864.08	-	$ 3,988,864.08	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (4,133,122.02)	-	$ (4,123,973.01)	-	$ (9,149.01)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (1,039,834.13)	-	$ (1,039,834.13)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 185,508.31	-	$ 185,508.31	-	$ -	-	$ -
SUBTOTAL	-	$ (998,583.76)	-	$ (989,434.75)	-	$ (9,149.01)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (26,282.22)	-	$ (26,282.22)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (5,453.73)	-	$ (5,453.73)	-	$ -	-	$ -
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	-	$ (31,735.95)	-	$ (31,735.95)	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,268,240)	$ (15,068,356.35)	143,031	$ 37,577,308.72	(1,411,271)	$ (52,645,665.07)	15,485	$ 708,883.32
x Net Congestion Amount	-	$ 27,998,734.27	-	$ 27,998,734.27	-	$ -	-	$ -
y Net Loss Amount	-	$ 7,011,365.24	-	$ 7,011,365.24	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (35,010,099.51)	-	$ (35,010,099.51)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(1,268,240)	$ (15,068,356.35)	143,031	$ 37,577,308.72	(1,411,271)	$ (52,645,665.07)	15,485	$ 708,883.32

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

December 2021		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	(1,403,237)	$ (19,075,295.06)	(2,821,655)	$ 24,934,748.22	1,418,418	$ (44,010,043.28)	-	$ -
5a	Day Ahead Non Asset Energy	(56,635)	$ (1,261,792.41)	(56,635)	$ (1,261,792.41)	-	$ -	17,692	$ 698,707.14
13a	Real Time Asset Energy	22,165	$ 828,786.29	(102,349)	$ 4,195,261.93	124,514	$ (3,366,475.64)	-	$ -
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	(1,437,707)	$ (19,508,301.18)	(2,980,639)	$ 27,868,217.74	1,542,932	$ (47,376,518.92)	17,692	$ 698,707.14
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c	Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3	Day Ahead Financial Bilateral Transaction Loss	-	$ (130,248.86)	-	$ (130,248.86)	-	$ -	-	$ -
13c	Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c	Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14	Real Time Distribution Losses	-	$ (1,401,227.79)	-	$ (1,401,227.79)	-	$ -	-	$ -
16	Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (1,531,476.65)	-	$ (1,531,476.65)	-	$ -	-	$ -
	Virtual Energy								
12	Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27	Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)	-	$ 736,890.70	-	$ 612,054.76	-	$ 124,835.94	-	$ 1,562.01
19	Real Time Market Administration (Schedule 17)	-	$ 85,186.32	-	$ 74,079.53	-	$ 11,106.79	-	$ -
29	Financial Transmission Rights Administration (Schedule 16)	-	$ 30,794.15	-	$ 30,794.15	-	$ -	-	$ -
33	Day-Ahead Schedule 24 Allocation Amount	-	$ 104,239.89	-	$ 86,483.78	-	$ 17,756.11	-	$ 221.39
34	Real -Time Schedule 24 Allocation Amount	-	$ (88,648.71)	-	$ 2,140.57	-	$ (90,789.28)	-	$ -
35	Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 868,462.35	-	$ 805,552.79	-	$ 62,909.56	-	$ 1,783.40
	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	-	$ (419,258.53)	-	$ (419,258.53)	-	$ -	-	$ -
15	Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28	Financial Transmission Rights Hourly Allocation	-	$ 582,597.95	-	$ 582,597.95	-	$ -	-	$ -
30	Financial Transmission Rights Monthly Allocation	-	$ (180,970.98)	-	$ (180,970.98)	-	$ -	-	$ -
32	Financial Transmission Rights Yearly Allocation	-	$ -	-	$ -	-	$ -	-	$ -
31	Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	-	$ 69,868.59	-	$ 69,868.59	-	$ -	-	$ -
37	Financial Transmission Guarantee Uplift Amount	-	$ (143,064.56)	-	$ (143,064.56)	-	$ -	-	$ -
38	Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ (90,827.53)	-	$ (90,827.53)	-	$ -	-	$ -
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 108,523.40	-	$ 108,523.40	-	$ -	-	$ -
11	Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (303,123.52)	-	$ (192,983.00)	-	$ (110,140.52)	-	$ -
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 135,029.10	-	$ 135,029.10	-	$ -	-	$ -
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (110,987.19)	-	$ (60,574.90)	-	$ (50,412.29)	-	$ -
43	Real Time Price Volatility Make Whole Payment	-	$ (94,731.54)	-	$ (41,602.32)	-	$ (53,129.22)	-	$ -
	SUBTOTAL	-	$ (265,289.75)	-	$ (51,607.72)	-	$ (213,682.03)	-	$ -
	Other Charges								
20	Real Time Miscellaneous	-	$ 963,604.97	-	$ 1,048,756.70	-	$ (85,151.73)	-	$ -
21	Real Time Net Inadvertent Distribution	-	$ 45,497.88	-	$ 45,497.88	-	$ -	-	$ 78.39
23	Real Time Revenue Neutrality Uplift Amount	-	$ 356,815.07	-	$ 356,815.07	-	$ -	-	$ -
26	Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
	SUBTOTAL	-	$ 1,365,917.92	-	$ 1,451,069.65	-	$ (85,151.73)	-	$ 78.39
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	-	$ 6,409,766.32	-	$ 6,409,766.32	-	$ -	-	$ -
40	Auction Revenue Rights - Monthly ARR Revenue	-	$ (6,456,472.05)	-	$ (6,436,899.43)	-	$ (19,572.62)	-	$ -
41	Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (235,898.85)	-	$ (235,898.85)	-	$ -	-	$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 76,750.07	-	$ 76,750.07	-	$ -	-	$ -
	SUBTOTAL	-	$ (205,854.51)	-	$ (186,281.89)	-	$ (19,572.62)	-	$ -
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (89,235.75)	-	$ (89,235.75)	-	$ -	-	$ -
7	Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (7,368.05)	-	$ (7,368.05)	-	$ -	-	$ -
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	-	$ (96,603.80)	-	$ (96,603.80)	-	$ -	-	$ -
	Total MISO Day 2 Charges	(1,437,707)	$ (19,463,973.15)	(2,980,639)	$ 28,168,042.59	1,542,932	$ (47,632,015.74)	17,692	$ 700,568.93
x	Net Congestion Amount	-	$ 17,170,229.59	-	$ 17,170,229.59	-	$ -	-	$ -
y	Net Loss Amount	-	$ 5,515,084.39	-	$ 5,515,084.39	-	$ -	-	$ -
z	Net Congestion and Loss Energy Offset	-	$ (22,685,313.98)	-	$ (22,685,313.98)	-	$ -	-	$ -
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	(1,437,707)	$ (19,463,973.15)	(2,980,639)	$ 28,168,042.59	1,542,932	$ (47,632,015.74)	17,692	$ 700,568.93

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

January - December 2021	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	(9,605,882)	$ (15,553,083.77)	(20,905,470)	$ 378,749,043.22	11,299,588	$ (394,302,126.99)	-	$ -
5a Day Ahead Non Asset Energy	(1,825,119)	$ (75,062,119.21)	(1,825,119)	$ (75,062,119.21)	-	$ -	172,000	$ 6,679,147.82
13a Real Time Asset Energy	(87,538)	$ (4,259,424.67)	(1,428,121)	$ 31,954,956.00	1,340,583	$ (36,214,380.67)	-	$ -
22a Real Time Non Asset Energy	(420)	$ (31,107.88)	(420)	$ (31,107.88)	-	$ -	-	$ -
SUBTOTAL	(11,518,959)	$ (94,905,735.53)	(24,159,130)	$ 335,610,772.13	12,640,171	$ (430,516,507.66)	172,000	$ 6,679,147.82
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ -	-	$ -	-	$ -	-	$ -
5c Day Ahead Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ (106,399.24)	-	$ (106,399.24)	-	$ -	-	$ -
13c Real Time Loss	-	$ -	-	$ -	-	$ -	-	$ -
22c Real Time Non Asset Loss	-	$ -	-	$ -	-	$ -	-	$ -
14 Real Time Distribution Losses	-	$ (16,653,788.00)	-	$ (16,653,788.00)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (16,760,187.24)	-	$ (16,760,187.24)	-	$ -	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
27 Real Time Virtual Energy	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 7,608,828.76	-	$ 6,681,418.96	-	$ 927,409.80	-	$ 14,156.74
19 Real Time Market Administration (Schedule 17)	-	$ 787,369.36	-	$ 677,241.32	-	$ 110,128.04	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 268,361.61	-	$ 268,361.61	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 1,173,033.55	-	$ 1,030,251.01	-	$ 142,782.54	-	$ 2,175.97
34 Real -Time Schedule 24 Allocation Amount	-	$ (1,069,577.03)	-	$ 107,454.82	-	$ (1,177,031.85)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 8,768,016.25	-	$ 8,764,727.72	-	$ 3,288.53	-	$ 16,332.71
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	-	$ (186,615.93)	-	$ (186,615.93)	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ -	-	$ -	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (51,515,645.96)	-	$ (51,515,645.96)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (2,227,856.92)	-	$ (2,227,856.92)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ (324,720.42)	-	$ (324,720.42)	-	$ -	-	$ (11.82)
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (1,519,976.47)	-	$ (1,519,976.47)	-	$ -	-	$ 11.82
37 Financial Transmission Guarantee Uplift Amount	-	$ 1,387,781.50	-	$ 1,387,781.50	-	$ -	-	$ 177.01
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ (54,387,034.20)	-	$ (54,387,034.20)	-	$ -	-	$ 177.01
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 1,495,996.26	-	$ 1,495,996.26	-	$ -	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (2,238,347.60)	-	$ (1,281,324.14)	-	$ (957,023.46)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 5,555,575.89	-	$ 5,555,575.89	-	$ -	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (5,464,571.39)	-	$ (2,823,662.76)	-	$ (2,640,908.63)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (2,581,765.51)	-	$ (2,176,909.77)	-	$ (404,855.74)	-	$ -
SUBTOTAL	-	$ (3,233,112.35)	-	$ 769,675.48	-	$ (4,002,787.83)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 2,089,839.42	-	$ 2,819,555.38	-	$ (729,715.96)	-	$ (14.01)
21 Real Time Net Inadvertent Distribution	-	$ (438,459.88)	-	$ (438,459.88)	-	$ -	-	$ (788.62)
23 Real Time Revenue Neutrality Uplift Amount	-	$ 11,090,474.13	-	$ 11,090,474.13	-	$ -	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 12,741,853.67	-	$ 13,471,569.63	-	$ (729,715.96)	-	$ (802.63)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 37,394,971.43	-	$ 37,394,971.43	-	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (37,911,935.92)	-	$ (37,697,791.00)	-	$ (214,144.92)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (6,326,541.61)	-	$ (6,326,541.61)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 1,226,021.20	-	$ 1,226,021.20	-	$ -	-	$ -
SUBTOTAL	-	$ (5,617,484.90)	-	$ (5,403,339.98)	-	$ (214,144.92)	-	$ -
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (308,922.00)	-	$ (308,922.00)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ (32,710.54)	-	$ (32,710.54)	-	$ -	-	$ -
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	-	$ (341,632.54)	-	$ (341,632.54)	-	$ -	-	$ -
Total MISO Day 2 Charges	(11,518,959)	$ (153,735,316.84)	(24,159,130)	$ 281,724,551.00	12,640,171	$ (435,459,867.84)	172,000	$ 6,694,854.91
x Net Congestion Amount	-	$ 223,164,243.88	-	$ 223,164,243.88	-	$ -	-	$ -
y Net Loss Amount	-	$ 61,020,743.36	-	$ 61,020,743.36	-	$ -	-	$ -
z Net Congestion and Loss Energy Offset	-	$ (284,184,987.24)	-	$ (284,184,987.24)	-	$ -	-	$ -
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO Day 2 Charges	(11,518,959)	$ (153,735,316.84)	(24,159,130)	$ 281,724,551.00	12,640,171	$ (435,459,867.84)	172,000	$ 6,694,854.91

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 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (107,521.87)		$ (107,521.87)	$ (76,026.11)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (153,895.77)		$ (153,895.77)	$ (108,815.97)
3	Day-Ahead Supplemental Reserve	$ (13,394.14)		$ (13,394.14)	$ (9,470.67)
4	Real-Time Regulation Amount (See Note 1)	$ (13,550.57)	$ 16,491.89	$ 2,941.32	$ 2,079.74
5	Real-Time Spinning Reserve Amount	$ (24,990.56)	$ 111,837.33	$ 86,846.77	$ 61,407.25
6	Real-Time Supplemental Reserve Amount.	$ 7.39	$ 2,982.62	$ 2,990.01	$ 2,114.16
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (2,888.10)		$ (2,888.10)	$ (2,042.11)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,574,764.76		$ 1,574,764.76	$ 1,113,478.03
8b	Real Time Non Excessive Energy Congestion	$ 173,023.50	$ -	$ 173,023.50	$ 122,340.73
8c	Real Time Non Excessive Energy Loss	$ 83,846.13	$ -	$ 83,846.13	$ 59,285.57
9	Real Time Net Regulation Adjustment Amount	$ (3,556.30)	$ 1,497.94	$ (2,058.36)	$ (1,455.42)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 137,447.39		$ 137,447.39	$ 97,185.72
11	Real Time Spinning Reserve Cost Distribution	$ 70,031.50		$ 70,031.50	$ 49,517.58
12	Real Time Supplemental Reserve Cost Distribution	$ 10,391.51		$ 10,391.51	$ 7,347.59
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 24,860.59	$ (10,167.21)	$ 14,693.38	$ 10,389.33
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,754,575.46**	**$ 122,642.57**	**$ 1,877,218.03**	**$ 1,327,335.42**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (1,142.90)		$ (1,142.90)	$ (808.12)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,115.01)		$ (2,115.01)	$ (1,495.47)
	Total	$ (3,257.91)		$ (3,257.91)	$ (2,303.59)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	February 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (278,603.44)		$ (278,603.44)	$ (195,289.88)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (469,812.70)		$ (469,812.70)	$ (329,319.93)
3	Day-Ahead Supplemental Reserve	$ (444,003.53)		$ (444,003.53)	$ (311,228.73)
4	Real-Time Regulation Amount (See Note 1)	$ (315,611.81)	$ 476,826.51	$ 161,214.70	$ 113,005.06
5	Real-Time Spinning Reserve Amount	$ 230,405.11	$ 187,026.31	$ 417,431.42	$ 292,602.74
6	Real-Time Supplemental Reserve Amount.	$ (201,777.17)	$ 746,454.94	$ 544,677.77	$ 381,797.35
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (59,295.86)		$ (59,295.86)	$ (41,564.03)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (877,156.03)		$ (877,156.03)	$ (614,851.32)
8b	Real Time Non Excessive Energy Congestion	$ 98,652.96	$ -	$ 98,652.96	$ 69,151.78
8c	Real Time Non Excessive Energy Loss	$ 61,299.98	$ -	$ 61,299.98	$ 42,968.84
9	Real Time Net Regulation Adjustment Amount	$ (93,522.17)	$ 41,593.31	$ (51,928.86)	$ (36,400.06)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 332,861.73		$ 332,861.73	$ 233,322.77
11	Real Time Spinning Reserve Cost Distribution	$ 267,940.97		$ 267,940.97	$ 187,815.91
12	Real Time Supplemental Reserve Cost Distribution	$ 377,553.33		$ 377,553.33	$ 264,649.80
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 83,389.16	$ (27,129.07)	$ 56,260.09	$ 39,436.07
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ (1,287,679.47)**	**$ 1,424,772.00**	**$ 137,092.53**	**$ 96,096.39**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (4,572.76)		$ (4,572.76)	$ (3,205.32)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (1,650.99)		$ (1,650.99)	$ (1,157.28)
	Total	$ (6,223.75)		$ (6,223.75)	$ (4,362.60)

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	March 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (147,873.73)		$ (147,873.73)	$ (104,382.14)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (264,050.78)		$ (264,050.78)	$ (186,390.01)
3	Day-Ahead Supplemental Reserve	$ (34,514.95)		$ (34,514.95)	$ (24,363.65)
4	Real-Time Regulation Amount (See Note 1)	$ (54,966.23)	$ 11,282.46	$ (43,683.77)	$ (30,835.80)
5	Real-Time Spinning Reserve Amount	$ (120,527.33)	$ 262,750.46	$ 142,223.13	$ 100,393.46
6	Real-Time Supplemental Reserve Amount.	$ 3,311.12	$ (166,988.27)	$ (163,677.15)	$ (115,537.57)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 26,366.18		$ 26,366.18	$ 18,611.54
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,390,823.20		$ 1,390,823.20	$ 981,763.99
8b	Real Time Non Excessive Energy Congestion	$ (52,201.16)	$ -	$ (52,201.16)	$ (36,848.12)
8c	Real Time Non Excessive Energy Loss	$ 48,606.59	$ -	$ 48,606.59	$ 34,310.76
9	Real Time Net Regulation Adjustment Amount	$ 5,578.83	$ 8,513.04	$ 14,091.87	$ 9,947.27
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 52,728.12		$ 52,728.12	$ 37,220.09
11	Real Time Spinning Reserve Cost Distribution	$ 102,375.62		$ 102,375.62	$ 72,265.62
12	Real Time Supplemental Reserve Cost Distribution	$ (75,784.60)		$ (75,784.60)	$ (53,495.36)
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 33,778.24	$ (11,123.83)	$ 22,654.41	$ 15,991.45
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 913,649.12**	**$ 104,433.86**	**$ 1,018,082.98**	**$ 718,651.52**

Note 1:

	Ramp Capability Amounts (Included in Regulation Amounts)	System	Intersystem	Retail	Minnesota Retail
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (1,309.22)		$ (1,309.22)	$ (924.16)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (1,809.02)		$ (1,809.02)	$ (1,276.96)
	Total	$ (3,118.24)		$ (3,118.24)	$ (2,201.13)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	April 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (262,770.12)		$ (262,770.12)	$ (186,478.53)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (203,962.87)		$ (203,962.87)	$ (144,745.14)
3	Day-Ahead Supplemental Reserve	$ (46,997.77)		$ (46,997.77)	$ (33,352.63)
4	Real-Time Regulation Amount (See Note 1)	$ (161,628.01)	$ 287,655.81	$ 126,027.80	$ 89,437.41
5	Real-Time Spinning Reserve Amount	$ (42,853.44)	$ 128,956.63	$ 86,103.19	$ 61,104.35
6	Real-Time Supplemental Reserve Amount.	$ 14,062.21	$ 8,767.12	$ 22,829.33	$ 16,201.16
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 36,014.12		$ 36,014.12	$ 25,557.93
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,067,871.82		$ 1,067,871.82	$ 757,830.34
8b	Real Time Non Excessive Energy Congestion	$ 7,998.12	$ -	$ 7,998.12	$ 5,675.98
8c	Real Time Non Excessive Energy Loss	$ 89,173.41	$ -	$ 89,173.41	$ 63,283.17
9	Real Time Net Regulation Adjustment Amount	$ (19,141.28)	$ 19,562.34	$ 421.06	$ 298.81
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 154,382.71		$ 154,382.71	$ 109,559.87
11	Real Time Spinning Reserve Cost Distribution	$ 151,787.35		$ 151,787.35	$ 107,718.04
12	Real Time Supplemental Reserve Cost Distribution	$ 23,611.63		$ 23,611.63	$ 16,756.33
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 30,047.21	$ (18,224.02)	$ 11,823.19	$ 8,390.49
14	Real Time Contingency Reserve Deployment Failure	$ 74,081.54	$ (127.63)	$ 73,953.91	$ 52,482.44
	TOTAL MISO ASM CHARGES	**$ 911,676.63**	**$ 426,590.25**	**$ 1,338,266.88**	**$ 949,720.02**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (1,014.52)		$ (1,014.52)	$ (719.97)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (1,362.82)		$ (1,362.82)	$ (967.14)
	Total	$ (2,377.34)		$ (2,377.34)	$ (1,687.11)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	May 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (322,838.33)		$ (322,838.33)	$ (233,084.63)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (243,955.90)		$ (243,955.90)	$ (176,132.65)
3	Day-Ahead Supplemental Reserve	$ (25,452.43)		$ (25,452.43)	$ (18,376.29)
4	Real-Time Regulation Amount (See Note 1)	$ (142,422.10)	$ 376,409.80	$ 233,987.70	$ 168,935.75
5	Real-Time Spinning Reserve Amount	$ (74,579.24)	$ 217,833.99	$ 143,254.75	$ 103,427.87
6	Real-Time Supplemental Reserve Amount.	$ 23,963.76	$ 8,804.68	$ 32,768.44	$ 23,658.34
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (8,323.69)		$ (8,323.69)	$ (6,009.58)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 829,165.07		$ 829,165.07	$ 598,645.26
8b	Real Time Non Excessive Energy Congestion	$ (582,490.27)	$ -	$ (582,490.27)	$ (420,549.60)
8c	Real Time Non Excessive Energy Loss	$ (2,209.07)	$ -	$ (2,209.07)	$ (1,594.92)
9	Real Time Net Regulation Adjustment Amount	$ (12,224.20)	$ 5,372.39	$ (6,851.81)	$ (4,946.91)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 155,843.28		$ 155,843.28	$ 112,516.61
11	Real Time Spinning Reserve Cost Distribution	$ 175,778.27		$ 175,778.27	$ 126,909.38
12	Real Time Supplemental Reserve Cost Distribution	$ 27,492.21		$ 27,492.21	$ 19,848.98
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 61,069.64	$ (33,804.84)	$ 27,264.80	$ 19,684.79
14	Real Time Contingency Reserve Deployment Failure	$ (73,850.00)	$ (0.10)	$ (73,850.10)	$ (53,318.71)
	TOTAL MISO ASM CHARGES	**$ (215,033.00)**	**$ 574,615.92**	**$ 359,582.92**	**$ 259,613.70**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (750.15)		$ (750.15)	$ (541.60)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (936.98)		$ (936.98)	$ (676.49)
	Total	$ (1,687.13)		$ (1,687.13)	$ (1,218.08)

		System	Intersystem	Retail	Minnesota Retail
June 2021 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (107,195.17)		$ (107,195.17)	$ (78,198.44)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (136,940.29)		$ (136,940.29)	$ (99,897.38)
3	Day-Ahead Supplemental Reserve	$ (16,079.64)		$ (16,079.64)	$ (11,730.03)
4	Real-Time Regulation Amount (See Note 1)	$ (221,612.40)	$ 86,977.20	$ (134,635.20)	$ (98,215.83)
5	Real-Time Spinning Reserve Amount	$ (145,971.12)	$ 124,910.70	$ (21,060.42)	$ (15,363.49)
6	Real-Time Supplemental Reserve Amount.	$ (19,536.27)	$ 8,941.64	$ (10,594.63)	$ (7,728.74)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 9,601.54		$ 9,601.54	$ 7,004.28
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 4,815,443.07		$ 4,815,443.07	$ 3,512,845.98
8b	Real Time Non Excessive Energy Congestion	$ (890,279.97)	$ -	$ (890,279.97)	$ (649,455.59)
8c	Real Time Non Excessive Energy Loss	$ (17,581.40)	$ -	$ (17,581.40)	$ (12,825.56)
9	Real Time Net Regulation Adjustment Amount	$ (49,644.62)	$ 16,989.78	$ (32,654.84)	$ (23,821.57)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 181,940.28		$ 181,940.28	$ 132,724.69
11	Real Time Spinning Reserve Cost Distribution	$ 191,220.19		$ 191,220.19	$ 139,494.34
12	Real Time Supplemental Reserve Cost Distribution	$ 114,052.45		$ 114,052.45	$ 83,200.79
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 12,826.26	$ (7,611.02)	$ 5,215.24	$ 3,804.50
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 3,720,242.91**	**$ 230,208.30**	**$ 3,950,451.21**	**$ 2,881,837.96**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (146.32)		$ (146.32)	$ (106.74)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (658.97)		$ (658.97)	$ (480.72)
	Total	$ (805.29)		$ (805.29)	$ (587.46)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (239,360.49)		$ (239,360.49)	$ (174,405.28)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (252,603.34)		$ (252,603.34)	$ (184,054.42)
3	Day-Ahead Supplemental Reserve	$ (34,148.62)		$ (34,148.62)	$ (24,881.72)
4	Real-Time Regulation Amount (See Note 1)	$ (252,040.44)	$ 313,622.93	$ 61,582.49	$ 44,870.86
5	Real-Time Spinning Reserve Amount	$ (139,093.51)	$ 274,760.15	$ 135,666.64	$ 98,850.81
6	Real-Time Supplemental Reserve Amount.	$ (9,401.72)	$ 19,794.04	$ 10,392.32	$ 7,572.16
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (9,544.36)		$ (9,544.36)	$ (6,954.31)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 6,740,447.44		$ 6,740,447.44	$ 4,911,293.42
8b	Real Time Non Excessive Energy Congestion	$ (45,170.89)	$ -	$ (45,170.89)	$ (32,912.87)
8c	Real Time Non Excessive Energy Loss	$ (50,570.41)	$ -	$ (50,570.41)	$ (36,847.13)
9	Real Time Net Regulation Adjustment Amount	$ (15,776.67)	$ 18,105.52	$ 2,328.85	$ 1,696.87
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 193,382.57		$ 193,382.57	$ 140,904.38
11	Real Time Spinning Reserve Cost Distribution	$ 228,895.40		$ 228,895.40	$ 166,780.10
12	Real Time Supplemental Reserve Cost Distribution	$ 47,342.28		$ 47,342.28	$ 34,495.01
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 62,434.67	$ (27,055.94)	$ 35,378.73	$ 25,778.01
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 6,224,791.91**	**$ 599,226.70**	**$ 6,824,018.61**	**$ 4,972,185.89**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (2,964.97)		$ (2,964.97)	$ (2,160.37)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (5,451.97)		$ (5,451.97)	$ (3,972.47)
	Total	$ (8,416.94)		$ (8,416.94)	$ (6,132.84)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	August 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (360,133.58)		$ (360,133.58)	$ (263,180.09)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (394,149.77)		$ (394,149.77)	$ (288,038.60)
3	Day-Ahead Supplemental Reserve	$ (38,999.21)		$ (38,999.21)	$ (28,500.02)
4	Real-Time Regulation Amount (See Note 1)	$ (143,246.65)	$ 321,258.04	$ 178,011.39	$ 130,087.99
5	Real-Time Spinning Reserve Amount	$ (12,851.55)	$ 254,411.17	$ 241,559.62	$ 176,528.06
6	Real-Time Supplemental Reserve Amount.	$ 421.77	$ 12,208.23	$ 12,630.00	$ 9,229.81
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 12,880.06		$ 12,880.06	$ 9,412.55
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,718,463.46		$ 3,718,463.46	$ 2,717,396.00
8b	Real Time Non Excessive Energy Congestion	$ 588,779.17	$ -	$ 588,779.17	$ 430,270.78
8c	Real Time Non Excessive Energy Loss	$ 29,201.80	$ -	$ 29,201.80	$ 21,340.23
9	Real Time Net Regulation Adjustment Amount	$ (13,179.72)	$ 10,215.70	$ (2,964.02)	$ (2,166.06)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 183,187.63		$ 183,187.63	$ 133,870.71
11	Real Time Spinning Reserve Cost Distribution	$ 211,466.71		$ 211,466.71	$ 154,536.62
12	Real Time Supplemental Reserve Cost Distribution	$ 72,863.31		$ 72,863.31	$ 53,247.39
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 106,167.62	$ (51,045.38)	$ 55,122.24	$ 40,282.49
14	Real Time Contingency Reserve Deployment Failure	$ -	$ (0.68)	$ (0.68)	$ (0.50)
	TOTAL MISO ASM CHARGES	**$ 3,960,871.05**	**$ 547,047.08**	**$ 4,507,918.13**	**$ 3,294,317.36**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (7,679.54)		$ (7,679.54)	$ (5,612.09)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,142.80)		$ (2,142.80)	$ (1,565.93)
	Total	$ (9,822.34)		$ (9,822.34)	$ (7,178.02)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	September 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (237,883.74)		$ (237,883.74)	$ (172,631.15)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (226,786.86)		$ (226,786.86)	$ (164,578.19)
3	Day-Ahead Supplemental Reserve	$ (42,668.01)		$ (42,668.01)	$ (30,963.98)
4	Real-Time Regulation Amount (See Note 1)	$ (194,616.85)	$ 252,370.36	$ 57,753.51	$ 41,911.46
5	Real-Time Spinning Reserve Amount	$ (88,095.35)	$ 201,296.99	$ 113,201.64	$ 82,149.92
6	Real-Time Supplemental Reserve Amount.	$ 13,008.87	$ 17,185.36	$ 30,194.23	$ 21,911.82
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 9,626.64		$ 9,626.64	$ 6,986.01
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 526,183.12		$ 526,183.12	$ 381,848.70
8b	Real Time Non Excessive Energy Congestion	$ (190,522.33)	$ -	$ (190,522.33)	$ (138,261.19)
8c	Real Time Non Excessive Energy Loss	$ 106,108.51	$ -	$ 106,108.51	$ 77,002.46
9	Real Time Net Regulation Adjustment Amount	$ (2,782.73)	$ 1,031.40	$ (1,751.33)	$ (1,270.93)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 174,002.33		$ 174,002.33	$ 126,272.70
11	Real Time Spinning Reserve Cost Distribution	$ 135,417.52		$ 135,417.52	$ 98,271.88
12	Real Time Supplemental Reserve Cost Distribution	$ 9,302.63		$ 9,302.63	$ 6,750.88
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 65,611.33	$ (27,155.25)	$ 38,456.08	$ 27,907.40
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 55,905.08**	**$ 444,728.86**	**$ 500,633.94**	**$ 363,307.77**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (9,881.84)		$ (9,881.84)	$ (7,171.21)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ 4,172.99		$ 4,172.99	$ 3,028.32
	Total	$ (5,708.85)		$ (5,708.85)	$ (4,142.89)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	October 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (473,628.04)		$ (473,628.04)	$ (341,498.27)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (224,177.99)		$ (224,177.99)	$ (161,638.22)
3	Day-Ahead Supplemental Reserve	$ (30,432.94)		$ (30,432.94)	$ (21,942.95)
4	Real-Time Regulation Amount (See Note 1)	$ (385,076.85)	$ 589,478.57	$ 204,401.72	$ 147,379.01
5	Real-Time Spinning Reserve Amount	$ (131,281.50)	$ 216,591.98	$ 85,310.48	$ 61,511.10
6	Real-Time Supplemental Reserve Amount.	$ 35,387.80	$ 7,504.05	$ 42,891.85	$ 30,926.15
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 19,577.14		$ 19,577.14	$ 14,115.63
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,833,703.98		$ 2,833,703.98	$ 2,043,175.06
8b	Real Time Non Excessive Energy Congestion	$ 2,424,755.88	$ -	$ 2,424,755.88	$ 1,748,312.73
8c	Real Time Non Excessive Energy Loss	$ 258,210.39	$ -	$ 258,210.39	$ 186,176.48
9	Real Time Net Regulation Adjustment Amount	$ (9,124.72)	$ 523.46	$ (8,601.26)	$ (6,201.73)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 198,170.16		$ 198,170.16	$ 142,885.89
11	Real Time Spinning Reserve Cost Distribution	$ 277,281.47		$ 277,281.47	$ 199,927.23
12	Real Time Supplemental Reserve Cost Distribution	$ 59,556.84		$ 59,556.84	$ 42,942.05
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 146,255.57	$ (44,072.36)	$ 102,183.21	$ 73,676.78
14	Real Time Contingency Reserve Deployment Failure	$ 1,463.22	$ -	$ 1,463.22	$ 1,055.02
	TOTAL MISO ASM CHARGES	**$ 5,000,640.41**	**$ 770,025.70**	**$ 5,770,666.11**	**$ 4,160,801.96**

``

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (64,062.21)		$ (64,062.21)	$ (46,190.54)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (8,399.84)		$ (8,399.84)	$ (6,056.51)
	Total	$ (72,462.05)		$ (72,462.05)	$ (52,247.04)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	November 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (299,431.61)		$ (299,431.61)	$ (213,631.49)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (321,238.92)		$ (321,238.92)	$ (229,190.06)
3	Day-Ahead Supplemental Reserve	$ (9,832.34)		$ (9,832.34)	$ (7,014.95)
4	Real-Time Regulation Amount (See Note 1)	$ (231,805.88)	$ 222,919.31	$ (8,886.57)	$ (6,340.18)
5	Real-Time Spinning Reserve Amount	$ (105,470.44)	$ 323,362.64	$ 217,892.20	$ 155,456.65
6	Real-Time Supplemental Reserve Amount.	$ (433.75)	$ 730.46	$ 296.71	$ 211.69
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 29,975.35		$ 29,975.35	$ 21,386.11
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,244,857.02		$ 2,244,857.02	$ 1,601,608.31
8b	Real Time Non Excessive Energy Congestion	$ 2,375,979.62	$ -	$ 2,375,979.62	$ 1,695,158.61
8c	Real Time Non Excessive Energy Loss	$ 317,528.34	$ -	$ 317,528.34	$ 226,542.73
9	Real Time Net Regulation Adjustment Amount	$ (7,017.36)	$ (22,055.34)	$ (29,072.70)	$ (20,742.11)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 161,884.56		$ 161,884.56	$ 115,497.63
11	Real Time Spinning Reserve Cost Distribution	$ 134,104.70		$ 134,104.70	$ 95,677.90
12	Real Time Supplemental Reserve Cost Distribution	$ 17,018.59		$ 17,018.59	$ 12,142.03
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 132,259.35	$ (43,378.15)	$ 88,881.20	$ 63,412.89
14	Real Time Contingency Reserve Deployment Failure	$ 61,702.91	$ -	$ 61,702.91	$ 44,022.36
	TOTAL MISO ASM CHARGES	**$ 4,500,080.14**	**$ 481,578.92**	**$ 4,981,659.06**	**$ 3,554,198.09**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (29,213.84)		$ (29,213.84)	$ (20,842.81)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (15,396.76)		$ (15,396.76)	$ (10,984.92)
	Total	$ (44,610.60)		$ (44,610.60)	$ (31,827.73)

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
December 2021 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (23,741.55)		$ (23,741.55)	$ (16,721.51)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (223,985.03)		$ (223,985.03)	$ (157,755.82)
3	Day-Ahead Supplemental Reserve	$ (75,375.94)		$ (75,375.94)	$ (53,088.34)
4	Real-Time Regulation Amount (See Note 1)	$ (101,360.47)	$ 112,616.34	$ 11,255.87	$ 7,927.67
5	Real-Time Spinning Reserve Amount	$ (14,061.04)	$ 173,360.29	$ 159,299.25	$ 112,196.71
6	Real-Time Supplemental Reserve Amount.	$ 7,517.31	$ 1,185.99	$ 8,703.30	$ 6,129.86
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 22,729.74		$ 22,729.74	$ 16,008.88
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 4,733,266.33		$ 4,733,266.33	$ 3,333,706.37
8b	Real Time Non Excessive Energy Congestion	$ 3,428,256.50	$ -	$ 3,428,256.50	$ 2,414,569.51
8c	Real Time Non Excessive Energy Loss	$ 201,835.62	$ -	$ 201,835.62	$ 142,155.68
9	Real Time Net Regulation Adjustment Amount	$ 1,986,342.02	$ (40,788.45)	$ 1,945,553.57	$ 1,370,280.88
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 132,526.54		$ 132,526.54	$ 93,340.32
11	Real Time Spinning Reserve Cost Distribution	$ 115,734.84		$ 115,734.84	$ 81,513.68
12	Real Time Supplemental Reserve Cost Distribution	$ 164,440.69		$ 164,440.69	$ 115,817.90
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 114,035.85	$ (45,387.61)	$ 68,648.24	$ 48,349.93
14	Real Time Contingency Reserve Deployment Failure	$ 627.30	$ (963.33)	$ (336.03)	$ (236.67)
	TOTAL MISO ASM CHARGES	**$ 10,468,788.71**	**$ 200,023.23**	**$ 10,668,811.94**	**$ 7,514,195.04**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (23,741.55)		$ (23,741.55)	$ (16,721.51)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,632.69)		$ (2,632.69)	$ (1,854.24)
	Total	$ (26,374.24)		$ (26,374.24)	$ (18,575.75)

Northern States Power Company

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January - December 2021 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (2,860,981.67)		$ (2,860,981.67)	$ (2,015,029.83)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (3,115,560.22)		$ (3,115,560.22)	$ (2,194,333.10)
3	Day-Ahead Supplemental Reserve	$ (811,899.52)		$ (811,899.52)	$ (571,832.31)
4	Real-Time Regulation Amount (See Note 1)	$ (2,217,938.26)	$ 3,067,909.22	$ 849,970.96	$ 598,646.56
5	Real-Time Spinning Reserve Amount	$ (669,369.97)	$ 2,477,098.64	$ 1,807,728.67	$ 1,273,208.85
6	Real-Time Supplemental Reserve Amount.	$ (133,468.68)	$ 667,570.86	$ 534,102.18	$ 376,175.71
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 86,718.76		$ 86,718.76	$ 61,077.25
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 29,597,833.24		$ 29,597,833.24	$ 20,846,172.27
8b	Real Time Non Excessive Energy Congestion	$ 7,336,781.13	$ -	$ 7,336,781.13	$ 5,167,398.64
8c	Real Time Non Excessive Energy Loss	$ 1,125,449.89	$ -	$ 1,125,449.89	$ 792,670.26
9	Real Time Net Regulation Adjustment Amount	$ 1,765,951.08	$ 60,561.09	$ 1,826,512.17	$ 1,286,438.34
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 2,058,357.30		$ 2,058,357.30	$ 1,449,730.14
11	Real Time Spinning Reserve Cost Distribution	$ 2,062,034.54		$ 2,062,034.54	$ 1,452,320.07
12	Real Time Supplemental Reserve Cost Distribution	$ 847,840.87		$ 847,840.87	$ 597,146.31
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 872,735.49	$ (346,154.68)	$ 526,580.81	$ 370,878.31
14	Real Time Contingency Reserve Deployment Failure	$ 64,024.97	$ (1,091.74)	$ 62,933.23	$ 44,324.76
	TOTAL MISO ASM CHARGES	**$ 36,008,508.95**	**$ 5,925,893.39**	**$ 41,934,402.34**	**$ 29,534,992.25**

Note 1:

		System	Intersystem	Retail	Minnesota Retail
Ramp Capability Amounts (Included in Regulation Amounts)					
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$ (146,479.82)		$ (146,479.82)	$ (105,077.28)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (38,384.86)		$ (38,384.86)	$ (27,535.37)
	Total	$ (184,864.68)		$ (184,864.68)	$ (132,612.65)

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

		January 21	February 21	March 21	1st Qt	April 21	May 21	June 21	2nd Qt	July 21	August 21	September 21	3rd Qt	October 21	November 21	December 21	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (107,521.87)	$ (278,603.44)	$ (147,873.73)	$ (533,999.04)	$ (262,770.12)	$ (322,838.33)	$ (107,195.17)	$ (692,803.62)	$ (239,360.49)	$ (360,133.58)	$ (237,883.74)	$ (837,377.81)	$ (473,628.04)	$ (299,431.61)	$ (23,741.55)	$ (796,801.20)	$ (2,860,981.67)
4	Real-Time Regulation Amount	$ (13,550.57)	$ (315,611.81)	$ (54,966.23)	$ (384,128.61)	$ (161,628.01)	$ (142,422.10)	$ (221,612.40)	$ (525,662.51)	$ (252,040.44)	$ (143,246.65)	$ (194,616.85)	$ (589,903.94)	$ (385,076.85)	$ (231,805.88)	$ (101,360.47)	$ (718,243.20)	$ (2,217,938.26)
10	Real Time Regulation Reserve Cost Distribution Amc	$ 137,447.39	$ 332,861.73	$ 52,728.12	$ 523,037.24	$ 154,382.71	$ 155,843.28	$ 181,940.28	$ 492,166.27	$ 193,382.57	$ 183,187.63	$ 174,002.33	$ 550,572.53	$ 198,170.16	$ 161,884.56	$ 132,526.54	$ 492,581.26	$ 2,058,357.30
	SUBTOTAL	$ 16,374.95	$ (261,353.52)	$ (150,111.84)	$ (395,090.41)	$ (270,015.42)	$ (309,417.15)	$ (146,867.29)	$ (726,299.86)	$ (298,018.36)	$ (320,192.60)	$ (258,498.26)	$ (876,709.22)	$ (660,534.73)	$ (369,352.93)	$ 7,424.52	$ (1,022,463.14)	$ (3,020,562.63)
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (153,895.77)	$ (469,812.70)	$ (264,050.78)	$ (887,759.25)	$ (203,962.87)	$ (243,955.90)	$ (136,940.29)	$ (584,859.06)	$ (252,603.34)	$ (394,149.77)	$ (226,786.86)	$ (873,539.97)	$ (224,177.99)	$ (321,238.92)	$ (223,985.03)	$ (769,401.94)	$ (3,115,560.22)
5	Real-Time Spinning Reserve Amount	$ (24,990.56)	$ 230,405.11	$ (120,527.33)	$ 84,887.22	$ (42,853.44)	$ (74,579.24)	$ (145,971.12)	$ (263,403.80)	$ (139,093.51)	$ (12,851.55)	$ (88,095.35)	$ (240,040.41)	$ (131,281.50)	$ (105,470.44)	$ (14,061.04)	$ (250,812.98)	$ (669,369.97)
11	Real Time Spinning Reserve Cost Distribution	$ 70,031.50	$ 267,940.97	$ 102,375.62	$ 440,348.09	$ 151,787.35	$ 175,778.27	$ 191,220.19	$ 518,785.81	$ 228,895.40	$ 211,466.71	$ 135,417.52	$ 575,779.63	$ 277,281.47	$ 134,104.70	$ 115,734.84	$ 527,121.01	$ 2,062,034.54
	SUBTOTAL	$ (108,854.83)	$ 28,533.38	$ (282,202.49)	$ (362,523.94)	$ (95,028.96)	$ (142,756.87)	$ (91,691.22)	$ (329,477.05)	$ (162,801.45)	$ (195,534.61)	$ (179,464.69)	$ (537,800.75)	$ (78,178.02)	$ (292,604.66)	$ (122,311.23)	$ (493,093.91)	$ (1,722,895.65)
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (13,394.14)	$ (444,003.53)	$ (34,514.95)	$ (491,912.62)	$ (46,997.77)	$ (25,452.43)	$ (16,079.64)	$ (88,529.84)	$ (34,148.62)	$ (38,999.21)	$ (42,668.01)	$ (115,815.84)	$ (30,432.94)	$ (9,832.34)	$ (75,375.94)	$ (115,641.22)	$ (811,899.52)
6	Real-Time Supplemental Reserve Amount.	$ 7.39	$ (201,777.17)	$ 3,311.12	$ (198,458.66)	$ 14,062.21	$ 23,963.76	$ (19,536.27)	$ 18,489.70	$ (9,401.72)	$ 421.77	$ 13,008.87	$ 4,028.92	$ 35,387.80	$ (433.75)	$ 7,517.31	$ 42,471.36	$ (133,468.68)
12	Real Time Supplemental Reserve Cost Distribution	$ 10,391.51	$ 377,553.33	$ (75,784.60)	$ 312,160.24	$ 23,611.63	$ 27,492.21	$ 114,052.45	$ 165,156.29	$ 47,342.28	$ 72,863.31	$ 9,302.63	$ 129,508.22	$ 59,556.84	$ 17,018.59	$ 164,440.69	$ 241,016.12	$ 847,840.87
	SUBTOTAL	$ (2,995.24)	$ (268,227.37)	$ (106,988.43)	$ (378,211.04)	$ (9,323.93)	$ 26,003.54	$ 78,436.54	$ 95,116.15	$ 3,791.94	$ 34,285.87	$ (20,356.51)	$ 17,721.30	$ 64,511.70	$ 6,752.50	$ 96,582.06	$ 167,846.26	$ (97,527.33)
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -	$ 74,081.54	$ (73,850.00)	$ -	$ 231.54	$ -	$ -	$ -	$ -	$ 1,463.22	$ 61,702.91	$ 627.30	$ 63,793.43	$ 64,024.97
13	Real Time Excessive/Deficient Energy Deployment	$ 24,860.59	$ 83,389.16	$ 33,778.24	$ 142,027.99	$ 30,047.21	$ 61,069.64	$ 12,826.26	$ 103,943.11	$ 62,434.67	$ 106,167.62	$ 65,611.33	$ 234,213.62	$ 146,255.57	$ 132,259.35	$ 114,035.85	$ 392,550.77	$ 872,735.49
9	Real Time Net Regulation Adjustment Amount	$ (3,556.30)	$ (93,522.17)	$ 5,578.83	$ (91,499.64)	$ (19,141.28)	$ (12,224.20)	$ (49,644.62)	$ (81,010.10)	$ (15,776.67)	$ (13,179.72)	$ (2,782.73)	$ (31,739.12)	$ (9,124.72)	$ (7,017.36)	$ 1,986,342.02	$ 1,970,199.94	$ 1,765,951.08
	SUBTOTAL	$ 21,304.29	$ (10,133.01)	$ 39,357.07	$ 50,528.35	$ 84,987.47	$ (25,004.56)	$ (36,818.36)	$ 23,164.55	$ 46,658.00	$ 92,987.90	$ 62,828.60	$ 202,474.50	$ 138,594.07	$ 186,944.90	$ 2,101,005.17	$ 2,426,544.14	$ 2,702,711.54
	TOTAL MISO ASM CHARGES	$ (74,170.83)	$ (511,180.52)	$ (499,945.69)	$ (1,085,297.04)	$ (289,380.84)	$ (451,175.04)	$ (196,940.33)	$ (937,496.21)	$ (410,369.87)	$ (388,453.44)	$ (395,490.86)	$ (1,194,314.17)	$ (535,606.98)	$ (468,260.19)	$ 2,082,700.52	$ 1,078,833.35	$ (2,138,274.07)
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (2,888.10)	$ (59,295.86)	$ 26,366.18	$ (35,817.78)	$ 36,014.12	$ (8,323.69)	$ 9,601.54	$ 37,291.97	$ (9,544.36)	$ 12,880.06	$ 9,626.64	$ 12,962.34	$ 19,577.14	$ 29,975.35	$ 22,729.74	$ 72,282.23	$ 86,718.76
7b	Real Time Excessive Energy Congestion				$ -				$ -				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss				$ -				$ -				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,574,764.76	$ (877,156.03)	$ 1,390,823.20	$ 2,088,431.93	$ 1,067,871.82	$ 829,165.07	$ 4,815,443.07	$ 6,712,479.96	$ 6,740,447.44	$ 3,718,463.46	$ 526,183.12	$ 10,985,094.02	$ 2,833,703.98	$ 2,244,857.02	$ 4,733,266.33	$ 9,811,827.33	$ 29,597,833.24
8b	Real Time Non Excessive Energy Congestion	$ 173,023.50	$ 98,652.96	$ (52,201.16)	$ 219,475.30	$ 7,998.12	$ (582,490.27)	$ (890,279.97)	$ (1,464,772.12)	$ (45,170.89)	$ 588,779.17	$ (190,522.33)	$ 353,085.95	$ 2,424,755.88	$ 2,375,979.62	$ 3,428,256.50	$ 8,228,992.00	$ 7,336,781.13
8c	Real Time Non Excessive Energy Loss	$ 83,846.13	$ 61,299.98	$ 48,606.59	$ 193,752.70	$ 89,173.41	$ (2,209.07)	$ (17,581.40)	$ 69,382.94	$ (50,570.41)	$ 29,201.80	$ 106,108.51	$ 84,739.90	$ 258,210.39	$ 317,528.34	$ 201,835.62	$ 777,574.35	$ 1,125,449.89
	SUBTOTAL	$ 1,828,746.29	$ (776,498.95)	$ 1,413,594.81	$ 2,465,842.15	$ 1,201,057.47	$ 236,142.04	$ 3,917,183.24	$ 5,354,382.75	$ 6,635,161.78	$ 4,349,324.49	$ 451,395.94	$ 11,435,882.21	$ 5,536,247.39	$ 4,968,340.33	$ 8,386,088.19	$ 18,890,675.91	$ 38,146,783.02
	GRAND TOTAL MISO ASM CHARGES	$ 1,754,575.46	$ (1,287,679.47)	$ 913,649.12	$ 1,380,545.11	$ 911,676.63	$ (215,033.00)	$ 3,720,242.91	$ 4,416,886.54	$ 6,224,791.91	$ 3,960,871.05	$ 55,905.08	$ 10,241,568.04	$ 5,000,640.41	$ 4,500,080.14	$ 10,468,788.71	$ 19,969,509.26	$ 36,008,508.95

Northern States Power Company

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

		January 21	February 21	March 21	1st Qt	April 21	May 21	June 21	2nd Qt	July 21	August 21	September 21	3rd Qt	October 21	November 21	December 21	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount				$ -				$ -				$ -				$ -	$ -
4	Real-Time Regulation Amount	$ 16,491.89	$ 476,826.51	$ 11,282.46	$ 504,600.86	$ 287,655.81	$ 376,409.80	$ 86,977.20	$ 751,042.81	$ 313,622.93	$ 321,258.04	$ 252,370.36	$ 887,251.33	$ 589,478.57	$ 222,919.31	$ 112,616.34	$ 925,014.22	$ 3,067,909.22
10	Real Time Regulation Reserve Cost Distribution Amount				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 16,491.89	$ 476,826.51	$ 11,282.46	$ 504,600.86	$ 287,655.81	$ 376,409.80	$ 86,977.20	$ 751,042.81	$ 313,622.93	$ 321,258.04	$ 252,370.36	$ 887,251.33	$ 589,478.57	$ 222,919.31	$ 112,616.34	$ 925,014.22	$ 3,067,909.22
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount				$ -				$ -				$ -				$ -	$ -
5	Real-Time Spinning Reserve Amount	$ 111,837.33	$ 187,026.31	$ 262,750.46	$ 561,614.10	$ 128,956.63	$ 217,833.99	$ 124,910.70	$ 471,701.32	$ 274,760.15	$ 254,411.17	$ 201,296.99	$ 730,468.31	$ 216,591.98	$ 323,362.64	$ 173,360.29	$ 713,314.91	$ 2,477,098.64
11	Real Time Spinning Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 111,837.33	$ 187,026.31	$ 262,750.46	$ 561,614.10	$ 128,956.63	$ 217,833.99	$ 124,910.70	$ 471,701.32	$ 274,760.15	$ 254,411.17	$ 201,296.99	$ 730,468.31	$ 216,591.98	$ 323,362.64	$ 173,360.29	$ 713,314.91	$ 2,477,098.64
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve				$ -				$ -				$ -				$ -	$ -
6	Real-Time Supplemental Reserve Amount.	$ 2,982.62	$ 746,454.94	$ (166,988.27)	$ 582,449.29	$ 8,767.12	$ 8,804.68	$ 8,941.64	$ 26,513.44	$ 19,794.04	$ 12,208.23	$ 17,185.36	$ 49,187.63	$ 7,504.05	$ 730.46	$ 1,185.99	$ 9,420.50	$ 667,570.86
12	Real Time Supplemental Reserve Cost Distribution				$ -				$ -				$ -				$ -	$ -
	SUBTOTAL	$ 2,982.62	$ 746,454.94	$ (166,988.27)	$ 582,449.29	$ 8,767.12	$ 8,804.68	$ 8,941.64	$ 26,513.44	$ 19,794.04	$ 12,208.23	$ 17,185.36	$ 49,187.63	$ 7,504.05	$ 730.46	$ 1,185.99	$ 9,420.50	$ 667,570.86
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -	$ (127.63)	$ (0.10)	$ -	$ (127.73)	$ -	$ (0.68)	$ -	$ (0.68)	$ -	$ -	$ (963.33)	$ (963.33)	$ (1,091.74)
13	Real Time Excessive/Deficient Energy Deployment	$ (10,167.21)	$ (27,129.07)	$ (11,123.83)	$ (48,420.11)	$ (18,224.02)	$ (33,804.84)	$ (7,611.02)	$ (59,639.88)	$ (27,055.94)	$ (51,045.38)	$ (27,155.25)	$ (105,256.57)	$ (44,072.36)	$ (43,378.15)	$ (45,387.61)	$ (132,838.12)	$ (346,154.68)
9	Real Time Net Regulation Adjustment Amount	$ 1,497.94	$ 41,593.31	$ 8,513.04	$ 51,604.29	$ 19,562.34	$ 5,372.39	$ 16,989.78	$ 41,924.51	$ 18,105.52	$ 10,215.70	$ 1,031.40	$ 29,352.62	$ 523.46	$ (22,055.34)	$ (40,788.45)	$ (62,320.33)	$ 60,561.09
	SUBTOTAL	$ (8,669.27)	$ 14,464.24	$ (2,610.79)	$ 3,184.18	$ 1,210.69	$ (28,432.55)	$ 9,378.76	$ (17,843.10)	$ (8,950.42)	$ (40,830.36)	$ (26,123.85)	$ (75,904.63)	$ (43,548.90)	$ (65,433.49)	$ (87,139.39)	$ (196,121.78)	$ (286,685.33)
	TOTAL MISO ASM CHARGES	$ 122,642.57	$ 1,424,772.00	$ 104,433.86	$ 1,651,848.43	$ 426,590.25	$ 574,615.92	$ 230,208.30	$ 1,231,414.47	$ 599,226.70	$ 547,047.08	$ 444,728.86	$ 1,591,002.64	$ 770,025.70	$ 481,578.92	$ 200,023.23	$ 1,451,627.85	$ 5,925,893.39
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	$ 122,642.57	$ 1,424,772.00	$ 104,433.86	$ 1,651,848.43	$ 426,590.25	$ 574,615.92	$ 230,208.30	$ 1,231,414.47	$ 599,226.70	$ 547,047.08	$ 444,728.86	$ 1,591,002.64	$ 770,025.70	$ 481,578.92	$ 200,023.23	$ 1,451,627.85	$ 5,925,893.39

Northern States Power Company

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

		January 21	February 21	March 21	1st Qt	April 21	May 21	June 21	2nd Qt	July 21	August 21	September 21	3rd Qt	October 21	November 21	December 21	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (107,521.87)	$ (278,603.44)	$ (147,873.73)	$ (533,999.04)	$ (262,770.12)	$ (322,838.33)	$ (107,195.17)	$ (692,803.62)	$ (239,360.49)	$ (360,133.58)	$ (237,883.74)	$ (837,377.81)	$ (473,628.04)	$ (299,431.61)	$ (23,741.55)	$ (796,801.20)	$ (2,860,981.67)
4	Real-Time Regulation Amount	$ 2,941.32	$ 161,214.70	$ (43,683.77)	$ 120,472.25	$ 126,027.80	$ 233,987.70	$ (134,635.20)	$ 225,380.30	$ 61,582.49	$ 178,011.39	$ 57,753.51	$ 297,347.39	$ 204,401.72	$ (8,886.57)	$ 11,255.87	$ 206,771.02	$ 849,970.96
10	Real Time Regulation Reserve Cost Distribution Amo	$ 137,447.39	$ 332,861.73	$ 52,728.12	$ 523,037.24	$ 154,382.71	$ 155,843.28	$ 181,940.28	$ 492,166.27	$ 193,382.57	$ 183,187.63	$ 174,002.33	$ 550,572.53	$ 198,170.16	$ 161,884.56	$ 132,526.54	$ 492,581.26	$ 2,058,357.30
	SUBTOTAL	$ 32,866.84	$ 215,472.99	$ (138,829.38)	$ 109,510.45	$ 17,640.39	$ 66,992.65	$ (59,890.09)	$ 24,742.95	$ 15,604.57	$ 1,065.44	$ (6,127.90)	$ 10,542.11	$ (71,056.16)	$ (146,433.62)	$ 120,040.86	$ (97,448.92)	$ 47,346.59
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (153,895.77)	$ (469,812.70)	$ (264,050.78)	$ (887,759.25)	$ (203,962.87)	$ (243,955.90)	$ (136,940.29)	$ (584,859.06)	$ (252,603.34)	$ (394,149.77)	$ (226,786.86)	$ (873,539.97)	$ (224,177.99)	$ (321,238.92)	$ (223,985.03)	$ (769,401.94)	$ (3,115,560.22)
5	Real-Time Spinning Reserve Amount	$ 86,846.77	$ 417,431.42	$ 142,223.13	$ 646,501.32	$ 86,103.19	$ 143,254.75	$ (21,060.42)	$ 208,297.52	$ 135,666.64	$ 241,559.62	$ 113,201.64	$ 490,427.90	$ 85,310.48	$ 217,892.20	$ 159,299.25	$ 462,501.93	$ 1,807,728.67
11	Real Time Spinning Reserve Cost Distribution	$ 70,031.50	$ 267,940.97	$ 102,375.62	$ 440,348.09	$ 151,787.35	$ 175,778.27	$ 191,220.19	$ 518,785.81	$ 228,895.40	$ 211,466.71	$ 135,417.52	$ 575,779.63	$ 277,281.47	$ 134,104.70	$ 115,734.84	$ 527,121.01	$ 2,062,034.54
	SUBTOTAL	$ 2,982.50	$ 215,559.69	$ (19,452.03)	$ 199,090.16	$ 33,927.67	$ 75,077.12	$ 33,219.48	$ 142,224.27	$ 111,958.70	$ 58,876.56	$ 21,832.30	$ 192,667.56	$ 138,413.96	$ 30,757.98	$ 51,049.06	$ 220,221.00	$ 754,202.99
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (13,394.14)	$ (444,003.53)	$ (34,514.95)	$ (491,912.62)	$ (46,997.77)	$ (25,452.43)	$ (16,079.64)	$ (88,529.84)	$ (34,148.62)	$ (38,999.21)	$ (42,668.01)	$ (115,815.84)	$ (30,432.94)	$ (9,832.34)	$ (75,375.94)	$ (115,641.22)	$ (811,899.52)
6	Real-Time Supplemental Reserve Amount.	$ 2,990.01	$ 544,677.77	$ (163,677.15)	$ 383,990.63	$ 22,829.33	$ 32,768.44	$ (10,594.63)	$ 45,003.14	$ 10,392.32	$ 12,630.00	$ 30,194.23	$ 53,216.55	$ 42,891.85	$ 296.71	$ 8,703.30	$ 51,891.86	$ 534,102.18
12	Real Time Supplemental Reserve Cost Distribution	$ 10,391.51	$ 377,553.33	$ (75,784.60)	$ 312,160.24	$ 23,611.63	$ 27,492.21	$ 114,052.45	$ 165,156.29	$ 47,342.28	$ 72,863.31	$ 9,302.63	$ 129,508.22	$ 59,556.84	$ 17,018.59	$ 164,440.69	$ 241,016.12	$ 847,840.87
	SUBTOTAL	$ (12.62)	$ 478,227.57	$ (273,976.70)	$ 204,238.25	$ (556.81)	$ 34,808.22	$ 87,378.18	$ 121,629.59	$ 23,585.98	$ 46,494.10	$ (3,171.15)	$ 66,908.93	$ 72,015.75	$ 7,482.96	$ 97,768.05	$ 177,266.76	$ 570,043.53
Other Charges																		
13	Real Time Excessive/Deficient Energy Deployment	$ -	$ -	$ -	$ -	$ 73,953.91	$ (73,850.10)	$ -	$ 103.81	$ -	$ (0.68)	$ -	$ (0.68)	$ 1,463.22	$ 61,702.91	$ (336.03)	$ 62,830.10	$ 62,933.23
14	Real Time Contingency Reserve Deployment Failure	$ 14,693.38	$ 56,260.09	$ 22,654.41	$ 93,607.88	$ 11,823.19	$ 27,264.80	$ 5,215.24	$ 44,303.23	$ 35,378.73	$ 55,122.24	$ 38,456.08	$ 128,957.05	$ 102,183.21	$ 88,881.20	$ 68,648.24	$ 259,712.65	$ 526,580.81
9	Real Time Net Regulation Adjustment Amount	$ (2,058.36)	$ (51,928.86)	$ 14,091.87	$ (39,895.35)	$ 421.06	$ (6,851.81)	$ (32,654.84)	$ (39,085.59)	$ 2,328.85	$ (2,964.02)	$ (1,751.33)	$ (2,386.50)	$ (8,601.26)	$ (29,072.70)	$ 1,945,553.57	$ 1,907,879.61	$ 1,826,512.17
	SUBTOTAL	$ 12,635.02	$ 4,331.23	$ 36,746.28	$ 53,712.53	$ 86,198.16	$ (53,437.11)	$ (27,439.60)	$ 5,321.45	$ 37,707.58	$ 52,157.54	$ 36,704.75	$ 126,569.87	$ 95,045.17	$ 121,511.41	$ 2,013,865.78	$ 2,230,422.36	$ 2,416,026.21
	TOTAL MISO ASM CHARGES	$ 48,471.74	$ 913,591.48	$ (395,511.83)	$ 566,551.39	$ 137,209.41	$ 123,440.88	$ 33,267.97	$ 293,918.26	$ 188,856.83	$ 158,593.64	$ 49,238.00	$ 396,688.47	$ 234,418.72	$ 13,318.73	$ 2,282,723.75	$ 2,530,461.20	$ 3,787,619.32
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (2,888.10)	$ (59,295.86)	$ 26,366.18	$ (35,817.78)	$ 36,014.12	$ (8,323.69)	$ 9,601.54	$ 37,291.97	$ (9,544.36)	$ 12,880.06	$ 9,626.64	$ 12,962.34	$ 19,577.14	$ 29,975.35	$ 22,729.74	$ 72,282.23	$ 86,718.76
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,574,764.76	$ (877,156.03)	$ 1,390,823.20	$ 2,088,431.93	$ 1,067,871.82	$ 829,165.07	$ 4,815,443.07	$ 6,712,479.96	$ 6,740,447.44	$ 3,718,463.46	$ 526,183.12	$ 10,985,094.02	$ 2,833,703.98	$ 2,244,857.02	$ 4,733,266.33	$ 9,811,827.33	$ 29,597,833.24
8b	Real Time Non Excessive Energy Congestion	$ 173,023.50	$ 98,652.96	$ (52,201.16)	$ 219,475.30	$ 7,998.12	$ (582,490.27)	$ (890,279.97)	$ (1,464,772.12)	$ (45,170.89)	$ 588,779.17	$ (190,522.33)	$ 353,085.95	$ 2,424,755.88	$ 2,375,979.62	$ 3,428,256.50	$ 8,228,992.00	$ 7,336,781.13
8c	Real Time Non Excessive Energy Loss	$ 83,846.13	$ 61,299.98	$ 48,606.59	$ 193,752.70	$ 89,173.41	$ (2,209.07)	$ (17,581.40)	$ 69,382.94	$ (50,570.41)	$ 29,201.80	$ 106,108.51	$ 84,739.90	$ 258,210.39	$ 317,528.34	$ 201,835.62	$ 777,574.35	$ 1,125,449.89
	SUBTOTAL	$ 1,828,746.29	$ (776,498.95)	$ 1,413,594.81	$ 2,465,842.15	$ 1,201,057.47	$ 236,142.04	$ 3,917,183.24	$ 5,354,382.75	$ 6,635,161.78	$ 4,349,324.49	$ 451,395.94	$ 11,435,882.21	$ 5,536,247.39	$ 4,968,340.33	$ 8,386,088.19	$ 18,890,675.91	$ 38,146,783.02
	GRAND TOTAL MISO ASM CHARGES	$ 1,877,218.03	$ 137,092.53	$ 1,018,082.98	$ 3,032,393.54	$ 1,338,266.88	$ 359,582.92	$ 3,950,451.21	$ 5,648,301.01	$ 6,824,018.61	$ 4,507,918.13	$ 500,633.94	$ 11,832,570.68	$ 5,770,666.11	$ 4,981,659.06	$ 10,668,811.94	$ 21,421,137.11	$ 41,934,402.34

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

		January 21	February 21	March 21	1st Qt	April 21	May 21	June 21	2nd Qt	July 21	August 21	September 21	3rd Qt	October 21	November 21	December 21	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (76,026.11)	$ (195,289.88)	$ (104,382.14)	$ (375,698.13)	$ (186,478.53)	$ (233,084.63)	$ (78,198.44)	$ (497,761.60)	$ (174,405.28)	$ (263,180.09)	$ (172,631.15)	$ (610,216.52)	$ (341,498.27)	$ (213,631.49)	$ (16,721.51)	$ (571,851.27)	$ (2,055,527.52)
4	Real-Time Regulation Amount	$ 2,079.74	$ 113,005.06	$ (30,835.80)	$ 84,248.99	$ 89,437.41	$ 168,935.75	$ (98,215.83)	$ 160,157.34	$ 44,870.86	$ 130,087.99	$ 41,911.46	$ 216,870.31	$ 147,379.01	$ (6,340.18)	$ 7,927.67	$ 148,966.50	$ 610,243.14
10	Real Time Regulation Reserve Cost Distribution Amo	$ 97,185.72	$ 233,322.77	$ 37,220.09	$ 367,728.59	$ 109,559.87	$ 112,516.61	$ 132,724.69	$ 354,801.17	$ 140,904.38	$ 133,870.71	$ 126,272.70	$ 401,047.78	$ 142,885.89	$ 115,497.63	$ 93,340.32	$ 351,723.84	$ 1,475,301.37
	SUBTOTAL	$ 23,239.35	$ 151,037.96	$ (97,997.85)	$ 76,279.45	$ 12,518.75	$ 48,367.73	$ (43,689.58)	$ 17,196.91	$ 11,369.96	$ 778.61	$ (4,446.99)	$ 7,701.58	$ (51,233.36)	$ (104,474.05)	$ 84,546.47	$ (71,160.93)	$ 30,017.00
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (108,815.97)	$ (329,319.93)	$ (186,390.01)	$ (624,525.91)	$ (144,745.14)	$ (176,132.65)	$ (99,897.38)	$ (420,775.17)	$ (184,054.42)	$ (288,038.60)	$ (164,578.19)	$ (636,671.21)	$ (161,638.22)	$ (229,190.06)	$ (157,755.82)	$ (548,584.11)	$ (2,230,556.40)
5	Real-Time Spinning Reserve Amount	$ 61,407.25	$ 292,602.74	$ 100,393.46	$ 454,403.45	$ 61,104.35	$ 103,427.87	$ (15,363.49)	$ 149,168.73	$ 98,850.81	$ 176,528.06	$ 82,149.92	$ 357,528.79	$ 61,511.10	$ 155,456.65	$ 112,196.71	$ 329,164.46	$ 1,290,265.42
11	Real Time Spinning Reserve Cost Distribution	$ 49,517.58	$ 187,815.91	$ 72,265.62	$ 309,599.11	$ 107,718.04	$ 126,909.38	$ 139,494.34	$ 374,121.77	$ 166,780.10	$ 154,536.62	$ 98,271.88	$ 419,588.60	$ 199,927.23	$ 95,677.90	$ 81,513.68	$ 377,118.81	$ 1,480,428.29
	SUBTOTAL	$ 2,108.85	$ 151,098.73	$ (13,730.93)	$ 139,476.65	$ 24,077.25	$ 54,204.60	$ 24,233.47	$ 102,515.33	$ 81,576.49	$ 43,026.09	$ 15,843.60	$ 140,446.17	$ 99,800.10	$ 21,944.49	$ 35,954.57	$ 157,699.17	$ 540,137.31
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (9,470.67)	$ (311,228.73)	$ (24,363.65)	$ (345,063.06)	$ (33,352.63)	$ (18,376.29)	$ (11,730.03)	$ (63,458.95)	$ (24,881.72)	$ (28,500.02)	$ (30,963.98)	$ (84,345.72)	$ (21,942.95)	$ (7,014.95)	$ (53,088.34)	$ (82,046.24)	$ (574,913.97)
6	Real-Time Supplemental Reserve Amount.	$ 2,114.16	$ 381,797.35	$ (115,537.57)	$ 268,373.94	$ 16,201.16	$ 23,658.34	$ (7,728.74)	$ 32,130.76	$ 7,572.16	$ 9,229.81	$ 21,911.82	$ 38,713.78	$ 30,926.15	$ 211.69	$ 6,129.86	$ 37,267.70	$ 376,486.19
12	Real Time Supplemental Reserve Cost Distribution	$ 7,347.59	$ 264,649.80	$ (53,495.36)	$ 218,502.02	$ 16,756.33	$ 19,848.98	$ 83,200.79	$ 119,806.10	$ 34,495.01	$ 53,247.39	$ 6,750.88	$ 94,493.28	$ 42,942.05	$ 12,142.03	$ 115,817.90	$ 170,901.98	$ 603,703.38
	SUBTOTAL	$ (8.92)	$ 335,218.42	$ (193,396.59)	$ 141,812.91	$ (395.15)	$ 25,131.03	$ 63,742.02	$ 88,477.91	$ 17,185.46	$ 33,977.17	$ (2,301.29)	$ 48,861.34	$ 51,925.25	$ 5,338.77	$ 68,859.42	$ 126,123.44	$ 405,275.59
Other Charges																		
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -	$ 52,482.44	$ (53,318.71)	$ -	$ (836.27)	$ -	$ (0.50)	$ -	$ (0.50)	$ 1,055.02	$ 44,022.36	$ (236.67)	$ 44,840.70	$ 44,003.94
13	Real Time Excessive/Deficient Energy Deployment	$ 10,389.33	$ 39,436.07	$ 15,991.45	$ 65,816.86	$ 8,390.49	$ 19,684.79	$ 3,804.50	$ 31,879.78	$ 25,778.01	$ 40,282.49	$ 27,907.40	$ 93,967.90	$ 73,676.78	$ 63,412.89	$ 48,349.93	$ 185,439.59	$ 377,104.14
9	Real Time Net Regulation Adjustment Amount	$ (1,455.42)	$ (36,400.06)	$ 9,947.27	$ (27,908.20)	$ 298.81	$ (4,946.91)	$ (23,821.57)	$ (28,469.67)	$ 1,696.87	$ (2,166.06)	$ (1,270.93)	$ (1,740.12)	$ (6,201.73)	$ (20,742.11)	$ 1,370,280.88	$ 1,343,337.03	$ 1,285,219.03
	SUBTOTAL	$ 8,933.92	$ 3,036.02	$ 25,938.72	$ 37,908.66	$ 61,171.74	$ (38,580.82)	$ (20,017.08)	$ 2,573.84	$ 27,474.88	$ 38,115.93	$ 26,636.47	$ 92,227.28	$ 68,530.07	$ 86,693.13	$ 1,418,394.13	$ 1,573,617.33	$ 1,706,327.11
	TOTAL MISO ASM CHARGES	$ 34,273.19	$ 640,391.12	$ (279,186.65)	$ 395,477.66	$ 97,372.60	$ 89,122.54	$ 24,268.85	$ 210,763.99	$ 137,606.79	$ 115,897.80	$ 35,731.79	$ 289,236.38	$ 169,022.06	$ 9,502.34	$ 1,607,754.60	$ 1,786,279.00	$ 2,681,757.02
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (2,042.11)	$ (41,564.03)	$ 18,611.54	$ (24,994.59)	$ 25,557.93	$ (6,009.58)	$ 7,004.28	$ 26,552.63	$ (6,954.31)	$ 9,412.55	$ 6,986.01	$ 9,444.25	$ 14,115.63	$ 21,386.11	$ 16,008.88	$ 51,510.62	$ 62,512.91
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,113,478.03	$ (614,851.32)	$ 981,763.99	$ 1,480,390.70	$ 757,830.34	$ 598,645.26	$ 3,512,845.98	$ 4,869,321.58	$ 4,911,293.42	$ 2,717,396.00	$ 381,848.70	$ 8,010,538.12	$ 2,043,175.06	$ 1,601,608.31	$ 3,333,706.37	$ 6,978,489.74	$ 21,338,740.14
8b	Real Time Non Excessive Energy Congestion	$ 122,340.73	$ 69,151.78	$ (36,848.12)	$ 154,644.39	$ 5,675.98	$ (420,549.60)	$ (649,455.59)	$ (1,064,329.21)	$ (32,912.87)	$ 430,270.78	$ (138,261.19)	$ 259,096.71	$ 1,748,312.73	$ 1,695,158.61	$ 2,414,569.51	$ 5,858,040.84	$ 5,207,452.74
8c	Real Time Non Excessive Energy Loss	$ 59,285.57	$ 42,968.84	$ 34,310.76	$ 136,565.16	$ 63,283.17	$ (1,594.92)	$ (12,825.56)	$ 48,862.70	$ (36,847.13)	$ 21,340.23	$ 77,002.46	$ 61,495.56	$ 186,176.48	$ 226,542.73	$ 142,155.68	$ 554,874.88	$ 801,798.31
	SUBTOTAL	$ 1,293,062.22	$ (544,294.73)	$ 997,838.18	$ 1,746,605.67	$ 852,347.42	$ 170,491.16	$ 2,857,569.11	$ 3,880,407.69	$ 4,834,579.11	$ 3,178,419.56	$ 327,575.98	$ 8,340,574.65	$ 3,991,779.90	$ 3,544,695.75	$ 5,906,440.44	$ 13,442,916.09	$ 27,410,504.10
	GRAND TOTAL MISO ASM CHARGES	$ 1,327,335.42	$ 96,096.39	$ 718,651.52	$ 2,142,083.33	$ 949,720.02	$ 259,613.70	$ 2,881,837.96	$ 4,091,171.68	$ 4,972,185.89	$ 3,294,317.36	$ 363,307.77	$ 8,629,811.02	$ 4,160,801.96	$ 3,554,198.09	$ 7,514,195.04	$ 15,229,195.08	$ 30,092,261.12

Northern States Power Company
MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January 2021	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	-	$ (222,870.11)	-	$ (114,718.38)	-	$ (108,151.73)		
2 Day-Ahead Spinning Reserve Amount	-	$ (184,405.08)	-	$ (79,067.80)	-	$ (105,337.28)		
3 Day-Ahead Supplemental Reserve	-	$ (36,839.82)	-	$ (4,910.47)	-	$ (31,929.35)		
4 Real-Time Regulation Amount (See Note 1)	-	$ 50,363.99	-	$ 50,363.99	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ 46,863.35	-	$ 46,863.35	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 2,974.45	-	$ 2,974.45	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(822)	$ (13,268.54)	(822)	$ (13,268.54)	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	165,884	$ 2,860,297.06	165,884	$ 2,860,297.06	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 5,697.01	-	$ 5,504.16	-	$ 192.85		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 111,321.30	-	$ 111,321.30	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 76,300.71	-	$ 76,300.71	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 21,400.92	-	$ 21,400.92	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 29,363.95	-	$ 20,436.85	-	$ 8,927.10		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ (70.54)	-	$ 70.54		
MISO ASM CHARGES	165,062	$ 2,747,199.19	165,062	$ 2,983,427.06	-	$ (236,227.87)	-	$ -
x Net Congestion Amount	-	$ (131,073.51)	-	$ (131,073.51)	-	$ -		
y Net Loss Amount	-	$ (68,882.86)	-	$ (68,882.86)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 199,956.37	-	$ 199,956.37	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**165,062**	**$ 2,747,199.19**	**165,062**	**$ 2,983,427.06**	**-**	**$ (236,227.87)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

Northern States Power Company
MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

February 2021					Intersystem			
	NET INVOICE		RETAIL		ASSET BASED		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	-	$ (231,511.33)	-	$ (5,963.90)	-	$ (225,547.43)		
2 Day-Ahead Spinning Reserve Amount	-	$ (123,481.97)	-	$ 85,608.21	-	$ (209,090.18)		
3 Day-Ahead Supplemental Reserve	-	$ (28,971.64)	-	$ 9,120.41	-	$ (38,092.05)		
4 Real-Time Regulation Amount (See Note 1)	-	$ 34,791.79	-	$ 34,791.79	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (31,632.62)	-	$ (31,632.62)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (173.46)	-	$ (173.46)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(617)	$ (7,907.35)	(617)	$ (7,907.35)	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	(71,486)	$ (463,662.43)	(71,486)	$ (463,662.43)	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (6,457.85)	-	$ (1,977.51)	-	$ (4,480.34)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 108,152.70	-	$ 108,152.70	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 61,960.75	-	$ 61,960.75	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 9,808.49	-	$ 9,808.49	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 35,284.70	-	$ 24,274.66	-	$ 11,010.04		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	(72,103)	$ (643,800.22)	(72,103)	$ (177,600.26)	-	$ (466,199.96)	-	$ -
x Net Congestion Amount	-	$ 84,356.90	-	$ 84,356.90	-	$ -		
y Net Loss Amount	-	$ 105,131.56	-	$ 105,131.56	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (189,488.46)	-	$ (189,488.46)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**(72,103)**	**$ (643,800.22)**	**(72,103)**	**$ (177,600.26)**	**-**	**$ (466,199.96)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

March 2021	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	-	$ (147,873.73)	-	$ (136,591.27)	-	$ (11,282.46)		
2 Day-Ahead Spinning Reserve Amount	-	$ (264,050.78)	-	$ (1,300.32)	-	$ (262,750.46)		
3 Day-Ahead Supplemental Reserve	-	$ (34,514.95)	-	$ (201,503.22)	-	$ 166,988.27		
4 Real-Time Regulation Amount (See Note 1)	-	$ (54,966.23)	-	$ (54,966.23)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (120,527.33)	-	$ (120,527.33)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 3,311.12	-	$ 3,311.12	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(4,448)	$ 26,366.18	(4,448)	$ 26,366.18	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	52,728	$ 1,387,228.63	52,728	$ 1,387,228.63	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 5,578.83	-	$ 14,091.87	-	$ (8,513.04)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 52,728.12	-	$ 52,728.12	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 102,375.62	-	$ 102,375.62	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ (75,784.60)	-	$ (75,784.60)	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 33,778.24	-	$ 22,654.41	-	$ 11,123.83		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	48,280	$ 913,649.12	48,280	$ 1,018,082.98	-	$ (104,433.86)	-	$ -
x Net Congestion Amount	-	$ (52,201.16)	-	$ (52,042.26)	-	$ (158.90)		
y Net Loss Amount	-	$ 48,606.59	-	$ 45,174.30	-	$ 3,432.29		
z Net Congestion and Loss Energy Offset	-	$ 3,594.57	-	$ 3,594.57	-	$ -		
SUBTOTAL	-	$ -	-	$ (3,273.39)	-	$ 3,273.39		
TOTAL MISO ASM CHARGES	**48,280**	**$ 913,649.12**	**48,280**	**$ 1,014,809.59**	**-**	**$ (101,160.47)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

April 2021	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	-	$ (262,770.12)	-	$ 24,885.69	-	$ (287,655.81)		
2 Day-Ahead Spinning Reserve Amount	-	$ (203,962.87)	-	$ (75,006.24)	-	$ (128,956.63)		
3 Day-Ahead Supplemental Reserve	-	$ (46,997.77)	-	$ (38,230.65)	-	$ (8,767.12)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (161,628.01)	-	$ (161,628.01)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (42,853.44)	-	$ (42,853.44)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 14,062.21	-	$ 14,062.21	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,488)	$ 36,014.12	(3,488)	$ 36,014.12	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	100,315	$ 1,165,043.33	100,315	$ 1,165,043.33	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (19,141.28)	-	$ 421.06	-	$ (19,562.34)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 154,382.71	-	$ 154,382.71	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 151,787.35	-	$ 151,787.35	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 23,611.63	-	$ 23,611.63	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 30,047.21	-	$ 11,823.19	-	$ 18,224.02		
14 Real Time Contingency Reserve Deployment Failure	-	$ 74,081.54	-	$ 73,953.91	-	$ 127.63		
MISO ASM CHARGES	96,828	$ 911,676.61	96,828	$ 1,338,266.86	-	$ (426,590.25)	-	$ -
x Net Congestion Amount	-	$ 7,998.12	-	$ 7,998.12	-	$ -		
y Net Loss Amount	-	$ 89,173.41	-	$ 89,173.41	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (97,171.53)	-	$ (97,171.53)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**96,828**	**$ 911,676.61**	**96,828**	**$ 1,338,266.86**	**-**	**$ (426,590.25)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

May 2021	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	-	$ (322,838.33)	-	$ 53,571.47	-	$ (376,409.80)		
2 Day-Ahead Spinning Reserve Amount	-	$ (243,955.90)	-	$ (26,121.91)	-	$ (217,833.99)		
3 Day-Ahead Supplemental Reserve	-	$ (25,452.43)	-	$ (16,647.75)	-	$ (8,804.68)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (142,422.10)	-	$ (142,422.10)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (74,579.24)	-	$ (74,579.24)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 23,963.76	-	$ 23,963.76	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(926)	$ (8,323.69)	(926)	$ (8,323.69)	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	155,931	$ 244,465.73	155,931	$ 244,465.73	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (12,224.20)	-	$ (6,851.81)	-	$ (5,372.39)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 155,843.28	-	$ 155,843.28	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 175,778.27	-	$ 175,778.27	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 27,492.21	-	$ 27,492.21	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 61,069.64	-	$ 27,264.80	-	$ 33,804.84		
14 Real Time Contingency Reserve Deployment Failure	-	$ (73,850.00)	-	$ (73,850.10)	-	$ 0.10		
MISO ASM CHARGES	155,005	$ (215,033.00)	155,005	$ 359,582.92	-	$ (574,615.92)	-	$ -
x Net Congestion Amount	-	$ (582,490.27)	-	$ (582,490.27)	-	$ -		
y Net Loss Amount	-	$ (2,209.07)	-	$ (2,209.07)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 584,699.34	-	$ 584,699.34	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**155,005**	**$ (215,033.00)**	**155,005**	**$ 359,582.92**	**-**	**$ (574,615.92)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

June 2021	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	-	$ (107,195.17)	-	$ (20,217.97)	-	$ (86,977.20)		
2 Day-Ahead Spinning Reserve Amount	-	$ (136,940.29)	-	$ (12,029.59)	-	$ (124,910.70)		
3 Day-Ahead Supplemental Reserve	-	$ (16,079.64)	-	$ (7,138.00)	-	$ (8,941.64)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (221,612.40)	-	$ (221,612.40)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (145,971.12)	-	$ (145,971.12)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (19,536.27)	-	$ (19,536.27)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,691)	$ 9,601.54	(1,691)	$ 9,601.54	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	173,909	$ 3,907,581.69	173,909	$ 3,907,581.69	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (49,644.62)	-	$ (32,654.84)	-	$ (16,989.78)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 181,940.28	-	$ 181,940.28	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 191,220.19	-	$ 191,220.19	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 114,052.45	-	$ 114,052.45	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 12,826.26	-	$ 5,215.24	-	$ 7,611.02		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	172,219	$ 3,720,242.90	172,219	$ 3,950,451.20	-	$ (230,208.30)	-	$ -
x Net Congestion Amount	-	$ (890,279.97)	-	$ (890,279.97)	-	$ -		
y Net Loss Amount	-	$ (17,581.40)	-	$ (17,581.40)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 907,861.37	-	$ 907,861.37	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**172,219**	**$ 3,720,242.90**	**172,219**	**$ 3,950,451.20**	**-**	**$ (230,208.30)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

July 2021	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	-	$ (239,360.49)	-	$ 74,262.44	-	$ (313,622.93)		
2 Day-Ahead Spinning Reserve Amount	-	$ (252,603.34)	-	$ 22,156.81	-	$ (274,760.15)		
3 Day-Ahead Supplemental Reserve	-	$ (34,148.62)	-	$ (14,354.58)	-	$ (19,794.04)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (252,040.44)	-	$ (252,040.44)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (139,093.51)	-	$ (139,093.51)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (9,401.72)	-	$ (9,401.72)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,120)	$ (9,544.36)	(3,120)	$ (9,544.36)	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	185,209	$ 6,644,706.15	185,209	$ 6,644,706.15	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (15,776.67)	-	$ 2,328.85	-	$ (18,105.52)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 193,382.57	-	$ 193,382.57	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 228,895.40	-	$ 228,895.40	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 47,342.28	-	$ 47,342.28	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 62,434.67	-	$ 35,378.73	-	$ 27,055.94		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	182,089	$ 6,224,791.92	182,089	$ 6,824,018.62	-	$ (599,226.70)	-	$ -
x Net Congestion Amount	-	$ (45,170.89)	-	$ (45,170.89)	-	$ -		
y Net Loss Amount	-	$ (50,570.41)	-	$ (50,570.41)	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 95,741.30	-	$ 95,741.30	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**182,089**	**$ 6,224,791.92**	**182,089**	**$ 6,824,018.62**	**-**	**$ (599,226.70)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

August 2021	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	-	$ (360,133.58)	-	$ (38,875.54)	-	$ (321,258.04)		
2 Day-Ahead Spinning Reserve Amount	-	$ (394,149.77)	-	$ (139,738.60)	-	$ (254,411.17)		
3 Day-Ahead Supplemental Reserve	-	$ (38,999.21)	-	$ (26,790.98)	-	$ (12,208.23)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (143,246.65)	-	$ (143,246.65)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (12,851.55)	-	$ (12,851.55)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 421.77	-	$ 421.77	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,242)	$ 12,880.06	(3,242)	$ 12,880.06	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	160,028	$ 4,336,444.42	160,028	$ 4,336,444.42	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (13,179.72)	-	$ (2,964.02)	-	$ (10,215.70)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 183,187.63	-	$ 183,187.63	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 211,466.71	-	$ 211,466.71	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 72,863.31	-	$ 72,863.31	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 106,167.62	-	$ 55,122.24	-	$ 51,045.38		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ 0.68		
MISO ASM CHARGES	156,786	$ 3,960,871.04	156,786	$ 4,507,918.80	-	$ (547,047.08)	-	$ -
x Net Congestion Amount	-	$ 588,779.17	-	$ 588,779.17	-	$ -		
y Net Loss Amount	-	$ 29,201.80	-	$ 29,201.80	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (617,980.97)	-	$ (617,980.97)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**156,786**	**$ 3,960,871.04**	**156,786**	**$ 4,507,918.80**	**-**	**$ (547,047.08)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

September 2021	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	-	$ (237,883.74)	-	$ 14,486.62	-	$ (252,370.36)		
2 Day-Ahead Spinning Reserve Amount	-	$ (226,786.86)	-	$ (25,489.87)	-	$ (201,296.99)		
3 Day-Ahead Supplemental Reserve	-	$ (42,668.01)	-	$ (25,482.65)	-	$ (17,185.36)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (194,616.85)	-	$ (194,616.85)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (88,095.35)	-	$ (88,095.35)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 13,008.87	-	$ 13,008.87	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,781)	$ 9,626.64	(1,781)	$ 9,626.64	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	51,466	$ 441,769.30	51,466	$ 441,769.30	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (2,782.73)	-	$ (1,751.33)	-	$ (1,031.40)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 174,002.33	-	$ 174,002.33	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 135,417.52	-	$ 135,417.52	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 9,302.63	-	$ 9,302.63	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 65,611.33	-	$ 38,456.08	-	$ 27,155.25		
14 Real Time Contingency Reserve Deployment Failure	-	$ -	-	$ -	-	$ -		
MISO ASM CHARGES	49,685	$ 55,905.08	49,685	$ 500,633.94	-	$ (444,728.86)	-	$ -
x Net Congestion Amount	-	$ (190,522.33)	-	$ (190,522.33)	-	$ -		
y Net Loss Amount	-	$ 106,108.51	-	$ 106,108.51	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ 84,413.82	-	$ 84,413.82	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**49,685**	**$ 55,905.08**	**49,685**	**$ 500,633.94**	**-**	**$ (444,728.86)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

October 2021	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	-	$ (473,628.04)	-	$ 115,850.53	-	$ (589,478.57)		
2 Day-Ahead Spinning Reserve Amount	-	$ (224,177.99)	-	$ (7,586.01)	-	$ (216,591.98)		
3 Day-Ahead Supplemental Reserve	-	$ (30,432.94)	-	$ (22,928.89)	-	$ (7,504.05)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (385,076.85)	-	$ (385,076.85)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (131,281.50)	-	$ (131,281.50)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 35,387.80	-	$ 35,387.80	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,809)	$ 19,577.14	(2,809)	$ 19,577.14	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	134,422	$ 5,516,670.25	134,422	$ 5,516,670.25	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (9,124.72)	-	$ (8,601.26)	-	$ (523.46)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 198,170.16	-	$ 198,170.16	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 277,281.47	-	$ 277,281.47	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 59,556.84	-	$ 59,556.84	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 146,255.57	-	$ 102,183.21	-	$ 44,072.36		
14 Real Time Contingency Reserve Deployment Failure	-	$ 1,463.22	-	$ 1,463.22	-	$ -		
MISO ASM CHARGES	131,613	$ 5,000,640.41	131,613	$ 5,770,666.11	-	$ (770,025.70)	-	$ -
x Net Congestion Amount	-	$ 2,424,755.88	-	$ 2,424,755.88	-	$ -		
y Net Loss Amount	-	$ 258,210.39	-	$ 258,210.39	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (2,682,966.27)	-	$ (2,682,966.27)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**131,613**	**$ 5,000,640.41**	**131,613**	**$ 5,770,666.11**	**-**	**$ (770,025.70)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

November 2021	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	-	$ (299,431.61)	-	$ (76,512.30)	-	$ (222,919.31)		
2 Day-Ahead Spinning Reserve Amount	-	$ (321,238.92)	-	$ 2,123.72	-	$ (323,362.64)		
3 Day-Ahead Supplemental Reserve	-	$ (9,832.34)	-	$ (9,101.88)	-	$ (730.46)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (231,805.88)	-	$ (231,805.88)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (105,470.44)	-	$ (105,470.44)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (433.75)	-	$ (433.75)	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,285)	$ 29,975.35	(2,285)	$ 29,975.35	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	(58)	$ 4,938,364.97	(58)	$ 4,938,364.97	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ (7,017.36)	-	$ (29,072.70)	-	$ 22,055.34		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 161,884.56	-	$ 161,884.56	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 134,104.70	-	$ 134,104.70	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 17,018.59	-	$ 17,018.59	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 132,259.35	-	$ 88,881.20	-	$ 43,378.15		
14 Real Time Contingency Reserve Deployment Failure	-	$ 61,702.91	-	$ 61,702.91	-	$ -		
MISO ASM CHARGES	(2,343)	$ 4,500,080.13	(2,343)	$ 4,981,659.05	-	$ (481,578.92)	-	$ -
x Net Congestion Amount	-	$ 2,375,979.62	-	$ 2,375,979.62	-	$ -		
y Net Loss Amount	-	$ 317,528.34	-	$ 317,528.34	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (2,693,507.96)	-	$ (2,693,507.96)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**(2,343)**	**$ 4,500,080.13**	**(2,343)**	**$ 4,981,659.05**	**-**	**$ (481,578.92)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

December 2021	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	-	$ (182,830.02)	-	$ (70,213.68)	-	$ (112,616.34)		
2 Day-Ahead Spinning Reserve Amount	-	$ (223,985.03)	-	$ (50,624.74)	-	$ (173,360.29)		
3 Day-Ahead Supplemental Reserve	-	$ (9,940.23)	-	$ (8,754.24)	-	$ (1,185.99)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (65,435.71)	-	$ (65,435.71)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (101,360.47)	-	$ (101,360.47)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (14,061.04)	-	$ (14,061.04)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (2,727.56)	-	$ (2,727.56)	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 10,244.87	-	$ 10,244.87	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,722)	$ 22,729.74	(1,722)	$ 22,729.74	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	73,923	$ 8,363,358.45	73,923	$ 8,363,358.45	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 1,986,342.02	-	$ 1,945,553.57	-	$ 40,788.45		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 132,526.54	-	$ 132,526.54	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 115,734.84	-	$ 115,734.84	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 19,017.75	-	$ 19,017.75	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 145,422.94	-	$ 145,422.94	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 114,035.85	-	$ 68,648.24	-	$ 45,387.61		
14 Real Time Contingency Reserve Deployment Failure	-	$ 598.96	-	$ (364.37)	-	$ 963.33		
15 Real Time Short Term Reserve Deployment Failure	-	$ 28.34	-	$ 28.34	-	$ -		
MISO ASM CHARGES	72,201	$ 10,309,700.24	72,201	$ 10,509,723.47	-	$ (200,023.23)		
x Net Congestion Amount	-	$ 3,428,256.50	-	$ 3,428,256.50	-	$ -		
y Net Loss Amount	-	$ 201,835.62	-	$ 201,835.62	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (3,630,092.12)	-	$ (3,630,092.12)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**72,201**	**$ 10,309,700.24**	**72,201**	**$ 10,509,723.47**	**-**	**$ (200,023.23)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

January - December 2021	NET INVOICE		RETAIL		Intersystem			
					ASSET BASED		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	-	$ (3,020,070.14)	-	$ 47,839.08	-	$ (3,067,909.22)		
2 Day-Ahead Spinning Reserve Amount	-	$ (3,115,560.22)	-	$ (638,461.58)	-	$ (2,477,098.64)		
3 Day-Ahead Supplemental Reserve	-	$ (746,463.81)	-	$ (78,892.95)	-	$ (667,570.86)		
4 Real-Time Regulation Amount (See Note 1)	-	$ (65,435.71)	-	$ (65,435.71)	-	$ -		
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (2,217,938.26)	-	$ (2,217,938.26)	-	$ -		
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (669,369.97)	-	$ (669,369.97)	-	$ -		
7 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ (143,713.55)	-	$ (143,713.55)	-	$ -		
8 Real-Time Short Term Reserve Amount. (See Note 1)	-	$ 10,244.87	-	$ 10,244.87	-	$ -		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(28,589)	$ 86,718.76	(28,589)	$ 86,718.76	-	$ -		
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
8a Real Time Non Excessive Energy Amount	1,132,942	$ 38,060,064.23	1,132,942	$ 38,060,064.23	-	$ -		
8b Real Time Non Excessive Energy Congestion	-	$ -	-	$ -	-	$ -		
8c Real Time Non Excessive Energy Loss	-	$ -	-	$ -	-	$ -		
9 Real Time Net Regulation Adjustment Amount	-	$ 1,765,951.08	-	$ 1,826,512.17	-	$ (60,561.09)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 2,058,357.30	-	$ 2,058,357.30	-	$ -		
11 Real Time Spinning Reserve Cost Distribution	-	$ 2,062,034.54	-	$ 2,062,034.54	-	$ -		
12 Real Time Supplemental Reserve Cost Distribution	-	$ 702,417.93	-	$ 702,417.93	-	$ -		
13 Real Time Short Term Reserve Cost Distribution	-	$ 145,422.94	-	$ 145,422.94	-	$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 872,735.49	-	$ 526,580.81	-	$ 346,154.68		
14 Real Time Contingency Reserve Deployment Failure	-	$ 63,996.63	-	$ 62,904.89	-	$ 1,091.74		
15 Real Time Short Term Reserve Deployment Failure	-	$ 28.34	-	$ 28.34	-	$ -		
MISO ASM CHARGES	1,104,353	$ 35,849,420.45	1,104,353	$ 41,775,313.84	-	$ (5,925,893.39)		
x Net Congestion Amount	-	$ 7,336,781.13	-	$ 7,336,781.13	-	$ -		
y Net Loss Amount	-	$ 1,125,449.89	-	$ 1,125,449.89	-	$ -		
z Net Congestion and Loss Energy Offset	-	$ (8,462,231.02)	-	$ (8,462,231.02)	-	$ -		
SUBTOTAL	-	$ -	-	$ -	-	$ -		
TOTAL MISO ASM CHARGES	**1,104,353**	**$ 35,849,420.45**	**1,104,353**	**$ 41,775,313.84**	**-**	**$ (5,925,893.39)**	**-**	**$ -**

NOTE 1: The Company did not break out Day Ahead and Real Time asset-based amounts that are reclassified to wholesale revenue; both Day Ahead and Real Time amounts are included in this line item.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	January 2021	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	(703,460)	$ (5,377,785.68)	3,479,808	$ 77,493,628.50	(3,318,187)	$ (64,615,962.97)			(865,081)	$ (18,255,451.21)				
5a	Day Ahead Non Asset Energy	(106,875)	$ (2,429,321.93)	8	$ 169.63	(106,883)	$ (2,429,491.56)					11,688	$ 255,736.87	-	$ -
13a	Real Time Asset Energy	(3,352)	$ 106,738.21	50,373	$ 1,192,314.95	58,880	$ 825,230.17			(112,605)	$ (1,910,806.91)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(813,687)	$ (7,700,369.40)	3,530,189	$ 78,686,113.08	(3,366,190)	$ (66,220,224.36)	-	$ -	(977,686)	$ (20,166,258.12)	11,688	$ 255,736.87	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 458.16		$ 1,563.17		$ (1,105.01)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (833,743.05)		$ -		$ (833,743.05)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (833,284.89)		$ 1,563.17		$ (834,848.06)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 615,120.24		$ 546,206.20		$ -		$ 68,914.04				$ 924.19		
19	Real Time Market Administration (Schedule 17)		$ 62,254.43		$ 53,357.48		$ -		$ 8,896.95				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 24,952.66		$ 24,952.66		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 95,570.45		$ 84,900.46		$ -		$ 10,669.99				$ 142.56		
34	Real -Time Schedule 24 Allocation Amount		$ (86,200.61)		$ 17,493.78		$ -				$ (103,694.39)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 711,697.17		$ 726,910.58		$ -		$ 88,480.98		$ (103,694.39)		$ 1,066.75		$ -
	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		$ 1,011.32		$ 5,087.93		$ (4,076.61)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,295,128.45)		$ 569,483.24		$ (1,864,611.69)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (45,031.42)		$ -		$ (45,031.42)								$ -
32	Financial Transmission Rights Yearly Allocation		$ (324,720.42)		$ -		$ (324,720.42)						$ -		$ (11.82)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 178,365.73		$ 178,365.73		$ -								$ 11.82
37	Financial Transmission Guarantee Uplift Amount		$ (158,348.63)		$ -		$ (158,348.63)						$ 177.01		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,643,851.87)		$ 752,936.90		$ (2,396,788.77)		$ -		$ -		$ 177.01		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 40,571.55		$ 40,571.55				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (184,241.08)				$ (153,632.90)				$ (30,608.18)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 37,396.59		$ 37,396.59				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (68,735.05)				$ (43,864.79)				$ (24,870.26)				
43	Real Time Price Volatility Make Whole Payment		$ (50,758.60)		$ -		($26,434.99)				$ (24,323.61)				
	SUBTOTAL		$ (225,766.59)		$ 77,968.14		$ (223,932.68)		$ -		$ (79,802.05)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (343.49)		$ 36,350.61		$ (35,207.34)				$ (1,486.76)		$ -		
21	Real Time Net Inadvertent Distribution		$ 4,466.68		$ 38,039.31		$ (33,572.63)						$ 50.36		$ (47.27)
23	Real Time Revenue Neutrality Uplift Amount		$ 698,709.55		$ 859,643.94		$ (160,934.39)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 702,832.74		$ 934,033.86		$ (229,714.36)		$ -		$ (1,486.76)		$ 50.36		$ (47.27)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,635,397.07		$ 1,702,032.22		$ (66,635.15)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,639,395.05)		$ 66,003.13		$ (1,671,519.04)				$ (33,879.14)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (202,829.18)		$ -		$ (202,829.18)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 22,539.98		$ 22,539.98		$ -								
	SUBTOTAL		$ (184,287.18)		$ 1,790,575.33		$ (1,940,983.37)		$ -		$ (33,879.14)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (1,011.32)		$ 4,076.61		$ (5,087.93)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (458.16)		$ 1,105.01		$ (1,563.17)								
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	-	$ (1,469.48)	-	$ 5,181.62	-	$ (6,651.10)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(813,687)	$ (9,174,499.50)	3,530,189	$ 82,975,282.68	(3,366,190)	$ (71,853,142.70)	-	$ 88,480.98	(977,686)	$ (20,385,120.46)	11,688	$ 257,030.99	-	$ (47.27)
x	Net Congestion Amount		$ 6,068,127.34		$ 6,068,127.34				$ -						
y	Net Loss Amount		$ 2,966,567.76		$ 2,966,567.76				$ -						
z	Net Congestion and Loss Energy Offset		$ (9,034,695.10)		$ (9,034,695.10)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(813,687)**	$ (9,174,499.50)	3,530,189	$ 82,975,282.68	(3,366,190)	$ (71,853,142.70)	-	$ 88,480.98	(977,686)	$ (20,385,120.46)	11,688	$ 257,030.99	-	$ (47.27)

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 2021	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	(722,420)	$ (30,548,662.37)	3,312,497	$ 259,069,106.15	(3,198,922)	$ (234,116,950.37)			(835,995)	$ (55,500,818.15)				
5a	Day Ahead Non Asset Energy	(92,097)	$ (9,475,430.91)	34	$ 1,120.36	(92,131)	$ (9,476,551.27)					10,344	$ 806,634.91	-	$ -
13a	Real Time Asset Energy	(32,269)	$ (3,300,381.50)	38,611	$ 1,509,331.60	83,110	$ 966,389.90			(153,990)	$ (5,776,103.00)				
22a	Real Time Non Asset Energy	2	$ 77.72	2	$ 77.72	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(846,784)	$ (43,324,397.06)	3,351,144	$ 260,579,635.83	(3,207,943)	$ (242,627,111.74)	-	$ -	(989,985)	$ (61,276,921.15)	10,344	$ 806,634.91	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 17,560.74		$ 20,166.13		$ (2,605.39)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (3,687,207.29)		$ -		$ (3,687,207.29)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (3,669,646.55)		$ 20,166.13		$ (3,689,812.68)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 641,194.54		$ 569,390.67		$ -		$ 71,803.87				$ 891.72		
19	Real Time Market Administration (Schedule 17)		$ 64,581.44		$ 51,290.93		$ -		$ 13,290.51				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 22,576.00		$ 22,576.00		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 98,206.73		$ 87,216.45		$ -		$ 10,990.28				$ 135.76		
34	Real -Time Schedule 24 Allocation Amount		$ (95,126.55)		$ (1,870.86)		$ -				$ (93,255.69)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 731,432.16		$ 728,603.19		$ -		$ 96,084.66		$ (93,255.69)		$ 1,027.48		$ -
	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		$ (35,521.91)		$ 23,706.77		$ (59,228.68)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ 62,560.31		$ 2,894,377.02		$ (2,831,816.71)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (87,106.47)		$ -		$ (87,106.47)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (8,272.26)		$ -		$ (8,272.26)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 27,483.00		$ 27,483.00		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (40,857.33)		$ 2,945,566.79		$ (2,986,424.12)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 581,708.22		$ 581,708.22				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (100,861.42)				$ (15,040.96)				$ (85,820.46)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 2,297,660.28		$ 2,297,660.28				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (12,024,549.38)				$ (4,431,496.61)				$ (7,593,052.77)				
43	Real Time Price Volatility Make Whole Payment		$ (523,280.24)		$ -		($479,643.15)				$ (43,637.09)				
	SUBTOTAL		$ (9,769,322.54)		$ 2,879,368.50		$ (4,926,180.72)		$ -		$ (7,722,510.32)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 40,027.98		$ 77,166.37		$ (35,795.51)				$ (1,342.88)		$ -		
21	Real Time Net Inadvertent Distribution		$ 30,397.26		$ 66,293.00		$ (35,895.74)						$ 85.00		$ (46.65)
23	Real Time Revenue Neutrality Uplift Amount		$ (3,535,925.54)		$ 3,115,332.98		$ (6,651,258.52)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ (3,465,500.30)		$ 3,258,792.35		$ (6,722,949.77)		$ -		$ (1,342.88)		$ 85.00		$ (46.65)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,635,397.07		$ 1,702,032.22		$ (66,635.15)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,639,395.05)		$ 66,003.13		$ (1,671,501.90)				$ (33,896.28)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (202,828.97)		$ -		$ (202,828.97)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 22,539.50		$ 22,539.50		$ -								
	SUBTOTAL		$ (184,287.45)		$ 1,790,574.85		$ (1,940,966.02)		$ -		$ (33,896.28)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 35,521.91		$ 59,228.68		$ (23,706.77)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (17,560.74)		$ 2,605.39		$ (20,166.13)								
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	-	$ 17,961.17	-	$ 61,834.07	-	$ (43,872.90)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(846,784)	$ (59,704,617.90)	3,351,144	$ 272,264,541.71	(3,207,943)	$ (262,937,317.95)	-	$ 96,084.66	(989,985)	$ (69,127,926.32)	10,344	$ 807,747.39	-	$ (46.65)
x	Net Congestion Amount		$ 5,456,963.49		$ 5,456,963.49				$ -						
y	Net Loss Amount		$ 6,759,034.12		$ 6,759,034.12				$ -						
z	Net Congestion and Loss Energy Offset		$ (12,215,997.61)		$ (12,215,997.61)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(846,784)**	$ (59,704,617.90)	3,351,144	$ 272,264,541.71	(3,207,943)	$ (262,937,317.95)	-	$ 96,084.66	(989,985)	$ (69,127,926.32)	10,344	$ 807,747.39	-	$ (46.65)

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 2021		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	(683,676)	$ 4,157,347.96	3,070,668	$ 59,893,175.66	(2,987,790)	$ (42,761,016.05)			(766,554)	$ (12,974,811.65)				
5a	Day Ahead Non Asset Energy	(103,614)	$ (2,233,545.46)	16	$ 222.61	(103,630)	$ (2,233,768.07)					12,845	$ 238,051.42	-	$ -
13a	Real Time Asset Energy	10,393	$ 445,205.69	80,517	$ 1,959,348.32	73,574	$ (173,208.26)			(143,698)	$ (1,340,934.37)				
22a	Real Time Non Asset Energy	(9)	$ (4.01)	(9)	$ (4.01)	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(776,906)	$ 2,369,004.18	3,151,191	$ 61,852,742.58	(3,017,845)	$ (45,167,992.38)	-	$ -	(910,252)	$ (14,315,746.02)	12,845	$ 238,051.42	-	$ -
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (4,571.15)		$ (3,695.30)		$ (875.85)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ 473,842.13		$ -		$ 473,842.13								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ 469,270.98		$ (3,695.30)		$ 472,966.28		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 435,010.14		$ 385,589.55		$ -		$ 49,420.59				$ 814.09		
19	Real Time Market Administration (Schedule 17)		$ 44,833.83		$ 36,104.43		$ -		$ 8,729.40				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 22,508.92		$ 22,508.92		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 89,402.63		$ 79,498.46		$ -		$ 9,904.17				$ 168.09		
34	Real -Time Schedule 24 Allocation Amount		$ (78,930.48)		$ 19,657.20		$ -				$ (98,587.68)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 512,825.04		$ 543,358.56		$ -		$ 68,054.16		$ (98,587.68)		$ 982.18		$ -
	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		$ 558.65		$ 2,076.95		$ (1,518.30)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (4,564,911.22)		$ 975,673.18		$ (5,540,584.40)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (172,381.16)		$ -		$ (172,381.16)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (99,092.25)		$ -		$ (99,092.25)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 93,724.42		$ 93,724.42		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (4,742,101.56)		$ 1,071,474.55		$ (5,813,576.11)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ (188,545.40)		$ (202,657.39)				$ 14,111.99						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (172,381.16)				$ (6,822,289.04)				$ 6,649,907.88				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ (376,273.57)		$ (384,742.59)				$ 8,469.02						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ 10,785,612.14				$ 10,809,782.71				$ (24,170.57)				
43	Real Time Price Volatility Make Whole Payment		$ (144,989.30)		$ -		($107,393.04)				$ (37,596.26)				
	SUBTOTAL		$ 9,903,422.71		$ (587,399.98)		$ 3,880,100.63		$ 22,581.01		$ 6,588,141.05		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 22,241.59		$ 99,004.81		$ (62,121.72)				$ (14,641.50)		$ -		
21	Real Time Net Inadvertent Distribution		$ 5,138.96		$ 35,439.25		$ (30,300.29)						$ 56.80		$ (43.11)
23	Real Time Revenue Neutrality Uplift Amount		$ 2,893,264.89		$ 1,640,412.35		$ 1,180,861.42		$ 71,991.12						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 2,920,645.44		$ 1,774,856.41		$ 1,088,439.41		$ 71,991.12		$ (14,641.50)		$ 56.80		$ (43.11)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,379,554.71		$ 2,563,346.05		$ (183,791.34)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,379,799.01)		$ 183,049.59		$ (2,536,968.18)				$ (25,880.42)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (134,061.22)		$ -		$ (134,061.22)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 5,619.74		$ 5,619.74		$ -								
	SUBTOTAL		$ (128,685.78)		$ 2,752,015.38		$ (2,854,820.74)		$ -		$ (25,880.42)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (558.65)		$ 1,518.30		$ (2,076.95)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 4,571.15		$ 875.85		$ 3,695.30								
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	-	$ 4,012.50	-	$ 2,394.15	-	$ 1,618.35	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(776,906)	$ 11,308,393.51	3,151,191	$ 67,405,746.36	(3,017,845)	$ (48,393,264.56)	-	$ 162,626.28	(910,252)	$ (7,866,714.57)	12,845	$ 239,090.40	-	$ (43.11)
x	Net Congestion Amount		$ 10,023,361.37		$ 9,695,736.41				$ 327,624.96						
y	Net Loss Amount		$ 2,617,902.35		$ 2,098,891.94				$ 519,010.41						
z	Net Congestion and Loss Energy Offset		$ (12,641,263.72)		$ (12,641,263.72)										
	SUBTOTAL	-	$ -	-	$ (846,635.37)	-	$ -	-	$ 846,635.37	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	(776,906)	$ 11,308,393.51	3,151,191	$ 66,559,110.99	(3,017,845)	$ (48,393,264.56)	-	$ 1,009,261.65	(910,252)	$ (7,866,714.57)	12,845	$ 239,090.40	-	$ (43.11)

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 2021	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	(596,130)	$ 13,100,247.42	2,882,591	$ 74,996,652.36	(2,793,305)	$ (49,761,765.29)			(685,416)	$ (12,134,639.65)				
5a	Day Ahead Non Asset Energy	(97,940)	$ (2,361,301.93)	40	$ 1,100.29	(97,980)	$ (2,362,402.22)					14,268	$ 370,290.78	-	$ (0.88)
13a	Real Time Asset Energy	(5,486)	$ (215,996.53)	43,942	$ 1,415,728.64	30,280	$ 558,443.20			(79,707)	$ (2,190,168.37)				
22a	Real Time Non Asset Energy	18	$ 4.69	18	$ 4.69	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(699,537)	$ 10,522,953.65	2,926,591	$ 76,413,485.98	(2,861,005)	$ (51,565,724.31)	-	$ -	(765,123)	$ (14,324,808.02)	14,268	$ 370,290.78	-	$ (0.88)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 962.40		$ 2,354.52		$ (1,392.12)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (629,706.81)		$ -		$ (629,706.81)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (628,744.41)		$ 2,354.52		$ (631,098.93)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 682,827.56		$ 612,628.92		$ -		$ 70,198.64				$ 1,498.28		
19	Real Time Market Administration (Schedule 17)		$ 83,621.11		$ 74,223.86		$ -		$ 9,397.25				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 31,323.66		$ 31,323.66		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 91,079.32		$ 81,476.98		$ -		$ 9,602.34				$ 201.08		
34	Real -Time Schedule 24 Allocation Amount		$ (84,063.93)		$ (2,202.57)		$ -				$ (81,861.36)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 804,787.72		$ 797,450.85		$ -		$ 89,198.23		$ (81,861.36)		$ 1,699.36		$ -
	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		$ 22,736.97		$ 26,978.71		$ (4,241.74)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (4,442,331.44)		$ 3,786,230.16		$ (8,228,561.60)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (305,351.77)		$ -		$ (305,351.77)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (167,653.17)		$ -		$ (167,653.17)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 171,940.98		$ 171,940.98		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (4,720,658.43)		$ 3,985,149.85		$ (8,705,808.28)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 81,298.83		$ 81,298.83				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (155,118.81)				$ (77,011.31)				$ (78,107.50)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 323,706.30		$ 323,706.30				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (172,649.25)				$ (79,462.21)				$ (93,187.04)				
43	Real Time Price Volatility Make Whole Payment		$ (210,202.18)		$ -		($189,310.72)				$ (20,891.46)				
	SUBTOTAL		$ (132,965.11)		$ 405,005.13		$ (345,784.24)		$ -		$ (192,186.00)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 25,713.05		$ 88,452.56		$ (69,979.87)				$ 7,240.36		$ -		
21	Real Time Net Inadvertent Distribution		$ (6,260.99)		$ 73,454.28		$ (79,715.27)						$ 144.70		$ (155.31)
23	Real Time Revenue Neutrality Uplift Amount		$ 999,614.34		$ 1,468,798.85		$ (469,184.51)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,019,066.40		$ 1,630,705.69		$ (618,879.65)		$ -		$ 7,240.36		$ 144.70		$ (155.31)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,379,554.71		$ 2,563,346.05		$ (183,791.34)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,379,799.01)		$ 183,049.59		$ (2,535,822.80)				$ (27,025.80)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (134,061.22)		$ -		$ (134,061.22)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 5,619.74		$ 5,619.74		$ -								
	SUBTOTAL		$ (128,685.78)		$ 2,752,015.38		$ (2,853,675.36)		$ -		$ (27,025.80)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (11,600.84)		$ 4,241.74		$ (15,842.58)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 621.35		$ 1,370.28		$ (748.93)								
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	-	$ (10,979.49)	-	$ 5,612.02	-	$ (16,591.51)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(699,537)	$ 6,724,774.55	2,926,591	$ 85,991,779.42	(2,861,005)	$ (64,737,562.28)	-	$ 89,198.23	(765,123)	$ (14,618,640.82)	14,268	$ 372,134.84	-	$ (156.19)
x	Net Congestion Amount		$ 19,123,635.44		$ 19,123,635.44				$ -						
y	Net Loss Amount		$ 2,973,243.50		$ 2,973,243.50				$ -						
z	Net Congestion and Loss Energy Offset		$ (22,096,878.94)		$ (22,096,878.94)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(699,537)**	$ 6,724,774.55	2,926,591	$ 85,991,779.42	(2,861,005)	$ (64,737,562.28)	-	$ 89,198.23	(765,123)	$ (14,618,640.82)	14,268	$ 372,134.84	-	$ (156.19)

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 2021	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	(545,336)	$ 8,987,223.10	3,051,837	$ 79,330,659.76	(2,830,396)	$ (53,579,835.66)			(766,777)	$ (16,763,601.00)				
5a	Day Ahead Non Asset Energy	(210,539)	$ (5,311,957.02)	40	$ 781.29	(210,579)	$ (5,312,738.31)					13,735	$ 352,896.13	-	$ (0.86)
13a	Real Time Asset Energy	16,701	$ 319,398.75	65,654	$ 1,804,161.55	29,569	$ 284,718.35			(78,521)	$ (1,769,481.15)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(739,173)	$ 3,994,664.83	3,117,531	$ 81,135,602.60	(3,011,406)	$ (58,607,855.62)	-	$ -	(845,298)	$ (18,533,082.15)	13,735	$ 352,896.13	-	$ (0.86)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 123.68		$ 1,661.62		$ (1,537.94)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (702,423.16)		$ -		$ (702,423.16)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (702,299.48)		$ 1,661.62		$ (703,961.10)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 548,421.51		$ 472,512.46		$ -		$ 75,909.05				$ 1,096.59		
19	Real Time Market Administration (Schedule 17)		$ 61,652.66		$ 53,944.12		$ -		$ 7,708.54				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 18,574.12		$ 18,574.12		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 74,939.60		$ 64,589.56		$ -		$ 10,350.04				$ 149.77		
34	Real -Time Schedule 24 Allocation Amount		$ (90,117.19)		$ 9,890.50		$ -				$ (100,007.69)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 613,470.70		$ 619,510.76		$ -		$ 93,967.63		$ (100,007.69)		$ 1,246.36		$ -
	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		$ 5,290.87		$ 10,823.47		$ (5,532.60)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (3,584,911.84)		$ 1,804,369.79		$ (5,389,281.63)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (151,677.06)		$ -		$ (151,677.06)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 130,721.60		$ 130,721.60		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (123,728.78)		$ -		$ (123,728.78)						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (3,724,305.21)		$ 1,945,914.86		$ (5,670,220.07)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 98,289.44		$ 98,289.44				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (165,172.58)				$ (75,050.23)				$ (90,122.35)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 269,064.79		$ 269,064.79				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (255,493.70)				$ (130,902.35)				$ (124,591.35)				
43	Real Time Price Volatility Make Whole Payment		$ (185,940.71)		$ -		($162,374.24)				$ (23,566.47)				
	SUBTOTAL		$ (239,252.76)		$ 367,354.23		$ (368,326.82)		$ -		$ (238,280.17)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 40,240.08		$ 135,232.99		$ (65,142.23)				$ (29,850.68)		$ -		
21	Real Time Net Inadvertent Distribution		$ 4,934.44		$ 84,019.36		$ (79,084.92)						$ 141.97		$ (140.36)
23	Real Time Revenue Neutrality Uplift Amount		$ 694,539.47		$ 985,230.47		$ (290,691.00)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 739,713.99		$ 1,204,482.82		$ (434,918.15)		$ -		$ (29,850.68)		$ 141.97		$ (140.36)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,379,554.71		$ 2,563,346.05		$ (183,791.34)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,379,799.01)		$ 183,049.59		$ (2,536,548.51)				$ (26,300.09)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (134,061.22)		$ -		$ (134,061.22)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 5,619.74		$ 5,619.74		$ -								
	SUBTOTAL		$ (128,685.78)		$ 2,752,015.38		$ (2,854,401.07)		$ -		$ (26,300.09)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (5,310.68)		$ 5,512.79		$ (10,823.47)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 60.49		$ 1,537.94		$ (1,477.45)								
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	-	$ (5,250.19)	-	$ 7,050.73	-	$ (12,300.92)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(739,173)	$ 548,056.10	3,117,531	$ 88,033,593.00	(3,011,406)	$ (68,651,983.75)	-	$ 93,967.63	(845,298)	$ (18,927,520.78)	13,735	$ 354,284.46	-	$ (141.22)
x	Net Congestion Amount		$ 15,676,958.05		$ 15,676,958.05				$ -						
y	Net Loss Amount		$ 3,225,747.53		$ 3,225,747.53				$ -						
z	Net Congestion and Loss Energy Offset		$ (18,902,705.58)		$ (18,902,705.58)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(739,173)**	$ 548,056.10	3,117,531	$ 88,033,593.00	(3,011,406)	$ (68,651,983.75)	-	$ 93,967.63	(845,298)	$ (18,927,520.78)	13,735	$ 354,284.46	-	$ (141.22)

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 2021		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	(533,235)	$ 14,912,011.09	3,954,898	$ 167,370,433.86	(3,681,106)	$ (123,454,414.66)			(807,027)	$ (29,004,008.11)				
5a	Day Ahead Non Asset Energy	(232,118)	$ (10,100,736.46)	77	$ 1,878.01	(232,195)	$ (10,102,614.47)					14,369	$ 581,360.34	-	$ (0.96)
13a	Real Time Asset Energy	(13,295)	$ (112,544.99)	65,911	$ 3,042,988.91	31,785	$ 302,506.53			(110,991)	$ (3,458,040.43)				
22a	Real Time Non Asset Energy	(469)	$ (33,537.83)	-	$ -	(469)	$ (33,537.83)					-	$ -	-	$ -
	SUBTOTAL	(779,117)	$ 4,665,191.81	4,020,886	$ 170,415,300.78	(3,881,985)	$ (133,288,060.43)	-	$ -	(918,018)	$ (32,462,048.54)	14,369	$ 581,360.34	-	$ (0.96)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,807.89		$ 3,458.30		$ (1,650.41)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,535,171.17)		$ -		$ (1,535,171.17)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,533,363.28)		$ 3,458.30		$ (1,536,821.58)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 825,853.41		$ 760,819.35		$ -		$ 65,034.06				$ 1,402.85		
19	Real Time Market Administration (Schedule 17)		$ 75,529.22		$ 67,048.91		$ -		$ 8,480.31				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 24,870.79		$ 24,870.79		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 119,194.58		$ 109,678.19		$ -		$ 9,516.39				$ 203.62		
34	Real -Time Schedule 24 Allocation Amount		$ (91,217.54)		$ 9,201.51		$ -				$ (100,419.05)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 954,230.46		$ 971,618.75		$ -		$ 83,030.76		$ (100,419.05)		$ 1,606.47		$ -
	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		$ 94,891.49		$ 100,042.59		$ (5,151.10)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (5,703,649.41)		$ 1,603,616.19		$ (7,307,265.60)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (135,194.21)		$ -		$ (135,194.21)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 36,507.45		$ 36,507.45		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (34,476.93)		$ -		$ (34,476.93)						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (5,741,921.61)		$ 1,740,166.23		$ (7,482,087.84)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 82,260.14		$ 82,260.14				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (70,707.96)				$ 6,686,537.85				$ (6,757,245.81)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 351,452.58		$ 351,452.58				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (736,358.10)				$ (7,167,070.25)				$ 6,430,712.15				
43	Real Time Price Volatility Make Whole Payment		$ (203,569.64)		$ -		($190,310.11)				$ (13,259.53)				
	SUBTOTAL		$ (576,922.98)		$ 433,712.72		$ (670,842.51)		$ -		$ (339,793.19)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 20,992.20		$ 142,343.34		$ (103,504.95)				$ (17,846.19)		$ (14.01)		
21	Real Time Net Inadvertent Distribution		$ (73,797.39)		$ 22,737.43		$ (96,534.82)						$ 42.17		$ (147.66)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,521,239.08		$ 1,852,378.26		$ (331,139.18)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,468,433.89		$ 2,017,459.03		$ (531,178.95)		$ -		$ (17,846.19)		$ 28.16		$ (147.66)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,869,718.20		$ 2,910,997.76		$ (41,279.56)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,879,303.56)		$ 38,836.42		$ (2,912,437.86)				$ (5,702.12)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (721,099.72)		$ -		$ (721,099.72)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 176,935.83		$ 176,935.83		$ -								
	SUBTOTAL		$ (553,749.25)		$ 3,126,770.01		$ (3,674,817.14)		$ -		$ (5,702.12)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (95,535.43)		$ 4,507.16		$ (100,042.59)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,694.94)		$ 1,650.41		$ (3,345.35)								
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	-	$ (97,230.37)	-	$ 6,157.57	-	$ (103,387.94)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(779,117)	$ (1,415,331.33)	4,020,886	$ 178,714,643.39	(3,881,985)	$ (147,287,196.39)	-	$ 83,030.76	(918,018)	$ (32,925,809.09)	14,369	$ 582,994.97	-	$ (148.62)
x	Net Congestion Amount		$ 25,055,560.49		$ 25,055,560.49				$ -						
y	Net Loss Amount		$ 5,489,185.72		$ 5,489,185.72				$ -						
z	Net Congestion and Loss Energy Offset		$ (30,544,746.21)		$ (30,544,746.21)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(779,117)**	$ (1,415,331.33)	4,020,886	$ 178,714,643.39	(3,881,985)	$ (147,287,196.39)	-	$ 83,030.76	(918,018)	$ (32,925,809.09)	14,369	$ 582,994.97	-	$ (148.62)

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 2021		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	(730,275)	$ (5,644,032.14)	4,141,622	$ 172,386,140.12	(3,957,985)	$ (143,633,047.78)			(913,911)	$ (34,397,124.48)				
5a	Day Ahead Non Asset Energy	(220,957)	$ (9,900,174.95)	-	$ -	(220,957)	$ (9,900,174.95)					16,135	$ 647,797.57	-	$ (1.09)
13a	Real Time Asset Energy	(75,437)	$ (2,631,940.94)	49,741	$ 2,126,255.59	(70,957)	$ (3,442,083.02)			(54,221)	$ (1,316,113.51)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,026,669)	$ (18,176,148.03)	4,191,363	$ 174,512,395.71	(4,249,899)	$ (156,975,305.75)	-	$ -	(968,132)	$ (35,713,237.99)	16,135	$ 647,797.57	-	$ (1.09)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 3,626.01		$ 4,751.68		$ (1,125.67)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (2,035,691.96)		$ -		$ (2,035,691.96)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (2,032,065.95)		$ 4,751.68		$ (2,036,817.63)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 618,549.28		$ 556,460.91		$ -		$ 62,088.37				$ 1,087.81		
19	Real Time Market Administration (Schedule 17)		$ 53,545.13		$ 50,269.34		$ -		$ 3,275.79				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 24,301.05		$ 24,301.05		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 98,264.69		$ 88,472.27		$ -		$ 9,792.42				$ 172.35		
34	Real -Time Schedule 24 Allocation Amount		$ (87,176.37)		$ 21,199.49		$ -				$ (108,375.86)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 707,483.78		$ 740,703.06		$ -		$ 75,156.58		$ (108,375.86)		$ 1,260.16		$ -
	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		$ 12,385.35		$ 15,422.15		$ (3,036.80)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (3,783,139.82)		$ 1,242,405.85		$ (5,025,545.67)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (26,444.18)		$ -		$ (26,444.18)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 96,332.85		$ 96,332.85		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (95,905.39)		$ -		$ (95,905.39)						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (3,796,771.19)		$ 1,354,160.85		$ (5,150,932.04)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 114,720.83		$ 114,720.83				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (34,898.02)				$ (15,060.61)				$ (19,837.41)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 914,878.30		$ 914,878.30				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (875,997.76)				$ (618,211.03)				$ (257,786.73)				
43	Real Time Price Volatility Make Whole Payment		$ (119,396.10)		$ -		($90,746.40)				$ (28,649.70)				
	SUBTOTAL		$ (692.75)		$ 1,029,599.13		$ (724,018.04)		$ -		$ (306,273.84)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 92,735.55		$ 333,926.53		$ (103,696.68)				$ (137,494.30)		$ -		
21	Real Time Net Inadvertent Distribution		$ (89,110.53)		$ 66,058.60		$ (155,169.13)						$ 108.81		$ (247.67)
23	Real Time Revenue Neutrality Uplift Amount		$ 404,740.51		$ 652,836.79		$ (248,096.28)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 408,365.53		$ 1,052,821.92		$ (506,962.09)		$ -		$ (137,494.30)		$ 108.81		$ (247.67)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,869,718.20		$ 2,910,997.76		$ (41,279.56)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,879,303.56)		$ 38,836.42		$ (2,910,730.31)				$ (7,409.67)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (721,099.72)		$ -		$ (721,099.72)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 176,935.83		$ 176,935.83		$ -								
	SUBTOTAL		$ (553,749.25)		$ 3,126,770.01		$ (3,673,109.59)		$ -		$ (7,409.67)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (12,234.20)		$ 3,187.95		$ (15,422.15)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,660.69)		$ 1,125.67		$ (4,786.36)								
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	-	$ (15,894.89)	-	$ 4,313.62	-	$ (20,208.51)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,026,669)	$ (23,459,472.75)	4,191,363	$ 181,825,515.98	(4,249,899)	$ (169,087,353.65)	-	$ 75,156.58	(968,132)	$ (36,272,791.66)	16,135	$ 649,166.54	-	$ (248.76)
x	Net Congestion Amount		$ 14,000,967.41		$ 14,000,967.41				$ -						
y	Net Loss Amount		$ 5,974,107.23		$ 5,974,107.23				$ -						
z	Net Congestion and Loss Energy Offset		$ (19,975,074.64)		$ (19,975,074.64)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,026,669)**	$ (23,459,472.75)	4,191,363	$ 181,825,515.98	(4,249,899)	$ (169,087,353.65)	-	$ 75,156.58	(968,132)	$ (36,272,791.66)	16,135	$ 649,166.54	-	$ (248.76)

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-20-417
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

August 2021		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	(1,041,859)	$ (9,349,363.88)	3,959,345	$ 160,788,664.51	(3,809,018)	$ (126,608,773.24)			(1,192,186)	$ (43,529,255.15)				
5a	Day Ahead Non Asset Energy	(184,413)	$ (7,989,668.25)	-	$ -	(184,413)	$ (7,989,668.25)					16,956	$ 659,814.63	-	$ (0.96)
13a	Real Time Asset Energy	(19,778)	$ (957,419.67)	64,276	$ 2,593,867.26	15,944	$ 51,709.74			(99,998)	$ (3,602,996.67)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,246,050)	$ (18,296,451.80)	4,023,621	$ 163,382,531.77	(3,977,487)	$ (134,546,731.75)	-	$ -	(1,292,184)	$ (47,132,251.82)	16,956	$ 659,814.63	-	$ (0.96)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 0.11		$ 2,453.80		$ (2,453.69)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,864,583.13)		$ -		$ (1,864,583.13)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,864,583.02)		$ 2,453.80		$ (1,867,036.82)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 666,323.60		$ 579,601.73		$ -		$ 86,721.87				$ 1,234.44		
19	Real Time Market Administration (Schedule 17)		$ 62,387.12		$ 55,055.20		$ -		$ 7,331.92				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 21,061.38		$ 21,061.38		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 106,826.41		$ 92,863.14		$ -		$ 13,963.27				$ 196.97		
34	Real -Time Schedule 24 Allocation Amount		$ (96,079.67)		$ (6,776.73)		$ -				$ (89,302.94)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 760,518.84		$ 741,804.72		$ -		$ 108,017.06		$ (89,302.94)		$ 1,431.41		$ -
	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		$ 32,084.57		$ 38,124.02		$ (6,039.45)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (6,092,957.45)		$ 679,345.36		$ (6,772,302.81)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (219,011.77)		$ -		$ (219,011.77)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (187,062.85)		$ -		$ (187,062.85)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 182,528.91		$ 182,528.91		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (6,284,418.59)		$ 899,998.29		$ (7,184,416.88)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 120,212.82		$ 120,212.82				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (168,497.95)				$ (133,077.70)				$ (35,420.25)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 539,923.33		$ 539,923.33				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (736,535.44)				$ (481,293.37)				$ (255,242.07)				
43	Real Time Price Volatility Make Whole Payment		$ (518,669.17)		$ -		($458,967.31)				$ (59,701.86)				
	SUBTOTAL		$ (763,566.41)		$ 660,136.15		$ (1,073,338.38)		$ -		$ (350,364.18)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 104,783.26		$ 346,501.89		$ (103,165.97)				$ (138,552.66)		$ -		
21	Real Time Net Inadvertent Distribution		$ 33,797.24		$ 125,814.66		$ (92,017.42)						$ 183.04		$ (141.82)
23	Real Time Revenue Neutrality Uplift Amount		$ 241,134.07		$ 1,197,769.86		$ (956,635.79)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 379,714.57		$ 1,670,086.41		$ (1,151,819.18)		$ -		$ (138,552.66)		$ 183.04		$ (141.82)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,869,718.20		$ 2,910,997.76		$ (41,279.56)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,879,303.56)		$ 38,836.42		$ (2,910,489.74)				$ (7,650.24)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (721,099.72)		$ -		$ (721,099.72)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 176,935.83		$ 176,935.83		$ -								
	SUBTOTAL		$ (553,749.25)		$ 3,126,770.01		$ (3,672,869.02)		$ -		$ (7,650.24)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (32,084.57)		$ 6,039.45		$ (38,124.02)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (0.11)		$ 2,453.69		$ (2,453.80)								
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	-	$ (32,084.68)	-	$ 8,493.14	-	$ (40,577.82)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,246,050)	$ (26,654,620.34)	4,023,621	$ 170,492,274.29	(3,977,487)	$ (149,536,789.85)	-	$ 108,017.06	(1,292,184)	$ (47,718,121.84)	16,956	$ 661,429.08	-	$ (142.78)
x	Net Congestion Amount		$ 19,827,147.65		$ 19,827,147.65				$ -						
y	Net Loss Amount		$ 6,356,837.72		$ 6,356,837.72				$ -						
z	Net Congestion and Loss Energy Offset		$ (26,183,985.37)		$ (26,183,985.37)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,246,050)**	$ (26,654,620.34)	4,023,621	$ 170,492,274.29	(3,977,487)	$ (149,536,789.85)	-	$ 108,017.06	(1,292,184)	$ (47,718,121.84)	16,956	$ 661,429.08	-	$ (142.78)

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-20-417
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

September 2021		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	(620,968)	$ 20,351,891.64	3,255,787	$ 141,910,355.35	(3,088,510)	$ (89,960,656.61)			(788,244)	$ (31,597,807.10)				
5a	Day Ahead Non Asset Energy	(179,332)	$ (7,930,836.84)	-	$ -	(179,332)	$ (7,930,836.84)					14,048	$ 573,780.25	-	$ (1.04)
13a	Real Time Asset Energy	(11,717)	$ (350,474.82)	47,517	$ 2,428,226.91	48,327	$ (49,170.86)			(107,561)	$ (2,729,530.87)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(812,017)	$ 12,070,579.98	3,303,304	$ 144,338,582.26	(3,219,516)	$ (97,940,664.31)	-	$ -	(895,805)	$ (34,327,337.97)	14,048	$ 573,780.25	-	$ (1.04)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (3,033.09)		$ 1,376.01		$ (4,409.10)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,487,885.67)		$ -		$ (1,487,885.67)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,490,918.76)		$ 1,376.01		$ (1,492,294.77)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 601,019.33		$ 536,582.47		$ -		$ 64,436.86				$ 1,153.56		
19	Real Time Market Administration (Schedule 17)		$ 58,202.58		$ 49,256.72		$ -		$ 8,945.86				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 17,803.32		$ 17,803.32		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 99,757.00		$ 89,432.58		$ -		$ 10,324.42				$ 191.11		
34	Real -Time Schedule 24 Allocation Amount		$ (93,675.82)		$ 17,960.56		$ -				$ (111,636.38)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 683,106.41		$ 711,035.65		$ -		$ 83,707.14		$ (111,636.38)		$ 1,344.67		$ -
	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		$ 41,854.26		$ 46,471.79		$ (4,617.53)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (13,375,718.57)		$ 648,091.91		$ (14,023,810.48)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (303,401.68)		$ -		$ (303,401.68)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (860,405.56)		$ -		$ (860,405.56)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 857,294.93		$ 857,294.93		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (13,640,376.62)		$ 1,551,858.63		$ (15,192,235.25)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 118,572.21		$ 118,572.21				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (288,323.00)				$ (77,053.97)				$ (211,269.03)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 283,126.26		$ 283,126.26				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (618,442.68)				$ (384,181.56)				$ (234,261.12)				
43	Real Time Price Volatility Make Whole Payment		$ (66,200.40)		$ -		($18,663.25)				$ (47,537.15)				
	SUBTOTAL		$ (571,267.61)		$ 401,698.47		$ (479,898.78)		$ -		$ (493,067.30)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 138,005.05		$ 393,247.24		$ (114,956.03)				$ (140,286.16)		$ -		
21	Real Time Net Inadvertent Distribution		$ (28,545.77)		$ 155,455.36		$ (184,001.13)						$ 261.58		$ (313.45)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,820,760.18		$ 2,222,320.39		$ (401,560.21)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,930,219.46		$ 2,771,022.99		$ (700,517.37)		$ -		$ (140,286.16)		$ 261.58		$ (313.45)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,988,864.08		$ 4,010,299.12		$ (21,435.04)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,133,122.02)		$ 20,695.05		$ (4,144,971.18)				$ (8,845.89)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,039,833.53)		$ -		$ (1,039,833.53)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 185,508.32		$ 185,508.32		$ -								
	SUBTOTAL		$ (998,583.15)		$ 4,216,502.49		$ (5,206,239.75)		$ -		$ (8,845.89)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (41,854.26)		$ 4,617.53		$ (46,471.79)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 3,033.09		$ 4,409.10		$ (1,376.01)								
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	-	$ (38,821.17)	-	$ 9,026.63	-	$ (47,847.80)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(812,017)	$ (2,056,061.46)	3,303,304	$ 154,001,103.13	(3,219,516)	$ (121,059,698.03)	-	$ 83,707.14	(895,805)	$ (35,081,173.70)	14,048	$ 575,386.50	-	$ (314.49)
x	Net Congestion Amount		$ 35,881,892.16		$ 35,881,892.16				$ -						
y	Net Loss Amount		$ 5,762,297.71		$ 5,762,297.71				$ -						
z	Net Congestion and Loss Energy Offset		$ (41,644,189.87)		$ (41,644,189.87)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(812,017)**	$ (2,056,061.46)	3,303,304	$ 154,001,103.13	(3,219,516)	$ (121,059,698.03)	-	$ 83,707.14	(895,805)	$ (35,081,173.70)	14,048	$ 575,386.50	-	$ (314.49)

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 2021	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	(879,145)	$ (2,877,414.15)	3,163,243	$ 172,638,110.90	(3,026,421)	$ (127,310,476.95)			(1,015,967)	$ (48,205,048.10)				
5a	Day Ahead Non Asset Energy	(200,823)	$ (10,214,480.83)	-	$ -	(200,823)	$ (10,214,480.83)					14,437	$ 786,232.87	-	$ (0.85)
13a	Real Time Asset Energy	6,857	$ 831,885.96	61,524	$ 3,429,920.13	52,852	$ 1,714,751.88			(107,518)	$ (4,312,786.05)				
22a	Real Time Non Asset Energy	38	$ 2,351.55	38	$ 2,351.55	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,073,073)	$ (12,257,657.47)	3,224,805	$ 176,070,382.58	(3,174,392)	$ (135,810,205.90)	-	$ -	(1,123,485)	$ (52,517,834.15)	14,437	$ 786,232.87	-	$ (0.85)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 4,800.20		$ 6,166.55		$ (1,366.35)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,329,827.33)		$ -		$ (1,329,827.33)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,325,027.13)		$ 6,166.55		$ (1,331,193.68)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 607,995.69		$ 524,684.66		$ -		$ 83,311.03				$ 1,184.14		
19	Real Time Market Administration (Schedule 17)		$ 65,360.10		$ 56,548.69		$ -		$ 8,811.41				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 15,946.98		$ 15,946.98		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 100,152.23		$ 86,243.18		$ -		$ 13,909.05				$ 194.97		
34	Real -Time Schedule 24 Allocation Amount		$ (91,346.08)		$ 6,806.26		$ -				$ (98,152.34)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 698,108.92		$ 690,229.77		$ -		$ 106,031.49		$ (98,152.34)		$ 1,379.11		$ -
	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		$ 28,735.99		$ 39,333.16		$ (10,597.17)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (2,732,219.29)		$ 2,801,358.36		$ (5,533,577.65)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (226,867.25)		$ -		$ (226,867.25)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (157,972.70)		$ -		$ (157,972.70)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 124,594.63		$ 124,594.63		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (2,963,728.62)		$ 2,965,286.15		$ (5,929,014.77)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 161,165.12		$ 161,165.12				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (160,287.50)				$ (68,409.31)				$ (91,878.19)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 636,609.31		$ 636,609.31				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (476,951.36)				$ (170,810.38)				$ (306,140.98)				
43	Real Time Price Volatility Make Whole Payment		$ (198,525.68)		$ -		($156,420.23)				$ (42,105.45)				
	SUBTOTAL		$ (37,990.11)		$ 797,774.43		$ (395,639.92)		$ -		$ (440,124.62)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 413,447.69		$ 611,449.03		$ (112,849.61)				$ (85,151.73)		$ -		
21	Real Time Net Inadvertent Distribution		$ (108,991.15)		$ 33,320.81		$ (142,311.96)						$ 57.95		$ (242.50)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,294,349.60		$ 1,654,210.28		$ (359,860.68)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,598,806.14		$ 2,298,980.12		$ (615,022.25)		$ -		$ (85,151.73)		$ 57.95		$ (242.50)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,988,864.08		$ 4,010,299.12		$ (21,435.04)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,133,122.02)		$ 20,695.05		$ (4,144,983.43)				$ (8,833.64)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,039,834.13)		$ -		$ (1,039,834.13)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 185,508.31		$ 185,508.31		$ -								
	SUBTOTAL		$ (998,583.76)		$ 4,216,502.48		$ (5,206,252.60)		$ -		$ (8,833.64)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (28,735.99)		$ 10,597.17		$ (39,333.16)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (4,800.20)		$ 1,366.35		$ (6,166.55)								
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	-	$ (33,536.19)	-	$ 11,963.52	-	$ (45,499.71)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,073,073)	$ (15,319,608.22)	3,224,805	$ 187,057,285.60	(3,174,392)	$ (149,332,828.83)	-	$ 106,031.49	(1,123,485)	$ (53,150,096.48)	14,437	$ 787,669.93	-	$ (243.35)
x	Net Congestion Amount		$ 26,880,666.62		$ 26,880,666.62				$ -						
y	Net Loss Amount		$ 6,369,370.09		$ 6,369,370.09				$ -						
z	Net Congestion and Loss Energy Offset		$ (33,250,036.71)		$ (33,250,036.71)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,073,073)**	$ (15,319,608.22)	3,224,805	$ 187,057,285.60	(3,174,392)	$ (149,332,828.83)	-	$ 106,031.49	(1,123,485)	$ (53,150,096.48)	14,437	$ 787,669.93	-	$ (243.35)

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

November 2021		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	(1,146,141)	$ (4,189,251.70)	3,077,441	$ 144,331,065.89	(2,979,569)	$ (100,590,798.48)			(1,244,012)	$ (47,929,519.11)				
5a	Day Ahead Non Asset Energy	(139,777)	$ (5,852,872.22)	-	$ -	(139,777)	$ (5,852,872.22)					15,485	$ 707,852.65	-	$ (1.10)
13a	Real Time Asset Energy	17,677	$ 777,318.88	67,978	$ 3,425,249.35	116,958	$ 1,793,013.23			(167,259)	$ (4,440,943.70)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,268,240)	$ (9,264,805.04)	3,145,419	$ 147,756,315.24	(3,002,388)	$ (104,650,657.47)	-	$ -	(1,411,271)	$ (52,370,462.81)	15,485	$ 707,852.65	-	$ (1.10)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 2,114.67		$ 5,994.54		$ (3,879.87)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,620,162.77)		$ -		$ (1,620,162.77)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,618,048.10)		$ 5,994.54		$ (1,624,042.64)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 629,622.76		$ 524,887.28		$ -		$ 104,735.48				$ 1,307.06		
19	Real Time Market Administration (Schedule 17)		$ 70,215.42		$ 56,062.11		$ -		$ 14,153.31				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 13,648.58		$ 13,648.58		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 95,400.02		$ 79,395.96		$ -		$ 16,004.06				$ 198.30		
34	Real -Time Schedule 24 Allocation Amount		$ (86,994.08)		$ 13,955.11		$ -				$ (100,949.19)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 721,892.70		$ 687,949.04		$ -		$ 134,892.85		$ (100,949.19)		$ 1,505.36		$ -
	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		$ 28,615.04		$ 47,428.34		$ (18,813.30)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (6,585,836.73)		$ 3,880,807.89		$ (10,466,644.62)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (374,418.97)		$ -		$ (374,418.97)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (551,313.90)		$ -		$ (551,313.90)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 485,738.92		$ 485,738.92		$ -						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (6,997,215.64)		$ 4,413,975.15		$ (11,411,190.79)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 177,219.10		$ 177,219.10				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (434,734.60)				$ (338,252.96)				$ (96,481.64)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 143,002.62		$ 143,002.62				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (173,483.62)				$ (65,578.02)				$ (107,905.60)				
43	Real Time Price Volatility Make Whole Payment		$ (265,501.95)		$ -		($255,044.01)				$ (10,457.94)				
	SUBTOTAL		$ (553,498.45)		$ 320,221.72		$ (658,874.99)		$ -		$ (214,845.18)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 228,391.49		$ 414,337.43		$ (100,794.21)				$ (85,151.73)		$ -		
21	Real Time Net Inadvertent Distribution		$ (255,986.51)		$ 39,251.83		$ (295,238.34)						$ 72.26		$ (545.85)
23	Real Time Revenue Neutrality Uplift Amount		$ 3,701,232.91		$ 4,008,688.78		$ (307,455.87)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 3,673,637.89		$ 4,462,278.04		$ (703,488.42)		$ -		$ (85,151.73)		$ 72.26		$ (545.85)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 3,988,864.08		$ 4,010,299.12		$ (21,435.04)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (4,133,122.02)		$ 20,695.05		$ (4,144,668.06)				$ (9,149.01)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (1,039,834.13)		$ -		$ (1,039,834.13)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 185,508.31		$ 185,508.31		$ -								
	SUBTOTAL		$ (998,583.76)		$ 4,216,502.48		$ (5,205,937.23)		$ -		$ (9,149.01)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (26,282.22)		$ 18,458.62		$ (44,740.84)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (5,453.73)		$ 540.81		$ (5,994.54)								
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	-	$ (31,735.95)	-	$ 18,999.43	-	$ (50,735.38)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,268,240)	$ (15,068,356.35)	3,145,419	$ 161,882,235.64	(3,002,388)	$ (124,304,926.92)	-	$ 134,892.85	(1,411,271)	$ (52,780,557.92)	15,485	$ 709,430.27	-	$ (546.95)
x	Net Congestion Amount		$ 27,998,734.27		$ 27,998,734.27				$ -						
y	Net Loss Amount		$ 7,011,365.24		$ 7,011,365.24				$ -						
z	Net Congestion and Loss Energy Offset		$ (35,010,099.51)		$ (35,010,099.51)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,268,240)**	$ (15,068,356.35)	3,145,419	$ 161,882,235.64	(3,002,388)	$ (124,304,926.92)	-	$ 134,892.85	(1,411,271)	$ (52,780,557.92)	15,485	$ 709,430.27	-	$ (546.95)

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 2021		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	(1,403,237)	$ (19,075,295.06)	3,383,970	$ 134,441,744.82	(6,205,625)	$ (109,506,996.60)			1,418,418	$ (44,010,043.28)				
5a	Day Ahead Non Asset Energy	(56,635)	$ (1,261,792.41)	-	$ -	(56,635)	$ (1,261,792.41)					17,692	$ 698,708.15	-	$ (1.01)
13a	Real Time Asset Energy	22,165	$ 828,786.29	77,765	$ 3,473,128.23	(180,113)	$ 722,133.70			124,514	$ (3,366,475.64)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(1,437,707)	$ (19,508,301.18)	3,461,734	$ 137,914,873.05	(6,442,373)	$ (110,046,655.31)	-	$ -	1,542,932	$ (47,376,518.92)	17,692	$ 698,708.15	-	$ (1.01)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (130,248.86)		$ 21,107.80		$ (151,356.66)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (1,401,227.79)		$ -		$ (1,401,227.79)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,531,476.65)		$ 21,107.80		$ (1,552,584.45)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 736,890.70		$ 612,054.76		$ -		$ 124,835.94				$ 1,562.01		
19	Real Time Market Administration (Schedule 17)		$ 85,186.32		$ 74,079.53		$ -		$ 11,106.79				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 30,794.15		$ 30,794.15		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 104,239.89		$ 86,483.78		$ -		$ 17,756.11				$ 221.39		
34	Real -Time Schedule 24 Allocation Amount		$ (88,648.71)		$ 2,140.57		$ -				$ (90,789.28)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 868,462.35		$ 805,552.79		$ -		$ 153,698.84		$ (90,789.28)		$ 1,783.40		$ -
	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		$ (419,258.53)		$ 135,144.75		$ (554,403.28)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ 582,597.95		$ 8,380,847.24		$ (7,798,249.29)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (180,970.98)		$ -		$ (180,970.98)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 69,868.59		$ 69,868.59		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (143,064.56)		$ -		$ (143,064.56)						$ -		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (90,827.53)		$ 8,585,860.58		$ (8,676,688.11)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 108,523.40		$ 108,523.40				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (303,123.52)				$ (192,983.00)				$ (110,140.52)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 135,029.10		$ 135,029.10				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (110,987.19)				$ (60,574.90)				$ (50,412.29)				
43	Real Time Price Volatility Make Whole Payment		$ (94,731.54)		$ -		($41,602.32)				$ (53,129.22)				
	SUBTOTAL		$ (265,289.75)		$ 243,552.50		$ (295,160.22)		$ -		$ (213,682.03)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 963,604.97		$ 1,164,451.13		$ (115,694.43)				$ (85,151.73)		$ -		
21	Real Time Net Inadvertent Distribution		$ 45,497.88		$ 134,531.31		$ (89,033.43)						$ 246.74		$ (168.35)
23	Real Time Revenue Neutrality Uplift Amount		$ 356,815.07		$ 915,299.54		$ (558,484.47)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,365,917.92		$ 2,214,281.98		$ (763,212.33)		$ -		$ (85,151.73)		$ 246.74		$ (168.35)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 6,409,766.32		$ 6,546,688.64		$ (136,922.32)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (6,456,472.05)		$ 127,673.70		$ (6,564,573.13)				$ (19,572.62)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (235,898.85)		$ -		$ (235,898.85)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 76,750.07		$ 76,750.07		$ -								
	SUBTOTAL		$ (205,854.51)		$ 6,751,112.41		$ (6,937,394.30)		$ -		$ (19,572.62)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (89,235.75)		$ (2,991.56)		$ (86,244.19)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (7,368.05)		$ 111.04		$ (7,479.09)								
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	-	$ (96,603.80)	-	$ (2,880.52)	-	$ (93,723.28)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(1,437,707)	$ (19,463,973.15)	3,461,734	$ 156,533,460.59	(6,442,373)	$ (128,365,418.00)	-	$ 153,698.84	1,542,932	$ (47,785,714.58)	17,692	$ 700,738.29	-	$ (169.36)
x	Net Congestion Amount		$ 17,170,229.59		$ 17,170,229.59				$ -						
y	Net Loss Amount		$ 5,515,084.39		$ 5,515,084.39				$ -						
z	Net Congestion and Loss Energy Offset		$ (22,685,313.98)		$ (22,685,313.98)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(1,437,707)**	$ (19,463,973.15)	3,461,734	$ 156,533,460.59	(6,442,373)	$ (128,365,418.00)	-	$ 153,698.84	1,542,932	$ (47,785,714.58)	17,692	$ 700,738.29	-	$ (169.36)

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-20-417
True-Up Report
Part B, Attachment 10

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

January - December 2021		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	(9,605,882)	$ (15,553,083.77)	40,733,705	$ 1,644,649,737.88	(61,639,175)	$ (1,265,900,694.66)			11,299,588	$ (394,302,126.99)				
5a	Day Ahead Non Asset Energy	(1,825,119)	$ (75,062,119.21)	215	$ 5,272.19	(1,825,334)	$ (75,067,391.40)					172,000	$ 6,679,156.57	-	$ (8.75)
13a	Real Time Asset Energy	(87,538)	$ (4,259,424.67)	713,808	$ 28,400,521.44	(2,141,929)	$ 3,554,434.56			1,340,583	$ (36,214,380.67)				
22a	Real Time Non Asset Energy	(420)	$ (31,107.88)	49	$ 2,429.95	(469)	$ (33,537.83)					-	$ -	-	$ -
	SUBTOTAL	(11,518,959)	$ (94,905,735.53)	41,447,777	$ 1,673,057,961.46	(65,606,907)	$ (1,337,447,189.33)	-	$ -	12,640,171	$ (430,516,507.66)	172,000	$ 6,679,156.57	-	$ (8.75)
	Day Ahead & Real Time Energy Loss														
1c	Day Ahead Loss														
5c	Day Ahead Non Asset Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (106,399.24)		$ 67,358.82		$ (173,758.06)								
13c	Real Time Loss														
22c	Real Time Non Asset Loss														
14	Real Time Distribution Losses		$ (16,653,788.00)		$ -		$ (16,653,788.00)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (16,760,187.24)		$ 67,358.82		$ (16,827,546.06)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 7,608,828.76		$ 6,681,418.96		$ -		$ 927,409.80				$ 14,156.74		
19	Real Time Market Administration (Schedule 17)		$ 787,369.36		$ 677,241.32		$ -		$ 110,128.04				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 268,361.61		$ 268,361.61		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 1,173,033.55		$ 1,030,251.01		$ -		$ 142,782.54				$ 2,175.97		
34	Real -Time Schedule 24 Allocation Amount		$ (1,069,577.03)		$ 107,454.82		$ -				$ (1,177,031.85)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 8,768,016.25		$ 8,764,727.72		$ -		$ 1,180,320.38		$ (1,177,031.85)		$ 16,332.71		$ -
	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		$ (186,615.93)		$ 490,640.63		$ (677,256.56)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (51,515,645.96)		$ 29,266,606.19		$ (80,782,252.15)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (2,227,856.92)		$ -		$ (2,227,856.92)								$ -
32	Financial Transmission Rights Yearly Allocation		$ (324,720.42)		$ -		$ (324,720.42)						$ -		$ (11.82)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (1,519,976.47)		$ -		$ (1,519,976.47)								$ 11.82
37	Financial Transmission Guarantee Uplift Amount		$ 1,387,781.50		$ 1,387,781.50		$ -						$ 177.01		
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (54,387,034.20)		$ 31,145,028.32		$ (85,532,062.52)		$ -		$ -		$ 177.01		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 1,495,996.26		$ 1,495,996.26				$ -						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (2,238,347.60)				$ (1,281,324.14)				$ (957,023.46)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 5,555,575.89		$ 5,555,575.89				$ -						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (5,464,571.39)				$ (2,823,662.76)				$ (2,640,908.63)				
43	Real Time Price Volatility Make Whole Payment		$ (2,581,765.51)		$ -		($2,176,909.77)				$ (404,855.74)				
	SUBTOTAL		$ (3,233,112.35)		$ 7,051,572.15		$ (6,281,896.67)		$ -		$ (4,002,787.83)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 2,089,839.42		$ 3,842,463.93		$ (1,022,908.55)				$ (729,715.96)		$ (14.01)		
21	Real Time Net Inadvertent Distribution		$ (438,459.88)		$ 874,415.20		$ (1,312,875.08)						$ 1,451.38		$ (2,240.00)
23	Real Time Revenue Neutrality Uplift Amount		$ 11,090,474.13		$ 20,644,913.61		$ (9,554,439.48)		$ -						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 12,741,853.67		$ 25,361,792.74		$ (11,890,223.11)		$ -		$ (729,715.96)		$ 1,437.37		$ (2,240.00)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 37,394,971.43		$ 38,404,681.87		$ (1,009,710.44)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (37,911,935.92)		$ 987,423.14		$ (38,685,214.14)				$ (214,144.92)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (6,326,541.61)		$ -		$ (6,326,541.61)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 1,226,021.20		$ 1,226,021.20		$ -								
	SUBTOTAL		$ (5,617,484.90)		$ 40,618,126.21		$ (46,021,466.19)		$ -		$ (214,144.92)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (308,922.00)		$ 118,994.44		$ (427,916.44)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (32,710.54)		$ 19,151.54		$ (51,862.08)								
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	-	$ (341,632.54)	-	$ 138,145.98	-	$ (479,778.52)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(11,518,959)	$ (153,735,316.84)	41,447,777	$ 1,786,204,713.40	(65,606,907)	$ (1,504,480,162.40)	-	$ 1,180,320.38	12,640,171	$ (436,640,188.22)	172,000	$ 6,697,103.66	-	$ (2,248.75)
x	Net Congestion Amount		$ 223,164,243.88		$ 223,164,243.88				$ -						
y	Net Loss Amount		$ 61,020,743.36		$ 61,020,743.36				$ -						
z	Net Congestion and Loss Energy Offset		$ (284,184,987.24)		$ (284,184,987.24)										
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(11,518,959)**	$ (153,735,316.84)	41,447,777	$ 1,786,204,713.40	(65,606,907)	$ (1,504,480,162.40)	-	$ 1,180,320.38	12,640,171	$ (436,640,188.22)	172,000	$ 6,697,103.66	-	$ (2,248.75)

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 2021	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		$ (222,870.11)		$ -		$ (114,718.38)				$ (108,151.73)				
2 Day-Ahead Spinning Reserve Amount		$ (184,405.08)		$ -		$ (79,067.80)				$ (105,337.28)				
3 Day-Ahead Supplemental Reserve		$ (36,839.82)		$ -		$ (4,910.47)				$ (31,929.35)				
4 Real-Time Regulation Amount		$ 50,363.99		$ 85,687.84		$ (35,323.85)								
5 Real-Time Spinning Reserve Amount		$ 46,863.35		$ 125,056.44		$ (78,193.09)								
6 Real-Time Supplemental Reserve Amount.		$ 2,974.45		$ 3,522.56		$ (548.11)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(822)	$ (13,268.54)	17	$ 12.48	(839)	$ (13,281.02)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	165,884	$ 2,860,297.06	472,220	$ 8,853,725.00	(306,336)	$ (5,993,427.94)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 5,697.01		$ 14,129.30		$ (8,625.14)		$ 192.85						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 111,321.30		$ 111,321.30		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 76,300.71		$ 76,300.71		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 21,400.92		$ 21,400.92		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 29,363.95		$ 20,436.85		$ -		$ 8,927.10						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ (70.54)		$ 70.54						
MISO ASM CHARGES	165,062	$ 2,747,199.19	472,237	$ 9,311,593.40	(307,175)	$ (6,328,166.34)	-	$ 9,190.49	-	$ (245,418.36)	-	$ -	-	$ -
x Net Congestion Amount		$ (131,073.51)		$ (131,073.51)										
y Net Loss Amount		$ (68,882.86)		$ (68,882.86)										
z Net Congestion and Loss Energy Offset		$ 199,956.37		$ 199,956.37										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	165,062	$ 2,747,199.19	472,237	$ 9,311,593.40	(307,175)	$ (6,328,166.34)	-	$ 9,190.49	-	$ (245,418.36)	-	$ -	-	$ -

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 2021	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		$ (231,511.33)		$ -		$ (5,963.90)				$ (225,547.43)				
2 Day-Ahead Spinning Reserve Amount		$ (123,481.97)		$ -		$ 85,608.21				$ (209,090.18)				
3 Day-Ahead Supplemental Reserve		$ (28,971.64)		$ -		$ 9,120.41				$ (38,092.05)				
4 Real-Time Regulation Amount		$ 34,791.79		$ 75,566.07		$ (40,774.28)								
5 Real-Time Spinning Reserve Amount		$ (31,632.62)		$ 29,552.57		$ (61,185.19)								
6 Real-Time Supplemental Reserve Amount.		$ (173.46)		$ 497.43		$ (670.89)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(617)	$ (7,907.35)	48	$ 612.05	(665)	$ (8,519.40)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	(71,486)	$ (463,662.43)	325,007	$ 4,967,367.29	(396,493)	$ (5,431,029.72)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (6,457.85)		$ 8,917.89		$ (10,895.40)		$ (4,480.34)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 108,152.70		$ 108,152.70		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 61,960.75		$ 61,960.75		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 9,808.49		$ 9,808.49		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 35,284.70		$ 24,274.66		$ -		$ 11,010.04						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		$ -						
MISO ASM CHARGES	(72,103)	$ (643,800.22)	325,055	$ 5,286,709.90	(397,158)	$ (5,464,310.16)	-	$ 6,529.70	-	$ (472,729.66)	-	$ -	-	$ -
x Net Congestion Amount		$ 84,356.90		$ 84,356.90										
y Net Loss Amount		$ 105,131.56		$ 105,131.56										
z Net Congestion and Loss Energy Offset		$ (189,488.46)		$ (189,488.46)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	(72,103)	$ (643,800.22)	325,055	$ 5,286,709.90	(397,158)	$ (5,464,310.16)	-	$ 6,529.70	-	$ (472,729.66)	-	$ -	-	$ -

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 2021	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		$ (147,873.73)		$ -		$ (136,591.27)				$ (11,282.46)				
2 Day-Ahead Spinning Reserve Amount		$ (264,050.78)		$ -		$ (1,300.32)				$ (262,750.46)				
3 Day-Ahead Supplemental Reserve		$ (34,514.95)		$ -		$ (201,503.22)				$ 166,988.27				
4 Real-Time Regulation Amount		$ (54,966.23)		$ 27,525.68		$ (82,491.91)								
5 Real-Time Spinning Reserve Amount		$ (120,527.33)		$ 53,045.93		$ (173,573.26)								
6 Real-Time Supplemental Reserve Amount.		$ 3,311.12		$ 3,380.64		$ (69.52)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(4,448)	$ 26,366.18	152	$ (497.75)	(4,600)	$ 26,863.93								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	52,728	$ 1,387,228.63	432,931	$ 5,224,445.37	(380,203)	$ (3,837,216.74)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 5,578.83		$ 5,268.50		$ 8,823.37		$ (8,513.04)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 52,728.12		$ 52,728.12		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 102,375.62		$ 102,375.62		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ (75,784.60)		$ (75,784.60)		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 33,778.24		$ 22,654.41		$ -		$ 11,123.83						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -								
MISO ASM CHARGES	48,280	$ 913,649.12	433,083	$ 5,415,141.92	(384,803)	$ (4,397,058.94)	-	$ 2,610.79	-	$ (107,044.65)	-	$ -	-	$ -
x Net Congestion Amount		$ (52,201.16)		$ (52,042.26)				$ (158.90)						
y Net Loss Amount		$ 48,606.59		$ 45,174.30				$ 3,432.29						
z Net Congestion and Loss Energy Offset		$ 3,594.57		$ 3,594.57										
SUBTOTAL	-	$ -	-	$ (3,273.39)	-	$ -	-	$ 3,273.39	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	48,280	$ 913,649.12	433,083	$ 5,411,868.53	(384,803)	$ (4,397,058.94)	-	$ 5,884.18	-	$ (107,044.65)	-	$ -	-	$ -

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 2021	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		$ (262,770.12)		$ -		$ 24,885.69				$ (287,655.81)				
2 Day-Ahead Spinning Reserve Amount		$ (203,962.87)		$ -		$ (75,006.24)				$ (128,956.63)				
3 Day-Ahead Supplemental Reserve		$ (46,997.77)		$ -		$ (38,230.65)				$ (8,767.12)				
4 Real-Time Regulation Amount		$ (161,628.01)		$ 86,531.50		$ (248,159.51)								
5 Real-Time Spinning Reserve Amount		$ (42,853.44)		$ 82,805.45		$ (125,658.89)								
6 Real-Time Supplemental Reserve Amount.		$ 14,062.21		$ 15,230.83		$ (1,168.62)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(3,488)	$ 36,014.12	157	$ 428.78	(3,644)	$ 35,585.34								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	100,315	$ 1,165,043.33	445,145	$ 6,508,575.08	(344,829)	$ (5,343,531.75)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (19,141.28)		$ 44,029.18		$ (43,608.12)		$ (19,562.34)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 154,382.71		$ 154,382.71		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 151,787.35		$ 151,787.35		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 23,611.63		$ 23,611.63		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 30,047.21		$ 11,823.19		$ -		$ 18,224.02						
14 Real Time Contignecy Reserve Deployment Failure		$ 74,081.54		$ 73,953.91		$ -				$ 127.63				
MISO ASM CHARGES	96,828	$ 911,676.61	445,301	$ 7,153,159.61	(348,473)	$ (5,814,892.75)	-	$ (1,338.32)	-	$ (425,251.93)	-	$ -	-	$ -
x Net Congestion Amount		$ 7,998.12		$ 7,998.12				$ -						
y Net Loss Amount		$ 89,173.41		$ 89,173.41				$ -						
z Net Congestion and Loss Energy Offset		$ (97,171.53)		$ (97,171.53)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	96,828	$ 911,676.61	445,301	$ 7,153,159.61	(348,473)	$ (5,814,892.75)	-	$ (1,338.32)	-	$ (425,251.93)	-	$ -	-	$ -

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

May 2021	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		$ (322,838.33)		$ -		$ 53,571.47				$ (376,409.80)				
2 Day-Ahead Spinning Reserve Amount		$ (243,955.90)		$ -		$ (26,121.91)				$ (217,833.99)				
3 Day-Ahead Supplemental Reserve		$ (25,452.43)		$ -		$ (16,647.75)				$ (8,804.68)				
4 Real-Time Regulation Amount		$ (142,422.10)		$ 99,876.62		$ (242,298.72)								
5 Real-Time Spinning Reserve Amount		$ (74,579.24)		$ 80,530.81		$ (155,110.05)								
6 Real-Time Supplemental Reserve Amount.		$ 23,963.76		$ 24,430.90		$ (467.14)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(926)	$ (8,323.69)	257	$ (2,653.97)	(1,183)	$ (5,669.72)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	155,931	$ 244,465.73	497,383	$ 5,772,426.16	(341,452)	$ (5,527,960.43)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (12,224.20)		$ 58,584.74		$ (65,436.55)		$ (5,372.39)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 155,843.28		$ 155,843.28		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 175,778.27		$ 175,778.27		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 27,492.21		$ 27,492.21		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 61,069.64		$ 27,264.80		$ -		$ 33,804.84						
14 Real Time Contignecy Reserve Deployment Failure		$ (73,850.00)		$ (73,850.10)		$ -				$ 0.10				
MISO ASM CHARGES	155,005	$ (215,033.00)	497,639	$ 6,345,723.72	(342,635)	$ (5,986,140.80)	-	$ 28,432.45	-	$ (603,048.37)	-	$ -	-	$ -
x Net Congestion Amount		$ (582,490.27)		$ (582,490.27)				$ -						
y Net Loss Amount		$ (2,209.07)		$ (2,209.07)				$ -						
z Net Congestion and Loss Energy Offset		$ 584,699.34		$ 584,699.34										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	155,005	$ (215,033.00)	497,639	$ 6,345,723.72	(342,635)	$ (5,986,140.80)	-	$ 28,432.45	-	$ (603,048.37)	-	$ -	-	$ -

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 2021	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		$ (107,195.17)		$ -		$ (20,217.97)				$ (86,977.20)				
2 Day-Ahead Spinning Reserve Amount		$ (136,940.29)		$ -		$ (12,029.59)				$ (124,910.70)				
3 Day-Ahead Supplemental Reserve		$ (16,079.64)		$ -		$ (7,138.00)				$ (8,941.64)				
4 Real-Time Regulation Amount		$ (221,612.40)		$ 25,766.14		$ (247,378.54)								
5 Real-Time Spinning Reserve Amount		$ (145,971.12)		$ 37,736.99		$ (183,708.11)								
6 Real-Time Supplemental Reserve Amount.		$ (19,536.27)		$ 2,235.12		$ (21,771.39)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,691)	$ 9,601.54	307	$ 669.75	(1,997)	$ 8,931.79								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	173,909	$ 3,907,581.69	500,631	$ 10,977,062.06	(326,722)	$ (7,069,480.37)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (49,644.62)		$ 25,285.02		$ (57,939.86)		$ (16,989.78)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 181,940.28		$ 181,940.28		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 191,220.19		$ 191,220.19		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 114,052.45		$ 114,052.45		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 12,826.26		$ 5,215.24		$ -		$ 7,611.02						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -				$ -				
MISO ASM CHARGES	172,219	$ 3,720,242.90	500,938	$ 11,561,183.24	(328,719)	$ (7,610,732.04)	-	$ (9,378.76)	-	$ (220,829.54)	-	$ -	-	$ -
x Net Congestion Amount		$ (890,279.97)		$ (890,279.97)				$ -						
y Net Loss Amount		$ (17,581.40)		$ (17,581.40)				$ -						
z Net Congestion and Loss Energy Offset		$ 907,861.37		$ 907,861.37										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	172,219	$ 3,720,242.90	500,938	$ 11,561,183.24	(328,719)	$ (7,610,732.04)	-	$ (9,378.76)	-	$ (220,829.54)	-	$ -	-	$ -

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 2021	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		$ (239,360.49)		$ -		$ 74,262.44				$ (313,622.93)				
2 Day-Ahead Spinning Reserve Amount		$ (252,603.34)		$ -		$ 22,156.81				$ (274,760.15)				
3 Day-Ahead Supplemental Reserve		$ (34,148.62)		$ -		$ (14,354.58)				$ (19,794.04)				
4 Real-Time Regulation Amount		$ (252,040.44)		$ 59,199.43		$ (311,239.87)								
5 Real-Time Spinning Reserve Amount		$ (139,093.51)		$ 58,722.17		$ (197,815.68)								
6 Real-Time Supplemental Reserve Amount.		$ (9,401.72)		$ 8,481.98		$ (17,883.70)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(3,120)	$ (9,544.36)	35	$ (165.00)	(3,155)	$ (9,379.36)								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	185,209	$ 6,644,706.15	460,477	$ 14,328,973.49	(275,268)	$ (7,684,267.34)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (15,776.67)		$ 54,030.84		$ (51,701.99)		$ (18,105.52)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 193,382.57		$ 193,382.57		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 228,895.40		$ 228,895.40		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 47,342.28		$ 47,342.28		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 62,434.67		$ 35,378.73		$ -		$ 27,055.94						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -				$ -				
MISO ASM CHARGES	182,089	$ 6,224,791.92	460,512	$ 15,014,241.89	(278,423)	$ (8,190,223.27)	-	$ 8,950.42	-	$ (608,177.12)	-	$ -	-	$ -
x Net Congestion Amount		$ (45,170.89)		$ (45,170.89)				$ -						
y Net Loss Amount		$ (50,570.41)		$ (50,570.41)				$ -						
z Net Congestion and Loss Energy Offset		$ 95,741.30		$ 95,741.30										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	182,089	$ 6,224,791.92	460,512	$ 15,014,241.89	(278,423)	$ (8,190,223.27)	-	$ 8,950.42	-	$ (608,177.12)	-	$ -	-	$ -

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 2021	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		$ (360,133.58)		$ -		$ (38,875.54)				$ (321,258.04)				
2 Day-Ahead Spinning Reserve Amount		$ (394,149.77)		$ -		$ (139,738.60)				$ (254,411.17)				
3 Day-Ahead Supplemental Reserve		$ (38,999.21)		$ -		$ (26,790.98)				$ (12,208.23)				
4 Real-Time Regulation Amount		$ (143,246.65)		$ 129,448.89		$ (272,695.54)								
5 Real-Time Spinning Reserve Amount		$ (12,851.55)		$ 87,111.29		$ (99,962.84)								
6 Real-Time Supplemental Reserve Amount.		$ 421.77		$ 10,387.46		$ (9,965.69)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(3,242)	$ 12,880.06	76	$ 1,161.24	(3,317)	$ 11,718.82								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	160,028	$ 4,336,444.42	518,515	$ 13,363,614.74	(358,487)	$ (9,027,170.32)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (13,179.72)		$ 45,465.24		$ (48,429.26)		$ (10,215.70)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 183,187.63		$ 183,187.63		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 211,466.71		$ 211,466.71		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 72,863.31		$ 72,863.31		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 106,167.62		$ 55,122.24		$ -		$ 51,045.38						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -				$ 0.68				
MISO ASM CHARGES	156,786	$ 3,960,871.04	518,590	$ 14,159,828.75	(361,804)	$ (9,651,909.95)	-	$ 40,829.68	-	$ (587,876.76)	-	$ -	-	$ -
x Net Congestion Amount		$ 588,779.17		$ 588,779.17				$ -						
y Net Loss Amount		$ 29,201.80		$ 29,201.80				$ -						
z Net Congestion and Loss Energy Offset		$ (617,980.97)		$ (617,980.97)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	156,786	$ 3,960,871.04	518,590	$ 14,159,828.75	(361,804)	$ (9,651,909.95)	-	$ 40,829.68	-	$ (587,876.76)	-	$ -	-	$ -

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 2021	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		$ (237,883.74)		$ -		$ 14,486.62				$ (252,370.36)				
2 Day-Ahead Spinning Reserve Amount		$ (226,786.86)		$ -		$ (25,489.87)				$ (201,296.99)				
3 Day-Ahead Supplemental Reserve		$ (42,668.01)		$ -		$ (25,482.65)				$ (17,185.36)				
4 Real-Time Regulation Amount		$ (194,616.85)		$ 79,219.97		$ (273,836.82)								
5 Real-Time Spinning Reserve Amount		$ (88,095.35)		$ 78,896.63		$ (166,991.98)								
6 Real-Time Supplemental Reserve Amount.		$ 13,008.87		$ 14,770.47		$ (1,761.60)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,781)	$ 9,626.64	21	$ (224.00)	(1,802)	$ 9,850.64								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	51,466	$ 441,769.30	408,367	$ 7,254,640.06	(356,901)	$ (6,812,870.76)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (2,782.73)		$ 32,654.04		$ (34,405.37)		$ (1,031.40)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 174,002.33		$ 174,002.33		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 135,417.52		$ 135,417.52		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 9,302.63		$ 9,302.63		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 65,611.33		$ 38,456.08		$ -		$ 27,155.25						
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -				$ -				
MISO ASM CHARGES	49,685	$ 55,905.08	408,388	$ 7,817,135.73	(358,703)	$ (7,316,501.79)	-	$ 26,123.85	-	$ (470,852.71)	-	$ -	-	$ -
x Net Congestion Amount		$ (190,522.33)		$ (190,522.33)				$ -						
y Net Loss Amount		$ 106,108.51		$ 106,108.51				$ -						
z Net Congestion and Loss Energy Offset		$ 84,413.82		$ 84,413.82										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	49,685	$ 55,905.08	408,388	$ 7,817,135.73	(358,703)	$ (7,316,501.79)	-	$ 26,123.85	-	$ (470,852.71)	-	$ -	-	$ -

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

October 2021	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		$ (473,628.04)		$ -		$ 115,850.53				$ (589,478.57)				
2 Day-Ahead Spinning Reserve Amount		$ (224,177.99)		$ -		$ (7,586.01)				$ (216,591.98)				
3 Day-Ahead Supplemental Reserve		$ (30,432.94)		$ -		$ (22,928.89)				$ (7,504.05)				
4 Real-Time Regulation Amount		$ (385,076.85)		$ 129,744.86		$ (514,821.71)								
5 Real-Time Spinning Reserve Amount		$ (131,281.50)		$ 58,605.14		$ (189,886.64)								
6 Real-Time Supplemental Reserve Amount.		$ 35,387.80		$ 39,067.73		$ (3,679.93)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,809)	$ 19,577.14	44	$ (823.04)	(2,853)	$ 20,400.18								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	134,422	$ 5,516,670.25	473,771	$ 11,867,002.93	(339,348)	$ (6,350,332.68)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (9,124.72)		$ 68,459.87		$ (77,061.13)		$ (523.46)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 198,170.16		$ 198,170.16		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 277,281.47		$ 277,281.47		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 59,556.84		$ 59,556.84		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 146,255.57		$ 102,183.21		$ -		$ 44,072.36						
14 Real Time Contignecy Reserve Deployment Failure		$ 1,463.22		$ 1,463.22		$ -				$ -				
MISO ASM CHARGES	131,613	$ 5,000,640.41	473,814	$ 12,800,712.39	(342,201)	$ (7,030,046.28)	-	$ 43,548.90	-	$ (813,574.60)	-	$ -	-	$ -
x Net Congestion Amount		$ 2,424,755.88		$ 2,424,755.88				$ -						
y Net Loss Amount		$ 258,210.39		$ 258,210.39				$ -						
z Net Congestion and Loss Energy Offset		$ (2,682,966.27)		$ (2,682,966.27)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	131,613	$ 5,000,640.41	473,814	$ 12,800,712.39	(342,201)	$ (7,030,046.28)	-	$ 43,548.90	-	$ (813,574.60)	-	$ -	-	$ -

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 2021	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		$ (299,431.61)		$ -		$ (76,512.30)				$ (222,919.31)				
2 Day-Ahead Spinning Reserve Amount		$ (321,238.92)		$ -		$ 2,123.72				$ (323,362.64)				
3 Day-Ahead Supplemental Reserve		$ (9,832.34)		$ -		$ (9,101.88)				$ (730.46)				
4 Real-Time Regulation Amount		$ (231,805.88)		$ 153,134.13		$ (384,940.01)								
5 Real-Time Spinning Reserve Amount		$ (105,470.44)		$ 98,072.95		$ (203,543.39)								
6 Real-Time Supplemental Reserve Amount.		$ (433.75)		$ 584.84		$ (1,018.59)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(2,285)	$ 29,975.35	51	$ (1,349.06)	(2,336)	$ 31,324.41								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	(58)	$ 4,938,364.97	436,522	$ 11,722,600.85	(436,580)	$ (6,784,235.88)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ (7,017.36)		$ 32,428.57		$ (61,501.27)		$ 22,055.34						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 161,884.56		$ 161,884.56		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 134,104.70		$ 134,104.70		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 17,018.59		$ 17,018.59		$ -								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 132,259.35		$ 88,881.20		$ -		$ 43,378.15						
14 Real Time Contignecy Reserve Deployment Failure		$ 61,702.91		$ 61,702.91		$ -				$ -				
MISO ASM CHARGES	(2,343)	$ 4,500,080.13	436,572	$ 12,469,064.24	(438,915)	$ (7,487,405.19)	-	$ 65,433.49	-	$ (547,012.41)	-	$ -	-	$ -
x Net Congestion Amount		$ 2,375,979.62		$ 2,375,979.62				$ -						
y Net Loss Amount		$ 317,528.34		$ 317,528.34				$ -						
z Net Congestion and Loss Energy Offset		$ (2,693,507.96)		$ (2,693,507.96)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	(2,343)	$ 4,500,080.13	436,572	$ 12,469,064.24	(438,915)	$ (7,487,405.19)	-	$ 65,433.49	-	$ (547,012.41)	-	$ -	-	$ -

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 2021	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		$ (182,830.02)		$ -		$ (70,213.68)				$ (112,616.34)				
2 Day-Ahead Spinning Reserve Amount		$ (223,985.03)		$ -		$ (50,624.74)				$ (173,360.29)				
3 Day-Ahead Supplemental Reserve		$ (9,940.23)		$ -		$ (8,754.24)				$ (1,185.99)				
4 Day-Ahead Short Term Reserve Amount		$ (65,435.71)		$ -		$ (65,435.71)								
5 Real-Time Regulation Amount (See Note 1)		$ (101,360.47)		$ 73,921.49		$ (175,281.96)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (14,061.04)		$ 116,404.07		$ (130,465.11)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (2,727.56)		$ 2,477.51		$ (5,205.07)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 10,244.87		$ 32,920.49		$ (22,675.62)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(1,722)	$ 22,729.74	89	$ (2,274.24)	(1,811)	$ 25,003.98								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	73,923	$ 8,363,358.45	544,422	$ 15,561,887.71	(470,499)	$ (7,198,529.26)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 1,986,342.02		$ 20,215.71		$ 1,925,337.86		$ 40,788.45						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 132,526.54		$ 132,526.54		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 115,734.84		$ 115,734.84		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 19,017.75		$ 19,017.75		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 145,422.94		$ 146,829.30		$ (1,406.36)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 114,035.85		$ 68,648.24		$ -		$ 45,387.61						
14 Real Time Contignecy Reserve Deployment Failure		$ 598.96		$ (364.37)		$ -				$ 963.33				
15 Real Time Short Term Reserve Deployment Failure		$ 28.34		$ 28.34		$ -								
MISO ASM CHARGES	72,201	$ 10,309,700.24	544,511	$ 16,287,973.38	(472,310)	$ (5,778,249.91)	-	$ 86,176.06	-	$ (286,199.29)	-	$ -	-	$ -
x Net Congestion Amount		$ 3,428,256.50		$ 3,428,256.50				$ -						
y Net Loss Amount		$ 201,835.62		$ 201,835.62				$ -						
z Net Congestion and Loss Energy Offset		$ (3,630,092.12)		$ (3,630,092.12)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	72,201	$ 10,309,700.24	544,511	$ 16,287,973.38	(472,310)	$ (5,778,249.91)	-	$ 86,176.06	-	$ (286,199.29)	-	$ -	-	$ -

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 2021	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		$ (3,020,070.14)		$ -		$ 47,839.08				$ (3,067,909.22)				
2 Day-Ahead Spinning Reserve Amount		$ (3,115,560.22)		$ -		$ (638,461.58)				$ (2,477,098.64)				
3 Day-Ahead Supplemental Reserve		$ (746,463.81)		$ -		$ (78,892.95)				$ (667,570.86)				
4 Day-Ahead Short Term Reserve Amount		$ (65,435.71)		$ -		$ (65,435.71)								
5 Real-Time Regulation Amount (See Note 1)		$ (2,217,938.26)		$ 1,060,924.71		$ (3,278,862.97)								
6 Real-Time Spinning Reserve Amount (See Note 1)		$ (669,369.97)		$ 1,227,235.65		$ (1,896,605.62)								
7 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (143,713.55)		$ 197,853.92		$ (341,567.47)								
8 Real-Time Short Term Reserve Amount. (See Note 1)		$ 10,244.87		$ 32,920.49		$ (22,675.62)								
Resource Energy Charges														
7a Real Time Excessive Energy Amount	(28,589)	$ 86,718.76	1,626	$ (8,028.44)	(30,215)	$ 94,747.20								
7b Real Time Excessive Energy Congestion														
7c Real Time Excessive Energy Loss														
8a Real Time Non Excessive Energy Amount	1,132,942	$ 38,060,064.23	5,523,703	$ 125,566,010.66	(4,390,761)	$ (87,505,946.43)								
8b Real Time Non Excessive Energy Congestion														
8c Real Time Non Excessive Energy Loss														
9 Real Time Net Regulation Adjustment Amount		$ 1,765,951.08		$ 482,438.44		$ 1,344,073.73		$ (60,561.09)						
Cost Distribution Charges														
10 Real Time Regulation Reserve Cost Distribution Amount		$ 2,058,357.30		$ 2,058,357.30		$ -								
11 Real Time Spinnng Reserve Cost Distribution		$ 2,062,034.54		$ 2,062,034.54		$ -								
12 Real Time Supplemental Reserve Cost Distribution		$ 702,417.93		$ 702,417.93		$ -								
13 Real Time Short Term Reserve Cost Distribution		$ 145,422.94		$ 146,829.30		$ (1,406.36)								
Penalty Charges														
13 Real Time Excessive/Dificient Energy Deployment		$ 872,735.49		$ 526,580.81		$ -		$ 346,154.68						
14 Real Time Contignecy Reserve Deployment Failure		$ 63,996.63		$ 62,904.89		$ -				$ 1,091.74				
15 Real Time Short Term Reserve Deployment Failure		$ 28.34		$ 28.34		$ -								
MISO ASM CHARGES	1,104,353	$ 35,849,420.45	5,525,329	$ 134,118,508.54	(4,420,976)	$ (92,343,194.70)	-	$ 285,593.59	-	$ (6,211,486.98)	-	$ -	-	$ -
x Net Congestion Amount		$ 7,336,781.13		$ 7,336,781.13				$ -						
y Net Loss Amount		$ 1,125,449.89		$ 1,125,449.89				$ -						
z Net Congestion and Loss Energy Offset		$ (8,462,231.02)		$ (8,462,231.02)										
SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
Total MISO ASM CHARGES	1,104,353	$ 35,849,420.45	5,525,329	$ 134,118,508.54	(4,420,976)	$ (92,343,194.70)	-	$ 285,593.59	-	$ (6,211,486.98)	-	$ -	-	$ -

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
Electric Operations – State of Minnesota
MISO – Ancillary Services Market

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
1/1/2021	(1,825,767)	(1,837,389)	11,622	0.63%	0	1,747	9	7,242	535	9,089	7,197
1/2/2021	(1,054,611)	(1,050,068)	-4,543	-0.43%	0	1,986	14	7,003	407	-7,284	3,390
1/3/2021	(664,244)	(677,937)	13,693	2.02%	0	401	-47	5,332	271	12,779	3,276
1/4/2021	(766,856)	(835,672)	68,816	8.23%	0	1,188	-109	5,115	441	67,182	2,976
1/5/2021	(1,877,652)	(1,869,195)	-8,457	-0.45%	0	1,690	-625	8,539	745	-10,450	14
1/6/2021	(1,860,621)	(1,843,148)	-17,473	-0.95%	0	353	-54	8,936	516	-18,717	1,856
1/7/2021	(2,135,462)	(2,128,659)	-6,803	-0.32%	0	1,660	525	9,703	214	-9,980	8,567
1/8/2021	(2,336,426)	(2,335,878)	-548	-0.02%	0	614	-476	10,233	175	-1,727	3,520
1/9/2021	(2,476,166)	(2,462,220)	-13,946	-0.57%	0	836	-2,766	11,219	195	-13,158	(4,634)
1/10/2021	(2,348,192)	(2,328,802)	-19,390	-0.83%	0	2,825	-90	10,874	584	-23,270	2,178
1/11/2021	(1,307,615)	(1,329,029)	21,414	1.61%	0	280	2	6,993	1,060	20,326	2,190
1/12/2021	(1,542,756)	(1,542,340)	-416	-0.03%	0	371	-102	7,828	851	-1,553	4,466
1/13/2021	(1,351,820)	(1,373,823)	22,003	1.60%	0	431	2	7,498	239	20,796	4,096
1/14/2021	(1,078,084)	(1,118,282)	40,198	3.59%	0	105	4	6,022	469	39,440	(2,523)
1/15/2021	(991,994)	(1,009,870)	17,876	1.77%	0	23	1	5,711	314	17,250	4,749
1/16/2021	(999,616)	(994,687)	-4,929	-0.50%	0	168	2	6,047	465	-5,751	14,579
1/17/2021	(1,012,965)	(1,010,708)	-2,257	-0.22%	0	66	1,417	6,183	375	-4,396	(2,589)
1/18/2021	(2,030,752)	(2,030,100)	-652	-0.03%	0	88	8	9,272	1,185	-1,794	(3,443)
1/19/2021	(2,178,215)	(2,179,221)	1,006	0.05%	0	1,068	-3	9,633	1,471	-1,170	(17,864)
1/20/2021	(1,502,127)	(1,498,984)	-3,143	-0.21%	0	1,085	-410	6,792	1,382	-4,635	(7,606)
1/21/2021	(880,654)	(924,907)	44,253	4.78%	0	505	0	5,527	168	43,178	(422)
1/22/2021	(1,645,176)	(1,655,392)	10,216	0.62%	0	2,397	-181	8,592	603	7,081	6,992
1/23/2021	(1,558,607)	(1,556,844)	-1,763	-0.11%	0	29	4	8,711	889	-2,756	4,927
1/24/2021	(1,721,553)	(1,721,126)	-427	-0.02%	0	592	43	8,857	437	-1,992	5,130
1/25/2021	(1,910,879)	(1,909,520)	-1,359	-0.07%	0	453	78	8,945	845	-2,869	9,816
1/26/2021	(2,533,802)	(2,528,314)	-5,488	-0.22%	0	1,263	-108	10,750	512	-7,769	10,636
1/27/2021	(2,375,746)	(2,396,585)	20,839	0.87%	0	545	-265	10,853	443	19,430	3,403
1/28/2021	(2,396,815)	(2,384,619)	-12,196	-0.51%	0	1,085	-47	10,584	783	-14,371	4,893
1/29/2021	(1,777,554)	(1,777,641)	87	0.00%	0	1,054	-95	8,913	813	-1,845	9,087
1/30/2021	(1,218,923)	(1,216,227)	-2,696	-0.22%	0	634	-36	6,853	744	-4,054	5,472
1/31/2021	(1,252,196)	(1,248,451)	-3,745	-0.30%	0	188	-30	6,796	297	-4,612	4,840
2/1/2021	(1,238,692)	(1,236,714)	-1,978	-0.16%	0	1,871	-225	8,753	683	-4,568	1,879
2/2/2021	(646,792)	(646,075)	-717	-0.11%	0	256	-463	8,954	498	-1,455	(21)
2/3/2021	(975,270)	(971,409)	-3,861	-0.40%	0	473	-194	10,426	622	-5,245	1,606
2/4/2021	(1,182,736)	(1,175,721)	-7,015	-0.60%	0	371	-21	10,984	790	-8,543	759
2/5/2021	(685,648)	(680,855)	-4,793	-0.70%	0	989	-133	9,683	961	-6,714	(3,402)
2/6/2021	(971,206)	(977,913)	6,707	0.69%	0	374	7	11,045	1,486	5,073	226

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
2/7/2021	(1,498,833)	(1,494,611)	-4,222	-0.28%	0	1,019	82	12,570	805	-6,660	(531)
2/8/2021	(1,707,445)	(1,771,913)	64,468	3.64%	0	2,022	-1,037	12,858	1,096	62,088	1,192
2/9/2021	(1,251,470)	(1,240,348)	-11,122	-0.90%	0	218	53	12,166	769	-12,686	1,599
2/10/2021	(1,507,215)	(1,492,899)	-14,316	-0.96%	0	631	-68	12,542	335	-16,167	1,343
2/11/2021	(1,365,672)	(1,361,020)	-4,652	-0.34%	0	254	35	11,549	465	-6,143	2,125
2/12/2021	(2,023,792)	(2,017,872)	-5,920	-0.29%	0	1,422	174	11,110	543	-8,681	3,263
2/13/2021	(4,352,428)	(4,337,985)	-14,443	-0.33%	0	1,475	2,441	11,001	664	-19,526	(1,022)
2/14/2021	(41,118,070)	(41,126,970)	8,900	0.02%	0	1,702	-1,323	11,234	166	7,381	(7,056)
2/15/2021	(134,785,200)	(134,756,800)	-28,400	-0.02%	0	29,719	-29,071	12,901	640	-30,402	(294)
2/16/2021	(94,779,700)	(94,888,370)	108,670	0.11%	0	4,295	-23,732	12,412	1,029	126,764	(1,227)
2/17/2021	(68,132,120)	(68,251,930)	119,810	0.18%	0	7,479	-19,289	11,735	414	130,405	(2,723)
2/18/2021	(28,947,100)	(29,041,850)	94,750	0.33%	0	18,703	5,373	11,235	387	69,511	(697)
2/19/2021	(2,294,022)	(2,291,114)	-2,908	-0.13%	0	3,731	-786	9,799	607	-6,894	7,583
2/20/2021	(548,570)	(543,219)	-5,351	-0.99%	0	471	-120	8,217	46	-6,528	8,405
2/21/2021	(641,486)	(647,372)	5,886	0.91%	0	1,913	-96	8,991	380	3,132	2,411
2/22/2021	(393,585)	(397,158)	3,573	0.90%	0	1,109	-159	6,791	214	1,923	2,931
2/23/2021	(521,301)	(515,260)	-6,041	-1.17%	0	365	-59	7,464	412	-7,134	742
2/24/2021	(614,360)	(611,680)	-2,680	-0.44%	0	531	-12	8,384	575	-4,094	3,074
2/25/2021	(654,022)	(650,578)	-3,444	-0.53%	0	642	-196	9,872	463	-4,924	4,458
2/26/2021	(490,943)	(490,750)	-193	-0.04%	0	931	-95	6,841	785	-1,792	956
2/27/2021	(602,004)	(600,187)	-1,817	-0.30%	0	1,213	-75	7,774	435	-3,776	5,299
2/28/2021	(446,795)	(445,369)	-1,426	-0.32%	0	587	32	6,055	491	-2,700	1,460
3/1/2021	(1,032,933)	(1,035,058)	2,125	0.21%	0	473	-623	5,788	357	1,660	(351)
3/2/2021	(354,110)	(349,692)	-4,418	-1.26%	0	321	-46	4,082	322	-5,134	(1,214)
3/3/2021	(935,138)	(944,501)	9,363	0.99%	0	278	-2,720	6,067	662	11,132	9,177
3/4/2021	(778,879)	(785,684)	6,805	0.87%	0	1,497	-765	5,832	640	5,426	2,903
3/5/2021	(935,929)	(943,755)	7,826	0.83%	0	4,644	-1,684	6,284	330	4,205	2,665
3/6/2021	(538,328)	(532,931)	-5,397	-1.01%	0	70	29	5,265	350	-6,058	2,173
3/7/2021	(361,754)	(381,975)	20,221	5.29%	0	0	5	3,586	91	19,848	(114)
3/8/2021	(458,340)	(474,100)	15,760	3.32%	0	123	-213	4,287	192	15,403	1,655
3/9/2021	(312,080)	(348,108)	36,028	10.35%	0	76	5	3,501	46	35,592	1,612
3/10/2021	(277,511)	(290,962)	13,451	4.62%	0	242	-31	3,760	205	12,843	5,179
3/11/2021	(370,591)	(393,020)	22,429	5.71%	0	1,485	-750	4,308	141	21,249	12,600
3/12/2021	(576,557)	(575,006)	-1,551	-0.27%	0	165	-18	5,184	174	-2,233	7,017
3/13/2021	(564,988)	(583,403)	18,415	3.16%	0	186	-147	4,987	261	17,851	1,935
3/14/2021	(311,956)	(354,092)	42,136	11.90%	0	75	-101	3,420	-54	41,825	11,009
3/15/2021	(582,840)	(598,010)	15,170	2.54%	0	2,207	744	4,744	322	11,713	7,326

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

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
3/16/2021	(1,101,324)	(1,110,486)	9,162	0.83%	0	1,462	-4,461	6,598	182	11,483	4,054
3/17/2021	(720,855)	(727,307)	6,452	0.89%	0	960	-2,205	5,652	315	7,100	6,127
3/18/2021	(315,400)	(316,566)	1,166	0.37%	0	242	126	4,129	419	343	2,999
3/19/2021	(576,950)	(602,076)	25,126	4.17%	0	201	-21	4,504	326	24,462	(3,670)
3/20/2021	(275,070)	(297,289)	22,219	7.47%	0	273	0	3,169	270	21,603	(235)
3/21/2021	(309,806)	(322,304)	12,498	3.88%	0	23	0	3,876	93	12,078	(1,064)
3/22/2021	(816,524)	(818,679)	2,155	0.26%	0	505	-1,301	5,763	267	2,349	(1,183)
3/23/2021	(537,478)	(536,700)	-778	-0.14%	0	114	4	4,909	436	-1,431	2,692
3/24/2021	(710,113)	(708,496)	-1,617	-0.23%	0	674	-30	5,024	592	-2,822	829
3/25/2021	(1,003,836)	(1,014,932)	11,096	1.09%	0	3,879	-358	6,125	965	6,866	1,382
3/26/2021	(743,898)	(750,379)	6,481	0.86%	0	1,598	-539	5,333	124	4,877	(7,497)
3/27/2021	(507,043)	(505,955)	-1,088	-0.22%	0	238	-27	4,470	163	-1,762	(2,398)
3/28/2021	(333,587)	(347,059)	13,472	3.88%	0	43	0	4,034	274	12,998	(1,772)
3/29/2021	(316,877)	(324,924)	8,047	2.48%	0	88	0	3,734	91	7,576	964
3/30/2021	(301,073)	(355,400)	54,327	15.29%	0	318	99	3,329	141	53,563	489
3/31/2021	(713,577)	(711,373)	-2,204	-0.31%	0	263	-73	4,579	300	-2,881	11,302
4/1/2021	(1,201,342)	(1,222,269)	20,927	1.71%	0	908	-1,302	9,107	936	20,317	9,669
4/2/2021	(469,594)	(466,503)	-3,091	-0.66%	232	118	-292	6,471	260	-3,822	(3,386)
4/3/2021	(512,617)	(509,083)	-3,534	-0.69%	0	435	12	7,089	468	-4,737	(1,294)
4/4/2021	(276,247)	(349,929)	73,682	21.06%	0	152	-35	5,454	26	73,017	(5,025)
4/5/2021	(338,346)	(365,680)	27,334	7.47%	0	289	-1,244	6,336	1,359	27,520	4,951
4/6/2021	(861,223)	(875,106)	13,883	1.59%	0	503	3,359	8,745	1,992	8,948	2,687
4/7/2021	(437,520)	(455,242)	17,722	3.89%	0	2,072	-2,521	5,982	131	17,560	7,841
4/8/2021	(510,617)	(523,332)	12,715	2.43%	0	5,649	-2,733	6,250	54	9,169	967
4/9/2021	(447,409)	(470,523)	23,114	4.91%	0	651	-1,271	5,847	135	23,136	(675)
4/10/2021	(487,368)	(511,889)	24,521	4.79%	0	1,277	-966	5,728	42	23,633	1,158
4/11/2021	(532,388)	(552,477)	20,089	3.64%	0	107	-854	5,972	169	20,222	3,546
4/12/2021	(711,257)	(721,560)	10,303	1.43%	0	101	-337	6,759	272	9,836	(10,461)
4/13/2021	(698,178)	(715,973)	17,795	2.49%	0	224	-904	6,617	631	17,750	(2,022)
4/14/2021	(484,929)	(541,831)	56,902	10.50%	0	184	-1,144	5,450	-14	57,318	492
4/15/2021	(801,248)	(827,794)	26,546	3.21%	0	1,020	-605	6,593	1,478	25,323	12,073
4/16/2021	(779,750)	(785,336)	5,586	0.71%	0	567	-1,065	7,743	664	5,243	7,214
4/17/2021	(560,696)	(569,417)	8,721	1.53%	0	351	-110	5,618	12	7,917	9,241
4/18/2021	(610,685)	(613,525)	2,840	0.46%	0	1,483	-1,315	5,939	328	2,045	5,190
4/19/2021	(597,716)	(597,383)	-333	-0.06%	0	878	427	6,691	812	-2,389	12,994
4/20/2021	(832,342)	(841,813)	9,471	1.13%	0	1,480	584	7,768	983	6,531	(8,519)
4/21/2021	(468,338)	(468,821)	483	0.10%	0	182	-932	6,103	129	610	13,338

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
4/22/2021	(457,769)	(470,056)	12,287	2.61%	0	1,416	707	5,520	677	9,545	4,915
4/23/2021	(745,935)	(751,015)	5,080	0.68%	0	699	-3,135	7,950	518	6,669	6,148
4/24/2021	(612,141)	(621,301)	9,160	1.47%	0	715	-632	7,706	139	8,293	10,118
4/25/2021	(623,367)	(627,121)	3,754	0.60%	0	168	-1,955	7,452	600	4,735	(6,289)
4/26/2021	(740,139)	(749,549)	9,410	1.26%	0	619	-1,401	6,733	1,245	9,394	(14,933)
4/27/2021	(913,441)	(922,472)	9,031	0.98%	0	12,452	-989	8,791	799	-3,391	(2,393)
4/28/2021	(1,306,985)	(1,335,217)	28,232	2.11%	0	926	-2,331	9,594	1,157	28,563	(3,369)
4/29/2021	(758,711)	(759,414)	703	0.09%	0	999	-1,514	7,945	1,043	319	31,913
4/30/2021	(1,014,675)	(1,027,581)	12,906	1.26%	0	2,215	-1,247	8,002	1,176	11,021	12,462
5/1/2021	(1,685,180)	(1,702,745)	17,565	1.03%	0	1,332	-101	5,604	734	15,700	87
5/2/2021	(1,262,864)	(1,310,997)	48,133	3.67%	0	3,922	-83	6,802	1,073	43,507	35,796
5/3/2021	(1,587,899)	(1,647,480)	59,581	3.62%	0	473	2,971	8,237	882	55,225	14,720
5/4/2021	(1,712,113)	(1,781,968)	69,855	3.92%	0	1,587	-426	9,087	927	67,693	13,750
5/5/2021	(1,825,300)	(1,847,278)	21,978	1.19%	0	703	-6,609	8,755	2,423	26,766	1,182
5/6/2021	(1,767,409)	(1,828,028)	60,619	3.32%	0	245	-238	8,209	554	59,736	10,226
5/7/2021	(1,372,979)	(1,430,618)	57,639	4.03%	0	2,931	-1,111	7,548	410	55,023	(22,135)
5/8/2021	(1,447,438)	(1,493,208)	45,770	3.07%	0	2,399	1,084	7,885	273	41,471	(655)
5/9/2021	(1,490,746)	(1,528,136)	37,390	2.45%	0	426	264	8,056	261	35,869	27,745
5/10/2021	(1,805,254)	(1,843,715)	38,461	2.09%	0	8,489	-4,735	8,941	457	33,767	27,312
5/11/2021	(1,583,370)	(1,576,963)	-6,407	-0.41%	0	1,357	-4,869	8,025	39	-3,701	15,437
5/12/2021	(1,502,921)	(1,506,688)	3,767	0.25%	0	2,895	-1,949	7,829	541	1,984	(14,932)
5/13/2021	(1,585,333)	(1,595,378)	10,045	0.63%	0	614	-821	8,230	557	9,374	(13,886)
5/14/2021	(1,399,031)	(1,421,290)	22,259	1.57%	0	1,078	358	7,757	155	20,032	(998)
5/15/2021	(1,008,615)	(1,018,356)	9,741	0.96%	0	569	-1,376	6,664	167	9,865	(6,464)
5/16/2021	(960,344)	(968,805)	8,461	0.87%	0	2,266	-1,328	6,435	141	6,866	849
5/17/2021	(982,275)	(972,558)	-9,717	-1.00%	0	2,449	-746	6,384	324	-12,091	(1,840)
5/18/2021	(1,036,166)	(1,040,942)	4,776	0.46%	0	988	130	6,597	372	2,961	61,564
5/19/2021	(1,079,750)	(1,064,066)	-15,684	-1.47%	0	1,568	-892	6,637	413	-17,065	4,693
5/20/2021	(1,245,180)	(1,232,398)	-12,782	-1.04%	0	1,635	-1,654	7,121	1,115	-13,587	1,889
5/21/2021	(1,138,592)	(1,114,628)	-23,964	-2.15%	0	1,117	-2,487	7,587	675	-23,421	453
5/22/2021	(832,081)	(836,930)	4,849	0.58%	0	210	18,718	6,489	242	-14,752	(1,985)
5/23/2021	(625,888)	(624,725)	-1,163	-0.19%	0	1,184	-925	5,648	360	-2,023	(2,312)
5/24/2021	(816,985)	(817,970)	985	0.12%	0	447	-379	6,327	76	277	1,946
5/25/2021	(877,560)	(879,262)	1,702	0.19%	0	164	-124	6,482	192	994	2,351
5/26/2021	(1,314,452)	(1,309,313)	-5,139	-0.39%	0	1,189	1,552	8,013	211	-8,702	1,237
5/27/2021	(721,044)	(721,938)	894	0.12%	0	189	-9	6,557	770	-19	(3,956)
5/28/2021	(1,008,397)	(1,006,771)	-1,626	-0.16%	0	15	0	7,760	392	-2,456	9,663

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
5/29/2021	(1,014,836)	(989,729)	-25,107	-2.54%	0	175	0	7,776	317	-26,091	62
5/30/2021	(1,253,416)	(1,237,503)	-15,913	-1.29%	0	265	6	8,524	254	-17,062	(3,353)
5/31/2021	(1,339,026)	(1,322,440)	-16,586	-1.25%	0	1,355	7	8,847	370	-18,869	(1,207)
6/1/2021	(1,937,759)	(1,936,578)	-1,181	-0.06%	0	401	-202	7,847	390	-2,204	(4,648)
6/2/2021	(1,444,906)	(1,453,638)	8,732	0.60%	0	421	-472	7,353	401	8,008	(2,734)
6/3/2021	(1,251,589)	(1,262,602)	11,013	0.87%	0	1,503	-575	6,621	321	9,390	29,593
6/4/2021	(1,877,023)	(1,883,514)	6,491	0.34%	0	62	-416	7,427	945	6,007	(903)
6/5/2021	(1,425,133)	(1,429,873)	4,740	0.33%	0	81	-55	7,381	476	3,928	5,644
6/6/2021	(1,591,721)	(1,583,698)	-8,023	-0.51%	0	206	262	7,808	692	-9,342	4,716
6/7/2021	(2,584,427)	(2,605,165)	20,738	0.80%	0	1,260	-1,083	10,153	384	19,508	(2,626)
6/8/2021	(2,758,408)	(2,761,471)	3,063	0.11%	0	64	386	10,277	222	1,563	(3,981)
6/9/2021	(2,585,225)	(2,591,481)	6,256	0.24%	0	123	-48	9,826	491	5,149	11,780
6/10/2021	(2,483,928)	(2,494,188)	10,260	0.41%	0	247	-30,685	9,120	491	39,736	(3,362)
6/11/2021	(2,577,952)	(2,624,156)	46,204	1.76%	0	236	-552	9,492	509	45,519	(4,606)
6/12/2021	(1,901,503)	(1,909,001)	7,498	0.39%	0	400	-3,182	8,452	143	9,421	6,466
6/13/2021	(2,025,531)	(2,040,952)	15,421	0.76%	0	307	604	8,820	784	13,549	(9,644)
6/14/2021	(2,603,454)	(2,614,953)	11,499	0.44%	0	1,031	-2,162	9,635	662	11,600	44,183
6/15/2021	(2,309,620)	(2,319,513)	9,893	0.43%	0	190	-554	9,709	303	9,256	42,640
6/16/2021	(1,782,469)	(1,798,788)	16,319	0.91%	0	389	733	8,405	462	14,310	43,190
6/17/2021	(2,360,597)	(2,412,157)	51,560	2.14%	0	1,153	-876	9,440	403	50,299	31,673
6/18/2021	(2,410,364)	(2,404,397)	-5,967	-0.25%	0	1,244	-1,075	9,916	720	-7,200	28,611
6/19/2021	(1,796,246)	(1,789,253)	-6,993	-0.39%	0	207	91	8,377	889	-8,218	12,935
6/20/2021	(804,481)	(811,370)	6,889	0.85%	0	137	-17	5,733	1,533	6,042	5,322
6/21/2021	(707,959)	(714,739)	6,780	0.95%	0	5	1	4,867	1,087	6,178	(1,623)
6/22/2021	(1,887,420)	(1,890,860)	3,440	0.18%	0	325	-498	8,348	470	2,731	(1,967)
6/23/2021	(1,497,154)	(1,503,738)	6,584	0.44%	0	300	141	7,505	634	5,330	(5,473)
6/24/2021	(1,969,693)	(1,987,521)	17,828	0.90%	0	233	823	8,409	540	15,878	(2,787)
6/25/2021	(2,058,551)	(2,077,173)	18,622	0.90%	0	453	980	9,026	169	16,269	(5,070)
6/26/2021	(1,680,051)	(1,683,600)	3,549	0.21%	0	1,322	-42	8,442	513	1,374	(2,192)
6/27/2021	(2,018,453)	(2,023,125)	4,672	0.23%	0	202	1,801	9,351	478	1,686	5,533
6/28/2021	(2,700,996)	(2,721,905)	20,909	0.77%	0	733	-1,521	10,481	841	20,564	(898)
6/29/2021	(3,532,375)	(3,543,922)	11,547	0.33%	0	860	-5,418	11,045	637	14,937	(1,466)
6/30/2021	(3,995,699)	(4,039,038)	43,339	1.07%	0	1,077	-2,094	11,459	795	43,131	3,291
7/1/2021	(3,736,549)	(3,738,802)	2,253	0.06%	0	1,819	-2,030	8,915	244	1,548	3,989
7/2/2021	(2,812,596)	(2,817,628)	5,032	0.18%	0	5,655	2,873	8,143	493	-4,360	(10,614)
7/3/2021	(2,362,656)	(2,363,257)	601	0.03%	0	5,749	-215	7,347	309	-5,699	(9,785)
7/4/2021	(2,629,262)	(2,618,231)	-11,031	-0.42%	0	304	-153	7,465	879	-12,016	(8,744)

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
7/5/2021	(2,572,629)	(2,566,109)	-6,520	-0.25%	0	1,234	446	8,433	588	-9,102	4,671
7/6/2021	(3,457,990)	(3,500,850)	42,860	1.22%	0	1,665	-3,390	8,944	710	43,620	(3,671)
7/7/2021	(3,179,755)	(3,181,191)	1,436	0.05%	0	827	15	8,356	683	-310	105,530
7/8/2021	(2,536,810)	(2,535,923)	-887	-0.03%	0	728	85	8,304	273	-2,558	36,726
7/9/2021	(3,387,454)	(3,382,929)	-4,525	-0.13%	0	617	-34	7,134	445	-5,865	5,575
7/10/2021	(2,868,120)	(2,859,989)	-8,131	-0.28%	0	895	379	6,043	1,102	-10,120	38,986
7/11/2021	(1,905,546)	(1,900,091)	-5,455	-0.29%	0	63	177	6,185	520	-6,366	10,720
7/12/2021	(2,256,109)	(2,258,431)	2,322	0.10%	0	5,961	411	8,127	259	-4,889	(7,173)
7/13/2021	(1,558,485)	(1,558,446)	-39	0.00%	0	1,966	-1,176	8,455	196	-1,694	(1,367)
7/14/2021	(1,967,896)	(1,984,999)	17,103	0.86%	0	395	-42	7,140	329	16,003	(5,899)
7/15/2021	(2,006,494)	(2,007,965)	1,471	0.07%	0	203	-430	7,643	340	900	(6,157)
7/16/2021	(2,499,510)	(2,505,960)	6,450	0.26%	0	2,868	-482	6,648	331	3,366	(2,645)
7/17/2021	(2,366,213)	(2,369,047)	2,834	0.12%	0	795	-202	6,613	612	1,518	(2,310)
7/18/2021	(2,197,330)	(2,224,692)	27,362	1.23%	0	405	-276	6,643	916	26,477	(6,620)
7/19/2021	(2,528,091)	(2,545,429)	17,338	0.68%	0	648	-3,592	8,363	606	19,385	(1,846)
7/20/2021	(3,168,837)	(3,179,239)	10,402	0.33%	0	322	-2,125	8,545	263	11,324	362
7/21/2021	(2,844,573)	(2,840,392)	-4,181	-0.15%	0	951	-3,494	7,657	537	-2,457	(2,151)
7/22/2021	(2,657,361)	(2,653,792)	-3,569	-0.13%	0	1,371	-937	7,626	341	-4,800	2,567
7/23/2021	(2,144,470)	(2,151,057)	6,587	0.31%	0	999	2	8,180	263	4,741	(10,582)
7/24/2021	(2,267,380)	(2,283,101)	15,721	0.69%	0	855	64	8,116	267	13,964	(6,559)
7/25/2021	(1,847,051)	(1,853,759)	6,708	0.36%	0	613	-2,494	8,361	509	7,702	(1,255)
7/26/2021	(2,122,262)	(2,435,090)	312,828	12.85%	0	2,286	-2,700	8,759	448	312,321	(7,912)
7/27/2021	(2,353,249)	(2,355,415)	2,166	0.09%	0	781	-1,485	8,947	493	1,926	(8,665)
7/28/2021	(2,139,221)	(2,141,656)	2,435	0.11%	0	1,677	-77	8,760	646	-105	(6,802)
7/29/2021	(2,465,611)	(2,467,514)	1,903	0.08%	0	1,084	-506	8,106	225	492	(10,234)
7/30/2021	(1,819,689)	(1,829,852)	10,163	0.56%	0	2,472	-1,245	8,407	324	8,062	(7,197)
7/31/2021	(2,128,081)	(2,133,547)	5,466	0.26%	0	2,914	-911	7,686	149	2,679	(6,275)
8/1/2021	(2,713,573)	(2,728,848)	15,275	0.56%	0	3,970	-1,327	7,844	312	11,816	(7,879)
8/2/2021	(2,523,175)	(2,529,597)	6,422	0.25%	0	2,822	46	9,604	112	2,583	26,391
8/3/2021	(2,426,366)	(2,434,874)	8,508	0.35%	0	3,059	-583	9,320	182	5,082	27,064
8/4/2021	(2,098,286)	(2,105,533)	7,247	0.34%	0	1,806	-170	8,564	455	4,709	30,669
8/5/2021	(2,171,592)	(2,188,280)	16,688	0.76%	0	3,166	-193	8,454	1,090	12,761	41,874
8/6/2021	(2,286,030)	(2,283,997)	-2,033	-0.09%	0	1,586	2,210	9,064	557	-6,791	38,579
8/7/2021	(1,539,880)	(1,539,427)	-453	-0.03%	0	901	-655	7,720	543	-1,525	32,306
8/8/2021	(2,210,012)	(2,216,779)	6,767	0.31%	0	3,612	27	8,948	207	2,212	36,409
8/9/2021	(2,642,784)	(2,646,681)	3,897	0.15%	0	1,574	-3,320	9,967	295	4,617	12,217
8/10/2021	(2,897,383)	(2,920,493)	23,110	0.79%	0	2,513	-2,852	10,155	598	22,374	16,489

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
8/11/2021	(2,630,390)	(2,627,970)	-2,420	-0.09%	0	1,810	-2,083	9,608	935	-3,202	3,892
8/12/2021	(2,452,043)	(2,456,866)	4,823	0.20%	0	760	-1,468	9,222	982	4,511	5,931
8/13/2021	(2,457,060)	(2,467,561)	10,501	0.43%	0	1,720	-1,112	9,437	670	8,883	12,588
8/14/2021	(1,900,888)	(1,905,820)	4,932	0.26%	0	7,042	1,107	8,047	732	-4,094	(1,299)
8/15/2021	(1,487,273)	(1,483,491)	-3,782	-0.25%	0	2,835	-646	7,253	289	-6,725	23,500
8/16/2021	(1,820,833)	(1,823,869)	3,036	0.17%	0	5,853	-1,808	8,015	666	-1,877	13,957
8/17/2021	(1,979,347)	(1,992,017)	12,670	0.64%	0	7,975	3,387	8,202	640	424	(4,915)
8/18/2021	(2,374,955)	(2,391,714)	16,759	0.70%	0	2,686	1,382	8,945	1,127	11,684	10,247
8/19/2021	(2,914,320)	(2,917,705)	3,385	0.12%	0	2,165	-163	9,527	850	345	1,941
8/20/2021	(2,201,853)	(2,202,745)	892	0.04%	0	52	323	8,321	428	-358	15,079
8/21/2021	(1,397,010)	(1,416,337)	19,327	1.36%	0	7,554	-1,625	6,675	529	12,678	(2,031)
8/22/2021	(1,195,791)	(1,210,029)	14,238	1.18%	0	3,084	726	5,776	433	9,807	(1,701)
8/23/2021	(2,700,015)	(2,713,255)	13,240	0.49%	0	2,974	2,539	9,210	1,084	6,697	(4,028)
8/24/2021	(2,720,530)	(2,730,783)	10,253	0.38%	0	3,396	-650	9,571	828	6,467	(1,245)
8/25/2021	(2,837,798)	(2,860,176)	22,378	0.78%	0	1,812	-974	9,714	689	20,499	54,286
8/26/2021	(1,961,970)	(1,969,516)	7,546	0.38%	0	2,084	484	7,599	600	4,158	44,962
8/27/2021	(1,975,874)	(1,982,579)	6,705	0.34%	0	4,351	-126	7,339	493	1,697	10,363
8/28/2021	(1,554,280)	(1,548,615)	-5,665	-0.37%	0	985	472	6,355	363	-7,794	71,539
8/29/2021	(1,842,875)	(1,842,510)	-365	-0.02%	0	2,298	-548	7,196	807	-2,915	(12,703)
8/30/2021	(2,389,946)	(2,381,332)	-8,614	-0.36%	0	2,853	-2,510	8,738	287	-9,859	849
8/31/2021	(2,192,286)	(2,190,348)	-1,938	-0.09%	0	4,830	-506	8,480	300	-7,140	(3)
9/1/2021	(1,917,249)	(1,927,582)	10,333	0.54%	0	1,239	-293	7,076	427	8,637	(3,638)
9/2/2021	(1,096,037)	(1,099,957)	3,920	0.36%	0	1,245	2,135	6,483	893	-198	1,341
9/3/2021	(1,334,399)	(1,332,948)	-1,451	-0.11%	0	685	-430	6,925	310	-2,430	(9,452)
9/4/2021	(798,030)	(790,438)	-7,592	-0.96%	0	26	448	5,773	-25	-8,640	(269)
9/5/2021	(547,898)	(542,418)	-5,480	-1.01%	0	68	20	4,832	300	-6,082	13,318
9/6/2021	(1,141,043)	(1,138,943)	-2,100	-0.18%	0	2,423	341	6,528	217	-5,538	47,656
9/7/2021	(707,897)	(721,296)	13,399	1.86%	0	1,118	1,886	5,364	140	9,844	18,430
9/8/2021	(985,429)	(984,775)	-654	-0.07%	0	380	-561	5,301	170	-1,020	34,318
9/9/2021	(1,736,610)	(1,742,519)	5,909	0.34%	0	5,270	-2,719	7,811	391	2,537	61,507
9/10/2021	(1,290,094)	(1,289,345)	-749	-0.06%	0	2,472	45	6,848	231	-3,974	47,824
9/11/2021	(1,302,854)	(1,307,356)	4,502	0.34%	0	902	392	6,831	159	2,509	(2,860)
9/12/2021	(1,491,129)	(1,493,878)	2,749	0.18%	0	699	-2,800	7,171	219	4,111	(6,924)
9/13/2021	(1,596,293)	(1,606,217)	9,924	0.62%	0	4,450	3,510	7,725	362	1,156	(5,440)
9/14/2021	(1,619,919)	(1,645,409)	25,490	1.55%	0	1,017	781	7,973	256	22,870	(2,966)
9/15/2021	(1,435,090)	(1,440,515)	5,425	0.38%	0	2,476	-673	7,635	639	2,794	13,268
9/16/2021	(1,539,896)	(1,549,500)	9,604	0.62%	0	1,534	-1,039	6,082	359	8,464	(3,056)

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
9/17/2021	(1,287,495)	(1,299,392)	11,897	0.92%	0	1,402	-170	6,703	607	9,934	1,220
9/18/2021	(863,807)	(875,482)	11,675	1.33%	0	1,000	-923	5,943	252	10,978	(9,515)
9/19/2021	(1,409,866)	(1,407,529)	-2,337	-0.17%	0	3,669	-391	7,055	506	-6,371	(5,851)
9/20/2021	(1,125,669)	(1,151,700)	26,031	2.26%	0	1,414	491	6,252	662	23,435	17,889
9/21/2021	(1,552,941)	(1,559,786)	6,845	0.44%	0	492	-530	7,246	610	6,097	25,993
9/22/2021	(1,486,841)	(1,489,875)	3,034	0.20%	0	1,139	20	7,762	199	1,079	(13,341)
9/23/2021	(1,548,383)	(1,563,657)	15,274	0.98%	0	737	-570	7,801	288	14,298	1,497
9/24/2021	(1,104,594)	(1,151,220)	46,626	4.05%	0	1,015	-744	5,768	422	45,735	(873)
9/25/2021	(1,038,642)	(1,030,660)	-7,982	-0.77%	0	266	0	5,715	202	-8,840	(3,221)
9/26/2021	(1,263,981)	(1,275,110)	11,129	0.87%	0	1,160	-107	6,778	523	9,346	(13,254)
9/27/2021	(2,540,825)	(2,552,536)	11,711	0.46%	0	2,123	407	9,399	615	8,180	4,383
9/28/2021	(2,007,897)	(2,012,191)	4,294	0.21%	0	2,654	1,170	8,982	1,025	-531	26,592
9/29/2021	(2,217,999)	(2,223,241)	5,242	0.24%	0	2,724	-3,273	8,910	625	4,837	21,621
9/30/2021	(2,341,733)	(2,333,693)	-8,040	-0.34%	0	1,264	-453	9,868	388	-9,876	(6,029)
10/1/2021	(3,655,464)	(3,657,114)	1,650	0.05%	0	1,948	-491	9,892	448	-842	441
10/2/2021	(1,939,425)	(1,961,398)	21,973	1.12%	0	1,470	-470	8,008	440	20,128	14,378
10/3/2021	(2,037,261)	(2,062,035)	24,774	1.20%	0	1,008	-8,078	8,219	578	30,965	1,330
10/4/2021	(2,308,752)	(2,356,479)	47,727	2.03%	0	4,946	-7,017	8,389	414	48,918	12,264
10/5/2021	(2,428,627)	(2,430,758)	2,131	0.09%	0	2,370	-4,680	8,155	574	3,568	11,014
10/6/2021	(2,090,304)	(2,104,456)	14,152	0.67%	0	1,236	-2,634	7,610	205	14,769	2,521
10/7/2021	(2,154,953)	(2,192,861)	37,908	1.73%	0	987	-159	7,720	249	36,283	4,218
10/8/2021	(2,097,095)	(2,120,334)	23,239	1.10%	0	1,233	-4,333	7,654	640	25,509	13,082
10/9/2021	(1,681,525)	(1,692,250)	10,725	0.63%	0	2,922	-1,946	6,986	535	8,997	5,767
10/10/2021	(1,128,773)	(1,132,244)	3,471	0.31%	0	4,629	-2,092	5,728	754	286	11,624
10/11/2021	(1,184,493)	(1,212,767)	28,274	2.33%	0	3,126	560	5,810	427	23,964	(4,313)
10/12/2021	(1,515,052)	(1,511,999)	-3,053	-0.20%	0	1,520	1,428	5,517	215	-6,573	2,633
10/13/2021	(1,330,799)	(1,334,796)	3,997	0.30%	0	3,355	-1,620	5,918	685	1,602	11,768
10/14/2021	(1,489,209)	(1,499,736)	10,527	0.70%	0	2,720	820	6,167	633	6,306	(10,017)
10/15/2021	(1,602,162)	(1,625,616)	23,454	1.44%	0	4,854	45	6,816	856	17,788	61,537
10/16/2021	(1,064,658)	(1,069,219)	4,561	0.43%	0	12,459	1,125	5,171	443	-9,584	30,551
10/17/2021	(1,400,348)	(1,407,980)	7,632	0.54%	0	12,502	1,232	5,986	308	-6,730	(4,418)
10/18/2021	(1,266,475)	(1,274,985)	8,510	0.67%	0	10,067	2,479	6,001	443	-4,680	54,631
10/19/2021	(1,312,514)	(1,325,327)	12,813	0.97%	0	8,532	2,729	5,780	293	945	(4,153)
10/20/2021	(1,822,627)	(1,834,833)	12,206	0.67%	0	4,133	11,789	6,486	414	-4,406	90
10/21/2021	(2,080,897)	(2,089,707)	8,810	0.42%	0	6,619	1,470	8,121	707	-162	(3,375)
10/22/2021	(2,026,373)	(2,055,102)	28,729	1.40%	0	1,252	1,395	7,948	316	25,256	6,016
10/23/2021	(1,680,815)	(1,706,849)	26,034	1.53%	0	8,777	1,157	7,270	498	15,323	24,018

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

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
10/24/2021	(1,509,438)	(1,525,256)	15,818	1.04%	0	7,880	2,824	6,705	802	4,364	33,451
10/25/2021	(2,059,978)	(2,073,730)	13,752	0.66%	0	6,542	1,251	6,860	663	5,207	(237)
10/26/2021	(1,296,429)	(1,298,939)	2,510	0.19%	0	2,787	543	5,967	478	-1,465	40
10/27/2021	(1,936,527)	(1,939,266)	2,739	0.14%	0	4,193	5,433	7,525	624	-7,702	(8,611)
10/28/2021	(1,780,907)	(1,785,427)	4,520	0.25%	0	1,890	1,500	7,216	442	364	(3,488)
10/29/2021	(1,641,890)	(1,647,190)	5,300	0.32%	0	1,521	1,211	6,853	779	1,805	70,129
10/30/2021	(1,361,618)	(1,366,984)	5,366	0.39%	0	582	901	6,415	416	3,200	3,515
10/31/2021	(1,182,674)	(1,190,499)	7,825	0.66%	0	2,456	-114	6,040	282	4,850	(6,686)
11/1/2021	(2,981,404)	(2,976,484)	-4,920	-0.17%	0	9,329	485	8,888	584	-15,680	(7,616)
11/2/2021	(2,348,665)	(2,349,419)	754	0.03%	0	5,315	4,549	9,638	183	-10,092	(1,048)
11/3/2021	(2,266,449)	(2,262,995)	-3,454	-0.15%	0	2,481	3,874	9,549	838	-10,848	866
11/4/2021	(1,785,374)	(1,793,641)	8,267	0.46%	61,703	1,819	1,464	8,106	625	-57,591	3,095
11/5/2021	(612,749)	(614,178)	1,429	0.23%	0	1,606	82	4,814	4	-741	23,294
11/6/2021	(1,437,748)	(1,443,851)	6,103	0.42%	0	3,128	-223	6,313	232	2,543	(2,619)
11/7/2021	(435,154)	(508,846)	73,692	14.48%	0	617	-116	4,377	374	72,716	90
11/8/2021	(1,819,692)	(1,861,588)	41,896	2.25%	0	10,693	-580	7,459	814	30,956	(2,151)
11/9/2021	(2,076,585)	(2,080,019)	3,434	0.17%	0	4,444	207	7,956	579	-2,071	(78)
11/10/2021	(924,535)	(923,283)	-1,252	-0.14%	0	1,638	1,441	5,536	277	-4,912	(4,220)
11/11/2021	(770,492)	(768,393)	-2,099	-0.27%	0	779	-511	5,183	297	-2,915	(4,367)
11/12/2021	(1,170,023)	(1,169,279)	-744	-0.06%	0	2,467	334	6,218	511	-4,218	(6,197)
11/13/2021	(1,845,761)	(1,851,127)	5,366	0.29%	0	10,528	-172	8,336	615	-5,885	(7,061)
11/14/2021	(1,280,730)	(1,276,587)	-4,143	-0.32%	0	830	-206	6,717	338	-5,472	(2,914)
11/15/2021	(2,097,208)	(2,108,134)	10,926	0.52%	0	2,661	-197	8,903	546	7,517	4,346
11/16/2021	(1,527,215)	(1,534,919)	7,704	0.50%	0	1,307	916	7,623	480	4,670	(3,279)
11/17/2021	(1,466,897)	(1,471,981)	5,084	0.35%	0	2,721	314	6,499	222	1,377	(4,651)
11/18/2021	(1,709,778)	(1,708,051)	-1,727	-0.10%	0	2,060	6,746	8,041	781	-11,416	1,941
11/19/2021	(1,641,675)	(1,663,981)	22,306	1.34%	0	8,047	519	7,799	1,444	12,815	(1,240)
11/20/2021	(1,828,924)	(1,840,338)	11,414	0.62%	0	1,531	812	7,442	1,014	8,225	(3,911)
11/21/2021	(1,991,107)	(1,985,282)	-5,825	-0.29%	0	11,242	1,533	8,762	943	-19,571	4,115
11/22/2021	(2,486,309)	(2,481,647)	-4,662	-0.19%	0	2,959	1,524	10,104	222	-10,178	(1,279)
11/23/2021	(1,439,089)	(1,449,963)	10,874	0.75%	0	3,847	482	7,405	323	5,772	(3,704)
11/24/2021	(1,225,240)	(1,225,224)	-16	0.00%	0	2,241	305	6,618	216	-3,245	(2,538)
11/25/2021	(2,023,372)	(2,039,390)	16,018	0.79%	0	9,299	199	8,900	557	5,574	824
11/26/2021	(1,625,587)	(1,660,824)	35,237	2.12%	0	7,509	-122	7,733	375	27,039	6,039
11/27/2021	(1,028,970)	(1,033,018)	4,048	0.39%	0	2,086	865	6,206	159	461	38,736
11/28/2021	(1,745,384)	(1,778,095)	32,711	1.84%	0	5,699	-96	8,045	196	26,284	37,901
11/29/2021	(1,790,717)	(1,779,521)	-11,196	-0.63%	0	20,484	5,954	8,417	989	-38,575	41,297

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

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
11/30/2021	(2,122,198)	(2,161,165)	38,967	1.80%	0	5,243	366	9,189	705	32,369	2,417
12/1/2021	(1,401,946)	(1,402,654)	708	0.05%	0	238	5,648	6,455	516	-5,875	(10,041)
12/2/2021	(2,212,364)	(2,212,088)	-276	-0.01%	0	2,273	1,782	8,912	300	-5,253	(3,866)
12/3/2021	(1,890,449)	(1,882,272)	-8,177	-0.43%	0	4,338	-476	9,133	635	-13,015	11,725
12/4/2021	(1,763,446)	(1,763,652)	206	0.01%	0	2,011	335	8,788	171	-3,036	11,390
12/5/2021	(1,322,834)	(1,320,548)	-2,286	-0.17%	0	2,459	-25	7,687	342	-5,524	5,570
12/6/2021	(2,093,305)	(2,097,515)	4,210	0.20%	0	2,626	718	9,362	381	-109	(4,753)
12/7/2021	(2,218,018)	(2,227,557)	9,539	0.43%	0	3,164	4,707	10,078	426	617	(3,597)
12/8/2021	(2,233,799)	(2,224,600)	-9,199	-0.41%	0	1,006	174	10,071	388	-11,425	(6,990)
12/9/2021	(1,563,341)	(1,568,489)	5,148	0.33%	0	1,739	-71	8,807	933	2,506	(7,891)
12/10/2021	(1,992,392)	(2,020,273)	27,881	1.38%	0	1,497	278	10,233	511	25,032	(2,606)
12/11/2021	(1,759,978)	(1,764,153)	4,175	0.24%	0	2,569	715	9,663	1,233	-198	28,682
12/12/2021	(1,583,920)	(1,596,825)	12,905	0.81%	0	2,634	313	8,885	866	8,983	324
12/13/2021	(2,118,449)	(2,143,571)	25,122	1.17%	0	3,158	13,114	10,261	747	7,750	(9,356)
12/14/2021	(1,819,162)	(1,823,639)	4,477	0.25%	0	2,627	650	9,669	736	160	20
12/15/2021	(1,296,196)	(1,299,265)	3,069	0.24%	0	746	278	7,857	1,265	1,132	(6,177)
12/16/2021	(1,760,403)	(1,761,882)	1,479	0.08%	0	6,236	473	9,054	621	-6,197	(2,998)
12/17/2021	(2,411,052)	(2,406,834)	-4,218	-0.18%	0	2,697	1,124	10,941	460	-9,179	1,196
12/18/2021	(2,184,817)	(2,201,713)	16,896	0.77%	0	3,984	936	10,675	222	10,886	(4,172)
12/19/2021	(1,566,207)	(1,572,553)	6,346	0.40%	0	1,246	265	8,884	349	3,912	(3,388)
12/20/2021	(2,108,092)	(2,108,471)	379	0.02%	0	656	2,762	9,841	914	-4,114	(8,298)
12/21/2021	(2,190,714)	(2,198,726)	8,012	0.36%	0	1,925	8,500	10,554	1,565	-3,625	60,348
12/22/2021	(2,303,532)	(2,323,163)	19,631	0.85%	0	3,762	101	10,871	864	14,594	28,337
12/23/2021	(2,363,500)	(2,361,826)	-1,674	-0.07%	0	1,990	-128	10,829	1,570	-4,776	(480)
12/24/2021	(1,320,546)	(1,313,122)	-7,424	-0.57%	0	1,098	-2	7,013	523	-9,273	14,214
12/25/2021	(1,901,227)	(1,907,713)	6,486	0.34%	0	2,905	10	9,753	1,243	2,472	(6,406)
12/26/2021	(1,393,151)	(1,388,083)	-5,068	-0.37%	0	214	-27	8,331	682	-6,156	11,134
12/27/2021	(1,855,998)	(1,846,049)	-9,949	-0.54%	0	1,803	331	9,349	821	-13,100	(17,413)
12/28/2021	(1,775,872)	(1,789,081)	13,209	0.74%	0	552	529	9,656	257	11,137	(4,967)
12/29/2021	(2,936,296)	(2,947,537)	11,241	0.38%	0	878	2,398	12,223	1,303	6,612	12,115
12/30/2021	(2,741,616)	(2,754,487)	12,871	0.47%	0	3,756	168	11,883	505	7,708	(9,632)
12/31/2021	(1,258,513)	(1,249,153)	-9,360	-0.75%	0	4	5	7,674	362	-10,173	47,241
Total	**(934,830,238)**	**(938,572,360)**	**3,742,122**	**0.01**	**61,934**	**763,695**	**(120,210)**	**2,833,274**	**192,545**	**2,734,122**	**2,052,718**

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

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ -	$ 265	$ -	$ -	$ 2	$ 299	$ 261	$ 1,440	$ -	$ 236	$ -	$ -
Anson_G3	$ 9	$ 228	$ -	$ 4	$ 441	$ 155	$ 284	$ 1,740	$ -	$ 1,489	$ -	$ -
Anson_G4	$ -	$ -	$ 108	$ 461	$ 109	$ 1,333	$ 234	$ 939	$ 7	$ 954	$ 1,165	$ 237
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_ A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G6	$ 963	$ -	$ 8,646	$ 24,619	$ 19,823	$ -	$ 16,314	$ 27,472	$ 4,846	$ 15,148	$ -	$ -
Blk_Dog_G52	$ 720	$ 21,441	$ 480	$ 2,432	$ 1,836	$ 1,092	$ 1,203	$ 1,170	$ 1,961	$ 2,759	$ 2,112	$ 2,309
Blue_Lk_G1	$ -	$ 22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ 270	$ -	$ -	$ -	$ 4	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ 271	$ -	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ -	$ -	$ 5	$ 68	$ 35	$ 814	$ 482	$ 617	$ -	$ -	$ 2	$ -
Blue_Lk_G8	$ -	$ -	$ -	$ 570	$ 501	$ 626	$ 22	$ 15	$ -	$ -	$ 46	$ -
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ -	$ 162	$ 65	$ 108	$ 2,034	$ 1,247	$ 476	$ 2,971	$ 1,272	$ 1,407	$ 4,813	$ 530
Canon_Falls2	$ -	$ 1,640	$ -	$ -	$ 40	$ 29	$ 36	$ 101	$ 269	$ 184	$ 4,260	$ 17
CC Highbridge1	$ 17	$ 11,072	$ -	$ 17	$ 37	$ -	$ 34	$ 259	$ 297	$ 25	$ 1,100	$ 809
CC Highbridge2	$ 56	$ 16,453	$ -	$ -	$ 42	$ -	$ 54	$ 53	$ 190	$ 646	$ 562	$ 4
CC Mankato	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato1	$ 1,096	$ 4,380	$ 1,151	$ 1,015	$ 1,728	$ 1,688	$ 1,813	$ 2,303	$ 2,692	$ 1,709	$ 7,214	$ 3,776
CC Mankato2	$ 344	$ 9,493	$ 606	$ 277	$ 1,033	$ 2,032	$ 1,382	$ 1,221	$ 951	$ 1,370	$ 3,896	$ 4,180
CCRiverside1	$ 1,169	$ -	$ -	$ -	$ -	$ 12	$ 823	$ 10,623	$ 7,353	$ 35,237	$ 43,303	$ 3,509
CCRiverside2	$ 1,793	$ -	$ -	$ -	$ -	$ -	$ 5,609	$ 5,352	$ 9,435	$ 39,749	$ 46,444	$ 3,752
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DPC.FLAMBEAU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flambe_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ 0	$ 122	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ 122	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Garwin_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
GranCty_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ 0	$ 12	$ 16	$ 1	$ 14	$ 13	$ 47	$ 0	$ 21
InvrHils_2	$ -	$ 60	$ -	$ 5	$ 1	$ 60	$ 392	$ 36	$ 39	$ 383	$ -	$ 9
InvrHils_3	$ -	$ 83	$ -	$ 16	$ 1	$ 102	$ 325	$ 19	$ 54	$ 24	$ 7	$ 2
InvrHils_4	$ -	$ 17	$ -	$ 40	$ 16	$ 367	$ 323	$ 26	$ 14	$ 43	$ -	$ 2
InvrHils_5	$ -	$ 36	$ -	$ 16	$ 4	$ 287	$ -	$ 7	$ 217	$ 46	$ -	$ 0
InvrHils_6	$ -	$ 2,900	$ -	$ 9	$ 1	$ 349	$ 289	$ 23	$ 38	$ 72	$ 6	$ 6
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ -	$ 2,611	$ 23	$ -	$ -	$ 343	$ 2,176	$ 13,286	$ -	$ -	$ 49	$ 11,597
LSPower_1	$ 3,659	$ 3,633	$ 5,558	$ 5,296	$ 8,688	$ 1,410	$ 14,421	$ 17,816	$ 7,568	$ 23,618	$ 22,562	$ 30,143
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MHEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.LASKIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.NSP1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP ROCK_CO BAT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ADAMSWD1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.GEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.SER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BIGBLUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.DANIELSN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.GRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.KEYCITYTWO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MARSHSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MORAINE2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL1_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL2_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.RIVRSD10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHAKOBIO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSPHATFIHAT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.BRDRS1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.COURTNY.WF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.GRANTCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.MPC.COYT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTPGRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rapidan_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIV9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD71	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock_County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ 13,213	$ 5,450	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G1	$ 1,469	$ 1,868	$ -	$ -	$ 169	$ 303	$ 287	$ 783	$ 532	$ 1,936	$ 4,069	$ 4,329
SHERCO_G2	$ 1,217	$ 2,012	$ 6,073	$ 3,671	$ 7,267	$ 599	$ 1,484	$ 4,773	$ 8,498	$ 1,421	$ -	$ 949
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Wheaton_1	$ -	$ 34	$ -	$ 22	$ 28	$ 326	$ 101	$ 279	$ 66	$ 53	$ 342	$ 49
Wheaton_2	$ -	$ 44	$ -	$ 189	$ 31	$ 451	$ 98	$ 315	$ 158	$ 1,876	$ 1,978	$ 265
Wheaton_3	$ -	$ 31	$ -	$ 4	$ 176	$ 501	$ 116	$ 144	$ 457	$ 31	$ 298	$ 246
Wheaton_4	$ 4	$ 41	$ -	$ 1	$ 178	$ 726	$ 82	$ 294	$ 137	$ 45	$ 381	$ 51
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ 3	$ 9	$ -	$ -	$ -	$ -	$ 39	$ 1	$ 4	$ -	$ -
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi UILK_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Velva	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Windvest_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Woodstk_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ 25,729**	**$ 84,764**	**$ 22,723**	**$ 38,840**	**$ 44,233**	**$ 15,174**	**$ 49,123**	**$ 94,127**	**$ 47,064**	**$ 130,514**	**$ 144,610**	**$ 66,793**

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_ A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G52	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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 Mankato	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DPC.FLAMBEAU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flambe_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Garwin_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LSPower_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MHEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.LASKIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.NSP1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP ROCK_CO BAT_SER_UNIT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ADAMSWD1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.GEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.SER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BIGBLUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.DANIELSN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.GRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.KEYCITYTWO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MARSHSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MORAINE2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
NSP.ODELL2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL1_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL2_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.RIVRSD10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHAKOBIO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSPHATFIHAT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.BRDRS1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.COURTNY.WF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.GRANTCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.MPC.COYT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTPGRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rapidan_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIV9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD71	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock_County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,703	$ -
SHERCO_G2	$ -	$ -	$ -	$ 232	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi UILK_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Velva	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Windvest_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Woodstk_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ -**	**$ -**	**$ -**	**$ 232**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 61,703**	**$ -**

2021 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 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 2021 reporting year as compared to the 2021 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 2022 curtailment forecast in our April 30, 2021 Petition and July 30, 2021 Reply Comments in Docket No. E002/AA-21-295. We will provide an estimate of 2023 curtailment payments, including forecast assumptions, in our 2023 fuel forecast Petition to be filed by May 2, 2022.

II. CURTAILMENT OVERVIEW

The Company expects that some level of wind curtailment from Power Purchase Agreement (PPA) facilities will occur in the foreseeable future. The reasons driving the curtailment have shifted from primarily local transmission constraints on NSP's transmission system in southwest Minnesota to regional transmission system congestion on the MISO system. The regional congestion, which results in negative LMP, was the largest driver of curtailment during this reporting period. Additionally, the nature of transmission congestion is accentuated by the large concentration and increased level of wind facility operations in Minnesota, North Dakota, South Dakota, and Iowa.

Significant transmission improvements in southwestern Minnesota and the region, such as the CapX2020 transmission projects (CapX2020), the Huntley – Wilmarth 345 kV line, and all but one of the MISO Multi-Value Projects (MVPs) are now in-service and will positively impact curtailment by reducing local congestion. However, the Company believes future curtailment in this area will continue to occur because of more regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance or repair activities and wind generation projects going into service before all required transmission facilities are completed and likely generation oversubscription of the transmission system.

To better manage regional congestion, MISO and the industry utilize Dispatchable Intermittent Resources (DIRs), which provides 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.

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	1340

The federal Production Tax Credit (PTC), which provides tax benefits to wind generating plants, is scheduled to be phased out over the next few years. As in the past, the uncertainty of PTC expiration is closely connected with increases in wind curtailment, since wind projects are often put into service to meet PTC eligibility requirements even though the necessary transmission upgrades were not completed. The Company is aware of 6,287 MW of new wind generation in Minnesota, North Dakota, South Dakota, and Iowa that has recently gone into service, or is expected to go into service in 2022. This includes 2,100 MW of Company-owned and PPA wind. Table 2 shows planned wind developments by NSP and other regional companies. All of these wind developments will be registered and operated as DIRs.

Table 2
Wind Generation Additions[1]

Company	MW	Location	In-Service Dates
Alliant Energy	1,150	IA	2019-2021
Great River Energy[2]	679	ND	2020-2023
MidAmerican	2,216	IA	2019-2021
Minnesota Municipal Power Agency	111	MN	2021
Minnesota Power	250	MN	2020
Northern States Power	2,100	ND, SD, MN	2019-2022
Otter Tail Power	150	ND	2020
Total	6,657		

The required transmission upgrades for these wind projects will not all be in-service at the time the projects begin producing energy. A number of transmission facilities that were identified in the interconnection studies as overloaded, along with MTEP related transmission facilities were, or will be, taken out of service and rebuilt. This has and will continue to have a negative effect on LMP pricing in the MISO energy market and will continue to 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,

[1] The wind repowering projects being developed by NSP are not included in this list.
[2] Great River Energy has announced plans to install an additional 430 MW of wind generation in 2023.

engineered, and constructed a number of projects designed to increase the transmission capacity in that area. Table 3 shows historic southwest Minnesota projects that increased the available transmission outlet in that area.

Table 3
Southwest Minnesota Wind Limits

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

The Company also participated in the development of three CapX2020 transmission projects, all of which have gone into service and are helping reduce wind curtailment on the NSP system. Table 4 lists the CapX2020 transmission projects.

Table 4
CapX2020 Transmission Projects

Transmission Project	Transmission Owner	Actual/Planned 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 - LaCrosse, Wisconsin 345 kV Line	Xcel Energy, SMMPA and non-MISO	September 16, 2016

In addition to the transmission projects discussed above, a number of other new transmission infrastructure projects have been placed in service, including the Huntley – Wilmarth 345 kV line, and all but one of the Multi-Value Projects (MVP). The Cardinal - Spring Green - Dubuque area 345 kV Line will be the last MVP to go into service, though the expected in-service date is not known at this time. The Huntley – Wilmarth line, which went into service on December 1, 2021, was classified as an Economic Project under the MTEP process and was installed to improve congestion, The MVPs were 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. The completion of the MVP projects, particularly the ones listed in Table 5, have had, or will have, a positive impact on Company-owned and PPA wind facilities.

Table 5
MVP Projects

Transmission Project	Transmission Owner	Planned/Actual 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 LaCrosse - 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 - Spring Green - Dubuque area 345 kV Line	American Transmission Company, ITC Midwest	Unknown

One of the design goals for the North LaCrosse - North Madison and Cardinal - Spring Green - Dubuque area 345 kV Lines was to increase the transmission export capacity from Iowa and Minnesota into the 345 kV system in Wisconsin that connects to the Milwaukee and Illinois load centers.

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

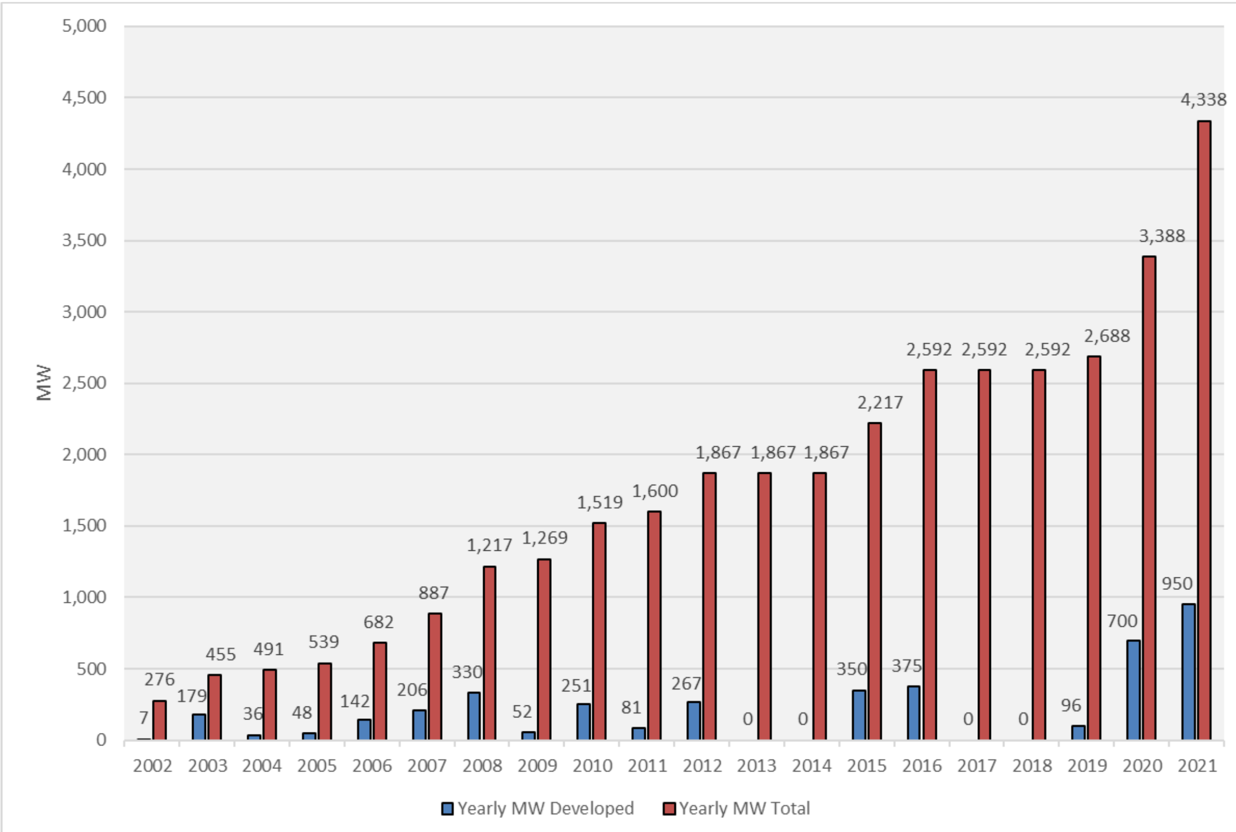
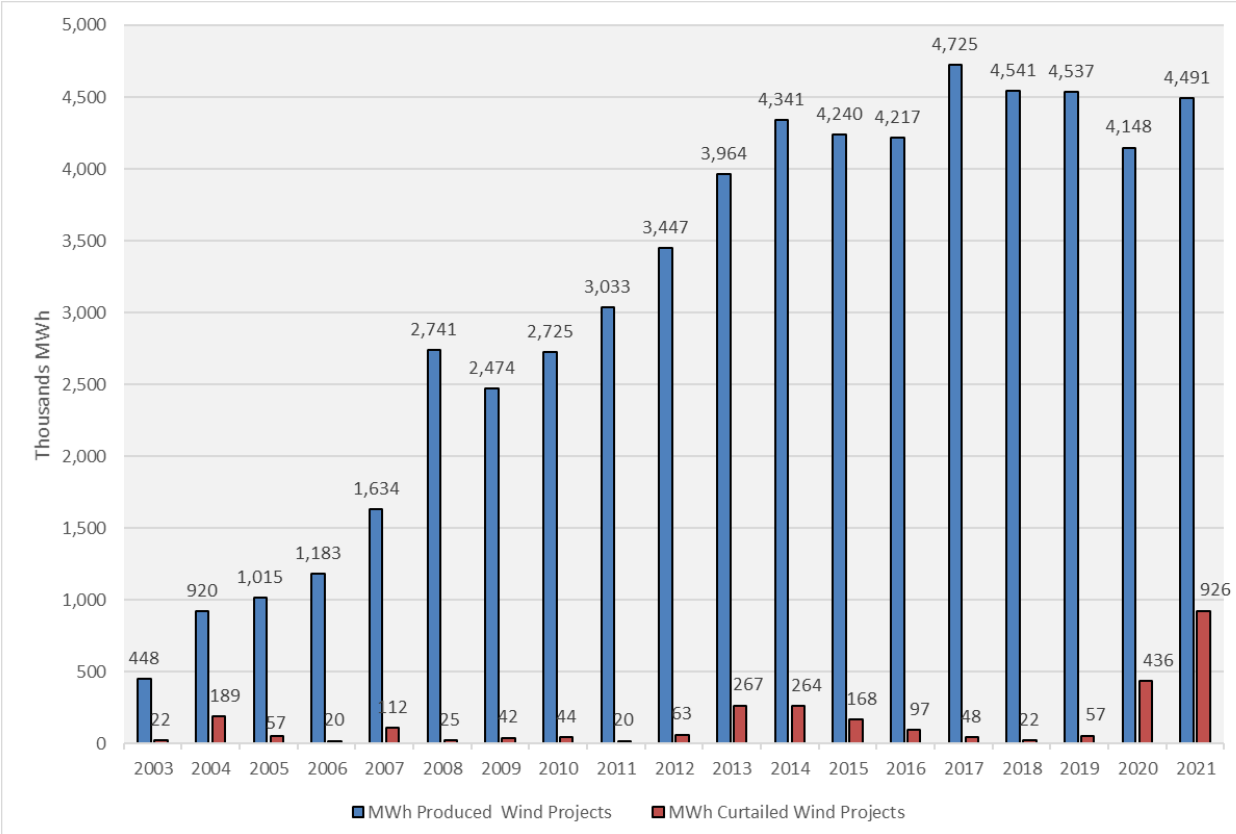


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through December 2021.[3] Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation delivered.

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 would not otherwise have been possible.

[3] Part C, Attachment 2.

Chart 2



The 2021 Curtailment in summarized in Table 6.

Table 6
2021 Wind Curtailment MWh and Costs

	MWh	Costs
Curtailment	926,013	$42,062,446

It is important to note that of the $42,062,446 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 farm.[4]

The Company typically has broken up curtailment into two categories to better explain the reasons for the curtailment and its cause. The two categories were Transmission Curtailment and DIR Curtailment. Transmission Curtailment was specifically related to situations where local transmission-related outages impacted

[4] 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 actually is produced or if it is curtailed.

wind projects. DIR Curtailment was considered curtailment that was not caused by local transmission outages, or where transmission outages did not impact a specific wind farm. This breakdown was informative when the curtailment was primarily related to local transmission constraints on NSP's transmission system in southwest Minnesota. However, since curtailment is almost entirely related to regional transmission congestion on the MISO system, the Company will no longer provide a breakout for Transmission Curtailment. The Company will refer to curtailment as "Economic Curtailment" or simply "Curtailment."

The Company believes that it will be more informative to provide details on the drivers of regional congestion as measured by the Real Time Binding Constraints which are used to manage congestion in the MISO Real Time Market along with a discussion on transmission outages that occurred during the year.

> *Per the MISO website, 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 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. The most frequent real time binding constraints in the NSP area[5] are listed in Table 7.

Table 7
2021 Real Time Binding Constraints

Constraint Name	Contingency Description	State	Hours Binding (year)	Average Shadow Price
Forman_230_115_TR1_flo_Hankinson_Wahpeton_230kV	HANKINSON-WAHPETON 230+WAHPETN TR2	ND	1,915.8	($271.0)
NSP34102_ROCHSTR_ROCHSWABAC16_1_1 (Rochester – Wabaco)	BRIGGS ROAD - NORTH ROCHESTER 345	MN	1,874.6	($222.8)
ALW34X17_FOX_LK_FOX_LRUTLA16_1_1	HUNTLEY 345/161 TR1	MN	669.8	($171.0)
NSP34107_SOUTHBND_TR6_TR6	LYON CO - HAWKS NEST LAKE 345	MN	602.8	($278.5)
DPCGEN01_ROCHSTR_ROCHSWABAC16_1_1 (Rochester – Wabaco)	ALMA UNIT6 (399MW)	MN	590.5	($810.1)
OTP23100_JOHNJCT_JOHNJGRACE11_1_1	HANKINSON-WAHPETON 230+WAHPETN TR2	MN	442.0	($1,225.2)
Temporary_577__S3GRANHAWLYN	LYON CO - HAWKS NEST LAKE 345	MN	437.3	($254.4)
OTP23016_HOOT_LK_HOOT_FERGS11_1_1	FERGUS FALLS - SILVER LAKE 230	MN	423.1	($676.7)
Blair_Granite_Falls_230_KV_FLO_Hawksnest_Ln_Lyon	LYON CO - HAWKS NEST LAKE 345	MN	409.0	($203.1)
Fargo_Sheyenne230_FLO_BUFFALO_JAMESTOWN345	BUFFALO - JAMESTOWN 345	SD	398.7	($321.3)
NSP34107_ERIE_RD_ERIE_S311_1_1	LYON CO - HAWKS NEST LAKE 345	MN	353.3	($214.8)
MDU23007_MERRICRT_MERRITATAN23_1_1	MERRICOURT - ELLENDALE 230	ND	333.2	($28.6)
Ellendal_AberdeenJct_115kV_flo_Ellendale2_BigSto	TWIN BROOKS - BIG STONE SOUTH 345	ND	262.1	($122.8)

[5] Area includes Minnesota, North Dakota, South Dakota and Wisconsin.

Constraint Name	Contingency Description	State	Hours Binding (year)	Average Shadow Price
Bigstone_BrownsVally_230kV_flo_Oaks_Ellenda_230k	ELLENDALE-OAKES 230	ND	248.2	($219.8)
White_Split_Rock_345_kV_FTLO_Hawks_Nest_Lyon_Cou	LYON CO - HAWKS NEST LAKE 345	SD	246.9	($77.8)
NSP3403_SOUTHBND_TR6_TR6	CRANDALL - WILMARTH 345	MN	242.2	($417.5)
ChubLake_345_115_TR1_flo_ChubLake_Hampton_345kV	CHUB LAKE-HAMPTON 345 (0961)	MN	182.5	($180.1)
FORMAN_FORMAN_115kV_TIE_FLO_HANKSON_WAHPETON_230	HANKINSON-WAHPETON 230+WAHPETN TR2	ND	167.9	($400.2)
Adams_BeaverCreek_161kV_flo_BriggsRd_NorthRoches	BRIGGS ROAD - NORTH ROCHESTER 345	MN	131.5	($278.0)
BASE_SOUTHBND_TR6_TR6		MN	123.5	($342.0)
Canby_GraniteFalls_115kV_flo_BrookingsCo_Astoria	BROOKINGS COUNTY - ASTORIA 345	MN	118.3	($325.3)
NSPOTP13_CANBY_CANBYGRANI11_1_1	BROOKINGS COUNTY - ASTORIA 345	MN	107.2	($297.3)

The real time binding constraints occurred for a number of reasons, including wind generation projects going into service before all required transmission facilities are completed, transmission outages required for construction, maintenance or repair activities and likely generation oversubscription of the transmission system.

Table 8 lists the transmission outages that the Company has identified as having the most impact on the binding constraints listed above and the resulting curtailment. The outages were required for a number of reasons including construction required for regional transmission upgrades and generator interconnection required upgrades along with regular maintenance or repair activities.

Table 8
2021 Significant Transmission Outages

Outage Request ID	Company	KV	From Station	To Station	IDC Equipment Name	State	Start Date	End Date (Actual or Planned)	Duration (Days)
1-25554035	GRE, MPCN,	230	SQBUTTEW	STANTON2	GRE-STANTON4230.00 SQBUTTE4 230.00 1	ND	2/1/2020	7/22/2021	538
1-25904955, 1-26191016, 1-26384463, 1-26458059	MDU	230	MANDAN	NAPOLNSW	MANDAN 4 230.00 NAPOLEON SW4230.00 1	ND	3/1/2020	2/18/2022	720
1-26308112	OTP	345	DKR_I_II	TWINBRKS	DAKOTARNG 3 345.00 TWINBRKS3 345.00 1	MN	5/31/2020	7/30/2021	426
1-24342017	NSP	345	CRANDAL	FIELDON	FIELD_S3 345.00 - CRANDAL 3 345.00 1	MN	9/8/2020	5/21/2021	255
1-24342017	GRE, NSP	345	FIELDON	WILMART	WILMART3 345.00 - FIELD_N3 345.00 1	MN	9/8/2020	5/21/2021	255
1-25872873	MDU, OTP	230	ELLENDL	OAKES	OAKES 4 230.00 ELLENDL4 230.00 1	ND	10/28/2020	1/22/2021	87
1-25868843	GRE, OTP	115	JOHNJCT	ORTONVL	GRE-JOHNJCT7115.00 ORTONVL7 115.00 1	MN	11/2/2020	9/22/2021	325
1-26233135	MPCN, NSP,	345	MAPLE_R TR1		MAPLE R3 345.00 MAPLE R4 230.00	ND	2/28/2021	1/31/2022	338
1-26120687	GRE, NSP	345	HELENAMN	SCOTTCO	HELENA 3 345.00 SCOTTCO3 345.00 1	MN	4/5/2021	11/4/2021	214
1-26272777	OTP	230	BROWNSV	HANKSON	BROWNSV4 230.00 HANKSON4 230.00 1	ND/ SD	4/15/2021	5/31/2021	47

Outage Request ID	Company	KV	From Station	To Station	IDC Equipment Name	State	Start Date	End Date (Actual or Planned)	Duration (Days)
1-26308777	GRE, NSP	345	LYON_CO TR9		LYON CO 3 345.00 LYON CO7 115.00	MN	5/28/2021	3/18/2022	295
1-26299934	GRE, OTP	115	JOHNJCT	GRACEV	GRE-JOHNJCT7115.00 GRE-GRACEV 7115.00 1	MN	7/19/2021	8/13/2021	26
1-26299934	GRE, OTP	115	JOHNJCT	MORRISOT	GRE-JOHNJCT7115.00 MORRIS 7 115.00 1	MN	7/19/2021	8/13/2021	26
1-26142419	NSP, WAUE	345	SPLT_RT	NOBLES	SPLT RK3 345.00 NOBLES 3 345.00	SD/ MN	8/9/2021	8/26/2021	18
1-24342018, 1-26307776	NSP	345	CRANDAL	FIELDON	FIELD_S3 345.00 CRANDAL 3 345.00 1	MN	8/16/2021	10/29/2021	75
1-24342018, 1-26307776	GRE, NSP	345	FIELDON	WILMART	WILMART3 345.00 FIELD_N3 345.00 1	MN	8/16/2021	10/29/2021	75
1-26370092	OTP	115	HOOT_LK	FERGSFL	HOOT LK7 115.00 FERGSFL7 115.00 1	MN	9/2/2021	10/6/2021	35
1-25868944	GRE, OTP	115	JOHNJCT	MORRISOT	GRE-JOHNJCT7115.00 MORRIS 7 115.00 1	MN	9/13/2021	2/1/2022	142
1-25985981	GRE, NSP	345	SHEASLK	WILMART	WILMART3 345.00 SHEAS LK3 345.00 1	MN	9/14/2021	9/30/2021	17
1-26335310	ITC_MW, NS	345	LAKEFLD	NOBLES	NOBLES 3 345.00 LAKEFLD3 345.00 1	MN	10/5/2021	10/8/2021	4
1-26214633	NSP	345	EAU_CLA TR9		EAU CL 3 345.00 EAU CL 5 161.00	WI	10/11/2021	10/21/2021	11
1-26214129	DPC	161	ROCHSTR	WABACO	WABACO 5 161.00 ROCHSTR5 161.00 1	MN	11/11/2021	5/31/2022	202

The Company believes that a majority of the binding constraints listed in Table 7 were either caused or made worse by the transmission outage identified in Table 8. An exception would be the Rochester – Wabaco binding constraint.

The Rochester – Wabaco 161 kV (for loss of North Rochester 345 kV line and loss of Alma Unit#6 Generating Plant) was the most common binding constraint in 2021. Rochester Wabaco bound throughout 2021 and was likely responsible for a significant amount of curtailment that occurred throughout the region. Rochester – Wabaco was identified as a MTEP transmission upgrade but was not scheduled for upgrade until 2022. Rochester – Wabaco was considered as "in-service" in the generator interconnection studies since it was an approved MTEP project, and a significant amount of generation went into service before the upgrade could be completed. Rochester – Wabaco is scheduled to be upgraded and back in service on May 31, 2022.

The Forman Transformer binding constraint was the second most common binding constraint in 2021. The Forman Transformer binding constraint was made worse by a number of different transmission outages that took place in 2021 including the Napoleon – Mandan outage which was out of service for the full year. The Napoleon – Mandan line is out of service for rebuilding as required by the generator interconnection process. The Napoleon – Mandan outage also likely contributed to the Ellendale – Aberdeen Jct, Hoot Lake – Fergus Falls, Big Stone – Browns Valley and Merricourt – Tatanka binding constraints. The Company believes that there is a risk that the Forman Transformer could continue to bind even after the transmission outages are complete.

The remaining binding constraints were likely related to the various transmission outages that occurred throughout 2021.

3. Curtailment Mitigation Efforts

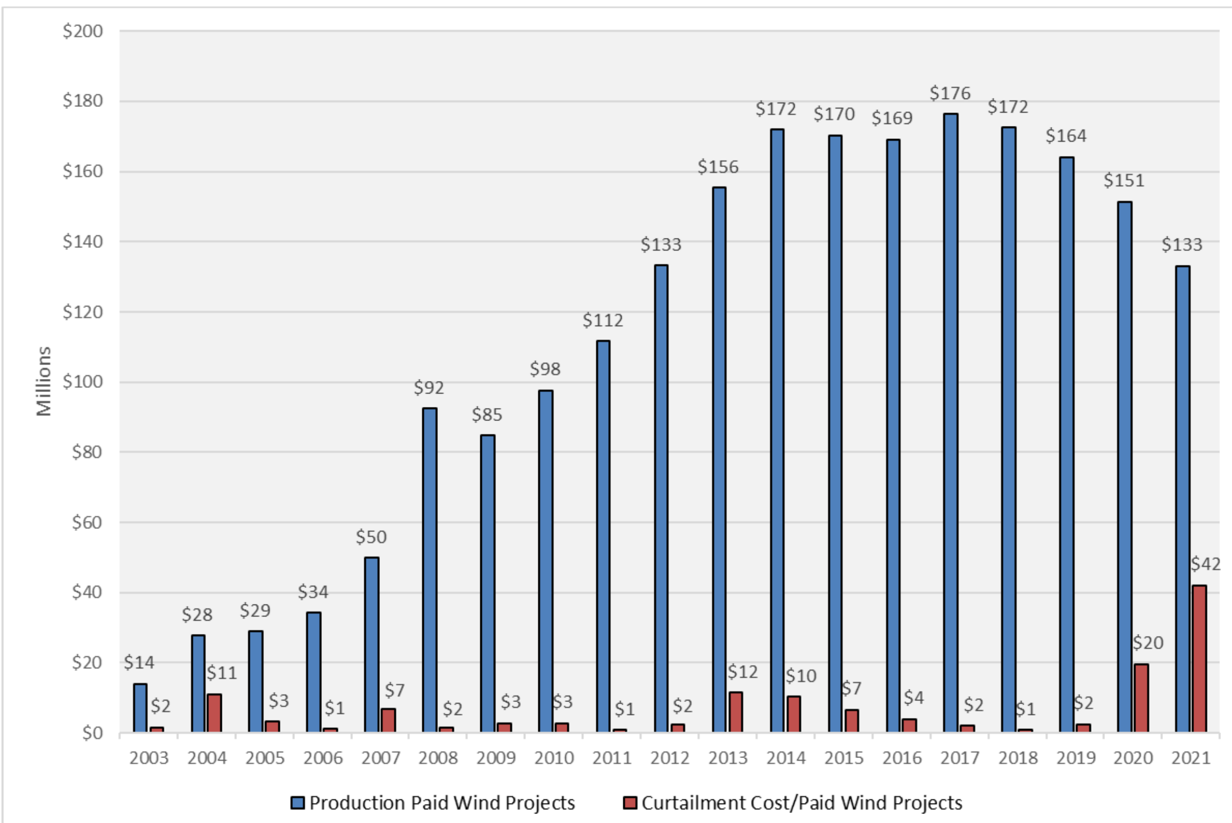
The Company has been working to schedule transmission outages to minimize curtailment for a number of years –performing multiple outages at the same time and scheduling these activities during times when wind is normally at its lowest levels – typically the summer months in the NSP service territory. 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.

The Company is also working to identify binding constraints that are likely to occur going forward and are developing plans to mitigate these constraints. The mitigation plans will be designed to cost effectively reduce both curtailment and congestion. The plans include breaker reconfiguration and transmission facility upgrades.

V. Wind Production and Curtailment Payments

Chart 3 shows the corresponding production and curtailment costs for 2003 through 2021.[6] As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

Chart 3



The Company has typically provided estimates of future potential curtailment payment estimates in the AAA Report. However, going forward these estimates will be provided in our fuel forecast Petition, including the one that will be filed by May 2, 2022. The Company is projecting future curtailment will occur because of regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance or repair activities and

[6] The data for 2019-2021 is shown in Part C, Attachment 2.

wind generation projects going into service before all required transmission facilities are completed.

Significant transmission improvements in southwestern Minnesota and the region such as the CapX2020 transmission projects (CapX2020), the Huntley – Wilmarth and all but one of the MISO Multi-Value Projects (MVPs)[7] are now in-service and will positively impact curtailment by reducing local congestion. However, the Company anticipates that wind generation curtailment and associated payment to vendors will continue to occur over the coming years because of regional congestion and the resulting negative LMP in the MISO energy market, along with transmission outages required for construction, maintenance, or repair activities and wind generation projects going into service before all required transmission facilities are completed and likely generation oversubscription of the transmission system. System conditions and wind project development are very dynamic and actual curtailment may vary from that 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 true-up and AAA reports.

The Company continues to utilize initiatives to reduce curtailment. Examples include, where possible, scheduling transmission activities which can impact curtailment during low wind months. The Company is also working to identify binding constraints that are likely to occur going forward and are developing plans to mitigate these constraints.

[7] The Cardinal - Hickory Creek 345 kV MVP line is scheduled to go into service in late 2023.

PUBLIC DOCUMENT

NOT PUBLIC DATA HAS BEEN EXCISED

Part C, Attachment 2

Wind Curtailment Report

Docket Nos. E002/M-02-51, E002/M-00-622, E002/M-04-404, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 & E002/M-06-85, E002/M-08-1487 E002/M-09-1366

2021 AAA Period

List of Wind Projects

LAKE BENTON I
LAKE BENTON II
CHANARAMBIE
MORAINE (Formerly Navitas)
NAE (Multiple Sites)
VELVA
FENTON (enXco)
FPL ENERGY MOWER COUNTY
MINNDAKOTA (Formerly Ivanhoe)
LINCOLN HEIGHTS WIND NORTH & SOUTH (Formerly Norgaard N & S)
BUFFALO RIDGE WIND ENERGY (Formerly Wind Power Partners 1993)
JJN WINDFARM LLC
JEFFERS WIND 20, LLC (Company Owned Effective December 31, 2020)
ULIK
EWINGTON
MORAINE II WIND LLC
PRAIRIE ROSE
ZEPHRY WIND
BIG BLUE WIND FARM
VALLEY VIEW WIND
RIDGEWIND POWER PARTNERS LLC
GRANT COUNTY WIND LLC
ADAMS WIND GENETATIONS LLC
ODELL
WOODSTOCK HILLS
CISCO
CROWNED RIDGE
GLEN ULLIN

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
2021 AAA Period

	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	Total Xcel Energy Paid
Jan-19			409,935.57	15,794,417.19	2,691.44	138,614.09	$ 15,933,031.28
Feb-19			316,550.82	12,067,583.35	1,755.04	84,703.94	$ 12,152,287.29
Mar-19			411,474.86	15,202,176.47	1,869.04	93,395.08	$ 15,295,571.55
Apr-19			320,446.94	11,945,738.10	15,514.36	714,235.19	$ 12,659,973.29
May-19			419,819.81	14,792,059.29	8,719.31	367,154.52	$ 15,159,213.81
Jun-19			307,889.93	10,765,318.39	2,914.02	116,848.22	$ 10,882,166.61
Jul-19			261,647.61	9,175,408.30	5,882.20	225,357.99	$ 9,400,766.29
Aug-19			238,064.67	8,453,872.37	1,705.60	68,807.54	$ 8,522,679.91
Sep-19			422,465.39	15,040,484.98	1,016.19	47,264.76	$ 15,087,749.74
Oct-19			527,632.25	18,941,335.79	11,579.78	477,171.98	$ 19,418,507.77
Nov-19			484,992.26	17,217,454.47	1,823.17	77,334.60	$ 17,294,789.07
Dec-19			416,115.75	14,719,570.78	1,533.90	70,503.00	$ 14,790,073.78
Total-19			4,537,035.83	$ 164,115,419.48	57,004.05	$ 2,481,390.91	$ 166,596,810.39
Jan-20			399,651.01	14,281,994.44	1,583.27	65,900.77	$ 14,347,895.21
Feb-20			503,731.90	17,936,163.91	5,269.02	229,785.49	$ 18,165,949.40
Mar-20			491,554.55	17,679,218.49	19,126.61	849,968.99	$ 18,529,187.48
Apr-20			426,745.32	15,159,859.92	19,377.19	842,513.17	$ 16,002,373.09
May-20			295,839.59	11,005,702.99	38,161.09	1,789,868.33	$ 12,795,571.32
Jun-20			303,865.09	11,215,457.53	68,698.92	3,054,847.02	$ 14,270,304.55
Jul-20			203,130.29	7,708,535.67	11,701.62	508,971.38	$ 8,217,507.05
Aug-20			267,227.71	10,037,747.80	13,175.80	604,055.79	$ 10,641,803.59
Sep-20			284,608.69	10,541,870.58	55,057.72	2,436,060.69	$ 12,977,931.27
Oct-20			293,763.86	10,900,396.21	73,618.56	3,273,477.66	$ 14,173,873.87
Nov-20			350,138.46	12,659,381.03	87,314.17	3,902,384.06	$ 16,561,765.09
Dec-20			327,718.91	12,277,242.13	43,189.37	2,055,139.30	$ 14,332,381.43
Total-20			4,147,975.37	$ 151,403,570.70	436,273.34	$ 19,612,972.65	$ 171,016,543.35
Jan-21			415,276.96	12,790,075.17	55,813.10	2,807,900.43	$ 15,597,975.60
Feb-21			299,731.39	9,077,653.32	33,081.74	1,494,249.98	$ 10,571,903.30
Mar-21			454,702.83	13,823,194.08	102,918.72	4,570,158.12	$ 18,393,352.20
Apr-21			452,040.18	13,764,354.19	95,559.76	4,295,598.08	$ 18,059,952.27
May-21			378,818.38	11,076,185.38	83,722.64	3,810,012.94	$ 14,886,198.32
Jun-21			279,425.87	8,220,002.13	53,729.94	2,451,113.61	$ 10,671,115.74
Jul-21			254,534.12	6,964,756.60	19,170.23	842,853.61	$ 7,807,610.21
Aug-21			334,103.43	9,296,401.87	45,423.20	2,027,854.35	$ 11,324,256.22
Sep-21			358,432.07	10,247,530.77	90,261.00	4,036,330.17	$ 14,283,860.94
Oct-21			367,370.10	10,395,303.71	127,250.80	5,717,621.97	$ 16,112,925.68
Nov-21			466,773.00	13,636,440.35	117,134.85	5,339,565.08	$ 18,976,005.43
Dec-21							$ -
Total-21			4,061,208.31	$ 119,291,897.57	824,065.99	$ 37,393,258.34	$ 156,685,155.91

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 1 (ATC)
2021 AAA Period

	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	Total Xcel Energy Paid
Jan-19							
Feb-19							
Mar-19							
Apr-19							
May-19							
Jun-19							
Jul-19							
Aug-19							
Sep-19							
Oct-19							
Nov-19							
Dec-19							
Total-19							
Jan-20							
Feb-20							
Mar-20							
Apr-20							
May-20							
Jun-20							
Jul-20							
Aug-20							
Sep-20							
Oct-20							
Nov-20							
Dec-20							
Total-20							
Jan-21							
Feb-21							
Mar-21							
Apr-21							
May-21							
Jun-21							
Jul-21							
Aug-21							
Sep-21							
Oct-21							
Nov-21							
Dec-21							
Total-21							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 2 (Low Load)
2021 AAA Period

	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	Total Xcel Energy Paid
Jan-19							
Feb-19							
Mar-19							
Apr-19							
May-19							
Jun-19							
Jul-19							
Aug-19							
Sep-19							
Oct-19							
Nov-19							
Dec-19							
Total-19							
Jan-20							
Feb-20							
Mar-20							
Apr-20							
May-20							
Jun-20							
Jul-20							
Aug-20							
Sep-20							
Oct-20							
Nov-20							
Dec-20							
Total-20							
Jan-21							
Feb-21							
Mar-21							
Apr-21							
May-21							
Jun-21							
Jul-21							
Aug-21							
Sep-21							
Oct-21							
Nov-21							
Dec-21							
Total-21							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)
2021 AAA Period

	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	Total Xcel Energy Paid
Jan-19			34,790.48	1,584,575.48	2,691.44	138,614.09	$ 1,723,189.57
Feb-19			46,095.81	1,975,647.30	1,755.04	84,703.94	$ 2,060,351.24
Mar-19			133,223.00	5,104,484.91	1,869.04	93,395.08	$ 5,197,879.99
Apr-19			132,374.40	5,618,629.76	15,514.36	714,235.19	$ 6,332,864.95
May-19			143,861.13	6,224,849.74	8,719.31	367,154.52	$ 6,592,004.26
Jun-19			103,936.66	4,463,954.31	2,914.02	116,848.22	$ 4,580,802.53
Jul-19			64,936.43	2,490,433.42	5,882.20	225,357.99	$ 2,715,791.41
Aug-19			65,097.85	2,490,144.14	1,705.60	68,807.54	$ 2,543,812.57
Sep-19			152,102.41	6,518,938.81	1,016.19	47,264.76	$ 6,566,203.57
Oct-19			192,968.52	8,558,704.45	11,579.78	477,171.98	$ 9,035,876.43
Nov-19			85,834.03	3,248,563.99	1,823.17	77,334.60	$ 3,325,898.59
Dec-19			143,811.28	6,362,151.94	1,533.90	70,503.00	$ 6,432,654.94
Total-19			1,299,031.99	$ 54,641,078.25	57,004.06	$ 2,481,390.91	$ 57,107,330.05
Jan-20			152,447.62	6,394,615.97	1,583.27	65,900.77	$ 6,460,516.74
Feb-20			199,042.07	8,284,249.02	5,269.02	229,785.49	$ 8,514,034.51
Mar-20			190,537.12	7,939,476.63	19,126.61	849,968.99	$ 8,789,445.62
Apr-20			158,348.00	6,624,111.36	19,377.19	842,513.17	$ 7,466,624.53
May-20			145,484.94	6,215,334.19	38,161.09	1,789,868.33	$ 8,005,202.52
Jun-20			226,908.24	8,515,332.08	68,698.92	3,054,847.02	$ 11,570,179.10
Jul-20			116,826.05	4,996,335.18	11,701.62	508,971.38	$ 5,505,306.56
Aug-20			168,459.46	6,230,107.58	13,175.80	604,055.79	$ 6,834,163.37
Sep-20			210,090.70	7,707,155.08	55,057.72	2,436,060.69	$ 10,143,215.77
Oct-20			211,822.27	7,810,296.30	73,618.56	3,273,477.66	$ 11,083,773.96
Nov-20			290,736.26	10,515,693.78	87,314.17	3,902,384.06	$ 14,418,077.84
Dec-20			268,369.30	9,992,099.21	43,189.37	2,055,139.30	$ 12,047,238.51
Total-20			2,339,072.03	$ 91,224,806.38	436,273.34	$ 19,612,972.65	$ 110,837,779.03
Jan-21			286,239.78	8,608,971.51	55,813.10	2,807,900.43	$ 11,416,871.94
Feb-21			207,036.82	5,238,392.38	33,081.74	1,494,249.98	$ 6,732,642.36
Mar-21			313,731.84	7,958,889.42	102,918.72	4,570,158.12	$ 12,529,047.54
Apr-21			359,879.41	10,295,738.72	95,559.76	4,295,598.08	$ 14,591,336.80
May-21			335,682.76	9,476,493.54	83,722.64	3,810,012.94	$ 13,286,506.48
Jun-21			244,634.08	6,801,152.64	53,729.94	2,451,113.61	$ 9,252,266.25
Jul-21			188,634.61	4,407,043.28	19,170.23	842,853.61	$ 5,249,896.89
Aug-21			279,344.49	7,183,597.10	45,423.20	2,027,854.35	$ 9,211,451.45
Sep-21			317,149.99	8,632,740.85	90,261.00	4,036,330.17	$ 12,669,071.02
Oct-21			322,379.24	8,637,684.25	127,250.80	5,717,621.97	$ 14,355,306.22
Nov-21			409,323.89	11,381,625.18	117,134.85	5,339,565.08	$ 16,721,190.26
Dec-21							
Total-21			3,264,036.89	$ 88,622,328.87	824,065.99	$ 37,393,258.34	$ 126,015,587.21

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 4 (Other-Paid)
2021 AAA Period

	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	Total Xcel Energy Paid
Jan-19							
Feb-19							
Mar-19							
Apr-19							
May-19							
Jun-19							
Jul-19							
Aug-19							
Sep-19							
Oct-19							
Nov-19							
Dec-19							
Total-19							
Jan-20							
Feb-20							
Mar-20							
Apr-20							
May-20							
Jun-20							
Jul-20							
Aug-20							
Sep-20							
Oct-20							
Nov-20							
Dec-20							
Total-20							
Jan-21							
Feb-21							
Mar-21							
Apr-21							
May-21							
Jun-21							
Jul-21							
Aug-21							
Sep-21							
Oct-21							
Nov-21							
Dec-21							
Total-21							

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lake Benton I
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lake Benton II
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Chanarambie
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Moraine (Formerly Navitas)
2021 AAA Period

[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	Total Paid
Jan-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Northern Alternative Energy (NAE)
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Velva
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Fenton (EnXco)
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - FPL Energy Mower County
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - MinnDakota (Formerly Ivanhoe)
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lincoln Heights Wind Holding North*
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

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

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Lincoln Heights Wind Holding South*
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

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

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Buffalo Ridge Wind Energy*
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

**Effective 9/1/15 Wind Power Partners 1993 changed name to Buffalo Ridge Wind Energy. Reporting of Wind Power Partners 1993 contract initiated on 12/2009.*

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company, a Minnesota Corporation
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - JJN Windfarm, LLC.
For FCC Reporting Month of March 2021

[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-10								
Feb-10								
Mar-10								
Apr-10								
May-10								
Jun-10								
Jul-10								
Aug-10								
Sep-10								
Oct-10								
Nov-10								
Dec-10								
Total-10								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Jeffers Wind 20, LLC*
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

**Effective 1/1/21 Jeffers Wind became company own facility.*

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ulik
2021 AAA Period

** Report initiated FCC Reporting Month of January 2011*

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ewington
2021 AAA Period

* *Report initiated FCC Reporting Month of January 2011*

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Moraine II Wind LLC
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Moraine II Wind LLC
2021 AAA Period

[PROTECTED DATA BEGINS

	Lost	Curtailment	Windsource Recovery		Fuel Cost Recovery	
	MWH	Payment	%	Amount ($)	%	Amount ($)
Jan-19						
Feb-19						
Mar-19						
Apr-19						
May-19						
Jun-19						
Jul-19						
Aug-19						
Sep-19						
Oct-19						
Nov-19						
Dec-19						
Total-19	-	$ -		$ -		$ -
Jan-20						
Feb-20						
Mar-20						
Apr-20						
May-20						
Jun-20						
Jul-20						
Aug-20						
Sep-20						
Oct-20						
Nov-20						
Dec-20						
Total-20	-	$ -		$ -		$ -
Jan-21						
Feb-21						
Mar-21						
Apr-21						
May-21						
Jun-21						
Jul-21						
Aug-21						
Sep-21						
Oct-21						
Nov-21						
Dec-21						
Total-21	-	$ -		$ -		$ -

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Prairie Rose
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Zephyr Wind, LLC
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Big Blue Wind Farm
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

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
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Ridgewind Power Partners LLC
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Grant County Wind LLC
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Adams Wind Generations
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Odell
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Woodstock Hills
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Cisco
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Crowned Ridge
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Glen Ullin
2021 AAA Period

[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-19								
Feb-19								
Mar-19								
Apr-19								
May-19								
Jun-19								
Jul-19								
Aug-19								
Sep-19								
Oct-19								
Nov-19								
Dec-19								
Total-19								
Jan-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Dakota Range III
2021 AAA Period

[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-20								
Feb-20								
Mar-20								
Apr-20								
May-20								
Jun-20								
Jul-20								
Aug-20								
Sep-20								
Oct-20								
Nov-20								
Dec-20								
Total-20								
Jan-21								
Feb-21								
Mar-21								
Apr-21								
May-21								
Jun-21								
Jul-21								
Aug-21								
Sep-21								
Oct-21								
Nov-21								
Dec-21								
Total-21								

PROTECTED DATA ENDS]

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 forced outages, contractor performance, and actions taken to prevent future outages. We provide this information below.

A. Forced Outages

Part C, Attachment 4 provides for each forced outage during the 2021 AAA reporting year the following details: [1]

- a description of the equipment that resulted in the forced outage;
- a description of the equipment failure;
- the change in energy costs resulting from the outage;
- the failure history during the reporting period; and
- the steps taken to alleviate reoccurrence of the outage.

In addition, Part C, Attachment 5 provides a comparison of forecasted outage costs by unit to actual outages experienced.

B. Contractor Performance

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

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).

[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.

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 Initiatives

As we have stated in prior AAA reports, we have several operational improvement initiatives at work under the Generation Operating Model Initiative, including the formation of the Performance Optimization department and the application of Continuous Improvement practices that include Lean Management, Event Assessments and Root Cause Analysis, Work Management Processes, and Operating Model governance. We provide greater detail on each of these initiatives below.

<u>Generation Operating Model</u>
The Generation Operating Model I launched in 2011 was successful in its purpose to standardize processes, create efficiencies, and identify and share best practices across the fleet. This success led to the development and implementation of the Generation Operating Model II in 2019.

A significant organizational change in the Generation Operating Model II was the creation of the Performance Optimization department that centralizes technical support services to correspond to the evolving generation portfolio. The Performance Optimization department is comprised of Reliability Engineering, Fleet Engineering, and Analytics & Practices. A brief explanation of each Performance Opimization area follows.

- The Reliability Engineering department is responsible for the daily engineering activities at our plants and provides on-site support. The Reliability Engineers ensure our plant design basis is maintained and a consistent asset strategy is implemented across the fleet and for similar generations types.

- The Fleet Engineering department is responsible for developing and implementing asset and equipment strategies consistently across the fleet. This department is broken into fleet engineering teams for common systems including Electrical and Controls, Boilers and Balance of Plant, Steam Turbines, Gas Turbines, Materials Engineering, and Non-Destructive Examination and Testing. This department also includes an Asset Strategy and Budget Integration team to ensure that fleet asset strategies are effectively integrated and prioritized.

- The Analytics and Practices department includes both a Monitoring and Diagnostics team and a System and Equipment Analytics team. The Monitoring and Diagnostics team utilizes the Company's remote monitoring capability and predictive analytics to identify abnormal operational issues and alert plant personnel for corrective actions prior to failure. The System and Equipment Analytics team integrates equipment monitoring, asset performance management analytical tools, and financial analysis.

Lean Management is a continuous improvement tools to eliminate waste and inefficiency. The people-based system produces improved processes, inventory management, teamwork, and customer relationships.

The standardized Event Assessments (EAs) and Root Cause Analysis (RCAs) practices have the objective of identifying the causes of events, not only to correct, but to share and prevent recurrence in the fleet. EAs and RCAs are performed for forced outages, major process breakdowns, equipment failures, and environmental permit exceedances.

Work Management processes continue to be improved. The System Analysis Program (SAP) software implemented in 2016 has allowed efficiencies and standardization in the Energy Supply work management processes. Along with SAP software, wireless tablets have been provided to field workers and permit electronic access, transfer, management, and completion of work order assignments.

Lastly, the Operating Model Governance role is to monitor, document, and provide resolutions for issues that arise while using the Operating Model Governance to continuously improve perfromance. Leadership is committed to ensure all aspects of continuous improvement are successful.

D. 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.

Unit Outage Information
2021 AAA Reporting Period: January 1 - December 31, 2021

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for 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
JANUARY 2021										
SHERCO_G2	Forced	5 CMILL OPERATION. 24 Cmill classifier belt, 23 Cmill OH.	01/27/2021	1/28/2021	1	24 Coal Mill	With 23 Coal Mill out of service for a planned overhaul, failure of 24 Coal Mill's classifier belt resulted in a derate until the belt could be replaced.		Similar occurrence on 2/1/2022 and 11/11/2021 to improve design of additional mills.	Alternative design drive belt installed allowing for faster changeout; however, we are finding they only last about 9 months compared to 3 years for the original. Original style belt will be installed during next mill overhaul as it lasts longer.
FEBRUARY 2021										
SHERCO_G1	Forced	5 CMILL OPERATION. 11 coal mill classifier out of service and requires derate to replace the classifier belts	02/01/2021	02/03/2021	2	11 Coal Mill	With 13 Coal Mill out of service for a planned overhaul, failure of 11 Coal Mill's classifier belt resulted in a derate until the belt could be replaced.		Subsequent occurrences on 11/11/2021 to improve design of additonal mills.	Alternative design drive belt installed allowing for faster changeout; however, we are finding they only last about 9 months compared to 3 years for the original. Original style belt will be installed during next mill overhaul as it lasts longer.
SHERCO_G1	Forced	Derate needed to maintain margin for enviromental permit.	02/08/2021	02/09/2021	1	Scrubber Modules	With 101 Module out of service for Major Clean, a failure of 102 Modules Upper Field and 112 Modules Spray Pump requiring a repack, derate taken to allow repair of 112 Modules spray pump and 102 Modules Upper Field.		Similar occurrence on 8/20/2021, 10/02/2021 and 10/04/2021. Derates necessary to support daily module cleaning with two modules previously out of service. Derating supports meeting environmental opacity limits.	Capacitors on the module field power supplies are being changed out with an improved design as well as cooling fans being added to the power supplies. Spray pump was repacked and module returned to service. Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERCO_G1	Forced	Derate needed to maintain margin for enviromental permit.	02/19/2021	02/24/2021	6	Scrubber Modules	Following an extended period of full power operations due to polar vortex, common stack was approaching the 30 day NOx limit. Derate necessary to maintain margin for environmental NOx limitations.		None	Operation of both units at their top operating level typically causes the daily NOx average to be at or above 0.15 lb/MMBtu. Operated at this capacity to support polar vortex. Extended periods of operation at these levels causes the 30 day rolling average to approach the 0.15 lb/MMBtu limit. Normal daily operation typically results in approximately 0.135 lb/MMBtu. Derate following the polar vortex event allowed for restoring the margin to environmental limits such that the units would be available to meet extended full power operation again should it be required.
SHERCO_G2	Forced	Derate needed to maintain margin for enviromental permit.	02/19/2021	02/24/2021	6	Scrubber Modules	Following an extended period of full power operations due to polar vortex, common stack was approaching the 30 day NOx limit. Derate necessary to maintain margin for environmental NOx limitations.		None	Operation of both units at their top operating level typically causes the daily NOx average to be at or above 0.15 lb/MMBtu. Operated at this capacity to support polar vortex. Extended periods of operation at these levels causes the 30 day rolling average to approach the 0.15 lb/MMBtu limit. Normal daily operation typically results in approximately 0.135 lb/MMBtu. Derate following the polar vortex event allowed for restoring the margin to environmental limits such that the units would be available to meet extended full power operation again should it be required.
MARCH 2021										
CC Highbridge1	Forced	Immediate Unit 7 outage to address aux gearbox noise.	03/24/2021	3/30/2021	6	U7 Combustion Turbine Aux Gear Box	U7 aux gear box had a bearing failure requiring replacement prior to damaging gears.		None	Bearing was replaced proactively during 2019 major overhaul.
APRIL 2021										
SHERCO_G2	Forced	Derate needed to maintain environmental margin for NOx limitations.	04/15/2021	4/22/2021	8	2 GSU Transformer	Following an extended period of operation with U1 offline and U2 firing to maintain steam supply to LPI while 2 GSU transformer was being repaired, the common stack 30 day rolling NOx average increased above 0.14 lb/MMBtu. Derate necessary to maintain margin for environmental NOx Limitations.		None	U1 was offline for major overhaul and 2 GSU transformer failed. The desire to maintain steam supply to LPI while generator was offline resulted in a mix of fuel oil use and a single coal mill to maintain this supply. This caused the 30 day rolling average to approach the 0.15 lb/MMBtu limit. Completion of the install of the new Aux Boiler will allievate the condition where either U1 or U2 would be required to be online to support LPI steam supply. Aux boiler commissioning is scheduled for December 2021.
CC Highbridge1	Forced	Unit 8 Hot Reheat bypass valve is not sealing. Need to disassemble to repair. Requires total plant outage and cool down.	04/21/2021	4/22/2021	2	U8 Hot Reheat Bypass Valve	U8 Hot Reheat Bypass valve internals were replaced with rebuilt plug and seat during Spring outage. Upon return, the valve did not seat and leaked by enough to exceed downstream temp limits while on-line.		None	Plant will use a different vendor for refurbishment and ensure contact checks are made for the plug/seat combination.
CC Highbridge2	Forced	Unit 8 Hot Reheat bypass valve is not sealing. Need to disassemble to repair. Requires total plant outage and cool down.	04/21/2021	4/22/2021	2	U8 Hot Reheat Bypass Valve	U8 Hot Reheat Bypass valve internals were replaced with rebuilt plug and seat during Spring outage. Upon return, the valve did not seat and leaked by enough to exceed downstream temp limits whil on-line. U7 required off-line to repair Unit 8 due to isolation requirements.		None	Plant will use a different vendor for refurbishment and ensure contact checks are made for the plug/seat combination.
SHERCO_G2	Forced	Generator Transformer Trouble - repairs to bladders on transformer needed.	04/05/2021	4/15/2021	9	2 GSU Transformer	Failure of 2 GSU transformer's bladder resulted in the unit being taken offline to drain oil from the transformer and replace the bladders.		None	Bladders were replaced and Performance Optimization group was tasked with reviewing PM frequency for transformer oil bladder replacement.

PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for 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
MAY 2021										
SHERCO_G1	Forced	Derate until relief valves can be set post overhaul. Currently scheduled for 5/3.	05/01/2021	05/03/2021	1	Boiler Relief Valves	Derate to maintain boiler pressure at lower level until the associated boiler relief valves replaced during unit outage could be set by independent contractor.		None	Contractor brought in and coordinated with operations to go to full load/pressure to perform post outage boiler relief valve setpoint verifications.
SHERCO_G1	Forced	Derated due to 14 Boiler Circ pump trouble/failure.	05/04/2021	05/31/2021	27	14 Boiler Circ Pump	Following replacement of 14 BCP during the U1 overhaul, during normal operation of the pump, the pump tripped offline. Investigation revealed a shorted winding which would require the pump to be removed and sent off site for rewind and repair. With only 3 of 4 BCPs available, unit derated to 610 MWn.		Similar derates were reported during this time period on 6/4/21, 7/1/21 and 8/1/21. All events were to support the repairs of this one (#14) circ pump.	Pump/Motor assemble was removed, blank installed and sent to Hayward Tyler for evaluation, quote, rewind and repair. Motor shipped back to the site on 7/30/21 and arrived on site on 8/2/21.
SHERCO_G2	Forced	High Condenser Back Pressure 3.00 psia, derate for turbine safety. Outer condenser loop out of service	05/19/2021	05/26/2021	7	Circ Water Cooling	Fouling of the outer loop of Circ Water cooling to the HP condenser required taking that loop out of service to clean the water boxes and tubes. Cause of the tubes being fouled was due to extended operations with no amertap system in service coupled with not cleaning the tubes during the U2 outage in 2019.		None	Loop was isolated to clean water boxes and tubes. Ammertap system for outer loop was repaired and returned to service. Cleaning of the units' inner loop proactively scheduled during U2 seasonal operations.
JUNE 2021										
SHERCO_G1	Forced	Derated due to 14 Boiler Circ pump trouble/failure.	06/04/2021	06/30/2021	26	14 Boiler Circ Pump	Following replacement of 14 BCP during the U1 overhaul, during normal operation of the pump, the pump tripped offline. Investigation revealed a shorted winding which would require the pump to be removed and sent off site for rewind and repair. With only 3 of 4 BCPs available, unit derated to 610 MWn.		Similar derates were reported during this time period on 5/4/21, 7/1/21 and 8/1/21. All events were to support the repairs of this one (#14) circ pump.	Pump/Motor assemble was removed, blank installed and sent to Hayward Tyler for evaluation, quote, rewind and repair. Motor shipped back to the site on 7/30/21 and arrived on site on 8/2/21.
SHERCO_G2	Forced	Tube leak outage to allow for lowering throttle pressure in order to minimize damage from leak.	06/01/2021	06/10/2021	9	Boiler Couton Bottom	Management decison to conservatively keep pressure lower following discovery of a tube leak to minimize potential damage to surrounding tubes until unit could be removed for repair.		Similar event on 6/22/21 and 6/25/21 (supporting same repair), and 12/24/21.	Maintenance worked with engineering to drill through the membrane and find the leaking tube. The faulty tube was removed and a window weld performed to replace the cutouot section of tubing. Air test was performed as post-maintenance test. Engineering determined that most likely cause was quench cracking event due to plugged bottom ash overflows causing abnormally high levels in the bottom ash hoppers. Seal trough drains and bottom ash overflows were cleaned to prevent recurrence.
SHERC3	Forced	Bag house availability. This derate needed to maintain margin to environmental limits.	06/04/2021	06/07/2021	3	Fabric Filter Compartments	FF Compartments 31-08, 32-16 and 33-02 were out of service for capital bag replacement project. FF Compartment 32-03 was isolated for spring retensioning. During startup, unit received opacity spikes. Unit derated to take offending compartments out of service and maintain compartment D/P limits in order to maintain environmental limits.		None	Fabric filter compartments with leaks were repaired and returned to service allowing for return to full power operation.
SHERC3	Forced	Apparent tube leak in feed water heater tube leak in FWH 36-2/37-2 string.	06/24/2021	06/30/2021	6	37-2 Feedwater Heater	During startup of Unit 3, operations personnel was unable to place high pressure heater string 36-2/37-2 in service due an apparent tube leak. Heater string was isolated and a tube leak was verified in 37-2 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar event on 7/1/22, 8/1/22 and 9/1/22. All events were related to the same leaking tube in FWH 37-2.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
SHERCO_G1	Forced	Remove 14 Boiler Circ Pump and install blank, replace drum relief valve - crack in the nozzle.	06/01/2021	06/04/2021	4	14 Boiler Circ Pump	Unit taken off line to remove failed 14 BCP and install blanking plate until 14 BCP could be repaired and an outage taken to remove the blanking plate and reinstall the pump.		Similar derates were reported during this time period on 5/4/21, 6/1/21, and 7/1/21. All events were to support the repairs of this one pump.	Pump/Motor assemble was removed, blank installed and sent to Hayward Tyler for evaluation, quote, rewind and repair. Motor shipped back to the site on 7/30/21 and arrived on site on 8/2/21.
SHERCO_G2	Forced	Tube leak discovered while unit was in reserve shutdown for economics.	06/22/2021	06/25/2021	4	Boiler Couton Bottom	Following taking unit offline for economic shutdown, the location of the tube leak noted on 6/1/21 was found. Based on failure analysis it was determined to have been from a quenching event due to high levels in the bottom ash hopper.		Similar event on 6/1/21 and 6/25/21(supporting same repair), and 12/24/21.	Maintenance worked with engineering to drill through the membrane and find the leaking tube. The faulty tube was removed and a window weld performed to replace the cutouot section of tubing. Air test was performed as post maintenance test. Engineering determined that most likely cause was quench cracking event due to plugged bottom ash overflows causing abnormally high levels in the bottom ash hoppers. Seal trough drains and bottom ash overflows were cleaned to prevent recurrence.
SHERCO_G2	Forced	Outage extension, difficulty in finding tube leak and subsequent repair.	06/25/2021	06/30/2021	5	Boiler Couton Bottom	Following taking unit offline for economic shutdown, the location of the tube leak noted on 6/1/21 was found. Based on failure analysis it was determined to have been from a quenching event due to high levels in the bottom ash hopper. Difficulty in locating the failed tube and accessing for repair caused the maintenance outage to extend.		Similar event on 6/1/21 and 6/22/21, (supporting same repair) and 12/24/21.	Maintenance worked with engineering to drill through the membrane and find the leaking tube. The faulty tube was removed and a window weld performed to replace the cutouot section of tubing. Air test was performed as post maintenance test. Engineering determined that most likely cause was quench cracking event due to plugged bottom ash overflows causing abnormally high levels in the bottom ash hoppers. Seal trough drains and bottom ash overflows were cleaned to prevent recurrence.

PROTECTED DATA ENDS]

Unit Outage Information
2021 AAA Reporting Period: January 1 - December 31, 2021

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for 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
JULY 2021										
SHERCO_G1	Forced	Derated due to 14 Boiler Circ pump trouble\ failure.	07/01/2021	7/31/2021	**31**	14 Boiler Circ Pump	Following replacement of 14 BCP during the U1 overhaul, during normal operation of the pump, the pump tripped offline. Investigation revealed a shorted winding which would require the pump to be removed and sent off site for rewind and repair. With only 3 of 4 BCPs available, unit derated to 610 MWn.		Similar derates were reported during this time period on 5/4/21, 6/1/21, and 8/1/21. All events were to support the repairs of this one (#14) circ pump.	Pump/Motor assemble was removed, blank installed and sent to Hayward Tyler for evaluation, quote, rewind and repair. Motor shipped back to the site on 7/30/21 and arrived on site on 8/2/21.
SHERCO_G2	Forced	Derate to 610 MWn due to failure of 24 BCP breaker. Only 3 out of 4 BCP"s available.	07/01/2021	7/9/2021	**8**	24 Boiler Circ Pump	Operations was contacted by engineering about smoke coming from the breaker associated with 24 Boiler Circ Pump. Operations was unable to trip the breaker remotely. Once the breaker was tripped locally, the breaker was found with charring in the control portion of the breaker. Troubleshooting revealed a ground on the Bus 24 cubicles 16 through 25 which included 24 Boiler Circ Pump. Unit derated until breaker could be repaired and tested.		No similar failures were reported during this reporting period.	Repaired cause of the ground, restored affected Bus 24 cubicles. Following repair of breaker for 24 Boiler Circ Pump, the breaker was reinstalled and the pump restored.
SHERC3	Forced	Apparent water heater tube leak in FWH 36-2/37-2 string, requiring derate to 755 MW.	07/01/2021	7/9/2021	**9**	37-2 Feedwater Heater	During startup of Unit 3, operations personnel was unable to place high pressure heater string 36-2/37-2 in service due an apparent tube leak. Heater string was isolated and a tube leak was verified in 37-2 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar event on 6/24/21, 8/1/21 and 9/1/21. All events were related to the same leaking tube in FWH 37-2.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
CCRiverside1	Forced	In order to maintain compliance with river temperature environmental permits, Unit 9 must be taken off-line.	07/03/2021	7/6/2021	**3**	No equipment failures were involved with this unit outage.	This was an outage to maintain compliance with an environmental permit requirement. River temperature limits related to environmental permits would be exceeded if the unit remained on-line. No equipment failures were involved.		No similar events included for this reporting period.	No equipment failures were involved with this unit outage. This was an outage to maintain compliance with an environmental permit requirement. River temperature limits related to environmental permits would be exceeded if the unit remained on-line. No equipment failures were involved.
AUGUST 2021										
CCRiverside2	Forced	Derate due to NOx emissions control	08/01/2021	08/02/2021	**2**	#14 Fuel Nozzle on Unit 9 Combustion Turbine	A portion of the #14 fuel nozzle failed which caused NOx emissions to increase from the combustion turbine.		No similar events occurred during this reporting period. There are 3 other entries in this report which are part of this same event.	Gas supply constituents contributed to the failure of a portion of the fuel nozzle which casued this event. The site maintains gas fuel conditioning equipment which is periodically maintained to mitigate this type of event.
CCRiverside2	Forced	Derate due to NOx emissions control	08/03/2021	08/05/2021	**2**	#14 Fuel Nozzle on Unit 9 Combustion Turbine	A portion of the #14 fuel nozzle failed which caused NOx emissions to increase from the combustion turbine.		No similar events occurred during this reporting period. There are 3 other entries in this report which are part of this same event.	Gas supply constituents contributed to the failure of a portion of the fuel nozzle which casued this event. The site maintains gas fuel conditioning equipment which is periodically maintained to mitigate this type of event.
SHERCO_G1	Forced	Derated due to 14 Boiler Circ pump trouble/failure.	08/01/2021	08/31/2021	**31**	14 Boiler Circ Pump	Following replacement of 14 BCP during the U1 overhaul, during normal operation of the pump, the pump tripped offline. Investigation revealed a shorted winding which would require the pump to be removed and sent off site for rewind and repair. With only 3 of 4 BCPs available, unit derated to 610 MWn.		Similar derates were reported during this time period on 5/4/21, 6/1/21, 7/1/21. All events were to support the repairs of this one (#14) circ pump.	Pump/Motor assemble was removed, blank installed and sent to Hayward Tyler for evaluation, quote, rewind and repair. Motor shipped back to the site on 7/30/21 and arrived on site on 8/2/21. Decision was made to take an outage to replace the pump to coincide with a state mandated boiler inspection the week of 9/11/21.
SHERCO_G1	Forced	Derated to allow scrubber module flushing.	08/20/2021	08/23/2021	**2**	Scrubber Modules	With 108 Module out of service for a major clean, a derate was necessary to allow for performing High Voltage cleaning of the West ESP fields due to sustained operation at high loads. This resulted in multiple modules being removed from service during the cleaning evolutions.		Similar occurrence on 2/8/21, 10/02/2021 and 10/02/2021. Derates necessary to support daily module cleaning with two modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions, but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERC3	Forced	Appparent tube leak in feed water heater tube	08/01/2021	08/31/2021	**31**	37-2 Feedwater Heater	During startup of Unit 3, operations personnel was unable to place high pressure heater string 36-2/37-2 in service due an apparent tube leak. Heater string was isolated and a tube leak was verified in 37-2 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar event on 6/24/22, 7/1/22, and 9/1/22. All events were related to the same leaking tube in FWH 37-2.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
CCRiverside1	Forced	High river temps forced unit off line.	08/19/2021	08/20/2021	**1**	No equipment failed for this event. Environmental Permit limits for river temperatures prevented operation of the unit.	No equipment failure for this event.		No equipment failure for this event.	This event is characterized as "OMC - Out of Management Control" because it is dependent on river temperatures which are driven by ambient weather conditions.
CCRiverside2	Forced	Borescope 14 fuel nozzle to inspect for damage.	08/05/2021	08/08/2021	**3**	#14 Fuel Nozzle on Unit 9 Combustion Turbine	A portion of the #14 fuel nozzle failed which caused NOx emissions to increase from the combustion turbine.		No similar events occurred during this reporting period. There are 3 other entries in this report which are part of this same event.	Gas supply constituents contributed to the failure of a portion of the fuel nozzle which casued this event. The site maintains gas fuel conditioning equipment which is periodically maintained to mitigate this type of event.

PROTECTED DATA ENDS]

Unit Outage Information
2021 AAA Reporting Period: January 1 - December 31, 2021

PUBLIC DOCUMENT
NOT PUBLIC DATA EXCISED

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for 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
SEPTEMBER 2021										
SHERC3	Forced	Apparent tube like in feed water heater tube leak in FWH 36-2/37-2 string.	09/01/2021	09/18/2021	**17**	37-2 Feedwater Heater	During startup of Unit 3, operations personnel was unable to place high pressure heater string 36-2/37-2 in service due an apparent tube leak. Heater string was isolated and a tube leak was verified in 37-2 feedwater heater. Unit derated due to feedwater heater string out of service.		Similar event on 6/24/22, 7/1/22, and 8/1/22 . All events were related to the same leaking tube in FWH 37-2.	Heater string removed from service and unit derated until a favorable market condition would allow for unit to be taken offline to repair the tube leak. Working with marketing determined that the best time for this would be during the planned outage for state mandated boiler inspection in September. Heater will be repaired and remaining tubes will have eddy current testing performed to determine if there are any other suspectable tubes.
OCTOBER 2021										
SHERCO_G1	Forced	Derate required to maintain opacity margin to environmental limit.	10/02/2021	10/03/2021	**2**	Scrubber Modules	With 103 and 108 modules out of service for major cleans, derate to allow performance of nightly flushing on remaining modules to maintain module performance margins.		Similar occurrence on 2/8/21, 8/20/2021, and 10/04/2021. Derates necessary to support daily module cleaning with two modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERCO_G1	Forced	Derate required to maintain opacity margin to environmental limit.	10/04/2021	10/10/2021	**6**	Scrubber Modules	With 103 and 108 modules out of service for major cleans, derate to allow performance of nightly flushing on remaining modules to maintain module performance margins.		Similar occurrence on 2/8/21, 8/20/2021, and 10/02/2021. Derates necessary to support daily module cleaning with two modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERCO_G2	Forced	Derate required to maintain opacity margin to environmental limit.	10/02/2021	10/03/2021	**2**	Scrubber Modules	With 203 and 208 modules out of service for major cleans, derate to allow performance of nightly flushing on remaining modules to maintain module performance margins.		Similar occurrence on 2/8/21, 8/20/2021, and 10/04/2021. Derates necessary to support daily module cleaning with two modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
SHERCO_G2	Forced	Derate required to maintain opacity margin to environmental limit.	10/04/2021	10/15/2021	**12**	Scrubber Modules	With 203 and 208 modules out of service for major cleans, poor performance of remaining modules lower fields necessitated a derate to maintain margin to environmental lilmits while lower field performance issues were addressed.		Similar occurrence on 2/8/21, 8/20/2021, and 10/02/2021. Derates necessary to support daily module cleaning with two modules previously out of service. Derating supports meeting environmental opacity limits.	Cleaning frequency for each scrubber module (12 total per unit) has increased from once a year to once every 8 months. This strategy will still require some smaller derates to complete all required cleaning evolutions but these smaller derates should be limited mainly to the spring and fall when energy prices are historically less. There will also be derates due to loss of other module components during times which we need to have two major cleans in progress at once due to the loss of reduncancy.
NOVEMBER 2021										
SHERCO_G2	Forced	5 CMILL OPERATION. 24 Cmill removed from service, 22 Cmill stuck discharge gate	11/11/2021	11/21/2021	**11**	24 Coal Mill	With 24 Coal Mill in an emergency use only status due to failing Lower Radial Bearings, failure of 22 Coal Mill discharge gate resulted in a derate due to only having 5 available coal mills. Unit was offline for seasonal operation during this period.		None	With 24 Coal Mill being in an emergency use only status, all future work, both planned and unexpected maintenance, on U2 coal mills will result in a derate.
DECEMBER 2021										
SHERCO_G2	Forced	Circ pump removed from service to maintain environmental compliance and Coal Mill operation (21 Hot Air Blast Gate issue & 24 Mills OOS).	12/28/2021	12/30/2021	**1**	Circ Water Cooling	A scale shedding event caused overboarding on U2 cooling tower due to high differential pressure. A derate was required to take a circ water pump out of service to stop the overboarding until cleaning and rebalancing of cooling tower cells could be peformed.		None	Cleaned cooliIng tower wet decks to remove scaling which corrected the cause of the high differential pressure and overboarding on the cooling tower. Cooling tower cell flows were redistributed and the circ water pump was returned to service.
SHERC3	Forced	Require unit offline to repair boiler tube leak in west end of the boiler in the superheat section.	12/24/2021	12/30/2021	**6**	Boiler Finishing Superheat	Initiating tube failure was short term overheating due to oxide exfoliation pluggage. It is hypothesized that the source of this oxide is from the outlet headers downstream of the finishing superheat assemblies. This indicates the oxide traveled backwards from the headers into the pendants. It is theorized this could happen during boiler air tests, during shutdowns when the steam inside the pendants and header are condensing, or during boiler drains when vents and drains are manipulated.		Similar event on 6/1/21, 6/22/21, and 6/25/21 (June's were to support one repair).	Replaced 8 tubes and pad welded 4 other tubes that were damaged during the tube failure event. Procedure changes have been made to minimize potential for the exfoliation events.

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Protected Data is Shaded

[PROTECTED DATA BEGINS

							Actual ($)				As Forecasted ($)				Actual ($/MWh)			As Forecasted ($/MWh)		
Unit	Type of Plant	Outage Category	Date			Duration (Days)	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh
Black Dog Total						0		0				2,469,988			0			25.89		
CC Highbridge1	CC	Forced	03/24/2021	-	03/30/2021	6		193,133												
CC Highbridge1	CC	Forced	04/21/2021	-	04/22/2021	2		104,390												
High Bridge 1x1 Total						7		297,523				377,235			26.38			26.68		
CC Highbridge2	CC	Forced	04/21/2021	-	04/22/2021	2		104,373												
High Bridge 2x1 Total						2		104,373				292,386			26.16			24.16		
CCRiverside1	CC	Forced	07/03/2021	-	07/06/2021	3		552,686												
CCRiverside1	CC	Forced	08/19/2021	-	08/20/2021	1		201,230												
Riverside 1x1 Total						4		753,915				699,703			36.41			21.60		
CCRiverside2	CC	Forced	08/01/2021	-	08/02/2021	2		99,186												
CCRiverside2	CC	Forced	08/03/2021	-	08/05/2021	2		141,415												
CCRiverside2	CC	Forced	08/05/2021	-	08/08/2021	3		488,146												
Riverside 2x1 Total						7		728,746				754,774			35.78			24.34		
Allen S King Total						0		0				2,022,062			0			32.10		
SHERCO_G1	Steam	Forced	02/01/2021	-	02/03/2021	2		83,723												
SHERCO_G1	Steam	Forced	02/08/2021	-	02/09/2021	1		82,859												
SHERCO_G1	Steam	Forced	02/19/2021	-	02/24/2021	6		696,900												
SHERCO_G1	Steam	Forced	05/01/2021	-	05/03/2021	1		53,689												
SHERCO_G1	Steam	Forced	05/04/2021	-	05/31/2021	27		219,571												
SHERCO_G1	Steam	Forced	06/04/2021	-	06/30/2021	26		877,134												
SHERCO_G1	Steam	Forced	06/01/2021	-	06/04/2021	4		1,469,584												
SHERCO_G1	Steam	Forced	07/01/2021	-	07/31/2021	31		700,493												
SHERCO_G1	Steam	Forced	08/01/2021	-	08/31/2021	31		558,290												
SHERCO_G1	Steam	Forced	08/20/2021	-	08/23/2021	2		141,520												
SHERCO_G1	Steam	Forced	10/02/2021	-	10/03/2021	2		135,952												
SHERCO_G1	Steam	Forced	10/04/2021	-	10/10/2021	6		245,587												
Sherburne 1 Total						139		5,265,303				6,092,857			39.78			28.56		
SHERCO_G2	Steam	Forced	01/27/2021	-	01/28/2021	1		63,469												
SHERCO_G2	Steam	Forced	02/19/2021	-	02/24/2021	6		1,313,171												
SHERCO_G2	Steam	Forced	04/15/2021	-	04/22/2021	8		1,384,218												
SHERCO_G2	Steam	Forced	04/05/2021	-	04/15/2021	9		2,512,910												
SHERCO_G2	Steam	Forced	05/19/2021	-	05/26/2021	7		1,753,618												
SHERCO_G2	Steam	Forced	06/01/2021	-	06/10/2021	9		863,785												
SHERCO_G2	Steam	Forced	06/22/2021	-	06/25/2021	4		740,806												
SHERCO_G3	Steam	Forced	06/25/2021	-	06/30/2021	5		3,207,606												
SHERCO_G2	Steam	Forced	07/01/2021	-	07/09/2021	8		128,290												
SHERCO_G2	Steam	Forced	10/02/2021	-	10/03/2021	2		294,661												
SHERCO_G2	Steam	Forced	10/04/2021	-	10/15/2021	12		1,342,380												
SHERCO_G2	Steam	Forced	11/11/2021	-	11/21/2021	11		3,347,594												
SHERCO_G2	Steam	Forced	12/28/2021	-	12/30/2021	1		271,944												
Sherburne 2 Total						83		17,224,452				8,673,395			37.53			27.75		
SHERC3	Steam	Forced	06/04/2021	-	06/07/2021	3		26,478												
SHERC3	Steam	Forced	06/24/2021	-	06/30/2021	6		133,744												
SHERC3	Steam	Forced	07/01/2021	-	07/09/2021	9		201,768												
SHERC3	Steam	Forced	08/01/2021	-	08/31/2021	31		911,027												
SHERC3	Steam	Forced	09/01/2021	-	09/18/2021	17		722,947												
SHERC3	Steam	Forced	12/24/2021	-	12/30/2021	6		2,611,345												
Sherburne 3 Total						72		4,607,308				1,974,161			39.87			27.38		
Monticello Total						0		0				1,906,934			0			21.17		
Prairie Island 1 Total						0		0				3,409,537			0			18.97		
Prairie Island 2 Total						0		0				4,358,735			0			19.30		
Total						314	763,270	28,981,620	18,784,610	10,197,010	1,341,606	33,031,765	21,536,212	11,495,554	37.97	24.61	13.36	24.62	16.05	8.57

PROTECTED DATA ENDS]

Notes:
(1) Outages/Derates of one day durations or longer and greater than or equal to 500 MWh are included

Protected Data is Shaded

[PROTECTED DATA BEGINS

					Actual ($)				As Forecasted ($)				Actual ($/MWh)			As Forecasted ($/MWh)		
Unit	Type of Plant	Outage Category	Date	Duration (Days)	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Outage MWh	Replacement Cost ($)	Unit Cost ($)	Energy Cost Due to Outages ($)	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh	Replacement Cost $/MWh	Unit Cost $/MWh	Outage Cost $/MWh
Blk_Dog_G52	Steam	Scheduled	03/08/2021 - 03/17/2021	9		161,846												
Blk_Dog_G52	Steam	Scheduled	05/23/2021 - 05/25/2021	3		411,686												
Blk_Dog_G52	Steam	Scheduled	10/10/2021 - 10/15/2021	6		1,603,468												
Black Dog 25 Total				**18**		**2,177,000**				1,141,521			43.09			24.41		
CC Highbridge1	CC	Scheduled	04/01/2021 - 04/18/2021	18		3,585,448												
CC Highbridge1	CC	Scheduled	05/22/2021 - 05/27/2021	5		1,000,577												
CC Highbridge1	CC	Scheduled	10/02/2021 - 10/14/2021	12		1,647,465												
Highbridge 1x1 Total				**35**		**6,233,490**				1,306,811			37.07			22.85		
CC Highbridge2	CC	Scheduled	04/01/2021 - 04/19/2021	18		3,667,798												
CC Highbridge2	CC	Scheduled	05/22/2021 - 05/26/2021	5		933,995												
CC Highbridge2	CC	Scheduled	10/04/2021 - 10/08/2021	4		1,225,038												
Highbridge 2x1 Total				**27**		**5,826,831**				1,275,777			37.11			22.98		
CCRiverside1	CC	Scheduled	01/28/2021 - 01/31/2021	3		252,031												
CCRiverside1	CC	Scheduled	04/01/2021 - 04/30/2021	30		4,162,551												
CCRiverside1	CC	Scheduled	06/01/2021 - 06/17/2021	17		3,544,925												
CCRiverside1	CC	Scheduled	06/17/2021 - 06/25/2021	8		1,129,261												
CCRiverside1	CC	Scheduled	11/14/2021 - 11/18/2021	5		698,841												
CCRiverside1	CC	Scheduled	12/04/2021 - 12/22/2021	19		2,858,193												
Riverside 1x1 Total				**81**		**12,645,801**				5,592,239			34.58			22.13		
CCRiverside2	CC	Scheduled	01/28/2021 - 01/31/2021	3		252,027												
CCRiverside2	CC	Scheduled	04/01/2021 - 04/30/2021	30		4,006,931												
CCRiverside2	CC	Scheduled	06/01/2021 - 06/23/2021	23		4,315,995												
CCRiverside2	CC	Scheduled	06/23/2021 - 06/28/2021	5		790,974												
CCRiverside2	CC	Scheduled	12/04/2021 - 12/20/2021	17		3,446,114												
Riverside 2x1 Total				**77**		**12,812,041**				5,326,894			33.73			21.75		
King_G1	Steam	Scheduled	04/22/2021 - 04/30/2021	9		855,887												
King_G1	Steam	Scheduled	10/01/2021 - 10/29/2021	29		9,717,315												
Allen S King Total				**38**		**10,573,201**				1,512,904			51.49			28.60		
SHERCO_G1	Steam	Scheduled	03/03/2021 - 03/31/2021	29		6,177,834												
SHERCO_G1	Steam	Scheduled	04/01/2021 - 04/30/2021	30		7,991,660												
SHERCO_G1	Steam	Scheduled	05/24/2021 - 05/31/2021	8		2,844,143												
SHERCO_G1	Steam	Scheduled	10/10/2021 - 10/14/2021	4		2,163,587												
Sherburne 1 Total				**71**		**19,177,225**				5,754,466			25.03			25.22		
SHERCO_G2	Steam	Scheduled	10/25/2021 - 10/31/2021	7		3,917,691												
SHERCO_G2	Steam	Scheduled	11/01/2021 - 11/05/2021	5		50,670												
Sherburne 2 Total				**12**		**3,968,361**				1,800,101			54.64			23.94		
SHERC3	Steam	Scheduled	05/10/2021 - 05/14/2021	5		985,588												
SHERC3	Steam	Scheduled	10/12/2021 - 10/14/2021	2		355,052												
SHERC3	Steam	Scheduled	10/18/2021 - 10/20/2021	2		157,931												
Sherburne 3 Total				**9**		**1,498,571**				0			31.53					
Monticello_1	Nuclear	Scheduled	03/01/2021 - 03/31/2021	31		716,930												
Monticello_1	Nuclear	Scheduled	04/01/2021 - 04/16/2021	16		1,194,384												
Monticello_1	Nuclear	Scheduled	04/17/2021 - 04/30/2021	14		5,882,889												
Monticello_1	Nuclear	Scheduled	05/01/2021 - 05/12/2021	11		4,369,906												
Monticello Total				**72**		**12,164,108**				6,818,602			24.23			17.81		
Prairie Island 1 Total				**0**		**0**							0.00					
PR_ISLD_2	Nuclear	Scheduled	09/01/2021 - 09/30/2021	30		1,125,717												
PR_ISLD_2	Nuclear	Scheduled	10/01/2021 - 10/29/2021	29		19,261,102												
Prairie Island 2 Total				**59**		**20,386,819**				5,687,649			49.15			17.81		
Total				**498**	**3,129,837**	**107,463,449**	**70,790,315**	**36,673,134**	**1,715,777**	**36,216,965**	**24,433,647**	**11,783,318**	**34.34**	**22.62**	**11.72**	**21.11**	**14.24**	**6.87**

PROTECTED DATA ENDS]

Notes:
(1) Outages/Derates of one day durations or longer and greater than or equal to 500 MWh are included

Northern States Power Company
Expenses Pertaining to Maintenance of Generation Plants

Energy Allocation Ratios	**87.3278%**	**86.7326%**	**86.8963% ****
Demand Allocation Ratios	**87.3461%**	**87.3247%**	**87.3699% ****

			NSP Minnesota Company Totals			**Minnesota Jurisdictional Totals ***		
FERC Account	**Description**	**Allocation Method**	**2016 Test Year**	**2020 Actuals**	**2021 Actuals**	**2016 Test Year**	**2020 Actuals**	**2021 Actuals**
510	Stm Maint Super&Eng	Energy	$ 2,008,848	$ 1,685,793	$ 1,542,150	$ 1,754,283	$ 1,462,132	$ 1,340,072
511	Stm Maint of Structures	Demand	$ 2,784,311	$ 4,793,012	$ 4,399,343	$ 2,431,987	$ 4,185,483	$ 3,843,702
512	Stm Maint of Boiler Plt	Energy	$ 39,704,208	$ 21,090,323	$ 20,006,444	$ 34,672,811	$ 18,292,186	$ 17,384,860
513	Stm Maint of Elec Plant	Energy	$ 4,931,682	$ 5,815,433	$ 7,614,614	$ 4,306,730	$ 5,043,876	$ 6,616,818
514	Stm Maint of Misc Stm Plt	Demand	$ 18,325,365	$ 9,076,136	$ 7,451,290	$ 16,006,492	$ 7,925,709	$ 6,510,184
528	Nuc Maint Super & Eng	Energy	$ 6,183,520	$ 8,157,881	$ 7,690,102	$ 5,399,932	$ 7,075,543	$ 6,682,414
529	Nuc Maint of Structures	Demand	$ 9,368	$ -	$ -	$ 8,183	$ -	$ -
530	Nuc Mtc of React Plt Equip	Energy	$ 48,934,011	$ 36,338,333	$ 32,883,569	$ 42,732,995	$ 31,517,181	$ 28,574,605
531	Nuc Maint of Elect Plant	Energy	$ 13,522,861	$ 13,215,566	$ 12,513,587	$ 11,809,217	$ 11,462,204	$ 10,873,844
532	Nuc Mtc of Misc Nuc Plant	Demand	$ 25,463,010	$ 26,910,874	$ 24,961,813	$ 22,240,946	$ 23,499,840	$ 21,809,111
541	Hydro Mtc Super& Eng	Energy	$ 5,509	$ 739	$ 882	$ 4,811	$ 641	$ 766
542	Hyd Maint of Structures	Demand	$ 22,000	$ 29,164	$ 45,690	$ 19,216	$ 25,468	$ 39,920
543	Hydro Mtc Resv, Dams	Demand	$ 22,000	$ 126,204	$ 66,760	$ 19,216	$ 110,207	$ 58,328
544	Hyd Maint of Elec Plant	Energy	$ 88,144	$ 151,124	$ 180,673	$ 76,974	$ 131,074	$ 156,998
545	Hyd Mt Misc Hyd Plnt Mjr	Demand	$ 59,713	$ 2,894	$ 4,031	$ 52,157	$ 2,527	$ 3,522
551	Oth Maint Super & Eng	Demand	$ 310,346	$ 1,949,100	$ 1,773,070	$ 271,075	$ 1,702,046	$ 1,549,130
552	Oth Maint of Structures	Demand	$ 3,242,151	$ 5,776,245	$ 6,883,128	$ 2,831,892	$ 5,044,089	$ 6,013,782
553	Oth Mtc of Gen & Ele Plant	Demand	$ 17,225,836	$ 9,492,999	$ 10,728,216	$ 15,046,096	$ 8,289,733	$ 9,373,232
554	Oth Mtc Misc Gen Plt Mjr	Demand	$ 1,866,543	$ 6,266,881	$ 11,718,138	$ 1,630,353	$ 5,472,535	$ 10,238,126
Production Maintenance Expense Totals			**$ 184,709,427**	**$ 150,878,701**	**$ 150,463,504**	**$ 161,315,366**	**$ 131,242,472**	**$ 131,069,415**

*Minnesota jurisdictional totals do not reflect Interchange Agreement billings to NSP-Wisconsin.

**Preliminary Minnesota Demand and Energy Allocation Ratios

	Generation Maintenance O&M Costs
2016 Test Year	$ 184,709,427
2019 Actual	$ 150,878,701
2020 Actual	$ 150,463,504

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Power Purchase Agreement Cost
PROTECTED DATA HAS BEEN SHADED

[PROTECTED DATA BEGINS

	Termination	Term (yrs)	Counterparty	MW	Fuel Type	MWh												
						January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021	November 2021	December 2021	Total
Barron County	12/31/2022	10	Barron County Waste-to-Energy Facility	1.865	RDF													
Byllesby 1	2/28/2021	33	Neshkoro Power Associates - Byllesby	1.780	Hydro													
Byllesby 2	2/28/2021	33	Neshkoro Power Associates - Byllesby	0.580	Hydro													
CC Calpine	12/31/2026	20	Mankato Energy Center LLC	375	Gas													
CC Calpine II	5/31/2039	20	Mankato Energy Center II LLC	345	Gas													
CC LSPower	9/30/2027	30	LSP- Cottage Grove, L.P.	245.1	Gas													
CT Invenergy 1	4/10/2025	17	Invenergy Cannon Falls LLC	178.5	Oil/Gas													
CT Invenergy 2	4/10/2025	17	Invenergy Cannon Falls LLC	178.5	Oil/Gas													
DPC Flambeau	1/31/2037	Life of Project	Dairyland Flambeau	2	Hydro													
Deuel Harvest Wind Energy LLC	9/30/2036	15	Duel Harvest Wind Energy LLC	300	Wind													
Eau Galle	7/31/2026	35	Eau Galle Renewable Energy Co. Inc.	0.300	Hydro													
Green Whey Dairy	2/16/2022	10	Green Whey Dairy	3.2	Digester													
Gundersen Lutheran Landfill	2/16/2022	10	Gundersen Lutheran	1.137	Landfill													
Hastings	6/30/2033	45	City of Hastings Hydro	0.450	Hydro													
Heller DairyFarm	5/1/2023	10	Cow Poo LLC	2.7	RDF													
HERC	12/30/2024	28	Hennepin Energy Resource Recovery (HERC)	33.7	Digester													
Koda	5/31/2022	10	KODA Energy, LLC	12	Biomass													
Lac Courte Oreilles	12/31/2021	35	Lac Courte Orielles Band of Lake Superior Chippewa Indians	3.1	Hydro													
Landfill Burnsville	3/31/2020	10	WM Renewable Energy, L.L.C.	4.7	Landfill													
Neshonoc	12/31/2020	33	Neshkoro Power Associates - Neshonoc	0.400	Hydro													
Part 3	4/30/2025	10	Manitoba Hydro Electric Board	Summer: 375, Winter: 325 (Summer = May thru October)	Hydro													
Rapidan	1/20/2020	33	Rapidan Hydro, LLC	2.900	Hydro													
SAF	12/18/2031	20	SAF Hydroelectric, LLC	9.2	Hydro													
Solar Aurora	12/30/2036	20	Aurora Distributed Solar	100	Solar													
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													
Wind CBED Adams	3/8/2031	20	Adams Wind Generations, LLC	19.8	Wind													
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													
Wind CBED Hilltop	2/19/2029	20	Hilltop Power	2	Wind													
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 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													

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company
Electric Utility - State of Minnesota
Power Purchase Agreement Cost
PROTECTED DATA HAS BEEN SHADED

[PROTECTED DATA BEGINS

						MWh												
	Termination	Term (yrs)	Counterparty	MW	Fuel Type	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021	November 2021	December 2021	Total
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													
Wind Moraine II	2/17/2029	10	Moraine Wind II LLC	49.5	Wind													
Wind Norgaard	5/10/2026	20	Roadrunner ,I LLC, Salty Dog-I LLC, Wallys Windfarm LLC, Windy Dog I LLC, Breezy Bucks-I & II LLC, Salty Dog II, LLC	8.75	Wind													
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													
Wind Shaokatan	4/30/2034	30	Northern Alternative Enrgy Shakotan Hills LLC	11.88	Wind													
Wind Source Cisco	5/27/2028	20	Cisco Wind Energy LLC	8	Wind													
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													
Wind Stahl	12/31/2024	20	Stahl Wind Energy LLC, Northern Lights Wind LLC, Lucky Wind LLC, Greenback Energy LLC Cartensen Wind LLC	8.25	Wind													
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													
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													
Wind Crown Ridge	1/9/2045	25	Crowned Ridge Wind, LLC	200	Wind													
Wind Clean Energy	12/31/2039	20	ALLETE Clean Energy, Inc.	106.08	Wind													
Wind Dakota Range III	4/30/2033	20	DAKOTA RANGE III, LLC	153.6	Wind													

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Power Purchase Agreement Cost
PROTECTED DATA HAS BEEN SHADED

						$ Energy and Curtailment														
	Termination	Term (yrs)	Counterparty	MW	Fuel Type	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021	November 2021	December 2021	Total	$/MWH	Total Capacity $
						[PROTECTED DATA BEGINS														
Barron County	12/31/2022	10	Barron County Waste-to-Energy Facility	1.865	RDF															
Byllesby 1	2/28/2021	33	Neshkoro Power Associates - Byllesby	1.780	Hydro															
Byllesby 2	2/28/2021	33	Neshkoro Power Associates - Byllesby	0.580	Hydro															
CC Calpine	12/31/2026	20	Mankato Energy Center LLC	375	Gas															
CC Calpine II	5/31/2039	20	Mankato Energy Center II LLC	345	Gas															
CC LSPower	9/30/2027	30	LSP- Cottage Grove, L.P.	245.1	Gas															
CT Invenergy 1	4/10/2025	17	Invenergy Cannon Falls LLC	178.5	Oil/Gas															
CT Invenergy 2	4/10/2025	17	Invenergy Cannon Falls LLC	178.5	Oil/Gas															
DPC Flambeau	1/31/2037	Life of Project	Dairyland Flambeau	2	Hydro															
Deuel Harvest Wind Energy LLC	9/30/2036	15	Duel Harvest Wind Energy LLC	300	Wind															
Eau Galle	7/31/2026	35	Eau Galle Renewable Energy Co. Inc.	0.300	Hydro															
Green Whey Dairy	2/16/2022	10	Green Whey Dairy	3.2	Digester															
Gundersen Lutheran Landfill	2/16/2022	10	Gundersen Lutheran	1.137	Landfill															
Hastings	6/30/2033	45	City of Hastings Hydro	0.450	Hydro															
Heller DairyFarm	5/1/2023	10	Cow Poo LLC	2.7	RDF															
HERC	12/30/2024	28	Hennepin Energy Resource Recovery (HERC)	33.7	Digester															
Koda	5/31/2022	10	KODA Energy, LLC	12	Biomass															
Lac Courte Oreilles	12/31/2021	35	Lac Courte Orielles Band of Lake Superior Chippewa Indians	3.1	Hydro															
Landfill Burnsville	3/31/2020	10	WM Renewable Energy, L.L.C.	4.7	Landfill															
Neshonoc	12/31/2020	33	Neshkoro Power Associates - Neshonoc	0.400	Hydro															
Part 3	4/30/2025	10	Manitoba Hydro Electric Board	Summer: 375, Winter: 325 (Summer = May thru October)	Hydro															
Rapidan	1/20/2020	33	Rapidan Hydro, LLC	2.900	Hydro															
SAF	12/18/2031	20	SAF Hydroelectric, LLC	9.2	Hydro															
Solar Aurora	12/30/2036	20	Aurora Distributed Solar	100	Solar															
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															
Wind CBED Adams	3/8/2031	20	Adams Wind Generations, LLC	19.8	Wind															
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															
Wind CBED Hilltop	2/19/2029	20	Hilltop Power	2	Wind															
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 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															

PROTECTED DATA ENDS]

Northern States Power Company
Electric Utility - State of Minnesota
Power Purchase Agreement Cost
PROTECTED DATA HAS BEEN SHADED

						$ Energy and Curtailment														
	Termination	Term (yrs)	Counterparty	MW	Fuel Type	January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021	November 2021	December 2021	Total	$/MWH	Total Capacity $
						[PROTECTED DATA BEGINS														
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															
Wind Moraine II	2/17/2029	10	Moraine Wind II LLC	49.5	Wind															
Wind Norgaard	5/10/2026	20	Roadrunner ,I LLC, Salty Dog-I LLC, Wallys Windfarm LLC, Windy Dog I LLC, Breezy Bucks-I & II LLC, Salty Dog II, LLC	8.75	Wind															
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															
Wind Shaokatan	4/30/2034	30	Northern Alternative Enrgy Shakotan Hills LLC	11.88	Wind															
Wind Source Cisco	5/27/2028	20	Cisco Wind Energy LLC	8	Wind															
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															
Wind Stahl	12/31/2024	20	Stahl Wind Energy LLC, Northern Lights Wind LLC, Lucky Wind LLC, Greenback Energy LLC Cartensen Wind LLC	8.25	Wind															
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															
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															
Wind Crown Ridge	1/9/2045	25	Crowned Ridge Wind, LLC	200	Wind															
Wind Clean Energy	12/31/2039	20	ALLETE Clean Energy, Inc.	106.08	Wind															
Wind Dakota Range III	4/30/2033	20	DAKOTA RANGE III, LLC	153.6	Wind															

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 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."

At the end of 2021, there were 426 active Community Solar Gardens in-service and 42 of these came on-line during the 2021 AAA 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 community solar garden receives permission to operate, there were a total of 420 gardens receiving bill credits during this reporting period. A total of $183,770,144 in Community Solar Gardens bill credits were included in this year's FCA. The corresponding subscribed and unsubscribed energy bill credits were $183,241,694 and $528,450 respectively. The Community Solar Gardens expenses included in the FCA are shown in Part C, Attachment 10. We note that total Community Solar Gardens expenses included in FCA recovery during the AAA reporting period may vary from other CSG reporting due to 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 2021 AAA period:

	System	MN Amount[1]	Estimated MN Retail Allocator
Market	$73,005,988	$52,529,317	0.717350
Above Market	$110,764,156	$110,764,156	1.000000
Total	$183,770,144	$163,293,473	

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, 2021 in Docket No. E002/M-13-867, and the next report is due on April 1, 2022.

[1] $118,200 in solar gardens developer late fees were credited to the FCA. This credit has resulted in a net solar garden cost recovery of $110,645,956 during the AAA reporting period.

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
1	Le Sueur	9/9/2015	0.036	149
2	Lincoln	4/25/2016	0.204	304
3	Ramsey	5/12/2016	0.125	161
4	Hennepin	8/22/2016	0.036	55
5	Chisago	12/14/2016	5	30
6	Dakota	12/14/2016	5	64
7	Chisago	12/15/2016	4	59
8	Dakota	12/20/2016	5	82
9	Carver	12/21/2016	5	49
10	Dakota	12/22/2016	5	59
11	Scott	12/22/2016	3	46
12	Stearns	1/4/2017	3	42
13	Stearns	1/5/2017	3	55
14	Goodhue	1/12/2017	4.86	52
15	Dakota	1/13/2017	5	80
16	Chisago	1/13/2017	3.888	61
17	Stearns	1/20/2017	5	29
18	Carver	2/28/2017	4.86	62
19	Goodhue	3/2/2017	4	71
20	Washington	3/10/2017	0.036	64
21	Wabasha	3/13/2017	3	51
22	Dakota	3/15/2017	5	81
23	Wright	3/28/2017	1	86
24	Blue Earth	5/31/2017	3	53
25	Redwood	5/31/2017	3	32
26	Winona	5/31/2017	0.25	38
27	Rice	6/30/2017	5	63
28	Dodge	7/18/2017	5	73
29	Washington	7/18/2017	5	67
30	Olmsted	7/19/2017	5	77
31	Kandiyohi	8/14/2017	2	27
32	Pipestone	8/18/2017	2	57
33	Chisago	8/22/2017	3	72
34	Stearns	8/24/2017	2	1643
35	Chippewa	8/29/2017	2	1345
36	Dakota	8/31/2017	5	290
37	Pope	9/13/2017	5	663
38	Stearns	9/13/2017	2.188	1053
39	Stearns	9/13/2017	4.86	462
40	Lincoln	9/14/2017	0.2	470

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
41	Sherburne	9/22/2017	5	777
42	Dodge	9/27/2017	4	1150
43	Benton	9/29/2017	2	499
44	McLeod	10/25/2017	3	113
45	Hennepin	10/25/2017	5	1169
46	McLeod	10/26/2017	5	47
47	Pipestone	10/30/2017	5	53
48	Stearns	10/30/2017	3	67
49	Benton	10/30/2017	5	5
50	Wright	11/3/2017	5	30
51	Stearns	11/9/2017	5	27
52	Wright	11/13/2017	5	196
53	Chippewa	11/14/2017	3	86
54	Stearns	11/16/2017	4	301
55	Nicollet	11/20/2017	5	383
56	Blue Earth	11/20/2017	5	533
57	Scott	11/30/2017	4.69	65
58	Scott	11/30/2017	0.7	34
59	Dakota	11/30/2017	2.7	26
60	Rice	11/30/2017	5	98
61	Stearns	12/13/2017	5	204
62	Chisago	12/13/2017	5	426
63	Carver	12/15/2017	5	265
64	Chisago	12/18/2017	5	226
65	Dodge	12/18/2017	5	516
66	Scott	12/20/2017	2.991	483
67	Carver	12/21/2017	4.361	204
68	Renville	12/28/2017	3	297
69	Washington	1/10/2018	5	221
70	Carver	1/16/2018	3	185
71	Le Sueur	1/18/2018	3	283
72	Dakota	1/23/2018	4.95	58
73	Wabasha	1/29/2018	4	82
74	Pipestone	1/31/2018	4.7	70
75	Sherburne	2/12/2018	3.25	219
76	Rice	2/14/2018	0.998	35
77	Le Sueur	2/23/2018	3	86
78	Carver	2/26/2018	1.996	92
79	Waseca	2/26/2018	5	63
80	Rice	2/28/2018	5	83

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
81	Le Sueur	2/28/2018	5	107
82	Washington	2/28/2018	4	87
83	Faribault	3/2/2018	1.84	719
84	Rice	3/2/2018	3	67
85	Steele	3/5/2018	3.4	151
86	Carver	3/6/2018	3	187
87	Chisago	3/13/2018	5	60
88	Carver	3/14/2018	0.998	30
89	Sherburne	3/14/2018	5	59
90	Pope	3/15/2018	5	147
91	Benton	3/25/2018	2	172
92	Scott	3/28/2018	4.95	142
93	Goodhue	4/12/2018	0.8	192
94	Pope	4/19/2018	3	41
95	Washington	4/20/2018	5	55
96	Goodhue	4/26/2018	0.998	8
97	Chisago	4/30/2018	3	61
98	Stearns	4/30/2018	5	37
99	Sherburne	4/30/2018	4	75
100	Goodhue	5/11/2018	1	20
101	Renville	5/16/2018	1	212
102	Renville	5/17/2018	1	25
103	Goodhue	5/22/2018	1	44
104	Blue Earth	5/30/2018	1	74
105	Steele	6/5/2018	1	30
106	Hennepin	6/6/2018	0.18	39
107	Chippewa	6/15/2018	4	135
108	Lyon	6/15/2018	3	49
109	Rice	6/20/2018	1	693
110	Le Sueur	6/29/2018	3	47
111	Sherburne	6/29/2018	5	79
112	Watonwan	7/2/2018	0.25	8
113	Sherburne	7/13/2018	5	31
114	Washington	7/16/2018	2.5	69
115	Steele	7/18/2018	1	61
116	Goodhue	7/19/2018	5	62
117	Washington	7/24/2018	3	87
118	Dakota	7/27/2018	5	16
119	Goodhue	7/30/2018	2	26
120	Chisago	8/1/2018	1	247

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
121	Douglas	8/2/2018	5	554
122	Le Sueur	8/6/2018	5	124
123	Blue Earth	8/7/2018	3.54	153
124	Chisago	8/9/2018	5	137
125	Wright	8/14/2018	0.972	338
126	Benton	8/14/2018	4.95	91
127	Carver	8/16/2018	4	129
128	Wright	8/27/2018	5	137
129	Chisago	8/30/2018	1	204
130	Washington	9/4/2018	5	154
131	Washington	9/7/2018	0.75	82
132	Goodhue	9/14/2018	1	138
133	Dakota	9/17/2018	0.75	212
134	Goodhue	9/19/2018	1	69
135	Waseca	9/27/2018	1	73
136	Chisago	9/28/2018	1	288
137	Chisago	9/28/2018	1	39
138	Hennepin	9/28/2018	0.32	368
139	Blue Earth	10/16/2018	5	94
140	Wright	10/17/2018	4	83
141	McLeod	10/25/2018	1	20
142	Waseca	10/25/2018	1	61
143	Washington	10/29/2018	4.875	36
144	Benton	10/30/2018	1	133
145	Waseca	11/1/2018	1	17
146	Chippewa	11/14/2018	1	6
147	Kandiyohi	11/14/2018	1	27
148	Pope	11/16/2018	1	130
149	Sherburne	11/16/2018	1	19
150	Chisago	11/26/2018	1	30
151	Chisago	11/27/2018	1	58
152	Wright	11/28/2018	5	83
153	Scott	11/28/2018	0.823	75
154	Hennepin	11/28/2018	0.527	6
155	Scott	11/28/2018	1	13
156	Chisago	11/28/2018	1	111
157	Chisago	11/28/2018	1	24
158	Chisago	11/29/2018	1	13
159	Sherburne	12/3/2018	5	8
160	Chisago	12/7/2018	1	15

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
161	Sherburne	12/10/2018	4.8	20
162	Chisago	12/11/2018	0.5	8
163	Stearns	12/17/2018	1	38
164	Benton	12/17/2018	1	16
165	Benton	12/17/2018	1	148
166	Chippewa	12/18/2018	1	12
167	Le Sueur	12/19/2018	1	29
168	Murray	12/20/2018	1	9
169	Murray	12/20/2018	1	60
170	Yellow Medicine	12/21/2018	5	35
171	Ramsey	1/8/2019	0.54	19
172	Dodge	1/9/2019	1	10
173	Hennepin	1/11/2019	5	36
174	Meeker	1/23/2019	0.76	22
175	Stearns	1/28/2019	0.324	10
176	Nicollet	1/31/2019	1	16
177	Waseca	2/13/2019	1	120
178	Chisago	2/27/2019	2	12
179	Stearns	3/4/2019	0.72	11
180	Stearns	3/4/2019	1	7
181	Blue Earth	3/5/2019	0.24	10
182	McLeod	3/12/2019	3	17
183	Washington	3/22/2019	1	150
184	Stearns	3/25/2019	1	152
185	Wabasha	3/26/2019	0.85	20
186	Pope	3/26/2019	1	23
187	Sherburne	3/28/2019	5	10
188	Pope	3/28/2019	1	11
189	Renville	3/29/2019	1	21
190	Goodhue	4/11/2019	5	16
191	Stearns	4/16/2019	1	92
192	Chisago	4/22/2019	3	52
193	Washington	4/22/2019	1	8
194	Wright	4/29/2019	5	16
195	Rice	4/30/2019	1	21
196	Carver	5/1/2019	1	17
197	Lyon	5/3/2019	1	15
198	Benton	5/13/2019	5	9
199	Dodge	5/15/2019	1	80
200	Dodge	5/15/2019	0.4	24

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
201	Kandiyohi	5/21/2019	1	15
202	Chisago	5/21/2019	1	36
203	Wright	5/31/2019	5	37
204	Stearns	6/3/2019	5	129
205	Dakota	6/7/2019	5	22
206	Dakota	6/7/2019	5	15
207	Sibley	6/14/2019	3.25	38
208	Stearns	6/18/2019	3	21
209	Freeborn	6/18/2019	0.25	12
210	Chisago	7/3/2019	1	19
211	Carver	7/22/2019	1	21
212	Scott	7/24/2019	0.598	111
213	Carver	7/25/2019	1	400
214	Sherburne	7/26/2019	3	29
215	Hennepin	7/30/2019	0.18	22
216	Sherburne	7/31/2019	0.996	37
217	Dakota	8/6/2019	1	156
218	Rice	8/8/2019	1	68
219	Scott	8/13/2019	1	12
220	Chisago	8/16/2019	0.998	6
221	Stearns	8/16/2019	1	21
222	Stearns	8/16/2019	1	128
223	Wabasha	8/20/2019	1	34
224	Wabasha	8/20/2019	1	85
225	Winona	8/21/2019	5	13
226	Winona	8/22/2019	1	193
227	Wabasha	8/22/2019	1	25
228	Winona	8/22/2019	1	59
229	Chippewa	8/26/2019	1	18
230	Carver	8/29/2019	1	17
231	McLeod	8/30/2019	1	83
232	Chisago	9/3/2019	1	20
233	Waseca	9/6/2019	1	244
234	Olmsted	9/9/2019	1	97
235	Pope	9/11/2019	1	69
236	Pope	9/11/2019	1	14
237	Hennepin	9/18/2019	0.96	9
238	Rice	9/18/2019	1	184
239	Blue Earth	9/24/2019	0.62	148
240	Goodhue	9/27/2019	4.4	10

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
241	Blue Earth	9/27/2019	0.62	200
242	Rice	10/9/2019	1	18
243	Stearns	10/23/2019	1	15
244	Stearns	10/25/2019	4.75	18
245	Sherburne	10/29/2019	1	5
246	Scott	10/30/2019	0.4	154
247	Waseca	11/18/2019	0.996	20
248	Sherburne	11/26/2019	1	11
249	Stearns	12/3/2019	1	200
250	Meeker	12/11/2019	1	22
251	Dakota	12/11/2019	1	190
252	Douglas	12/11/2019	1	13
253	Meeker	12/13/2019	1	203
254	Rice	12/13/2019	1	46
255	Pope	12/16/2019	1	174
256	Stearns	12/16/2019	1	239
257	Nicollet	12/18/2019	1	22
258	Blue Earth	12/18/2019	1	215
259	McLeod	12/18/2019	1	195
260	Chisago	12/19/2019	1	27
261	Stearns	12/23/2019	1	202
262	Sherburne	12/23/2019	1	47
263	Sherburne	12/26/2019	1	216
264	Stearns	12/27/2019	1	14
265	Douglas	12/27/2019	1	16
266	McLeod	12/27/2019	1	10
267	Renville	12/30/2019	1	32
268	Sherburne	12/30/2019	1	180
269	Goodhue	12/31/2019	0.59	236
270	Winona	1/3/2020	1	22
271	Winona	1/3/2020	1	160
272	Stearns	1/13/2020	1	17
273	Rice	1/14/2020	1	219
274	Dakota	1/15/2020	1	34
275	Meeker	1/17/2020	1	211
276	Winona	2/12/2020	1	39
277	Goodhue	2/13/2020	1	203
278	Pope	2/17/2020	1	33
279	Hennepin	2/17/2020	1	60
280	Rice	2/20/2020	1	7

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
281	Goodhue	2/26/2020	1	9
282	Pope	2/26/2020	1	24
283	Waseca	2/27/2020	1	8
284	Goodhue	2/28/2020	1	15
285	Goodhue	2/28/2020	1	17
286	Sherburne	2/28/2020	1	25
287	Waseca	3/4/2020	1	7
288	Washington	3/9/2020	3	31
289	Goodhue	3/9/2020	1	16
290	Rice	3/20/2020	1	20
291	Sibley	3/26/2020	1	35
292	Dakota	3/26/2020	1	58
293	Sibley	4/3/2020	1	9
294	Olmsted	4/3/2020	1	38
295	Dodge	4/7/2020	1	29
296	Douglas	4/9/2020	1	32
297	Olmsted	4/13/2020	1	7
298	Olmsted	4/16/2020	1	12
299	Rice	4/24/2020	0.96	16
300	Scott	4/27/2020	3	40
301	Rice	4/27/2020	1	17
302	Goodhue	4/30/2020	1	38
303	Chisago	5/19/2020	1	97
304	Benton	5/20/2020	1	8
305	Stearns	5/21/2020	1	16
306	Dodge	5/21/2020	1	32
307	Carver	5/28/2020	1	9
308	Pope	5/30/2020	1	15
309	Dakota	6/2/2020	1	18
310	Dakota	6/4/2020	1	11
311	Waseca	6/16/2020	1	12
312	Rice	6/17/2020	2	12
313	Winona	6/24/2020	1	12
314	Winona	6/24/2020	1	16
315	Benton	7/10/2020	1	31
316	Rice	7/13/2020	5	10
317	Rice	7/20/2020	4	31
318	McLeod	7/20/2020	4	12
319	Nicollet	7/30/2020	1	16
320	Goodhue	7/30/2020	1	17

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
321	Stearns	7/31/2020	1	21
322	Wright	7/31/2020	1	14
323	Le Sueur	7/31/2020	1	11
324	Sherburne	7/31/2020	1	16
325	Goodhue	8/18/2020	1	26
326	Sherburne	9/1/2020	1	21
327	Redwood	9/14/2020	0.86	22
328	Chisago	9/14/2020	1	15
329	Waseca	9/15/2020	1	17
330	Chippewa	9/16/2020	1	21
331	Redwood	9/16/2020	1	26
332	Waseca	9/21/2020	1	18
333	Steele	9/22/2020	1	29
334	Nicollet	9/22/2020	1	20
335	Redwood	9/28/2020	1	10
336	Washington	9/28/2020	1	21
337	Freeborn	9/29/2020	1	13
338	Wright	10/1/2020	1	11
339	Dodge	10/6/2020	1	29
340	Dakota	10/6/2020	1	11
341	Clay	10/8/2020	1	13
342	Clay	10/8/2020	1	24
343	Clay	10/8/2020	1	11
344	Clay	10/8/2020	1	29
345	Nicollet	10/8/2020	1	8
346	Benton	10/14/2020	1	11
347	Rice	10/15/2020	1	12
348	Kandiyohi	10/19/2020	1	22
349	Kandiyohi	10/19/2020	1	13
350	Washington	10/20/2020	1	15
351	Clay	10/21/2020	1	16
352	Goodhue	10/26/2020	1	20
353	Waseca	10/27/2020	1	9
354	Renville	10/29/2020	1	41
355	Freeborn	10/30/2020	1	15
356	Chippewa	10/30/2020	1	46
357	Benton	11/3/2020	1	22
358	Dakota	11/4/2020	1	24
359	Goodhue	11/5/2020	1	17
360	Olmsted	11/9/2020	1	14

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
361	Dodge	11/9/2020	1	18
362	Sherburne	11/10/2020	1	23
363	Dodge	11/16/2020	1	17
364	Goodhue	11/19/2020	1	20
365	Rice	11/19/2020	1	11
366	Dodge	11/23/2020	1	15
367	Winona	11/30/2020	1	18
368	Stearns	12/1/2020	1	0
369	Renville	12/4/2020	1	15
370	McLeod	12/4/2020	1	32
371	Lyon	12/7/2020	1	0
372	Chisago	12/9/2020	1	21
373	Stearns	12/9/2020	1	17
374	Carver	12/10/2020	1	18
375	Chisago	12/11/2020	1	13
376	Pope	12/14/2020	1	14
377	Pope	12/14/2020	1	7
378	Stearns	12/16/2020	1	0
379	Nicollet	12/17/2020	1	19
380	Rice	12/21/2020	1	30
381	Pope	12/21/2020	1	53
382	Pope	12/28/2020	1	62
383	McLeod	12/30/2020	0.7	16
384	Dodge	1/4/2021	1	12
385	Dodge	1/4/2021	1	8
386	Waseca	1/6/2021	1	13
387	Le Sueur	1/28/2021	1	16
388	Kandiyohi	2/2/2021	1	20
389	Blue Earth	3/2/2021	0.94	11
390	Stearns	3/22/2021	0.86	20
391	Rice	3/23/2021	0.83	16
392	Rice	3/25/2021	1	18
393	Redwood	3/31/2021	1	15
394	Redwood	3/31/2021	0.86	16
395	Waseca	4/7/2021	1	34
396	Benton	4/21/2021	1	13
397	Benton	4/22/2021	1	24
398	Sherburne	6/2/2021	1	23
399	Washington	6/8/2021	1	13
400	Steele	6/16/2021	1	100

	Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions (Dec. 2021)
401	Rice	7/9/2021	1	216
402	Wright	7/13/2021	4	116
403	Dodge	7/13/2021	0.78	39
404	Pope	7/20/2021	1	14
405	Renville	7/20/2021	1	18
406	Chisago	7/21/2021	1	15
407	Renville	7/21/2021	1	27
408	McLeod	7/21/2021	1	196
409	Chisago	8/3/2021	1	18
410	Chisago	8/3/2021	1	114
411	Pipestone	8/5/2021	1	104
412	Goodhue	8/13/2021	0.29	14
413	Benton	8/19/2021	1	19
414	Le Sueur	9/2/2021	1	30
415	Pope	9/23/2021	1	50
416	Goodhue	9/28/2021	1	14
417	Le Sueur	9/29/2021	1	129
418	Pope	10/5/2021	1	8
419	McLeod	10/12/2021	1	15
420	Le Sueur	10/22/2021	1	158
421	Blue Earth	11/30/2021	1	9
422	Renville	11/30/2021	1	73
423	Goodhue	11/30/2021	1	18
424	Chisago	12/8/2021	1	53
425	Chisago	12/8/2021	1	16
426	Chisago	12/16/2021	1	79

2021 Minnesota Jurisdictional Solar Gardens Program Cost Recovery Through Fuel Clause Rider

	January	February	March	Apri	May	June	July	August	September	October	November	December	Total 2021
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	$3,664,933	$3,120,459	$11,192,478	$6,263,675	$4,363,603	$15,230,696	$7,110,421	$5,640,286	$7,308,582	$4,329,133	$4,415,259	($161,987)	$72,477,538
[2] Solar Gardens Unsubscribed Energy <40 KW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
[3] Solar Gardens Unsubscribed Energy > 40 KW	$43,074	$87,259	$3,855	$9,942	$76,060	$9,739	$28,694	$46,153	$157,854	$35,799	$21,988	$8,031	$528,450
[4] Total Costs (System) [1]+[2]+[3]	$3,708,007	$3,207,718	$11,196,333	$6,273,617	$4,439,663	$15,240,436	$7,139,115	$5,686,439	$7,466,435	$4,364,932	$4,437,247	($153,955)	$73,005,988
Above Market Amount Recoverable in Minnesota Jurisdiction													
[5] Minnesota Direct Assigned Above Market Amount	$5,939,783	$5,633,105	$7,637,921	$6,049,883	$15,371,054	$13,699,998	$12,971,464	$13,634,885	$10,510,369	$7,184,180	$6,490,869	$5,640,645	$110,764,156
[6] **Total Bill Credits & Unsubscribed Energy Payments** [4]+[5]	**$9,647,790**	**$8,840,823**	**$18,834,254**	**$12,323,500**	**$19,810,717**	**$28,940,434**	**$20,110,579**	**$19,321,325**	**$17,976,804**	**$11,549,113**	**$10,928,116**	**$5,486,690**	**$183,770,144**
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]	**$5,939,783**	**$5,633,105**	**$7,637,921**	**$6,049,883**	**$15,371,054**	**$13,699,998**	**$12,971,464**	**$13,634,885**	**$10,510,369**	**$7,184,180**	**$6,490,869**	**$5,640,645**	**$110,764,156**
MWh Sales Weighting													
[8] Minnesota Jurisdiction Retail MWh Subject to FCA	2,302,412	2,111,340	2,187,920	1,943,763	2,226,221	2,712,853	2,850,947	2,848,011	2,282,281	2,265,386	2,166,920	2,297,815	28,195,869
[9] NSP System MWh Sales Exclude Windsource & Renewable*Connect	3,256,245	3,012,069	3,099,533	2,738,990	3,083,470	3,718,805	3,912,749	3,897,196	3,144,957	3,141,891	3,037,213	3,262,486	39,305,604
[10] Allocation Weighting [8]/[9]	70.7076%	70.0960%	70.5887%	70.9664%	72.1986%	72.9496%	72.8630%	73.0785%	72.5695%	72.1026%	71.3457%	70.4314%	71.7350%
Market Bill Credits and Payments Allocated to MN Fuel Clause Recovery													
[11] Market Amount Allocated to All Jurisdictions [4]	$3,708,007	$3,207,718	$11,196,333	$6,273,617	$4,439,663	$15,240,436	$7,139,115	$5,686,439	$7,466,435	$4,364,932	$4,437,247	($153,955)	$73,005,988
[12] Allocation Weighting [10]	70.7076%	70.0960%	70.5887%	70.9664%	72.1986%	72.9496%	72.8630%	73.0785%	72.5695%	72.1026%	71.3457%	70.4314%	71.7350%
[13] Market Amount Allocated to Minnesota Jurisdiction [11]*[12]	**$2,621,842**	**$2,248,482**	**$7,903,346**	**$4,452,161**	**$3,205,373**	**$11,117,835**	**$5,201,775**	**$4,155,563**	**$5,418,358**	**$3,147,231**	**$3,165,784**	**($108,433)**	**$52,529,317**
Total Solar Gardens Costs Recovery Included in MN Fuel Cost Charge													
[14] Market and Above Market Allocated Amount [17]+[13]	**$8,561,625**	**$7,881,587**	**$15,541,266**	**$10,502,044**	**$18,576,427**	**$24,817,834**	**$18,173,239**	**$17,790,448**	**$15,928,727**	**$10,331,411**	**$9,656,652**	**$5,532,212**	**$163,293,473**
[15] **Solar Gardens Developer Late Fees (Credit Back to MN Customers)**	**$0**	**$0**	**$1,200**	**$0**	**$97,600**	**$0**	**$0**	**$0**	**$19,400**	**$0**	**$0**	**$0**	**$118,200**
[16] **Net Solar Gardens Costs Recovery Included in MN Fuel Cost Charge**	**$8,561,625**	**$7,881,587**	**$15,540,066**	**$10,502,044**	**$18,478,827**	**$24,817,834**	**$18,173,239**	**$17,790,448**	**$15,909,327**	**$10,331,411**	**$9,656,652**	**$5,532,212**	**$163,175,273**
Market Bill Credits and Payments Allocated to Other Jurisdictions													
[17] Cost Allocated to Other Jurisdictions (Market Portion Based on LMP) [4]-[1	$1,086,165	$959,236	$3,292,987	$1,821,456	$1,234,290	$4,122,600	$1,937,340	$1,530,877	$2,048,077	$1,217,701	$1,271,463	($45,522)	$20,476,671
Direct Assigned Minnesota Cost Removed from System Cost													
[18] Minnesota Direct Assigned Above Market Amount [5]	$5,939,783	$5,633,105	$7,637,921	$6,049,883	$15,371,054	$13,699,998	$12,971,464	$13,634,885	$10,510,369	$7,184,180	$6,490,869	$5,640,645	$110,764,156
[19] Solar Gardens Developer Late Fees (Credit Back to MN Customers) [15]	$0	$0	$1,200	$0	$97,600	$0	$0	$0	$19,400	$0	$0	$0	$118,200
[20] Direct Assigned Minnesota Cost Removed from System Cost [18]-[19]	**$5,939,783**	**$5,633,105**	**$7,636,721**	**$6,049,883**	**$15,273,454**	**$13,699,998**	**$12,971,464**	**$13,634,885**	**$10,490,969**	**$7,184,180**	**$6,490,869**	**$5,640,645**	**$110,645,956**

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 market price for uranium started 2022 at $42.10 per pound, which is an increase of $12.10 as compared to the beginning of 2021. During the early part of first quarter of 2022, the spot market price has ranged from $42.10 per pound to a high of $45.75 per pound in mid-January. As of the later part of January, the market price is reported at $44.50 per pound. This market volatility is mainly due to geopolitical uncertainties due to recent unrest in Kazakhstan.

Despite the continued strength in market prices, the current prices are at a level that is impacting the forecast levels of uranium production. Existing supply in the marketplace has decreased through mines that remained closed, reduction of production at mines throughout the world due to impacts from COVID-19, buying by producers in the early part of 2021 to fulfill contractual obligations, and increased buying in the later part of 2021 by financial investors through investment trusts and hedge funds. Throughout 2021 and continuing into 2022, Uranium production issues remain of concern as the impact of supply chain and transportation challenges due to the COVID-19. Unpredicted differences between supply and demand is projected to be covered by end user inventories in 2022 and 2023. Spot market volume at 96.1

million pounds of U_3O_8 for 2021 is above the record amount of 94.5 million pounds of U_3O_8 for 2020. Volume in December 2021 declined from record levels in the previous months of 2021 and spot market prices also declined in the later part of 2021 from the high of $50.25 per pound that occurred in September 2021. Spot market volumes in 2022 are predicted to range from 56 – 101 million pounds, Spot market volumes in 2023 are projected to decrease slightly to a range of 53 to 96 million pounds. For the rest of 2022 and into 2023, strong demand from financial investors is expected to exert upward pressure on the spot market price. Prices for the rest of 2022 and into 2023 are projected to range between $38 to $52 per pound. The current market analysis forecasts supply and inventories meeting demand until about 2026, but will continue to be dependent on the willingness of suppliers to bring new supply into the market, as well as the interest of financial investors to continue their investment in the uranium market.

The potential western sanctions against Russia 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 2021. If sanctions 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 be significantly impacted. A list of current nuclear fuel components of service contracts is shown on Part D, Attachment 2.

C. Natural Gas

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 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 cost changes. Delivered wood fuel costs have seen a modest decline in price recently, primarily due to fuel switching to low-cost natural gas by many biomass fuel consumers such as wood product and paper mills. 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, Minnesota, and French Island, Wisconsin). See Part D, Attachment 5 for a listing of the contracts, and Part D, Attachment 6 for a listing of 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 LaCrosse. 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.

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Nuclear Fuel Components of Services for the Period of January through December 2021

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

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

	[PROTECTED DATA BEGINS			
12				
13				
14				
15				
16				
17				
				PROTECTED DATA ENDS]

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				
3				
4				
5				
6				
7				
8				
9				
10				
				PROTECTED DATA ENDS]

PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

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]

	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				
				PROTECTED DATA ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[PROTECTED DATA BEGINS				
23				
24				
25				
26				
27				
28				
29				
30				
31				
				PROTECTED DATA ENDS]

Cost Changes – January 1, 2021 to January 1, 2022

	Contract	Percent Change
[PROTECTED DATA BEGINS		

PROTECTED DATA ENDS]

Cost Changes – January 1, 2021 to January 1, 2022

	Contract*	Percent Change
[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, 2021 compared to the contract price on January 1, 2022.

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 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 wind will be on the system at a given time. The Company developed a wind generation forecasting tool in partnership with the National Center for Atmospheric Research. Xcel Energy uses this tool to forecast output from all NSP system wind farms, resulting in a reduction of wind forecast error. Similarly, Xcel Energy uses a solar forecast developed in conjunction with Global Weather Corporation (GWC) to estimate production from NSP system solar facilities. Reductions in forecast error translate directly into a long term decrease in fuel and purchased power costs because improved forecast 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 2021.

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

3. A contract was executed in **[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 $1.92/MBtu during 2020. (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 2019 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 2021, the Company disputed approximately 0 days of 0 MISO invoices.

The total dollar amount disputed in the 2021 AAA period is lower than in the 2020 AAA period. Discrepancies not requiring a formal dispute are routinely resolved through the normal settlement process.

CONSERVATION IMPROVEMENT PROGRAM

Xcel Energy's Conservation Improvement Program (CIP) is designed to help our customers use energy wisely. The Company has developed nearly 40 commercial and residential CIP 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 CIP. CIP programs are subject to regulation by the Minnesota Department of Commerce (Department). Currently, the Company offers a wide variety of programs that assist customers in implementing CIP 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, a CIP 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 2021-2023 CIP Triennial Plan, which was filed on July 1, 2020 and approved on November 25, 2020.[1]

On April 1 of each year, the Company is required to file with the Department an annual CIP Status Report, which details the cost-effectiveness and spending for the prior year's CIP program. The Deputy Commissioner issued approval of the Company's 2020 CIP Status Report on July 8, 2021.[2]

[1] Docket No. E,G002/CIP-20-473
[2] Docket No. E,G002/CIP-16-115.09

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)[1] are transmission-owning members of MISO. NSPM and NSPW (the NSP Companies) 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.

[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."

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[SM]

414 Nicollet Mall
Minneapolis, MN 55401

February 7, 2022

Judith Dockendorf
Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

**RE: 2021 ANNUAL AUTOMATIC ADJUSTMENT (AAA) CHARGES REPORT – ELECTRIC OPERATION
DOCKET NO. E002/AA-20-417**

Dear Ms. Dockendorf:

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 2021 Electric AAA and True-Up Report will be filed with the Commission and Minnesota Department of Commerce – Division of Energy Resources by March 1, 2022. This report covers the 2021 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.

<u>Scope of the Electric AAA Report</u>

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 2021. The Company implemented monthly fuel rates approved per the Commission's December 22, 2020 Order in Docket No. E002/AA-20-417. Monthly rates were later adjusted pursuant to the Commission's June 30, 2021 Order in Docket No. E002/M-19-293 and the Company's August 27, 2021 filing in Docket No. E002/AA-20-417. Appendix A to this letter shows the implemented 2021 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) as of 2021 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, 2021, 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 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 2021 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 instruments to hedge the price risk associated with those transactions. In preparing

[1] Pursuant to 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.

the auditor report to be submitted with the Company's 2021 Electric AAA and True-Up Report to be filed by March 1, 2022, 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 25, 2022. We will gladly work with you to establish a revised schedule if necessary. The Deloitte & Touche independent audit report should be provided to Amy Liberkowski, 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 are able to schedule a follow-up meeting to ensure that all the audit requirements are understood if such a meeting is necessary.

Sincerely,

/s/

REBECCA D. EILERS
REGULATORY POLICY SPECIALIST

cc: Amy Liberkowski
Lisa Peterson
John Chow

Xcel Energy Northern States Power Company

Minnesota Retail Electric Fuel Cost Charges ($/KWh)

UPDATED 09/30/2021

FUEL COST CHARGE ($/kWh)					
		C&I Demand			
			TOD		
Residential	C&I Non-Demand	Non-TOD	On-Peak	Off-Peak	Outdoor Lighting

2021 Forecast

FAF Ratio *	1.0177	1.0305	0.9984	1.2486	0.8166	0.7976
January	$0.02315	$0.02344	$0.02271	$0.02839	$0.01859	$0.01816
February	$0.02613	$0.02646	$0.02564	$0.03206	$0.02097	$0.02048
March	$0.02716	$0.02750	$0.02665	$0.03332	$0.02180	$0.02129
April	$0.02854	$0.02890	$0.02800	$0.03500	$0.02292	$0.02239
May	$0.03236	$0.03277	$0.03175	$0.03970	$0.02597	$0.02537
June	$0.03617	$0.03663	$0.03548	$0.04438	$0.02902	$0.02834
July	$0.03086	$0.03125	$0.03027	$0.03786	$0.02476	$0.02418
August	$0.03012	$0.03049	$0.02954	$0.03696	$0.02416	$0.02359
September	$0.02890	$0.02927	$0.02836	$0.03546	$0.02320	$0.02266
2020 True Up	$0.00177	$0.00179	$0.00174	$0.00217	$0.00142	$0.00139
Total	$0.03067	$0.03106	$0.03010	$0.03763	$0.02462	$0.02405
October	**$0.02743**	**$0.02777**	**$0.02691**	**$0.03364**	**$0.02201**	**$0.02150**
2021 True Up #	**$0.00387**	**$0.00392**	**$0.00379**	**$0.00474**	**$0.00310**	**$0.00303**
Total	**$0.03130**	**$0.03169**	**$0.03070**	**$0.03838**	**$0.02511**	**$0.02453**
November	**$0.02474**	**$0.02505**	**$0.02427**	**$0.03035**	**$0.01985**	**$0.01938**
2021 True Up #	**$0.00395**	**$0.00400**	**$0.00387**	**$0.00484**	**$0.00317**	**$0.00309**
Total	**$0.02869**	**$0.02905**	**$0.02814**	**$0.03519**	**$0.02302**	**$0.02247**
December	**$0.02310**	**$0.02339**	**$0.02266**	**$0.02834**	**$0.01854**	**$0.01811**
2021 True Up #	**$0.00362**	**$0.00367**	**$0.00355**	**$0.00445**	**$0.00291**	**$0.00284**
Total	**$0.02672**	**$0.02706**	**$0.02621**	**$0.03279**	**$0.02145**	**$0.02095**
Average	**$0.02932**	**$0.02969**	**$0.02877**	**$0.03597**	**$0.02353**	**$0.02298**

* FAF Ratio effective since October 1, 2017. # 2021 Mid-Year True Up

2020

January	$0.02472	$0.02503	$0.02426	$0.03031	$0.01986	$0.01940
February	$0.02685	$0.02719	$0.02634	$0.03293	$0.02155	$0.02105
March **	$0.02508	$0.02539	$0.02461	$0.03076	$0.02013	$0.01966
April **	$0.02587	$0.02620	$0.02538	$0.03172	$0.02077	$0.02030
May	$0.03080	$0.03119	$0.03022	$0.03778	$0.02473	$0.02416
June ***	$0.03134	$0.03173	$0.03074	$0.03845	$0.02515	$0.02456
July ***	$0.02717	$0.02752	$0.02666	$0.03334	$0.02180	$0.02130
August ***	$0.02657	$0.02691	$0.02607	$0.03260	$0.02132	$0.02083
September	$0.02879	$0.02915	$0.02824	$0.03531	$0.02310	$0.02257
October	$0.02782	$0.02817	$0.02729	$0.03412	$0.02233	$0.02181
November	$0.02519	$0.02550	$0.02471	$0.03090	$0.02021	$0.01974
December	$0.02335	$0.02364	$0.02291	$0.02864	$0.01874	$0.01831
Average	$0.02696	$0.02730	$0.02645	$0.03307	$0.02164	$0.02114

** Included true up from November and December 2019 amounts subject to Commission approval *** Included Summer FCA Rate Adjustment.

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
- 2020 Fuel Forecast and Factors – E002/AA-19-293, <u>Order dated June 30, 2021</u>
- <u>2021 Fuel Forecast and Factors– E002/AA-20-417, Order dated December 22, 2020 and Rate Adjustment filing dated September 28, 2021</u>

For the 12 months ending December 31, 2021, 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 exemption and end-of-life nuclear fuel accrual. These additional components of the FCA were approved by the MPUC in the following dockets:

- MISO ASM – E002/M-08-528
- MISO Day 2 – E002/M-04-1970
- Wind Contracts Curtailment Payments – E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/M-04-864, E002/CN-01-1958, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934, and E002/M-06-85
- Renewable Energy Purchase Agreements:
    - KODA Energy, LLC, E002/M-08-1098, Order dated January 29, 2009
    - Woodstock, LLC, Amendment approved in E002/M-17-26, Order dated October 8, 2018.
    - Winona, LLC, E002/M-09-1247, Notice of Approval dated December 1, 2009
    - Adams, LLC, E002/M-09-1366, Notice of Approval dated December 29, 2009
    - Danielson, LLC, E002/M-09-1367, Notice of Approval dated December 29, 2009
    - 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
  - 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
  - <u>Dakota Range III – E002/M-18-765, Order dated July 19, 2019</u>
  - <u>St. Paul Cogeneration – E002/M-21-590, Order dated January 24, 2022</u>
- 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
- Renewable*Connect Government Program – E002/M-15-985
- Renewable*Connect – Docket No. E002/M-19-33
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017

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, 2021 to December 31, 2021, and Independent Accountant's Report on Applying Agreed-Upon Procedures

Deloitte.

Deloitte & Touche LLP
Suite 2800
50 South Sixth Street
Minneapolis, MN 55402-1538
USA

Tel: +1 612 397 4000
Fax: +1 612 397 4450
www.deloitte.com

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, 2021 to December 31, 2021, in accordance with 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 ("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 (the "intended purpose") for the year ended December 31, 2021.

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, 2021 to December 31, 2021 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, 2021 to December 31, 2021 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, 2021 to December 31, 2021, 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, 2021 to December 31, 2021 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, 2021 to December 31, 2021 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, 2021 to December 31, 2021.

g. We reconciled total revenue and the cost of power for the period from January 1, 2021 to December 31, 2021 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, 2021 to December 31, 2021 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, 2022

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, 2021 TO DECEMBER 31, 2021
(DOLLAR PER KWH)

	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand On-Peak	C&I Demand Off-Peak	Outdoor Lighting
January 1, 2021	$ 0.02315	$ 0.02344	$ 0.02271	$ 0.02839	$ 0.01859	$ 0.01816
February 1, 2021	$ 0.02613	$ 0.02646	$ 0.02564	$ 0.03206	$ 0.02097	$ 0.02048
March 1, 2021	$ 0.02716	$ 0.02750	$ 0.02665	$ 0.03332	$ 0.02180	$ 0.02129
April 1, 2021	$ 0.02854	$ 0.02890	$ 0.02800	$ 0.03500	$ 0.02292	$ 0.02239
May 1, 2021	$ 0.03236	$ 0.03277	$ 0.03175	$ 0.03970	$ 0.02597	$ 0.02537
June 1, 2021	$ 0.03617	$ 0.03663	$ 0.03548	$ 0.04438	$ 0.02902	$ 0.02834
July 1, 2021	$ 0.03086	$ 0.03125	$ 0.03027	$ 0.03786	$ 0.02476	$ 0.02418
August 1, 2021	$ 0.03012	$ 0.03049	$ 0.02954	$ 0.03696	$ 0.02416	$ 0.02359
September 1, 2021	$ 0.03067	$ 0.03106	$ 0.03010	$ 0.03763	$ 0.02462	$ 0.02405
October 1, 2021	$ 0.03130	$ 0.03169	$ 0.03070	$ 0.03838	$ 0.02511	$ 0.02453
November 1, 2021	$ 0.02869	$ 0.02905	$ 0.02814	$ 0.03519	$ 0.02302	$ 0.02247
December 1, 2021	$ 0.02672	$ 0.02706	$ 0.02621	$ 0.03279	$ 0.02145	$ 0.02095

TRUE-UP FACTORS FOR THE PERIOD FROM JANUARY 1, 2021 TO DECEMBER 31, 2021
(DOLLAR PER KWH)

Annual true-up filing March 1, 2022 (factors proposed)	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand On-Peak	C&I Demand Off-Peak	Outdoor Lighting
September 2022	$ 0.00325	$ 0.00329	$ 0.00318	$ 0.00398	$ 0.00260	$ 0.00254
October 2022	$ 0.00333	$ 0.00337	$ 0.00326	$ 0.00408	$ 0.00267	$ 0.00261
November 2022	$ 0.00340	$ 0.00344	$ 0.00333	$ 0.00417	$ 0.00273	$ 0.00266
December 2022	$ 0.00309	$ 0.00313	$ 0.00304	$ 0.00380	$ 0.00248	$ 0.00242
January 2023	$ 0.00304	$ 0.00308	$ 0.00299	$ 0.00373	$ 0.00244	$ 0.00238
February 2023	$ 0.00352	$ 0.00357	$ 0.00345	$ 0.00432	$ 0.00283	$ 0.00276
March 2023	$ 0.00310	$ 0.00314	$ 0.00305	$ 0.00381	$ 0.00249	$ 0.00243
April 2023	$ 0.00357	$ 0.00362	$ 0.00350	$ 0.00438	$ 0.00287	$ 0.00280
May 2023	$ 0.00335	$ 0.00339	$ 0.00328	$ 0.00411	$ 0.00269	$ 0.00262
June 2023	$ 0.00306	$ 0.00310	$ 0.00301	$ 0.00376	$ 0.00246	$ 0.00240
July 2023	$ 0.00266	$ 0.00269	$ 0.00261	$ 0.00326	$ 0.00213	$ 0.00208
August 2023	$ 0.00273	$ 0.00276	$ 0.00268	$ 0.00335	$ 0.00219	$ 0.00214

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 with KODA Energy, LLC (Docket No. E002/M-08-1098)

The Company is required to report in the AAA 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 this AAA 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 AAA reports.

2. Power Purchase Agreement with WM Renewable Energy, LLC (Docket No. E002/M-10-161)

On April 30, 2010, the Commission approved the Company's Replacement Power Purchase Agreement with WM Renewable Energy, LLC. The Order also requires the Company to report any curtailments and curtailment payments of power from this Burnsville landfill gas facility in the monthly FCA filings. The Company is not aware of any curtailments or curtailment payments during the current reporting period.

3. Power Purchase Agreement with Diamond K Dairy, Inc. (Docket No. E002/M-10-486)

On August 26, 2010, the Commission approved the Company's Power Purchase Agreement with Diamond K Dairy, Inc. The Company is required to report in the AAA report any revenues the Company has received from any or all sources as a result of this PPA, and to report and itemize any such revenues by source and amount. As of this AAA reporting period, the Company has not received any new revenue as described in this Order.

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

In a February 1, 2018 letter 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-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 interim HERC agreement for the 2021 calendar year. The total cost paid during reporting period was $8.0 million, which is an average cost of $36.86/MWh.

5. 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 this current AAA 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 offsetting revenues and/or compensation credited during the 2021 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."

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 nearly two-thirds of neutrality expenses in 2021, were the most significant impact across the cost categories as illustrated in Table 1 below. Curtailments on program solar resources totaled nearly $125,000, and $29,437 were allocated to the program with less than 50% of solar curtailments allocated to the program in 2021. Wind curtailments associated with the programs wind resource increased sharply in 2021. Wind curtailments totaled nearly $1,620,000 and $302,024 were allocated to the program, a ten-fold increase compared to 2020.

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 resources. The analysis results in an estimate of nearly $230,000 in wind integration costs for the 2021 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 energy 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. The results have historically indicated a strong benefit for non-participants with nearly a $5.0 million benefit over the life of the program, however, the results for 2021 were a cost of approximately $0.6 million.

Overall, neutrality payments fell short of participant cost by nearly $360,000 in 2021. However, over the life of the programwhen 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 $4.9 million benefit due to the Renewable*Connect program.

Table 1: Non-Participants Impact

(in $000s)	**Total**	**2021**	**2020**	**2019**	**2018**	**2017**
Line Losses	$2,302	$677	$641	$532	$359	$92
Solar Curtailments	$120	$29	$66	$17	$4	$3
Wind Curtailments	$351	$302	$35	$11	$4	$0
Economic/Balancing	$920	$228	$230	$227	$185	$50
Total	$3,693	$1,236	$973	$787	$552	$145
Neutrality Payments	$3,555	$876	$891	$884	$717	$187
Non-Participant Cost/(Benefit)	$137	$360	$82	($97)	($165)	($42)
Net Economic Cost/(Benefit)[1]	($4,995)	$617	($2,889)	($1,792)	($688)	($244)
Total Cost/(Benefit)	($4,858)	$977	($2,807)	($1,889)	($853)	($286)

[1] Since Odell Wind and NorthStar Solar Energy were originally procured for the system, moving this higher cost energy from the Fuel Clause to Renewable*Connect provides a benefit to non-participant relative to energy procured at LMP.

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 during the 2021 reporting period.

Table 1: Unusual Items Over $500,000

Item Pertaining To	Period Affected	Descriptions	Amount (negative indicates cost decrease)	FCA Impact
NNG Pipeline Capacity Refund	Mar-21	The electric generation portion of this refund was credited to March fuel cost.	($538,469)	Yes
MISO Make Whole Payments	Mar-21	Company refunded the over credit to MISO market participants for Make Whole Payments received at Cannon Falls on 2/15/21. Company used the Market Monitor to adjust the settlement based upon actual gas prices.	$10,892,636	Yes
Black Dog Minimum Throughput True Up	Mar-21	True-up expense from Minimum Throughput requirement included in March fuel cost	$1,285,640	Yes
Dakota Range III Delay Damages	Apr-21	Dakota Range III delayed COD until April 29, 2021, which resulted in delay damage payments of $4,460,400.	($4,460,400)	Yes
NNG Pipeline Capacity Refund	Aug-21	The electric generation portion of this refund was credited to August fuel cost.	($723,158)	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 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). The variances and dockets that pertain to the 2021 FCA true-up and AAA reporting period are listed below.

- 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
- 2020 Fuel Forecast and Factors – E002/AA-19-293, Order dated June 30, 2021
- 2021 Fuel Forecast and Factors– E002/AA-20-417, Order dated December 22, 2020 and Rate Adjustment filing dated September 28, 2021

For the 12 months ending December 31, 2021, 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 exemption and end-of-life nuclear fuel accrual. These additional components of the FCA were approved by the MPUC in the following dockets:

- MISO ASM – E002/M-08-528
- MISO Day 2 – E002/M-04-1970
- Wind Contracts Curtailment Payments – E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/M-04-864, E002/CN-01-1958, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934, and E002/M-06-85
- Renewable Energy Purchase Agreements:
  - KODA Energy, LLC, E002/M-08-1098, Order dated January 29, 2009
  - Woodstock, LLC, Amendment approved in E002/M-17-26, Order dated October 8, 2018.
  - Winona, LLC, E002/M-09-1247, Notice of Approval dated December 1, 2009
  - Adams, LLC, E002/M-09-1366, Notice of Approval dated December 29, 2009
  - Danielson, LLC, E002/M-09-1367, Notice of Approval dated December 29, 2009

  - 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
  - University of Minnesota South East Plant, E002/M-20-39, Order dated April 10, 2020
  - Crowned Ridge, Clean Energy #1, Order dated September 1, 2017
  - Dakota Range III – E002/M-18-765, Order dated July 19, 2019
- 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
- Renewable*Connect Government Program – E002/M-15-985
- Inver Hills Sales Gain Sharing Refund – E002/PA-17-529, Order dated February 16, 2018
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017

Former AAA	Description	Docket or Rule	May 1, 2020 Annual Forecast of Rates	March 1, 2022 Annual True-Up Filing
Part D, Section 1 and all Schedules	Policies and Actions: Fuel Procurement	Rule 7825.2800	Part D, Attachment 1	Part D, Attachment 1
D-1, Schedule 1	Nuclear Fuel Component of Service	Rule 7825.2800	Part D, Attachment 2	Part D, Attachment 2
D-1, Schedule 2	Coal Contracts	Rule 7825.2800	Part D, Attachment 3	Part D, Attachment 3
D-1, Schedule 3	Transportation & Related Services Contracts	Rule 7825.2800	Part D, Attachment 4	Part D, Attachment 4
D-1, Schedule 4	Wood and RDF Contracts	Rule 7825.2800	Part D, Attachment 5	Part D, Attachment 5
D-1, Schedule 5	Cost Changes	Rule 7825.2800	Part D, Attachment 6	Part D, Attachment 6
Part D, Section 2	Policies and Actions: Dispatching Policies and Procedures	Rule 7825.2800	Part D, Attachment 7	Part D, Attachment 7
Part D, Section 3	Policies and Actions: Fuel Supply	Rule 7825.2800	Part D, Attachment 8	Part D, Attachment 8
Part D, Section 4	Policies and Actions: Conservation and Load Management Policy	Rule 7825.2800	Part D, Attachment 9	Part D, Attachment 9
Part D, Section 5	Policies and Actions: Other Actions to Minimize Costs	Rule 7825.2800	Part D, Attachment 10	Part D, Attachment 10
Part E, Section 1	Annual Report of Automatic Adjustment Charges: Base Cost of Fuel	Rule 7825.2810; Docket 04-1279	Part A, Attachment 1 and discussed in Petition	Report Narrative
Part E, Section 2	Annual Report of Automatic Adjustment Charges: Billing Adjustment Amounts Charged to Customers for Each Type of Energy Cost	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 3	Annual Report of Automatic Adjustment Charges: Total Cost of Fuel Delivered to Customers	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 4	Annual Report of Automatic Adjustment Charges: Revenue Collected from Customers for Energy Delivered	Rule 7825.2810; Docket 04-1279	Discussed in Petition	Part A
Part E, Section 5	Annual Report of Automatic Adjustment Charges: Monthly Fuel Clause Adjustment	Rule 7825.2810; Docket 04-1279	Part A, Attachment 1 and discussed in Petition	Part A, Attachment 8
Part F, Schedule 1	Memo Engaging Auditor	Rule 7825.2820	NA	Part E, Attachment 1
Part F, Schedule 2	Independent Auditor’s Report	Rule 7825.2820	NA	Part E, Attachment 2
Part G, Schedule 1	5-Year Fuel Cost Forecast – Per Unit Summary	Rule 7825.2830	Part A, Attachment 1 Part E, Attachment 1	NA
Part G, Schedule 2	5-Year Fuel Cost Forecast – Cost Summary	Rule 7825.2830	Part A, Attachment 2 Part E, Attachment 2	NA
Part G, Schedule 3	5-Year Fuel Cost Forecast – Energy Summary	Rule 7825.2830	Part A, Attachment 3 Part E, Attachment 3	NA
Part G, Schedule 4	Fossil Fuel Costs	Rule 7825.2830	Part B, Attachment 2	NA
Part G, Schedule 5	Coal Burn Expenses	Rule 7825.2830	Part B, Attachment 3	NA
Part G, Schedule 6	Nuclear Fuel Expenses	Rule 7825.2830	Part B, Attachment 4	NA
Part G, Schedule 7	Peak Demand and Energy Requirements	Rule 7825.2830	Part A, Attachment 4 Part E, Attachment 4	NA
Part G, Schedule 8	Estimated Load Management Impact	Rule 7825.2830	Part E, Attachment 5	NA

Former AAA	Description	Docket or Rule	May 1, 2020 Annual Forecast of Rates	March 1, 2022 Annual True-Up Filing
Part H, Section 3	Natural Gas Financial Instruments	Dockets M-01-1953 and AA-02-950	NA	Report Narrative Part E, Attachments 1 and 2
Part H, Section 5, Schedule 1	Wind Curtailment Summary	Dockets M-00-622, M-02-51, M-04-404, CN-01-1958, M-04-864, M-05-1850, M-05-1934 and M-06-85	NA	Part C, Attachment 2
Part H, Section 5, Schedule 2	Wind Curtailment Report Narrative	Docket AA-04-1279	Discussed in Petition Part G, Workpaper 10	Part C, Attachment 1
Part H, Section 6	KODA PPA	Docket M-08-1098	NA	Part F, Attachment 1
Part H, Section 7	WMRE PPA	Docket M-10-61	NA	Part F, Attachment 1
Part H, Section 8	Diamond K Dairy PPA	Docket M-486	NA	Part F, Attachment 1
Part H, Section 9 and Schedules H-9-1 and H-9-2	Community Solar Gardens	Docket M-13-867	Discussed in Petition Part B, Attachment 12 Part G, Workpapers 8 & 9	Part C, Attachments 8, 9, 10 Report Narrative
Part H, Section 10	FCA Rule Variance Dockets	Docket AA-15-611	Discussed in Petition Part C, Attachment 2	Part F, Attachment 4
Part H, Section 11	HERC	Docket 17-532	NA	Part F, Attachment 1
Part J, Sections 1-3	Summary of key factors affecting costs in the forecast, and plan for acquiring fuel and purchased energy	Docket 04-1970, Docket 06-1208, Docket GR-05-1428	Discussed in Petition	NA
Part J, Section 5	Monthly MISO Day 2 charges and allocation	Docket AA-07-1130	Discussed in Petition Part B, Attachment 8 Part F, Workpaper 5	Part B
Part J, Section 6	Annual and Daily Ancillary Services Market charges and summary	Docket M-08-528	NA	Part B
Part K, Section 1	Generation facilities maintenance expenses	Docket AA-06-1208	NA	Part C, Attachment 6
Part K, Section 3	Contractor and supplier performance	Docket AA-08-995	NA	Part C, Attachment 3
Part K, Section 4 Schedule 1	Offsetting Revenues and/or compensation Received by IOUs	Docket AA-10-884	NA	Part F, Attachment 1
Part K, Section 4 Schedule 2	Handling of forced outages	Docket 08-995 and Docket AA-10-884	NA	Part C, Attachments 3, 4, 5
Part K, Section 4 Schedule 3	Unusual Adjustments over $500,000	Dockets AA-09-961 and AA-10-884	NA	Part F, Attachment 3
New Compliance	Self-Scheduling	Docket AA-17-492	NA	Provided in 3/1/22 Report in Docket No. E999/CI-19-704
Part M	Notice of Reports Availability	Rule 7825.2840	Addendum to Petition	Part F, Attachment 7
New Compliance	Renewable*Connect Neutrality	Docket M-15-985	Discussed in Petition Part G, Workpaper 14	Part F, Attachment 2

TRADE SECRET JUSTIFICATION:

Under Minnesota Stat. § 13.37, 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 Trade Secret in this True-Up and AAA 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.

Xcel Energy requests Trade Secret protection of this information to maintain the Company's competitive position in the marketplace. 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.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE 2021 ANNUAL FUEL FORECAST AND MONTHLY FUEL COST CHARGES

DOCKET NO. E002/AA-20-417

NOTICE OF REPORT AVAILABILITY
ANNUAL TRUE-UP REPORT

On March 1, 2022, 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, 2021 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, Mustafa Adam, 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-20-417
E002/GR-21-630
E002/GR-15-826

Dated this 1st day of March 2022

/s/

____

Mustafa Adam
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_20-417_AA-20-417
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-417_AA-20-417
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-417_AA-20-417
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_20-417_AA-20-417
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-417_AA-20-417
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_20-417_AA-20-417
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-417_AA-20-417
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_20-417_AA-20-417
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_20-417_AA-20-417
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-417_AA-20-417
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-417_AA-20-417
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_20-417_AA-20-417
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_20-417_AA-20-417
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_20-417_AA-20-417
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_20-417_AA-20-417
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-417_AA-20-417

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_20-417_AA-20-417
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-417_AA-20-417
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_20-417_AA-20-417
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_20-417_AA-20-417
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_20-417_AA-20-417
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_20-417_AA-20-417

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-417_AA-20-417
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-417_AA-20-417
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_20-417_AA-20-417
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_20-417_AA-20-417
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_20-417_AA-20-417
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_20-417_AA-20-417
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-417_AA-20-417

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_20-417_AA-20-417
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	OFF_SL_20-417_AA-20-417
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_20-417_AA-20-417
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-417_AA-20-417
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_20-417_AA-20-417
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_20-417_AA-20-417
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_20-417_AA-20-417

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thomas	Tynes	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	OFF_SL_20-417_AA-20-417
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_20-417_AA-20-417
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_20-417_AA-20-417
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-417_AA-20-417

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kevin	Adams	kadams@caprw.org	Community Action Partnership of Ramsey & Washington Counties	450 Syndicate St N Ste 35 Saint Paul, MN 55104	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Kristin	Berkland	kristin.berkland@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official CC Service List
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official CC Service List
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_21-630_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-630_Official CC Service List
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_21-630_Official CC Service List
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_21-630_Official CC Service List
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Richard	Dornfeld	Richard.Dornfeld@ag.state.mn.us	Office of the Attorney General-DOC	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul, Minnesota 55101	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Lucas	Franco	lfranco@liunagroc.com	LIUNA	81 Little Canada Rd E Little Canada, MN 55117	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Janet	Gonzalez	Janet.gonzalez@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Matthew B	Harris	matt.b.harris@xcelenergy.com	XCEL ENERGY	401 Nicollet Mall FL 8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Shubha	Harris	Shubha.M.Harris@xcelenergy.com	Xcel Energy	414 Nicollet Mall, 401 - FL 8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec	414 Nicollet Mall, 401-7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota St Suite 1400 St. Paul, MN 55101-2134	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Geoffrey	Inge	ginge@regintllc.com	Regulatory Intelligence LLC	PO Box 270636 Superior, CO 80027-9998	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	Yes	OFF_SL_21-630_Official CC Service List
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Patrick	Kelly	pkelly@kellyandlemmons.com	City of Gem Lake	2350 Wycliff St Ste 200 Saint Paul, MN 55114	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Alice	Madden	alice@communitypowermn.org	Community Power	2720 E 22nd St Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_21-630_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_21-630_Official CC Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Christa	Moseng	christa.moseng@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 Saint Paul, MN 55164-0620	Electronic Service	Yes	OFF_SL_21-630_Official CC Service List
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-630_Official CC Service List
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Elizabeth	Schmiesing	eschmiesing@winthrop.com	Winthrop & Weinstine, P.A.	225 South Sixth Street Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Peter	Scholtz	peter.scholtz@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-630_Official CC Service List
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	Yes	OFF_SL_21-630_Official CC Service List
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Thomas	Tynes	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-630_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_15-826_Official
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-826_Official
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-826_Official
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_15-826_Official
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-826_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_15-826_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-826_Official
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_15-826_Official
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-826_Official
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-826_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_15-826_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_15-826_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_15-826_Official
Janet	Gonzalez	Janet.gonzalez@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-826_Official
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_15-826_Official
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_15-826_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_15-826_Official
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_15-826_Official
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_15-826_Official
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_15-826_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_15-826_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	Yes	OFF_SL_15-826_Official
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_15-826_Official
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_15-826_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	Yes	OFF_SL_15-826_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_15-826_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_15-826_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_15-826_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_15-826_Official
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	OFF_SL_15-826_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-826_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-826_Official
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	Yes	OFF_SL_15-826_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-826_Official
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_15-826_Official
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_15-826_Official
Thomas	Tynes	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	OFF_SL_15-826_Official
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-826_Official
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_15-826_Official
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett PA	150 S 5th St #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-826_Official