414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

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March 2, 2020

- VIA ELECTRONIC FILING -

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

RE: ANNUAL REPORT
2018-2019 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT - ELECTRIC
DOCKET NO. E999/AA-20-171

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed annual report pursuant to Minnesota Rules 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges for the Company's electric utility operations. In accordance with ordering paragraph 3 of the Commission's December 12, 2018 Order in Docket No. E999/CI-03-802, the reporting period is July 2018-December 2019.

Various attachments to this filing contain information that Xcel Energy considers Not Public. We provide justification for the identification of the data designated as Not Public in Attachment L of this filing.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and a filing summary has been served on the parties on the attached service lists. Please contact Rebecca Eilers at 612-330-5570 or rebecca.d.eilers@xcelenergy.com or me at 612-330-7681 or lisa.r.peterson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

LISA PETERSON
MANAGER, REGULATORY ANALYSIS

Enclosures
c Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS ELECTRIC OPERATION	DOCKET NO. E999/AA-20-171 **ANNUAL REPORT**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Annual Report as required in Minnesota Rules 7825.2800 to 7825.2840 governing Automatic Adjustment Charges (AAA) for electric utilities. In accordance with Order Point No. 3 of the Commission's December 12, 2018 Order in Docket No. E999/CI-03-802, we report on the period July 1, 2018 to December 31, 2019. This Report includes a summary of our fuel costs over the past 18 months and other reporting requirements.

I. SUMMARY OF FILING

Pursuant to Minn. R. 7829.1300, subp. 1, a one-paragraph summary of the filing accompanies this Report.

II. SERVICE ON OTHER PARTIES

The Company has electronically filed this document with the Minnesota Public Utilities Commission, and copies of the Notice of Report Availability have been served on the parties on the attached service lists.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following required information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company
414 Nicollet Mall
Minneapolis, Minnesota 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Matt Harris
Principal Attorney
Xcel Energy
414 Nicollet Mall – 401 8th Floor
Minneapolis, Minnesota 55401
(612) 330-7641

C. Date of Filing and Date Modified Rates Take Effect

Consistent with ordering paragraph 3 of the Commission's December 12, 2018 Order in Docket No. E999/CI-03-802, the date of this filing is March 2, 2020. The information contained in this filing is submitted in compliance with the aforementioned Rules concerning AAA reports.

D. Statute Controlling Schedule for Processing the Filing

No statute establishes a schedule for processing this filing. The applicable rules are Minn. R. 7825.2800 through 7825.2840.

E. Utility Employee Responsible for Filing

Lisa Peterson
Manager, Regulatory Analysis
Xcel Energy
414 Nicollet Mall – 401 7th Floor
Minneapolis, Minnesota 55401
(612) 330-7681

IV. MISCELLANEOUS INFORMATION

Pursuant to Minnesota Rule 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this matter:

Matt Harris
Principal Attorney
Xcel Energy
414 Nicollet Mall – 401 - 8th Floor
Minneapolis, Minnesota 55401
matt.b.harris@xcelenergy.com

Lynnette Sweet
Regulatory Administrator
Xcel Energy
414 Nicollet Mall – 401 - 7th Floor
Minneapolis, Minnesota 55401
regulatory.records@xcelenergy.com

V. DESCRIPTION AND PURPOSE OF FILING

A. Background

As noted above, this filing contains information provided in response to the annual reporting requirements specified in the following rule sections:

7825.2800 Annual Reports: Policies and Actions .... Part D
7825.2810 Annual Report: Automatic Adjustment Charges .... Part E
7825.2820 Annual Auditor's Report .... Part F
7825.2830 Annual Five-Year Projection. .... Part G

We provide the Annual Notice of Reports Availability under Minn. Rule 7825.2840 at the end of our filing. Attachment L contains the justification for treating certain information contained in this filing as Not Public.

7825.2800 Annual Reports: Policies and Actions

Part D includes the following schedules and a brief summary of the topics listed in the rule:

Section 1 Procurement Policies
Section 2 Dispatching Policies and Procedures
Section 3 Fuel Supply
Section 4 Conservation and Load Management Policy
Section 5 Other Actions

7825.2810 Annual Report: Automatic Adjustment of Charges

Part E contains a summary of the annual reporting (by month) of all electric automatic adjustment charges for each customer class for the prior year commencing July 1, 2018 and ending December 31, 2019. It includes the following schedules as set forth in Subp. 1:

Section 1 Base Cost of Fuel
Section 2 Billing Adjustment Amounts Charged Customers for Each
Section 3 Total Cost of Fuel Delivered to Customers
Section 4 Revenue Collected from Customers for Energy Delivered
Section 5 Monthly Fuel Cost Charge

7825.2820 Annual Auditor's Report

Part F, Section 2 contains the independent auditor's report evaluating the Company's accounting of electric automatic adjustments for the 18 months ending December 31, 2019. Deloitte & Touche LLP prepared this report. In addition, Part F, Section 1 contains the Company's letter of instruction to the independent auditor.

7825.2830 Annual Five-Year Projection and FCA Settlement Compliance

As discussed in Part G, a monthly five-year projection of fuel cost by energy source was provided with our May 1, 2019 Petition in Docket No. E002/AA-19-293, per the Commission's Orders approving fuel clause reform in Docket No. E999/CI-03-802. We will submit a new monthly five-year projection of fuel cost by energy source in our next fuel forecast Petition to be filed by May 1, 2020.

In addition, in compliance with the "FCA Settlement" in the Company's 2005 electric rate case (Docket No. E002/GR-05-1428), the Company has provided its quarterly 12-month FCA forecast to customers who have signed the protective agreement (Part J, Section 4, Schedule 1). The FCA forecast also discusses monthly deviations in FCA filings. This requirement is also cited in paragraph D in the December 20, 2006 Order in Docket No. E002/M-04-1970, the MISO Day 2 cost recovery docket.

7825.2840 Annual Notice of Reports Availability

Minn. Rules part 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 2013 and 2015 electric rate cases who have requested to remain on the docket service lists. The Company's notice is submitted as Part M and includes the following schedules:

Schedule 1 Notice of Reports Availability
Schedule 2 Certificate of Service
Schedule 3 Service Lists

VI. OTHER SUBMITTALS

We have included additional Parts H, I, J and K, as described in more detail below, which provide information that falls outside the requirements of the Commission's rules concerning the AAA. We note that, with FCA reform recently approved by the Commission in Docket No. E999/CI-03-802, some of these reporting requirements will not be required in future annual fuel clause reporting. With the exception of the forecast data that has already been provided in the fuel forecast docket, we have included all previously-required reporting requirements in this report as it is the last report under the prior FCA process.

A. Justification of Trade Secret Data Protection

Pursuant to Rule 7829.0500, the Company is requesting that certain parts of this report be designated as trade secret information. Justification for trade secret protection is provided in Attachment L.

B. Miscellaneous Compliance Reports

Parts H, I, J, and K contain responses related to various compliance reports required by Commission Orders issued in prior Company filings and AAA reports. The following is a list of these additional reports in compliance with Commission Orders for the referenced dockets:

Investigation of NSP's Practices Regarding Energy Marketing and Fuel Clause	E002/CI-00-415	Part H, Section 2
Natural Gas Financial Instruments	E002/M-01-1953 and E999/AA-02-951	Part H, Section 3
Transmission Transformer Report	E,G999/AA-07-1130, E999/M-07-1028, E999/M-09-602	Part H, Section 4
Wind Curtailment Report	E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85	Part H, Section 5
Renewable Energy Purchase Agreement with KODA Energy, LLC	E002/M-08-1098	Part H, Section 6
Power Purchase Agreement with WM Renewable Energy, LLC	E002/M-10-61	Part H, Section 7

Power Purchase Agreement with Diamond K Dairy, Inc.	E002/M-10-486	Part H, Section 8
Community Solar Gardens	E002/M-13-867	Part H, Section 9
Rule Variance Dockets	E002/AA-15-611	Part H, Section 10
HERC PPA Pricing	E002/M-17-532	Part H, Section 11
MISO "Day 1" Operations	E002/M-00-257	Part I, Sections 1-9
MISO "Day 2" Operations	E002/M-04-1970 *et al* E002/GR-05-1428 E,G999/AA-06-1208 E999/AA-14-469	Part J, Sections 1, 2, 3, 5, and 6
FCA Quarterly Forecasts	E002/GR-05-1428	Part J, Section 4
2006 AAA & MISO Filing Requirements	E,G999/AA-06-1208, E002/M-04-1970 *et al*	Part K, Section 1
2007 AAA Filing Requirements	E,G999/AA-07-1130	Part K, Section 2
2008 AAA Filing Requirements	E,G999/AA-08-995	Part K, Section 3
2009 & 2010 AAA Filing Requirements	E999/AA-09-961 and E999/AA-10-884	Part K, Section 4
2011 AAA Filing Requirements	E999/AA-11-792	Part K, Section 5
2017 & 2018 AAA Filing Requirements	E999/AA-17-492 E999/AA-18-373	Part K, Section 6

CONCLUSION

The Company submits this annual report for its electric utility operation pursuant to the Commission's rules regarding Automatic Adjustment of Charges and in accordance with Order Point No. 3 of the Commission's December 12, 2018 Order in Docket No. E999/CI-03-802.

Dated: March 2, 2020

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF NORTHERN STATES POWER COMPANY ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS ELECTRIC OPERATION

DOCKET NO. E999/AA-20-171

ANNUAL REPORT

SUMMARY

Please take notice that on March 2, 2020, Northern States Power Company, doing business as Xcel Energy, filed with the Minnesota Public Utilities Commission the annual report for its electric operations pursuant to the Commission's rules (Minn. R. Parts 7825.2800 to 7825.2840) regarding the Automatic Adjustment of Charges. In accordance with the Commission's December 12, 2018 Order in Docket No. E999/CI-03-802, the report covers the 18-month period from July 1, 2018 to December 31, 2019.

NORTHERN STATES POWER COMPANY
2018-2019
ANNUAL AUTOMATIC ADJUSTMENTS REPORTS
(Electric Utility)

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Docket No. E999/AA-20-171

March 2, 2020

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  4 Biennial Transmission Transformers Report (Docket Nos. E,G999/AA-07-1130, E999/M-07-1028, E999/M-09-602)
  5 Wind Curtailment Report (Docket Nos. E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85)
  6 Renewable Energy Purchase Agreement with KODA Energy, LLC (Docket No. E002/M-08-1098)
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2018-2019 ELECTRIC AAA REPORT

A. Overview

This report provides an overview of fuel costs as well as other expenses the Company is authorized to recover through the fuel clause rider during the eighteen-month period of July 1, 2018 – December 31, 2019. The Company has been providing detailed information in its monthly Fuel Clause Adjustment (FCA) filings during this reporting period, including the November and December true-up filing made January 31, 2020. We note that the Commission's December 19, 2017 Order in Docket No. E999/CI-03-802 approved reforms to the fuel clause mechanism that will impact implementation and reporting on the fuel clause beginning January 1, 2020.

B. Reporting Requirements

This report also includes the compliance reporting related to the effects of the Midcontinent Independent System Operator, Inc. (MISO) Day 2 wholesale energy market adopted by the Commission in its Orders in Docket No. E002/M-04-1970 *et al.*[1] Certain reporting requirements are similar to the additional forecast information required by the Settlement Agreement – Advanced Forecast for Fuel and Purchased Energy Costs (FCA Settlement) in our 2005 electric general rate case (Docket No. E002/GR-05-1428).[2] In addition to submitting additional compliance information in this AAA report and monthly FCA filings, the Company provided on a quarterly basis the 12-month fuel cost forecast information to customers who have signed a protective agreement with the Company.

Pursuant to Minnesota Rule, this report contains the annual reporting requirements specified in the following rule sections:

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

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[1] *In the Matter of Xcel Energy's Petition for Affirmation that MISO Day 2 Costs are Recoverable Under the Fuel Clause Rules and Associated Variances et al.*, ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS, Docket No. E002/M-04-1970 *et al.* (December 20, 2006), *aff'd by* Minnesota Court of Appeals in A07-0730.

[2] The FCA Settlement was approved in Docket No. E002/GR-05-1428, Order dated September 1, 2006.

C. Additional Compliance Reports

We have included additional compliance reports pursuant to other Commission Orders related to the Automatic Adjustment of Charges. The following is a list of these additional reports and the dockets in which the Commission ordered the reports to be provided:

Investigation of NSP's Practices Regarding Energy Marketing and Fuel Clause	E002/CI-00-415	Part H, Section 2
Natural Gas Financial Instruments	E002/M-01-1953 and E999/AA-02-951	Part H, Section 3
Transmission Transformer Report	E,G999/AA-07-1130, E999/M-07-1028, E999/M-09-602	Part H, Section 4
Wind Curtailment Report	E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85	Part H, Section 5
Renewable Energy Purchase Agreement with KODA Energy, LLC	E002/M-08-1098	Part H, Section 6
Power Purchase Agreement with WM Renewable Energy, LLC	E002/M-10-61	Part H, Section 7
Power Purchase Agreement with Diamond K Dairy, Inc.	E002/M-10-486	Part H, Section 8
Community Solar Gardens	E002/M-13-867	Part H, Section 9
Rule Variance Dockets	E999/AA-15-611	Part H, Section 10
HERC PPA Costs	E002/M-17-532	Part H, Section 11
MISO "Day 1" Operations	E002/M-00-257	Part I, Sections 1-9
MISO "Day 2" Operations	E002/M-04-1970 *et al* E002/GR-05-1428 E,G999/AA-06-1208 E999/AA-14-479	Part J, Sections 1, 2, 3 and 5
FCA Quarterly Forecasts	E002/GR-05-1428	Part J, Section 4
MISO Ancillary Services Market (ASM)	E002/M-08-528	Part J, Section 6
2006 AAA & MISO Filing Requirements	E,G999/AA-06-1208 and E002/M-04-1970 *et al*	Part K, Section 1
2007 AAA Filing Requirements	E,G999/AA-07-1130	Part K, Section 2
2008 AAA Filing Requirements	E,G999/AA-08-995	Part K, Section 3
2009 & 2010 AAA Filing Requirements	E999/AA-09-961 and E999/AA-10-884	Part K, Section 4
2011 AAA Filing Requirements	E999/AA-11-792	Part K, Section 5
2017 & 2018 AAA Filing Requirements	E999/AA-17-492 E999/AA-18-373	Part K, Section 6

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

PART D

POLICIES AND ACTIONS

FUEL PROCUREMENT POLICIES

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.

In the Company's Petition for a Plan to Offer Generating Resources into the MISO Market on a Seasonal Basis, Docket No. E002/M-19-809, we are seeking approval to offer the King Station and Unit 2 of the Sherburne County Generating Station into the MISO market on a seasonal basis. Although we expect this change in approach to dispatching these units will have an impact on our total coal requirements for these units, we do not expect it to change our general coal purchasing strategy to meet the lower requirements.

Nuclear

The market price for uranium during the early part of first quarter of 2020 has been relatively steady with a high spot market price of $25.00 per pound in early January to a low of $24.65 per pound in early February.

Even at today's market prices, the cost of nuclear fuel continues to be higher than the historical costs of the 1990s and early 2000s, when the market price for uranium was less than $10.00 per pound. With the continued weakness 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 the closure of mines, reduction of production targets, suspension of production at mines throughout the world, and buying by producers to fulfill contractual obligations. New supply entering the marketplace continues to slow due to the continuing low market price of uranium. Several planned uranium mine expansions globally have been cancelled or delayed until market conditions improve. Uncertainty continues in predicting the impact of the Japan event on worldwide construction of new nuclear power plants and the associated demand for uranium. Early closures of nuclear power plants in the United States have reduced demand, but uranium demand exceeds supply. However, the difference between supply and demand is projected to be covered by end user inventories. Spot market volume at 56.3 million pounds of U3O8 for 2019 is significantly below the 88.7 million pounds of U3O8 for 2018 and is approximately 36.5 percent less than the volume for this period in 2018. For the rest of 2020 and into 2021, prices will likely increase moderately as uranium end users draw down inventories, producers cover obligations, and anticipated U.S policy-related decisions occur. Spot market volumes are forecasted to increase slightly. Longer-term prices will likely increase.as production cuts continue to result in supplies continuing below demandand potential impacts that may occur based on any actions that are taken as a result of policy-related decisions. Additionally, demand is likely to increase with the restart of more reactors in Japan and as construction and start-up of new nuclear power plants world-wide continues. Prices could be further impacted if supply projections are not met. Closings of nuclear reactors world-wide have decreased demand and increased uranium end-user inventories. The current market analysis forecasts supply and inventories meeting demand until about 2023, but will continue to be dependent on the willingness of suppliers to bring new supply into the market, as well as the interest of companies and governments to continue construction of new nuclear power plants. Continued developments in government programs and agreements will favorably influence supply/demand projections and should help to moderate future increases to nuclear fuel prices.

Several trade activities, such as uncertainty with regard to trade policy with China and continuation of the existing Russian Suspension Agreement beyond 2020, and continued threats of 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 2020. If quotas and/or 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.

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.

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 20 and 25 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.

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

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PUBLIC DOCUMENT
NOT PUBLIC DATA HAS BEEN EXCISED

Nuclear Fuel Components of Services for the Period of July 2018 through December 2019

	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]

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				
8				
9				
				PROTECTED DATA ENDS]

Transportation & Related Services Contracts

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

Cost Changes - July 1, 2018 to December 31, 2019

	Contract	Percent Change
[PROTECTED DATA BEGINS		

PROTECTED DATA ENDS]

Cost Changes - July 1, 2018 to December 31, 2019

	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 July 1, 2018 compared to the contract price on December 31, 2019.

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 2019.

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

3. One contract was executed **[PROTECTED DATA BEGINS** *with Uranium One* **PROTECTED DATA ENDS]**

b. Fossil Fuel

1. Public documents released by the U.S. Energy Information Agency report average coal costs for utility consumption delivered in the U.S. was $2.06/MBtu during 2018. (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 2017 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 July 2018 through December 2019, the Company disputed approximately 3 days of 104 MISO invoices. As a result, $100,000 in disputed amounts were granted by MISO for the NSP System (through adjustments to MISO settlements).

NSP MISO Dispute Status

Disputed $ Amount			Dispute Status			
YEAR	Op Month	Operating Date	GRANTED	DENIED	OPEN	TOTAL
2018	2018-12	12/01/18	$100,000.00	$0.00	$0.00	$100,000.00
2018 Total			$100,000.00	$0.00	$0.00	$100,000.00
2019	2019-04	04/28/19	$0.00	$19.00	$0.00	$19.00
	2019-10	10/05/19	$0.00	$50.00	$0.00	$50.00
2019 Total			$0.00	$69.00	$0.00	$69.00
TOTAL			$100,000.00	$69.00	$0.00	$100,069.00

The total dollar amount disputed in the 2018 – 2019 AAA period is higher than in the 2017 – 2018 AAA period. During the current period the Company found a similar number discrepancies requiring a formal dispute to be filed with MISO where one dispute represented a majority of the total dollar amount disputed. Discrepancies not requiring a formal dispute are routinely resolved through the normal settlement process.

CONSERVATION IMPROVEMENT PROGRAM

Xcel Energy's Conservation Improvement Program (CIP), including energy efficiency, conservation and load management, is designed to help our customers use energy wisely. The Company has developed 35 commercial and residential CIP programs with the intent of providing our customers the opportunity to lower their energy consumption and overall energy bills.

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 customer education pilots aimed to help control demand through smart thermostats. 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 has three electric load management programs available to customers: Electric Rate Savings, Saver's Switch for Business® and Residential Demand Response. These programs provide customers rate discounts for reducing electric load on days with peak demand for electricity (termed "control periods" or "control days").

In the Electric Rate Savings program, business participants receive a monthly discount on their demand charges in return for reducing electric loads when notified by the Company. Customers must be able to reduce their electric loads by a minimum of 50 kW on control days. Participants can potentially save up to 50 percent on demand charges over the entire year for the demand they agree to reduce during control periods. Electric Rate Savings is designed to be utilized on hot, humid summer weekdays. Although control days typically occur during the summer months, they can occur anytime through the year when the reliability of the system may be at risk.

The Saver's Switch program – which is offered to business customers as a standalone program and to residential customers as part of the Residential Demand Response program – is a direct load control load management offering available to both business and residential customers. Similar to Electric Rate Savings, Saver's Switch is designed to be utilized on hot, humid summer weekdays. Saver's Switch participants receive electric bill discounts from June through September for agreeing to have the Company control electric central air conditioners during times of peak electric demand.[1]

Through our Residential Demand Response program, we also offer AC Rewards, which utilizes a smart thermostat to reduce customer air conditioner load during demand peaks. The opt-in control program allows customers to take control of their energy use during these peak times, earning an overall summer incentive.

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 2020 CIP Extension Plan, which was filed on July 1, 2019 and approved on November 26, 2019.[2]

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 2018 CIP Status Report on August 29, 2019.[3]

[1] Saver's Switch also has an additional water heating component providing year round incentives.
[2] Docket No. E,G002/CIP-16-115
[3] Docket No. E,G002/CIP-16-115.07.

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.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

PART E

AUTOMATIC ADJUSTMENT CHARGES

BASE COST OF ENERGY

On November 2, 2015, the Company filed a Petition to increase electric rates (Docket No. E002/GR-15-826). A new Base Cost of Energy (BCOE) of $0.02680 per kWh was approved in the associated docket, Docket No. E002/MR-15-827, and went into effect January 1, 2016. The Commission issued its Order approving the rate case on June 12, 2017. Final rates were implemented on October 1, 2017 and January 1, 2019.

The table below shows the Fuel Adjustment Factor (FAF) Ratio and BCOE by the Service Category effective during the July 1, 2018 through December 31, 2019 2018-2019 AAA period.

Service Category	FAF Ratio	BCOE
Residential	1.0177	$0.02727
C & I Non-Demand	1.0305	$0.02762
C & I Demand	0.9984	$0.02676
C & I Demand TOD On-Pk	1.2486	$0.03346
C & I Demand TOD Off-Pk	0.8166	$0.02188
Outdoor Lighting	0.7976	$0.02138

BILLING ADJUSTMENT AMOUNTS CHARGED TO CUSTOMERS FOR EACH TYPE OF ENERGY COST

Please refer to lines [2b] of Part E, Section 5, Schedule 1, Pages 5 and 6 of 14 for this information. The billing adjustments for the reporting period reflect several specific and distinct adjustments.

1. Class-Specific Fuel Cost Charge (FCC) Adjustments

The average system fuel cost is differentiated by six (6) separate class-specific charges. Schedule 1 includes detailed fuel, purchased energy costs and MISO Day 2 and ASM expenses data pursuant to reporting requirements under Minn. Rule 7825.2810 and the Commission's December 1, 2017 Order granting the Company's Renewal of Forecast FCA Method Rule Variance (Docket No. E002/M-17-445).

2. Exemption of WindSource

Pursuant to Commission Orders approving the Company's Voluntary Renewable Energy Rider (Windsource Program), beginning with the calendar month of March 2003, the Company is required to exempt Windsource energy from the Fuel Clause Adjustment.[1] Line [1b 13] of Part E, Section 5, Schedule 1, Pages 1 and 2 of 14 illustrates this amount of exempted energy.

As addressed in the Company's Windsource proceeding, a purchase of Renewable Energy Credits (RECs) is used to resolve the program deficit when wind farms do not generate enough wind energy to meet Windsource sales requirement over a 12 month period.[2]

As part of the 2011 test year general electric rate case (Docket No. E002/GR-10-971), the Company also agreed with the Department of Commerce's recommendation to more promptly credit retail customers through the FCC the Windsource "Brown Energy" as a result of use of RECs in place of a physical energy purchase. The May 2013 FCC was the beginning of such credits to retail customers on a quarterly basis that was previously applied annually. Beginning with July 2013 actuals, the "Brown

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[1] ORDER APPROVING XCEL'S RENEWABLE ENERGY RIDER WITH MODIFICATIONS, Docket No. E002/M-01-1479 (May 7, 2002); ORDER REQUIRING REVISED TARIFF, Docket No. E002/M-01-1479 (January 10, 2003).

[2] *See* Company response to Information Request No. DOC-14, November 20, 2009 in PETITION FOR APPROVAL OF REVISIONS TO ITS VOLUNTARY RENEWABLE AND HIGH EFFICIENCY PURCHASE (WINDSOURCE PROGRAM) RIDER (Docket No. E002/M-09-1177).

Energy" credit had been computed and returned to Minnesota retail customers on a monthly basis.

Pursuant to the Commission Order in Docket No. E002/M-19-0033, the Company received approval to transition the Windsource program to Renewable*Connect Month to Month program. Like Windsource, Renewable*Connect customers are also exempt from the Fuel Clause Adjustment. However, under the Renewable*Connect Month to Month program, the Company will no longer utilize the combination system energy ("brown energy") and purchased RECs as it has done for Windsource. Renewable*Connect will be sourced from 100% wind and solar energy. The Company anticipates the transition to Renewable*Connect to occur at the beginning of 2022 after the program's resources have been approved and have reached commercial operation. Until the transition, the Company will continue to operate the Windsource program as it has done since 2003.

3. MISO Day 2 Energy Market Charges

Pursuant to Commission Orders in Docket No. E002/M-04-1970 *et al.*,[3] the Company was authorized to recover certain MISO Day 2 wholesale energy market costs incurred starting April 1, 2005 through the FCA.

In November 2005, the Company filed its electric general rate case (Docket No. E002/GR-05-1428) using a 2006 test year. The rate case sought recovery of all MISO Day 1 and Day 2 charges in either base rates or the FCA. The Commission's interim rate order transferred collection of the MISO Schedule 16 and 17 energy market administrative charges from the base cost of the FCR to base rates.[4] Because the Company's FCA is on a forecast basis, the Company's March 2006 forecast excluded the Schedule 16 and 17 costs from the fuel and energy costs, pursuant to the Commission's decisions in Docket Nos. E002/GR-05-1428 and E002/M-05-1759.

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[3] ORDER AUTHORIZING INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, SUBJECT TO REFUND WITH INTEREST, Docket No. E002/M-04-1970 et al. (April 7, 2005); and ORDER ESTABLISHING SECOND INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, PROVIDING FOR REFUNDS, AND INITIATING INVESTIGATION, Docket No. E002/M-04-1970 et al. (December 21, 2005); ORDER ON RECONSIDERATION SUSPENDING REFUND, GRANTING DEFERRED ACCOUNTING AND REQUIRING FILINGS (February 24, 2006); and ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS (December 20, 2006) (together the "MISO Day 2 Orders"). *Aff'd by* Minnesota Court of Appeals in A07-0730 (April 15, 2008).

[4] "Xcel [Energy] has submitted a revised schedule, which the Commission finds consistent with the Commission's decision to reclassify Schedule 16 and 17 costs from fuel costs (hence collectible through the Fuel Adjustment Clause) to those recoverable through the base tariff rates." *In the Matter of Xcel Energy's Petition for Approval of a New Base Cost of Energy*, Docket No. E002/M-05-1759, ORDER APPROVING NEW BASE ELECTRIC COST AND REQUIRING ADJUSTED TARIFF (December 30, 2005), p. 2.

Schedule 16 and 17 costs were collected in interim rates outside of the FCA effective January 1, 2006. Line items [1b 5] and [1b 10] of Part E Section 5 Schedule 1, Pages 1 and 2 of 14 contain the monthly MISO Day 2 charges and Schedules 16, 17 and 24 amounts excluded from the monthly fuel clause.[5]

As a result of the obligations in the 2005 rate case and MISO Day 2 dockets, the following monthly refunds have been incorporated since the March 2007 FCC:

a. Asset Based Margin Sharing

The ongoing Asset Based Margin Sharing is included in the monthly Fuel Cost Charge on a two months lag basis.

b. Deferred Auction Revenue Rights(ARR) Credit

On March 17, 2009, the Commission issued an Order in Docket No. E001, E015, E002, E017/M-08-528, which authorized the Company to flow through three new Financial Transmission Rights (FTRs) amounts and four ARR charge types.

The three new FTR items are:

- FTR Full Funding Guarantee Amount
- FTR Guarantee Uplift Amount
- FTR Monthly Transaction Amount;

The four new ARR charge types are:

- ARR- FTR Auction Transactions
- Monthly ARR Revenue
- Infeasible ARR Uplift
- ARR Stage 2 Distribution

[5] The Company included its 2005 Schedule 16 and 17 costs in the FCA pending the outcome of Docket No. E002/M-04-1970, based on the April 7, 2005 interim order. The settlement in the Company's 2005 rate case (Docket No. E002/GR-05-1428) allowed base rate recovery of fifty percent; and deferred accounting of fifty percent of the 2006 test year Schedule 16 and 17 costs (approximately $8.9 million total) until the Company's next electric general rate case, rather than recover the full costs in the final rates in the 2005 rate case. The Commission approved the settlement agreement on September 1, 2006.

4. MISO Ancillary Services Market (ASM) Charges

On December 20, 2006 the Commission issued an Order in Docket No. E002/M-04-1970, et al., adopting the recommendation of the Joint Report and Recommendation (Joint Report) prepared by stakeholders, which, except for Schedules 16 and 17 costs, allowed the Company to recover the charges for MISO Day 2 operations.[6] On February 6, 2008 the Commission issued an Order in Docket No. E001/M-05-406, et. al., which made certain amendments to the December 20, 2006 Order, namely requiring Revenue Sufficiency Guarantee (RSG) charges and Revenue Neutrality Uplift (RNU) charges to be allocated on a straight megawatt-hour basis. Finally, and as noted above, on August 23, 2010 the Commission issued an order in Docket No. E001, E015, E002, E017/M-08-528,[7] which authorized the Company to recover costs and flow through revenues related to the new MISO ASM charge types. Line [1b 11] of Part E Section 5 Schedule 1, Pages 1 and 2 of 14 contains the monthly MISO ASM charges. In compliance with the Commission's March 16, 2018 Order, Day-Ahead and Real-Time Ramp Capability charges are reported as separate line items and are not combined with other MISO ancillary services market charges. See Part J, Section 5, Schedule 14, page 2 of 2 for the amounts.

5. Community Solar Garden Program Cost Recovery

Pursuant to the Commission's September 17, 2014 Order in our Community Solar Gardens Program (Docket No. E002/M-13-867), the Company is authorized to recover certain costs associated with this program through the Minnesota FCR. The costs include customer bill credits, additional Renewable Energy Credits (RECs) and unsubscribed energy. As of December 2019, the Company is recovering the monthly fuel costs from 268 community solar garden sites, or 690 community solar gardens. See Part H, Section 9 of this report for more detailed information.

6. Renewable*Connect Program

Pursuant to the Commission's February 27, 2017 Order in Docket No. E002/M-15-985, beginning with calendar month March 2017, the Company is required to exempt Renewable*Connect and Renewable*Connect Government pilot program energy from the Fuel Clause Adjustment. Line [1b 16] of Part E, Section 5, Schedule 1, Pages 1 and 2 of 14 illustrates this amount of exempted energy.

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[6] Those stakeholders included Minnesota investor-owned electric utilities, Minnesota Department of Commerce, MISO, Minnesota Chamber of Commerce and Large Power Interveners.

[7] Pursuant to the final Order, the Contingency Reserve Deployment Failure and the Excess/Deficient Energy charges are subject to refund.

TOTAL COST OF FUEL DELIVERED TO CUSTOMERS

Line item [3 1] of Part E, Section 5, Schedule 1, Pages 7 and 8 of 14, contains the Minnesota retail portion of NSP System fuel and purchased energy costs in cents per kWh. (The "NSP System" refers to the integrated generation and transmission systems of Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin.)

The class differentiated FCC method was used July 1, 2018 through December 31, 2019, the 2019 AAA reporting period. The individual class totals were reported on line items [3 23] through [3 29].

REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED

Line [4 8] and Line [4 16] of Part E, Section 5, Schedule 1, Pages 9 and 10 of 14 contain the Minnesota retail electric fuel revenues collected under both the Base Cost of Energy and fuel clause adjustment (fuel cost excess of Base).

While comparing line item cost and revenues may appear to reveal a mismatch between the current month cost and the collections in that month, such a comparison does not necessarily reveal an accurate picture of the financial impact such collections have on the Company. Following accepted accounting principles, each month Xcel Energy books an estimate of the expected future recovery of the energy costs associated with the current month. This accounting properly matches the energy expense of a particular month with the future cost recovery (the fuel clause revenue) associated with those expenses.

Line items [4 48] to [4 55] of Part E, Section 5, Schedule 1, Pages 9 and 10 of 14 are the actual fuel costs and the individual class totals that included the forecast true-up and any applicable recovery/refunds during the AAA reporting period.

In compliance with the Commission's December 7, 2005 Order in the 2004 electric AAA proceeding (Docket No. E,G999/AA-04-1279), the Company has included Part E, Section 5, Schedules 2, 3, 4 and 5 showing the reasonable proxies for billing adjustment amounts for each type of energy cost, pursuant to the Commission's interpretation of Rule 7825.2810, subp 1B.

	Month Fuel Cost Charges Applied to Customer Billing	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
MONTH AHEAD FORECASTED COST OF FUEL													
	Account 151 Fossil Fuel												
[1a 1]	Coal	$30,369,797	$30,733,677	$20,021,142	$27,865,266	$28,532,928	$34,090,958	$29,358,903	$25,313,700	$19,022,208	$18,291,646	$23,309,037	$22,654,695
[1a 2]	Wood/RDF	$1,112,550	$1,136,156	$833,680	$699,714	$1,092,815	$1,159,570	$1,111,543	$969,666	$711,697	$649,379	$1,055,192	$1,047,742
[1a 3]	Natural Gas CC	$12,064,389	$11,286,100	$8,251,407	$6,818,769	$5,455,338	$6,067,528	$14,595,038	$4,971,955	$8,897,062	$7,962,456	$11,602,584	$11,353,539
[1a 4]	Natural Gas / Oil CT	$2,789,710	$2,211,159	$1,014,390	$267,380	$175,705	$120,913	$401,960	$395,982	$398,944	$664,456	$1,353,250	$2,120,491
[1a 5]	Total Fossil Fuel	$46,336,446	$45,367,092	$30,120,619	$35,651,129	$35,256,786	$41,438,969	$45,467,444	$31,651,303	$29,029,911	$27,567,937	$37,320,063	$37,176,467
[1a 6]	Account 518 Nuclear Fuel	$9,734,904	$9,344,440	$8,005,480	$7,082,381	$9,926,580	$9,889,006	$10,028,217	$8,784,648	$9,358,211	$7,436,365	$8,434,654	$9,782,365
[1a 7]	Account 555 Energy Purchases	$60,530,395	$49,568,237	$42,985,575	$42,748,370	$38,251,912	$41,530,841	$45,735,272	$38,576,784	$41,931,005	$40,051,583	$43,426,203	$42,745,302
	Less: Fuel Cost of Intersystem Sales			$676,760	$3,164,075	$5,849,509	$4,265,316	$7,246,501	$3,209,927	$2,983,494	$3,450,042	$9,424,946	$6,493,157
	Less: Windsource and Renewable*Connect Cost	483,134.72	514,724.00	814,173	969,655	932,008	981,833	1,012,858	945,425	980,783	1,123,137	1,324,298	1,222,935
[1a 8]	Net System Cost Sum [1a 1]..[1a 7]	$116,118,611	$103,765,045	$79,620,741	$81,348,150	$76,653,761	$87,611,667	$92,971,574	$74,857,383	$76,354,850	$70,482,706	$78,431,676	$81,988,042
[1a 9]	Forecasted System MWH Sales *	3,946,643	3,872,701	3,273,839	3,167,413	3,142,629	3,451,075	3,552,874	3,037,025	3,278,380	2,892,061	3,149,163	3,478,722
[1a 10]	Forecasted Minn. Retail Sales Subject to FCC *	2,928,135	2,849,062	2,393,339	2,288,091	2,252,324	2,456,036	2,512,046	2,165,866	2,339,091	2,073,039	2,266,847	2,527,282
[1a 11]	Forecasted Cost of Fuel Per kWh [1a 8]/[1a 9]/10 **	2.942¢	2.679¢	2.432¢	2.568¢	2.439¢	2.539¢	2.617¢	2.465¢	2.329¢	2.437¢	2.491¢	2.357¢
[1a 12]	Forecasted Biomass PPA Termination Cost Recovery			$1,288,347	$1,255,519	$961,357	$1,340,695	$1,217,440	$988,646	$992,564	$989,456	$986,079	$985,367
[1a 13]	Forecasted Solar Gardens Above Market Cost Allocated to MN Jurisdiction			$5,946,488	$5,070,632	$3,804,574	$2,743,639	$3,892,766	$6,710,601	$9,748,665	$11,524,051	$13,894,686	$12,217,328
[1a 14]	Forecasted Minnesota Jurisdiction Direct Cost			$7,234,835	$6,326,151	$4,765,931	$4,084,334	$5,110,206	$7,699,247	$10,741,229	$12,513,507	$14,880,765	$13,202,695
[1a 15]	Forecasted Minnesota Jurisdiction Direct Cost Per kWh [1a 14]/[1a 9]/10 **			0.302¢	0.276¢	0.212¢	0.166¢	0.203¢	0.355¢	0.459¢	0.604¢	0.656¢	0.522¢
[1a 16]	Forecasted Total Minnesota Jurisdictional Energy Cost	$86,145,743	$76,326,381	$65,433,880	$65,073,304	$59,709,098	$66,435,786	$70,839,684	$61,077,424	$65,213,847	$63,041,121	$71,337,672	$72,760,454
[1a 17]	Forecasted Total Minnesota Jurisdictional Energy Cost Per kWh	2.942¢	2.679¢	2.734¢	2.844¢	2.651¢	2.705¢	2.820¢	2.820¢	2.788¢	3.041¢	3.147¢	2.879¢
ACTUAL COST OF FUEL													
[1b 1]	Account 151 Fossil Fuel	$53,303,552	$49,927,145	$42,354,879	$38,990,862	$45,454,418	$43,546,149	$46,075,337	$45,510,964	$39,723,436	$29,061,801	$37,581,979	$41,424,892
[1b 2]	Account 518 Nuclear Fuel	$10,476,560	$10,359,705	$8,491,311	$7,591,733	$10,212,886	$10,920,319	$10,475,574	$9,289,472	$9,929,308	$7,509,241	$8,912,307	$10,281,039
[1b 3]	Account 555 Energy Purchase (Ex Wind Curtailment Payment)	$56,246,444	$46,332,352	$47,050,833	$46,046,829	$34,445,059	$40,227,674	$44,309,264	$32,897,760	$48,675,546	$38,733,157	$50,251,814	$62,203,678
[1b 4]	Acct 555 Wind Curtailment Payment	$32,826	$25,341	$5,430	$64,513	$18,908	$66,293	$338,305	$138,587	$84,704	$97,525	$691,008	$346,503
[1b 5]	Account 555 MISO Day 2	$7,451,152	$6,913,746	$7,277,137	$10,493,511	$7,436,250	$7,176,374	$13,266,933	$7,901,462	$8,916,309	$7,230,771	$4,656,401	$2,224,746
[1b 6]	- Less: Account 555 MISO Day 2 - Sched. 16 & 17	$675,995	$571,063	$666,786	$804,664	$875,277	$676,250	$476,755	$535,109	$715,936	$666,682	$666,890	$889,451
[1b 7]	- Less: Account 555 MISO Day 2 - Sched. 24	$78,974	$107,836	$96,619	$101,812	$105,958	$96,697	$93,325	$95,362	$77,449	$109,987	$80,194	$101,373
[1b 8]	- Less: RSG/RNU Allocation Adjustment	$92,682	$26,482	$68,649	$90,207	$104,789	$106,746	$24,219	$432,432	$86,090	$55,507	$186,615	$79,078
[1b 9]	- Less: Congestion and Loss Allocation Adjustment	$883,273	$356,376	$624,089	$344,764	$776,436	$850,969	$848,216	$835,403	$888,519	$328,283	$932,845	$744,924
[1b 10]	Account 555 MISO Day 2 - Net	$5,720,227	$5,851,988	$5,820,994	$9,152,064	$5,573,791	$5,445,712	$11,824,417	$6,003,157	$7,148,315	$6,070,312	$2,789,857	$409,920
[1b 11]	Account 555 MISO ASM	$3,393,957	$2,928,566	$3,391,851	$2,746,368	$999,520	$1,413,903	$992,409	($346,287)	($669,516)	($1,296,834)	$3,361,017	($397,634)
[1b 12]	Less: Fuel Cost - Intersystem Sales	$19,998,175	$13,489,773	$15,739,978	$13,833,029	$15,701,935	$20,953,148	$21,155,828	$16,581,096	$18,164,790	$9,725,132	$20,732,706	$28,442,096
[1b 13]	Less: Net Windsource Program Expenses***	$976,183	$847,318	$529,569	$657,893	$582,611	$664,861	$540,102	$619,804	$1,534,638	($652,420)	$1,296,819	$733,006
[1b 14]	Less: Solar Gardens Program Costs (Above Market Portion)	$7,826,811	$4,911,139	$5,731,902	$5,050,152	$3,994,342	$2,828,022	$3,657,470	$734,935	$7,683,784	$5,175,210	$9,353,967	$10,051,617
[1b 15]	Less: Solar Garden Developer Late Fees	($221,600)	($95,400)	$0	($30,838)	($65,400)	$0	($55,000)	($197,800)	($165,250)	$0	$0	$0
[1b 16]	Less: Renewable*Connect Program Energy Costs	$346,072	$501,015	$562,807	$509,959	$474,959	$487,146	$499,600	$486,911	$507,766	$481,103	$466,286	$472,317
[1b 17]	Final Adjusted Net System Cost [1]+[2]+[3]+[4]+[10]+[11]-[12]-[13]-[14]-[15]-[16]	$100,247,924	$95,771,252	$84,551,043	$84,572,174	$76,016,136	$76,686,872	$88,217,306	$75,268,707	$77,166,064	$65,446,176	$71,738,204	$74,569,362
[1b 18]	Total MWH Sales (Cal. Month)	4,007,848	4,111,024	3,448,108	3,225,372	3,201,691	3,499,274	3,547,618	3,107,612	3,478,924	3,007,583	3,161,596	3,366,158
[1b 19]	Total Retail State of Minnesota	2,974,636	3,021,236	2,536,443	2,323,426	2,300,971	2,512,051	2,534,050	2,211,435	2,503,585	2,166,738	2,285,434	2,457,615
[1b 20]	MN Windsource & Renewable*Connect MWh not subject to FCA	28,641	34,343	31,999	32,589	28,257	30,935	32,363	30,583	31,553	42,720	41,612	43,188
[1b 21]	Total Retail State of Minnesota subject to FCA	2,945,995	2,986,893	2,504,444	2,290,837	2,272,714	2,481,116	2,501,687	2,180,852	2,472,032	2,124,018	2,243,822	2,414,427
[1b 22]	Actual Cost of Fuel per kWh [1b 17])/([1b 18]-[1b 20])/10**	2.519¢	2.349¢	2.475¢	2.649¢	2.395¢	2.211¢	2.510¢	2.446¢	2.238¢	2.207¢	2.299¢	2.244¢
[1b 23]	Net System Cost Applicable to MN Jurisdiction	$74,209,614	$70,169,464	$61,986,717	$60,680,928	$54,431,500	$54,858,839	$62,781,236	$53,346,889	$55,334,038	$46,885,425	$51,592,491	$54,181,142
[1b 24]	Benson Amortization - FERC 557 (Regulatory Asset)	$315,106	$320,286	$298,368	$298,532	$299,145	$298,203	$297,210	$299,013	$296,535	$296,672	$285,193	$286,965
[1b 25]	Benson Amortization - FERC 407 (Plant Impairment)	$295,751	$298,974	$297,362	$297,362	$297,362	$297,362	$297,362	$297,362	$297,362	$297,362	$297,362	$297,362
[1b 26]	Benson ROE (Regulatory Asset) - FERC 182.2	$165,475	$165,475	$165,475	$165,475	$165,475	$165,475	$188,937	$187,329	$185,720	$184,112	$182,504	$180,896
[1b 27]	Benson ROE (Regulatory Impairment) - FERC 182.3	$148,527	$148,536	$148,536	$148,535	$147,408	$147,504	$174,255	$172,661	$171,220	$169,452	$168,136	$167,478
[1b 28]	Benson O&M Pass Through	$569,604	$634,529	($54,884)	$193,365	$305,696	$467,539	($74,226)	($231,186)	$35,398	($27)	$0	$0
[1b 29]	Laurentian	$13,387,946	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,005,125	$0
[1b 30]	Pine Bend	$28,003	$28,698	$32,389	$31,699	$21,885	$27,110	$25,452	$28,918	$32,718	$37,397	$45,054	$44,879
[1b 31]	Total Biomass PPA Termination Cost Recovery	$14,910,412	$1,596,498	$887,246	$1,134,968	$1,236,971	$1,403,193	$908,990	$754,097	$1,018,953	$984,968	$13,983,374	$977,580
[1b 32]	Solar Gardens Above Market Bill Credit Amount	$7,826,811	$4,911,139	$5,731,902	$5,050,152	$3,994,342	$2,828,022	$3,657,470	$734,935	$7,664,181	$5,192,256	$9,494,967	$10,051,617
[1b 33]	Less Solar Garden Developer Late Fees Credit	$221,600	$95,400	$0	$30,838	$65,400	$0	$55,000	$197,800	$165,250	$0	$141,000	$0
[1b 34]	Solar Gardens Above Market Cost Allocated to MN Jurisdiction	$7,605,211	$4,815,739	$5,731,902	$5,019,314	$3,928,942	$2,828,022	$3,602,470	$537,135	$7,498,931	$5,175,210	$9,353,967	$10,051,617
[1b 35]	Minnesota Jurisdiction Direct Cost	$22,515,623	$6,412,237	$6,619,148	$6,154,282	$5,165,913	$4,231,215	$4,511,460	$1,291,232	$8,517,884	$6,160,178	$23,337,341	$11,029,197
[1b 36]	Minnesota Jurisdiction Direct Cost Per kWh	0.764¢	0.215¢	0.264¢	0.269¢	0.227¢	0.171¢	0.180¢	0.059¢	0.345¢	0.290¢	1.040¢	0.457¢
[1b 37]	Total Minnesota Jurisdictional Energy Cost	$96,725,237	$76,581,701	$68,605,865	$66,835,209	$59,597,413	$59,090,054	$67,292,696	$54,638,121	$63,851,922	$53,045,603	$74,929,832	$65,210,339
[1b 3822]	Total Minnesota Jurisdictional Energy Cost Per kWh [1b 22]+[1b 36]	3.283	2.564	2.739	2.918	2.622	2.382	2.690	2.505	2.583	2.497	3.339	2.701
[1b 39	Deviation (Actual Vs. Forecast) [1a 38] - [1b 17] **	0.341¢	-0.115¢	0.005¢	0.074¢	-0.029¢	-0.323¢	-0.130¢	-0.315¢	-0.205¢	-0.544¢	0.192¢	-0.178¢

	Month Fuel Cost Charges Applied to Customer Billing	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
MONTH AHEAD FORECASTED COST OF FUEL								
	Account 151 Fossil Fuel							
[1a 1]	Coal	$23,646,155	$23,767,747	$20,972,652	$21,184,230	$21,778,103	$25,359,947	$446,272,791
[1a 2]	Wood/RDF	$1,113,205	$1,136,030	$1,066,650	$993,381	$942,429	$981,213	$17,812,612
[1a 3]	Natural Gas CC	$12,741,389	$12,540,974	$8,923,686	$11,894,926	$5,108,092	$5,432,322	$165,967,554
[1a 4]	Natural Gas / Oil CT	$4,779,253	$4,415,855	$956,950	$643,396	$397,764	$441,145	$23,548,703
[1a 5]	Total Fossil Fuel	$42,280,002	$41,860,606	$31,919,938	$34,715,933	$28,226,388	$32,214,627	$653,601,660
[1a 6]	Account 518 Nuclear Fuel	$9,841,872	$10,005,490	$9,526,377	$7,107,706	$9,502,872	$10,430,159	$164,221,727
[1a 7]	Account 555 Energy Purchases	$46,974,094	$43,578,360	$38,974,373	$41,699,998	$37,562,857	$39,493,366	$776,364,527
	Less: Fuel Cost of Intersystem Sales	$4,197,035	$4,285,254	$6,287,528	$8,287,208	$5,417,664	$4,760,119	$79,998,535
	Less: Windsource and Renewable*Connect Cost	1,417,063	1,500,976	1,338,391	1,292,600	1,166,487	1,257,392	$19,277,873
[1a 8]	Net System Cost Sum [1a 1]..[1a 7]	$93,481,870	$89,658,226	$72,794,769	$73,943,829	$68,707,966	$76,120,641	$1,494,911,507
[1a 9]	Forecasted System MWH Sales *	3,939,188	3,824,528	3,221,796	3,108,462	3,051,091	3,437,639	60,825,227
[1a 10]	Forecasted Minn. Retail Sales Subject to FCC *	2,886,731	2,759,956	2,326,772	2,229,409	2,169,745	2,445,017	43,868,787
[1a 11]	Forecasted Cost of Fuel Per kWh [1a 8]/[1a 9]/10 **	2.373¢	2.344¢	2.259¢	2.379¢	2.252¢	2.214¢	2.458¢
[1a 12]	Forecasted Biomass PPA Termination Cost Recovery	$979,035	$972,276	$979,447	$975,722	$971,103	$961,267	$16,844,320
[1a 13]	Forecasted Solar Gardens Above Market Cost Allocated to MN Jurisdiction	$14,052,907	$13,463,262	$10,142,853	$7,952,077	$5,350,252	$4,493,158	$131,007,939
[1a 14]	Forecasted Minnesota Jurisdiction Direct Cost	$15,031,942	$14,435,538	$11,122,300	$8,927,799	$6,321,355	$5,454,425	$147,852,259
[1a 15]	Forecasted Minnesota Jurisdiction Direct Cost Per kWh [1a 14]/[1a 9]/10 **	0.521¢	0.523¢	0.478¢	0.400¢	0.291¢	0.223¢	0.337¢
[1a 16]	Forecasted Total Minnesota Jurisdictional Energy Cost	$83,541,984	$79,127,926	$63,683,761	$61,955,288	$55,176,604	$59,585,053	$1,226,132,596
[1a 17]	Forecasted Total Minnesota Jurisdictional Energy Cost Per kWh	2.894¢	2.867¢	2.737¢	2.779¢	2.543¢	2.437¢	2.795¢
ACTUAL COST OF FUEL								
[1b 1]	Account 151 Fossil Fuel	$48,145,198	$38,890,885	$31,656,070	$28,130,292	$30,777,503	$30,272,020	$720,827,381
[1b 2]	Account 518 Nuclear Fuel	$10,479,546	$10,448,678	$9,232,488	$7,967,255	$10,395,029	$10,765,431	$173,737,882
[1b 3]	Account 555 Energy Purchase (Ex Wind Curtailment Payment)	$70,511,707	$64,677,375	$61,595,473	$55,314,526	$48,808,076	$50,544,451	$898,872,018
[1b 4]	Acct 555 Wind Curtailment Payment	$104,402	$192,927	$82,122	$47,011	$318,684	$318,684	$2,973,774
[1b 5]	Account 555 MISO Day 2	$5,242,820	$2,555,930	$4,279,877	$7,747,330	$6,663,947	$6,379,070	$123,813,768
[1b 6]	- Less: Account 555 MISO Day 2 - Sched. 16 & 17	$707,970	$397,707	$602,482	$706,209	$610,302	$790,376	$12,035,905
[1b 7]	- Less: Account 555 MISO Day 2 - Sched. 24	$94,086	$106,425	$80,321	$88,828	$83,549	$108,486	$1,707,282
[1b 8]	- Less: RSG/RNU Allocation Adjustment	$120,152	$98,357	$35,604	$124,162	$16,457	$94,572	$1,842,799
[1b 9]	- Less: Congestion and Loss Allocation Adjustment	$1,399,288	$1,141,372	$906,856	$907,270	$970,081	$846,635	$14,585,601
[1b 10]	Account 555 MISO Day 2 - Net	$2,921,324	$812,068	$2,654,615	$5,920,862	$4,983,557	$4,539,001	$93,642,181
[1b 11]	Account 555 MISO ASM	$2,839,097	$2,602,761	$3,098,091	$679,504	$932,736	$1,114,868	$27,784,377
[1b 12]	Less: Fuel Cost - Intersystem Sales	$37,253,272	$29,847,648	$28,644,592	$20,724,992	$23,524,005	$24,721,487	$379,233,682
[1b 13]	Less: Net Windsource Program Expenses***	$1,206,231	$1,447,257	$1,460,523	$246,021	$833,335	$760,987	$14,284,739
[1b 14]	Less: Solar Gardens Program Costs (Above Market Portion)	$10,965,447	$10,781,126	$9,519,667	$8,805,427	$3,320,733	$5,452,794	$115,844,544
[1b 15]	Less: Solar Garden Developer Late Fees	$0	$0	($171,800)	($32,744)	($154,614)	($427,800)	($1,618,246)
[1b 16]	Less: Renewable*Connect Program Energy Costs	$528,508	$551,405	$453,520	$588,919	$450,957	$480,010	$8,849,261
[1b 17]	Final Adjusted Net System Cost [1]+[2]+[3]+[4]+[10]+[11]-[12]-[13]-[14]-[15]-[16]	$85,047,816	$74,997,259	$68,412,357	$67,726,834	$68,241,169	$66,566,977	$1,401,243,632
[1b 18]	Total MWH Sales (Cal. Month)	3,932,821	3,668,664	3,313,567	3,212,456	3,143,980	3,395,867	61,830,163
[1b 19]	Total Retail State of Minnesota	2,883,240	2,678,659	2,438,237	2,304,570	2,265,893	2,437,202	44,835,421
[1b 20]	MN Windsource & Renewable*Connect MWh not subject to FCA	49,597	51,785	47,349	50,316	41,826	46,962	696,618
[1b 21]	Total Retail State of Minnesota subject to FCA	2,833,643	2,626,874	2,390,888	2,254,254	2,224,067	2,390,240	44,138,803
[1b 22]	Actual Cost of Fuel per kWh [1b 17])/([1b 18]-[1b 20])/10**	2.190¢	2.074¢	2.095¢	2.142¢	2.200¢	1.988¢	2.292¢
[1b 23]	Net System Cost Applicable to MN Jurisdiction	$62,060,579	$54,481,367	$50,078,201	$48,281,702	$48,925,026	$47,511,374	$1,011,796,534
[1b 24]	Benson Amortization - FERC 557 (Regulatory Asset)	$286,394	$286,302	$286,223	$284,922	$284,334	$284,173	$5,303,576
[1b 25]	Benson Amortization - FERC 407 (Plant Impairment)	$297,362	$297,362	$297,362	$297,362	$297,259	$285,445	$5,340,497
[1b 26]	Benson ROE (Regulatory Asset) - FERC 182.2	$179,288	$177,679	$176,071	$174,463	$172,807	$165,570	$3,148,226
[1b 27]	Benson ROE (Regulatory Impairment) - FERC 182.3	$168,291	$169,341	$169,213	$168,037	$166,751	$166,740	$2,920,621
[1b 28]	Benson O&M Pass Through	$61	$5,458	$0	$0	$0	$0	$1,851,327
[1b 29]	Laurentian	$0	$0	$0	$0	$0	$0	$26,393,071
[1b 30]	Pine Bend	$37,050	$42,462	$47,277	$49,441	$43,201	$46,613	$650,246
[1b 31]	Total Biomass PPA Termination Cost Recovery	$968,446	$978,604	$976,146	$974,225	$964,352	$948,541	$45,607,564
[1b 32]	Solar Gardens Above Market Bill Credit Amount	$10,965,447	$10,781,126	$9,519,667	$8,805,427	$3,320,733	$5,452,794	$115,982,987
[1b 33]	Less Solar Garden Developer Late Fees Credit	$0	$0	$171,800	$32,744	$154,614	$427,800	$1,759,246
[1b 34]	Solar Gardens Above Market Cost Allocated to MN Jurisdiction	$10,965,447	$10,781,126	$9,347,867	$8,772,683	$3,166,119	$5,024,994	$114,206,696
[1b 35]	Minnesota Jurisdiction Direct Cost	$11,933,893	$11,759,730	$10,324,013	$9,746,908	$4,130,471	$5,973,535	$159,814,260
[1b 36]	Minnesota Jurisdiction Direct Cost Per kWh	0.421¢	0.448¢	0.432¢	0.432¢	0.186¢	0.250¢	0.362¢
[1b 37]	Total Minnesota Jurisdictional Energy Cost	$73,994,471	$66,241,097	$60,402,214	$58,028,611	$53,055,497	$53,484,909	$1,171,610,793
[1b 3822]	Total Minnesota Jurisdictional Energy Cost Per kWh [1b 22]+[1b 36]	2.611	2.522	2.526	2.574	2.386	2.238	2.654
[1b 39	Deviation (Actual Vs. Forecast) [1a 38] - [1b 17] **	-0.283¢	-0.345¢	-0.211¢	-0.205¢	-0.157¢	-0.199¢	-0.166¢

	Month Fuel Cost Charges Applied to Customer Billing	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
MONTHLY FUEL CLAUSE ADJUSTMENT FACTOR													
[1c 1a]	Forecasted Cost of Fuel Per kWh [1a 11] **	2.942¢	2.679¢	2.432¢	2.568¢	2.439¢	2.539¢	2.617¢	2.465¢	2.329¢	2.437¢	2.491¢	2.357¢
[1c 1b]	Forecasted Total Minnesota Jurisdictional Energy Cost Per kWh [1 17]	2.942¢	2.679¢	2.734¢	2.844¢	2.651¢	2.705¢	2.820¢	2.820¢	2.788¢	3.041¢	3.147¢	2.879¢
	True Up and Other Recoveries	**[TRADE SECRET DATA BEGINS**											
[1c 2]	Prior (2 Months Lag) Unrecovered Expenses												
[1c 3]	Less: Prior (2 Months Lag) Recovered Expenses												
[1c 4]	Over/Under Recovery (Actual Month)												
[1c 5]	Actual Cost Should have been recovered (Actual Month)												
	Other Recoveries/Adjustment												
[1c 6]	Saver's Switch Discount (Actual Month)												
[1c 7]	SES Exemption Recovery (Actual Month)												
[1c 8]	Solar Garden Recovery												
[1c 9]	Developer Late Fee												
[1c 9a]	NSPW Solar Garden Adjustment												
	Other Refunds												
[1c 10]	Sherco Outage Settlement Refund												
[1c 11]	Sherco Land Sale Gain Refund True Up												
[1c 12]	Inver Hill Asset Sale Refund ROE Adjustment												
[1c 12a]	High Bridge Gas Cost Refund												
[1c 13]	Balance of Unrecovered Expenses [2]-[3]-[4]+Sum[1c 5]..[1c 12]												
[1c 14]	Forecasted Minn. Retail Sales Subject to FCC *												
													TRADE SECRET DATA ENDS]
[1c 15]	True-Up of Actual Month [1c 13]/[1c 14]/10 **	0.412¢	-0.119¢	-0.009¢	0.076¢	-0.024¢	-0.738¢	-0.126¢	-0.320¢	-0.197¢	-0.442¢	0.153¢	-0.177¢
[1c 16]	True-Up Factor Applied to Billing (2-Month Lag)	-0.107¢	-0.354¢	0.412¢	-0.119¢	-0.009¢	0.076¢	-0.024¢	-0.738¢	-0.126¢	-0.320¢	-0.197¢	-0.442¢
[1c 17]	System Asset Based Margins Sharing Refund [5a 3]	-0.077¢	-0.084¢	-0.119¢	-0.035¢	-0.085¢	-0.053¢	-0.141¢	-0.113¢	-0.047¢	-0.124¢	-0.054¢	-0.063¢
[1c 18]	Fuel Clause Charge [1c1]+[1 c15]+[1c 17] **	2.759¢	2.241¢	3.027¢	2.690¢	2.557¢	2.728¢	2.655¢	1.969¢	2.615¢	2.597¢	2.896¢	2.374¢

* Calendar Month ** In cents per KWh

	Month Fuel Cost Charges Applied to Customer Billing	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
MONTHLY FUEL CLAUSE ADJUSTMENT FACTOR								
[1c 1a]	Forecasted Cost of Fuel Per kWh [1a 11] **	2.373¢	2.344¢	2.259¢	2.379¢	2.252¢	2.214¢	2.458¢
[1c 1b]	Forecasted Total Minnesota Jurisdictional Energy Cost Per kWh [1 17]	2.894¢	2.867¢	2.737¢	2.779¢	2.543¢	2.437¢	2.795¢
	True Up and Other Recoveries	**[TRADE SECRET DATA BEGINS**						
[1c 2]	Prior (2 Months Lag) Unrecovered Expenses							
[1c 3]	Less: Prior (2 Months Lag) Recovered Expenses							
[1c 4]	Over/Under Recovery (Actual Month)							
[1c 5]	Actual Cost Should have been recovered (Actual Month)							
	Other Recoveries/Adjustment							
[1c 6]	Saver's Switch Discount (Actual Month)							
[1c 7]	SES Exemption Recovery (Actual Month)							
[1c 8]	Solar Garden Recovery							
[1c 9]	Developer Late Fee							
[1c 9a]	NSPW Solar Garden Adjustment							
	Other Refunds							
[1c 10]	Sherco Outage Settlement Refund							
[1c 11]	Sherco Land Sale Gain Refund True Up							
[1c 12]	Inver Hill Asset Sale Refund ROE Adjustment							
[1c 12a]	High Bridge Gas Cost Refund							
[1c 13]	Balance of Unrecovered Expenses [2]-[3]-[4]+Sum[1c 5]..[1c 12]							
[1c 14]	Forecasted Minn. Retail Sales Subject to FCC *							
								TRADE SECRET DATA ENDS]
[1c 15]	True-Up of Actual Month [1c 13]/[1c 14]/10 **	-0.332¢	-0.421¢	-0.232¢	-0.307¢	-0.155¢	-0.196¢	-0.167¢
[1c 16]	True-Up Factor Applied to Billing (2-Month Lag)	0.153¢	-0.177¢	-0.332¢	-0.421¢	-0.232¢	-0.307¢	-0.159¢
[1c 17]	System Asset Based Margins Sharing Refund [5a 3]	-0.085¢	-0.080¢	-0.042¢	-0.041¢	-0.029¢	-0.030¢	-0.077¢
[1c 18]	Fuel Clause Charge [1c1]+[1 c15]+[1c 17] **	2.963¢	2.610¢	2.363¢	2.317¢	2.282¢	2.101¢	2.215¢

* Calendar Month ** In cents per KWh

RULE 7825.2810 SUBPART 1 A: COMMISSION-APPROVED BASE COST OF FUEL

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
[2a 1]	System Base cost of Fuel **	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢
[2a 2]	Residential FAF Ratio	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177
[2a 3]	Non-Demand FAF Ratio	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305
[2a 4]	C & I Demand Non-TOD FAF Ratio	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984
[2a 5]	C & I Demand TOD On-Peak FAF Ratio	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486
[2a 6]	C & I Demand TOD Off-Peak FAF Ratio	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166
[2a 7]	Outdoor Lighting FAF Ratio	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976
[2a 8]	Residential [2a 1]*[2a 2]	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢
[2a 9]	C & I Non-Demand [2a 1]*[2a 3]	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢
[2a 10]	C & I Demand Non-TOD [2a 1]*[2a 4]	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢
[2a 11]	C & I Demand TOD On-Peak [2a 1]*[2a 5]	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢
[2a 12]	C & I Demand TOD Off-Peak [2a 1]*[2a 6]	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢
[2a 13]	Outdoor Lighting [2a 1]*[2a 7]	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢

RULE 7825.2810 SUBPART 1 B: BILLING ADJUSTMENT AMOUNTS CHARGED CUSTOMERS FOR EACH TYPE OF ENERGY COST

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
[2b 1]	System Fuel Cost Excess of Base Cost [1a 11]-[2a 1] **	0.262¢	-0.001¢	0.054¢	0.164¢	-0.029¢	0.025¢	0.140¢	0.140¢	0.108¢	0.361¢	0.467¢	0.199¢
[2b 2]	Residential [2b 1]*[2a 2]	0.267¢	-0.001¢	0.055¢	0.167¢	-0.030¢	0.025¢	0.142¢	0.142¢	0.110¢	0.367¢	0.475¢	0.203¢
[2b 3]	C & I Non-Demand [2b 1]*[2a 3]	0.270¢	-0.001¢	0.056¢	0.169¢	-0.030¢	0.026¢	0.144¢	0.144¢	0.111¢	0.372¢	0.481¢	0.205¢
[2b 4]	C & I Demand Non-TOD [2b 1]*[2a 4]	0.262¢	-0.001¢	0.054¢	0.164¢	-0.029¢	0.025¢	0.140¢	0.140¢	0.108¢	0.360¢	0.466¢	0.199¢
[2b 5]	C & I Demand TOD On-Peak [2b 1]*[2a 5]	0.327¢	-0.001¢	0.067¢	0.205¢	-0.036¢	0.031¢	0.175¢	0.175¢	0.135¢	0.451¢	0.583¢	0.248¢
[2b 6]	C & I Demand TOD Off-Peak [2b 1]*[2a 6]	0.214¢	-0.001¢	0.044¢	0.134¢	-0.024¢	0.020¢	0.114¢	0.114¢	0.088¢	0.295¢	0.381¢	0.163¢
[2b 7]	Outdoor Lighting [2b 1]*[2a 7]	0.209¢	-0.001¢	0.043¢	0.131¢	-0.023¢	0.020¢	0.112¢	0.112¢	0.086¢	0.288¢	0.372¢	0.159¢
[2b 8]	System True-Up Factor [1c 15] **	-0.107¢	-0.354¢	0.412¢	-0.119¢	-0.009¢	0.076¢	-0.024¢	-0.738¢	-0.126¢	-0.320¢	-0.197¢	-0.442¢
[2b 9]	Residential [1c 15]*[2a 2]	-0.109¢	-0.361¢	0.419¢	-0.121¢	-0.010¢	0.078¢	-0.025¢	-0.751¢	-0.128¢	-0.325¢	-0.200¢	-0.450¢
[2b 10]	C & I Non-Demand [1c 15]*[2a 3]	-0.110¢	-0.365¢	0.425¢	-0.123¢	-0.010¢	0.079¢	-0.025¢	-0.761¢	-0.130¢	-0.330¢	-0.203¢	-0.456¢
[2b 11]	C & I Demand Non-TOD [1c 15]*[2a 4]	-0.107¢	-0.354¢	0.411¢	-0.119¢	-0.009¢	0.076¢	-0.024¢	-0.737¢	-0.126¢	-0.319¢	-0.196¢	-0.442¢
[2b 12]	C & I Demand TOD On-Peak [1c 15]*[2a 5]	-0.133¢	-0.443¢	0.515¢	-0.149¢	-0.012¢	0.095¢	-0.030¢	-0.922¢	-0.157¢	-0.399¢	-0.246¢	-0.552¢
[2b 13]	C & I Demand TOD Off-Peak [1c 5]*[2a 6]	-0.087¢	-0.289¢	0.337¢	-0.097¢	-0.008¢	0.062¢	-0.020¢	-0.603¢	-0.103¢	-0.261¢	-0.161¢	-0.361¢
[2b 14]	Outdoor Lighting [1c 15]*[2a 7]	-0.085¢	-0.283¢	0.329¢	-0.095¢	-0.008¢	0.061¢	-0.019¢	-0.589¢	-0.100¢	-0.255¢	-0.157¢	-0.353¢
[2b 15]	System Asset Based Margins Sharing Refund [1c 16]	-0.077¢	-0.084¢	-0.119¢	-0.035¢	-0.085¢	-0.053¢	-0.141¢	-0.113¢	-0.047¢	-0.124¢	-0.054¢	-0.063¢
[2b 16]	Residential [1c 16]*[2a 2]	-0.078¢	-0.085¢	-0.122¢	-0.036¢	-0.086¢	-0.054¢	-0.143¢	-0.115¢	-0.048¢	-0.126¢	-0.055¢	-0.064¢
[2b 17]	C & I Non-Demand [1c 16]*[2a 3]	-0.079¢	-0.086¢	-0.123¢	-0.036¢	-0.087¢	-0.055¢	-0.145¢	-0.116¢	-0.048¢	-0.128¢	-0.056¢	-0.065¢
[2b 18]	C & I Demand Non-TOD [1c 16]*[2a 4]	-0.076¢	-0.084¢	-0.119¢	-0.035¢	-0.084¢	-0.053¢	-0.141¢	-0.113¢	-0.047¢	-0.124¢	-0.054¢	-0.063¢
[2b 19]	C & I Demand TOD On-Peak [1c 16]*[2a 5]	-0.096¢	-0.104¢	-0.149¢	-0.044¢	-0.106¢	-0.066¢	-0.176¢	-0.141¢	-0.059¢	-0.155¢	-0.067¢	-0.078¢
[2b 20]	C & I Demand TOD Off-Peak [1c 16]*[2a 6]	-0.063¢	-0.068¢	-0.098¢	-0.029¢	-0.069¢	-0.043¢	-0.115¢	-0.092¢	-0.038¢	-0.101¢	-0.044¢	-0.051¢
[2b 21]	Outdoor Lighting [1c 16]*[2a 7]	-0.061¢	-0.067¢	-0.095¢	-0.028¢	-0.068¢	-0.042¢	-0.112¢	-0.090¢	-0.038¢	-0.099¢	-0.043¢	-0.050¢
[2b 22]	System Fuel Clause Charge Factor ** [2a 1]+[2b 1]+[2b 8]+[2b 15]	2.759¢	2.241¢	3.027¢	2.690¢	2.557¢	2.728¢	2.655¢	1.969¢	2.615¢	2.597¢	2.896¢	2.374¢
[2b 23]	Residential [2b 22]*[2a 2]	2.807¢	2.281¢	3.080¢	2.737¢	2.602¢	2.777¢	2.702¢	2.004¢	2.661¢	2.643¢	2.948¢	2.416¢
[2b 24]	C & I Non-Demand [2b 22]*[2a 3]	2.843¢	2.309¢	3.119¢	2.772¢	2.635¢	2.812¢	2.736¢	2.029¢	2.695¢	2.676¢	2.985¢	2.446¢
[2b 25]	C & I Demand Non-TOD [2b 22]*[2a 4]	2.754¢	2.237¢	3.022¢	2.685¢	2.553¢	2.724¢	2.651¢	1.966¢	2.611¢	2.593¢	2.892¢	2.370¢
[2b 26]	C & I Demand TOD On-Peak [2b 22]*[2a 5]	3.444¢	2.798¢	3.779¢	3.358¢	3.193¢	3.407¢	3.315¢	2.458¢	3.265¢	3.243¢	3.616¢	2.964¢
[2b 27]	C & I Demand TOD Off-Peak [2b 22]*[2a 6]	2.253¢	1.830¢	2.472¢	2.196¢	2.088¢	2.228¢	2.168¢	1.608¢	2.136¢	2.121¢	2.365¢	1.939¢
[2b 28]	Outdoor Lighting [2b 22]*[2a 7]	2.200¢	1.787¢	2.414¢	2.145¢	2.039¢	2.176¢	2.118¢	1.570¢	2.086¢	2.071¢	2.310¢	1.893¢

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
RULE 7825.2810 SUBPART 1 A: COMMISSION-APPROVED BASE COST OF F								
[2a 1]	System Base cost of Fuel **	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢	2.680¢
[2a 2]	Residential FAF Ratio	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.018
[2a 3]	Non-Demand FAF Ratio	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.031
[2a 4]	C & I Demand Non-TOD FAF Ratio	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.998
[2a 5]	C & I Demand TOD On-Peak FAF Ratio	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.249
[2a 6]	C & I Demand TOD Off-Peak FAF Ratio	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.817
[2a 7]	Outdoor Lighting FAF Ratio	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.798
[2a 8]	Residential [2a 1]*[2a 2]	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢	2.727 ¢
[2a 9]	C & I Non-Demand [2a 1]*[2a 3]	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢	2.762 ¢
[2a 10]	C & I Demand Non-TOD [2a 1]*[2a 4]	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢	2.676 ¢
[2a 11]	C & I Demand TOD On-Peak [2a 1]*[2a 5]	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢	3.346 ¢
[2a 12]	C & I Demand TOD Off-Peak [2a 1]*[2a 6]	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢	2.188 ¢
[2a 13]	Outdoor Lighting [2a 1]*[2a 7]	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢	2.138 ¢
RULE 7825.2810 SUBPART 1 B: BILLING ADJUSTMENT AMOUNTS CHARG								
[2b 1]	System Fuel Cost Excess of Base Cost [1a 11]-[2a 1] **	0.214¢	0.187¢	0.057¢	0.099¢	-0.137¢	-0.243¢	0.115¢
[2b 2]	Residential [2b 1]*[2a 2]	0.218¢	0.190¢	0.058¢	0.101¢	-0.139¢	-0.247¢	0.117¢
[2b 3]	C & I Non-Demand [2b 1]*[2a 3]	0.221¢	0.193¢	0.059¢	0.102¢	-0.141¢	-0.250¢	0.119¢
[2b 4]	C & I Demand Non-TOD [2b 1]*[2a 4]	0.214¢	0.187¢	0.057¢	0.099¢	-0.137¢	-0.243¢	0.115¢
[2b 5]	C & I Demand TOD On-Peak [2b 1]*[2a 5]	0.267¢	0.233¢	0.071¢	0.124¢	-0.171¢	-0.303¢	0.144¢
[2b 6]	C & I Demand TOD Off-Peak [2b 1]*[2a 6]	0.175¢	0.153¢	0.047¢	0.081¢	-0.112¢	-0.198¢	0.094¢
[2b 7]	Outdoor Lighting [2b 1]*[2a 7]	0.171¢	0.149¢	0.045¢	0.079¢	-0.109¢	-0.194¢	0.092¢
[2b 8]	System True-Up Factor [1c 15] **	0.153¢	-0.177¢	-0.332¢	-0.421¢	-0.232¢	-0.307¢	-0.159¢
[2b 9]	Residential [1c 15]*[2a 2]	0.156¢	-0.181¢	-0.338¢	-0.429¢	-0.237¢	-0.312¢	-0.162¢
[2b 10]	C & I Non-Demand [1c 15]*[2a 3]	0.158¢	-0.183¢	-0.343¢	-0.434¢	-0.240¢	-0.316¢	-0.164¢
[2b 11]	C & I Demand Non-TOD [1c 15]*[2a 4]	0.153¢	-0.177¢	-0.332¢	-0.421¢	-0.232¢	-0.306¢	-0.159¢
[2b 12]	C & I Demand TOD On-Peak [1c 15]*[2a 5]	0.191¢	-0.222¢	-0.415¢	-0.526¢	-0.290¢	-0.383¢	-0.198¢
[2b 13]	C & I Demand TOD Off-Peak [1c 5]*[2a 6]	0.125¢	-0.145¢	-0.271¢	-0.344¢	-0.190¢	-0.250¢	-0.130¢
[2b 14]	Outdoor Lighting [1c 15]*[2a 7]	0.122¢	-0.142¢	-0.265¢	-0.336¢	-0.185¢	-0.245¢	-0.127¢
[2b 15]	System Asset Based Margins Sharing Refund [1c 16]	-0.085¢	-0.080¢	-0.042¢	-0.041¢	-0.029¢	-0.030¢	-0.077¢
[2b 16]	Residential [1c 16]*[2a 2]	-0.086¢	-0.081¢	-0.043¢	-0.042¢	-0.029¢	-0.030¢	-0.078¢
[2b 17]	C & I Non-Demand [1c 16]*[2a 3]	-0.087¢	-0.082¢	-0.043¢	-0.042¢	-0.029¢	-0.031¢	-0.079¢
[2b 18]	C & I Demand Non-TOD [1c 16]*[2a 4]	-0.085¢	-0.080¢	-0.042¢	-0.041¢	-0.029¢	-0.030¢	-0.076¢
[2b 19]	C & I Demand TOD On-Peak [1c 16]*[2a 5]	-0.106¢	-0.100¢	-0.052¢	-0.051¢	-0.036¢	-0.037¢	-0.096¢
[2b 20]	C & I Demand TOD Off-Peak [1c 16]*[2a 6]	-0.069¢	-0.065¢	-0.034¢	-0.033¢	-0.023¢	-0.024¢	-0.063¢
[2b 21]	Outdoor Lighting [1c 16]*[2a 7]	-0.068¢	-0.064¢	-0.033¢	-0.033¢	-0.023¢	-0.024¢	-0.061¢
[2b 22]	System Fuel Clause Charge Factor ** [2a 1]+[2b 1]+[2b 8]+[2b 15]	2.963¢	2.610¢	2.363¢	2.317¢	2.282¢	2.101¢	2.215¢
[2b 23]	Residential [2b 22]*[2a 2]	3.015¢	2.656¢	2.405¢	2.358¢	2.322¢	2.138¢	2.254¢
[2b 24]	C & I Non-Demand [2b 22]*[2a 3]	3.053¢	2.689¢	2.435¢	2.387¢	2.352¢	2.165¢	2.282¢
[2b 25]	C & I Demand Non-TOD [2b 22]*[2a 4]	2.958¢	2.606¢	2.359¢	2.313¢	2.278¢	2.097¢	2.211¢
[2b 26]	C & I Demand TOD On-Peak [2b 22]*[2a 5]	3.699¢	3.259¢	2.950¢	2.893¢	2.849¢	2.623¢	2.765¢
[2b 27]	C & I Demand TOD Off-Peak [2b 22]*[2a 6]	2.419¢	2.131¢	1.929¢	1.892¢	1.863¢	1.715¢	1.808¢
[2b 28]	Outdoor Lighting [2b 22]*[2a 7]	2.363¢	2.082¢	1.885¢	1.848¢	1.820¢	1.676¢	1.766¢

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
RULE 7825.2810 SUBPART 1 D: TOTAL COST OF FUEL DELIVERED TO CUSTOMERS													
[3 1]	Actual Cost of Fuel Per kWh [20] **	2.519	2.349	2.475	2.649	2.395	2.211	2.510	2.446	2.238	2.207	2.299	2.244
[3 2]	Minnesota MWh Retail Sales (Cal. Mo) [1b 19]	2,974,636	3,021,236	2,536,443	2,323,426	2,300,971	2,512,051	2,534,050	2,211,435	2,503,585	2,166,738	2,285,434	2,457,615
[3 3]	Residential	930,116	970,268	701,360	611,638	664,595	743,838	812,757	679,907	690,278	564,606	594,959	736,671
[3 4]	C & I Non-Demand	78,847	79,374	67,313	61,732	66,478	76,129	80,665	73,299	81,007	67,115	66,320	67,928
[3 5]	C & I Demand Non-TOD	898,234	903,525	776,122	727,990	698,024	780,039	763,746	660,143	799,567	681,656	735,482	776,906
[3 6]	C & I Demand TOD On-Peak	407,597	412,840	382,997	350,784	338,743	340,460	311,247	300,346	357,416	322,009	338,797	338,387
[3 7]	C & I Demand TOD Off-Peak	652,873	646,428	596,976	560,460	517,549	555,557	549,969	485,552	562,904	522,531	542,059	530,282
[3 8]	Outdoor Lighting	6,969	8,801	11,675	10,822	15,582	16,028	15,666	12,188	12,413	8,821	7,817	7,441
[3 9]	Minnesota WindSource KWh Not Subject to FCA (Cal. Mo.) [1b 20] a)	28,641	34,343	31,999	32,589	28,257	30,935	32,363	30,583	31,553	42,720	41,612	43,188
[3 10]	Residential	15,998	16,343	13,498	13,762	12,365	13,275	15,884	13,625	14,879	13,637	12,871	13,155
[3 11]	C & I Non-Demand	386	508	172	160	7,206	160	169	157	171	154	146	173
[3 12]	C & I Demand Non-TOD	4,041	5,319	4,362	4,761	6,495	4,578	5,836	4,387	4,370	17,346	4,832	5,118
[3 13]	C & I Demand TOD On-Peak	3,353	4,969	5,701	5,676	892	5,273	4,274	5,066	4,951	4,728	9,701	10,101
[3 14]	C & I Demand TOD Off-Peak	4,860	7,200	8,262	8,225	1,293	7,643	6,193	7,342	7,176	6,850	14,058	14,637
[3 15]	Outdoor Lighting	3	4	4	5	6	6	7	6	6	5	4	4
[3 16]	Total Retail State of Minnesota subject to FCA [1b 21]	2,945,995	2,986,893	2,504,444	2,290,837	2,272,714	2,481,116	2,501,687	2,180,852	2,472,032	2,124,018	2,243,822	2,414,427
[3 17]	Residential	914,118	953,925	687,862	597,876	652,230	730,563	796,873	666,282	675,399	550,969	582,088	723,516
[3 18]	C & I Non-Demand	78,461	78,866	67,141	61,572	59,272	75,969	80,496	73,142	80,836	66,961	66,174	67,755
[3 19]	C & I Demand Non-TOD	894,193	898,206	771,760	723,229	691,529	775,461	757,910	655,756	795,197	664,310	730,650	771,788
[3 20]	C & I Demand TOD On-Peak	404,244	407,871	377,296	345,108	337,851	335,187	306,973	295,280	352,465	317,281	329,096	328,286
[3 21]	C & I Demand TOD Off-Peak	648,013	639,228	588,714	552,235	516,256	547,914	543,776	478,210	555,728	515,681	528,001	515,645
[3 22]	Outdoor Lighting	6,966	8,797	11,671	10,817	15,576	16,022	15,659	12,182	12,407	8,816	7,813	7,437
[3 23]	Total Cost of Fuel Delivered [3 1]x[3 16]x10	$74,209,614	$70,169,464	$61,986,717	$60,680,928	$54,431,500	$54,858,839	$62,781,236	$53,346,889	$55,334,038	$46,885,425	$51,592,491	$54,181,142
[3 24]	Residential [3 1]x[3 17]x10	$23,026,632	$22,410,045	$17,025,059	$15,836,862	$15,620,909	$16,153,150	$19,997,974	$16,298,250	$15,118,151	$12,162,051	$13,384,025	$16,236,119
[3 25]	C & I Non-Demand [3 1]x[3 18]x10	$1,976,433	$1,852,756	$1,661,786	$1,630,952	$1,419,564	$1,679,716	$2,020,092	$1,789,162	$1,809,435	$1,478,092	$1,521,547	$1,520,461
[3 26]	C & I Demand Non-TOD [3 1]x[3 19]x10	$22,524,722	$21,101,069	$19,101,593	$19,157,280	$16,562,120	$17,145,869	$19,020,176	$16,040,769	$17,799,714	$14,663,932	$16,799,930	$17,319,370
[3 27]	C & I Demand TOD On-Peak [3 1]x[3 20]x10	$10,182,906	$9,581,893	$9,338,336	$9,141,407	$8,091,531	$7,411,169	$7,703,659	$7,222,989	$7,889,587	$7,003,639	$7,566,947	$7,366,928
[3 28]	C & I Demand TOD Off-Peak [3 1]x[3 21]x10	$16,323,447	$15,017,038	$14,571,078	$14,627,899	$12,364,331	$12,114,680	$13,646,363	$11,697,729	$12,439,432	$11,383,106	$12,140,396	$11,571,373
[3 29]	Outdoor Lighting [3 1]x[3 22]x10	$175,474	$206,663	$288,865	$286,527	$373,045	$354,255	$392,971	$297,990	$277,719	$194,604	$179,645	$166,891

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
RULE 7825.2810 SUBPART 1 D: TOTAL COST OF FUEL DELIVERED TO CU								
[3 1]	Actual Cost of Fuel Per kWh [20] **	2.190	2.074	2.095	2.142	2.200	1.988	2.292
[3 2]	Minnesota MWh Retail Sales (Cal. Mo) [1b 19]	2,883,240	2,678,659	2,438,237	2,304,570	2,265,893	2,437,202	44,835,421
[3 3]	Residential	945,846	806,766	685,369	611,692	655,201	761,576	13,167,443
[3 4]	C & I Non-Demand	75,653	70,800	65,110	60,565	67,619	74,298	1,280,252
[3 5]	C & I Demand Non-TOD	868,478	806,582	769,781	730,572	718,083	740,370	13,835,300
[3 6]	C & I Demand TOD On-Peak	378,961	393,063	353,795	350,205	321,488	317,986	6,317,121
[3 7]	C & I Demand TOD Off-Peak	606,748	593,199	554,611	539,305	491,466	528,423	10,036,892
[3 8]	Outdoor Lighting	7,554	8,249	9,571	12,231	12,036	14,549	198,413
[3 9]	Minnesota WindSource KWh Not Subject to FCA (Cal. Mo.) [1b 20] a)	49,597	51,785	47,349	50,316	41,826	46,962	696,618
[3 10]	Residential	17,485	17,727	13,864	16,272	13,324	16,140	264,104
[3 11]	C & I Non-Demand	231	236	189	283	199	246	10,946
[3 12]	C & I Demand Non-TOD	6,250	6,742	6,242	6,454	5,151	5,730	108,014
[3 13]	C & I Demand TOD On-Peak	10,443	11,035	11,021	11,119	9,420	10,110	127,833
[3 14]	C & I Demand TOD Off-Peak	15,133	15,991	15,971	16,114	13,652	14,652	185,252
[3 15]	Outdoor Lighting	55	54	62	74	80	84	469
[3 16]	Total Retail State of Minnesota subject to FCA [1b 21]	2,833,643	2,626,874	2,390,888	2,254,254	2,224,067	2,390,240	44,138,803
[3 17]	Residential	928,361	789,039	671,505	595,420	641,877	745,436	12,903,339
[3 18]	C & I Non-Demand	75,422	70,564	64,921	60,282	67,420	74,052	1,269,306
[3 19]	C & I Demand Non-TOD	862,228	799,840	763,539	724,118	712,932	734,640	13,727,286
[3 20]	C & I Demand TOD On-Peak	368,518	382,028	342,774	339,086	312,068	307,876	6,189,288
[3 21]	C & I Demand TOD Off-Peak	591,615	577,208	538,640	523,191	477,814	513,771	9,851,640
[3 22]	Outdoor Lighting	7,499	8,195	9,509	12,157	11,956	14,465	197,944
[3 23]	Total Cost of Fuel Delivered [3 1]x[3 16]x10	$62,060,579	$54,481,367	$50,078,201	$48,281,702	$48,925,026	$47,511,374	$1,011,796,532
[3 24]	Residential [3 1]x[3 17]x10	$20,332,350	$16,364,669	$14,064,968	$12,752,729	$14,120,010	$14,817,210	$295,721,163
[3 25]	C & I Non-Demand [3 1]x[3 18]x10	$1,651,843	$1,463,497	$1,359,799	$1,291,122	$1,483,105	$1,471,949	$29,081,311
[3 26]	C & I Demand Non-TOD [3 1]x[3 19]x10	$18,883,949	$16,588,682	$15,992,660	$15,509,188	$15,683,078	$14,602,616	$314,496,717
[3 27]	C & I Demand TOD On-Peak [3 1]x[3 20]x10	$8,071,038	$7,923,261	$7,179,552	$7,262,558	$6,864,872	$6,119,725	$141,921,997
[3 28]	C & I Demand TOD Off-Peak [3 1]x[3 21]x10	$12,957,161	$11,971,294	$11,282,052	$11,205,726	$10,510,952	$10,212,349	$226,036,406
[3 29]	Outdoor Lighting [3 1]x[3 22]x10	$164,238	$169,964	$199,170	$260,379	$263,008	$287,524	$4,538,932

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
RULE 7825.2810 SUBPART 1 E: REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED													
[4 1]	Minnesota MWh Retail Sales Subject to FCA (Cal. Mo) [1b 21]	2,945,995	2,986,893	2,504,444	2,290,837	2,272,714	2,481,116	2,501,687	2,180,852	2,472,032	2,124,018	2,243,822	2,414,427
[4 2]	Residential [3 17]	914,118	953,925	687,862	597,876	652,230	730,563	796,873	666,282	675,399	550,969	582,088	723,516
[4 3]	C & I Non-Demand [3 18]	78,461	78,866	67,141	61,572	59,272	75,969	80,496	73,142	80,836	66,961	66,174	67,755
[4 4]	C & I Demand Non-TOD [3 19]	894,193	898,206	771,760	723,229	691,529	775,461	757,910	655,756	795,197	664,310	730,650	771,788
[4 5]	C & I Demand TOD On-Peak [3 20]	404,244	407,871	377,296	345,108	337,851	335,187	306,973	295,280	352,465	317,281	329,096	328,286
[4 6]	C & I Demand TOD Off-Peak [3 21]	648,013	639,228	588,714	552,235	516,256	547,914	543,776	478,210	555,728	515,681	528,001	515,645
[4 7]	Outdoor Lighting [3 22]	6,966	8,797	11,671	10,817	15,576	16,022	15,659	12,182	12,407	8,816	7,813	7,437
[4 8]	Base Cost Revenues												
[4 9]	Residential [2a 8]x[4 2]x10	$24,931,983	$26,017,694	$18,760,996	$16,306,685	$17,789,156	$19,925,638	$21,734,201	$18,172,415	$18,421,075	$15,027,327	$15,876,078	$19,733,436
[4 10]	C & I Non-Demand [2a 9]x[4 3]x10	$2,166,889	$2,178,074	$1,854,260	$1,700,459	$1,636,939	$2,098,066	$2,223,090	$2,019,992	$2,232,480	$1,849,289	$1,827,554	$1,871,217
[4 11]	C & I Demand Non-TOD [2a 10]x[4 4]x10	$23,926,029	$24,033,406	$20,650,075	$19,351,525	$18,503,324	$20,749,103	$20,279,489	$17,546,142	$21,277,182	$17,775,022	$19,550,090	$20,650,824
[4 12]	C & I Demand TOD On-Peak [2a 11]x[4 5]x10	$13,527,007	$13,648,375	$12,625,260	$11,548,170	$11,305,332	$11,216,188	$10,272,078	$9,880,801	$11,794,353	$10,617,009	$11,012,368	$10,985,264
[4 13]	C & I Demand TOD Off-Peak [2a 12]x[4 6]x10	$14,181,687	$13,989,428	$12,883,935	$12,085,597	$11,298,201	$11,991,032	$11,900,473	$10,465,568	$12,162,041	$11,285,617	$11,555,239	$11,284,829
[4 14]	Outdoor Lighting [2a 13]x[4 7]x10	$148,903	$188,042	$249,476	$231,221	$332,948	$342,481	$334,722	$260,399	$265,208	$188,448	$167,008	$158,971
[4 15]	Total Sum[4 9]..[4 14]	$78,882,498	$80,055,019	$67,024,002	$61,223,657	$60,865,900	$66,322,508	$66,744,053	$58,345,317	$66,152,339	$56,742,712	$59,988,337	$64,684,541
	Fuel Clause Revenues												
[4 16]	Fuel Cost Excess of Base												
[4 17]	Residential [2b 2]x[4 2]x10	$2,437,404	($9,730)	$378,049	$997,855	($192,473)	$185,855	$1,135,385	$949,319	$742,331	$2,024,205	$2,766,490	$1,465,265
[4 18]	C & I Non-Demand [2b 2]x[4 3]x10	$211,837	($812)	$37,364	$104,057	($17,710)	$19,570	$116,132	$105,522	$89,962	$249,102	$318,456	$138,945
[4 19]	C & I Demand Non-TOD [2b 2]x[4 4]x10	$2,339,030	($8,982)	$416,056	$1,184,215	($200,198)	$193,555	$1,059,407	$916,616	$857,461	$2,394,306	$3,406,656	$1,533,388
[4 20]	C & I Demand TOD On-Peak [2b 2]x[4 5]x10	$1,322,403	($5,098)	$254,373	$706,678	($122,336)	$104,612	$536,589	$516,149	$475,299	$1,430,112	$1,918,959	$815,692
[4 21]	C & I Demand TOD Off-Peak [2b 2]x[4 6]x10	$1,386,424	($5,242)	$259,623	$739,553	($122,249)	$111,829	$621,645	$546,690	$490,097	$1,520,176	$2,013,532	$837,923
[4 22]	Outdoor Lighting [2b 2]x[4 7]x10	$14,557	($70)	$5,027	$14,150	($3,603)	$3,195	$17,485	$13,602	$10,687	$25,384	$29,102	$11,804
[4 23]	Total Sum[4 17]..[4 22]	$7,711,655	($29,934)	$1,350,492	$3,746,508	($658,569)	$618,616	$3,486,643	$3,047,898	$2,665,837	$7,643,285	$10,453,195	$4,803,017
[4 24]	True-Up												
[4 25]	Residential [2b 9]x[4 2]x10	($994,432)	($3,441,055)	$2,884,749	($725,588)	($62,451)	$567,903	($197,234)	($5,006,709)	($864,457)	($1,792,947)	($1,165,765)	($3,257,059)
[4 26]	C & I Non-Demand [2b 10]x[4 3]x10	($86,428)	($288,068)	$285,117	($75,664)	($5,746)	$59,797	($20,175)	($556,531)	($104,765)	($220,643)	($134,196)	($308,850)
[4 27]	C & I Demand Non-TOD [2b 11]x[4 4]x10	($954,310)	($3,178,616)	$3,175,221	($861,069)	($64,955)	$591,374	($184,036)	($4,834,168)	($998,489)	($2,120,776)	($1,435,545)	($3,408,478)
[4 28]	C & I Demand TOD On-Peak [2b 12]x[4 5]x10	($539,536)	($1,805,111)	$1,941,297	($513,852)	($39,687)	$319,675	($93,218)	($2,722,275)	($553,479)	($1,266,741)	($808,628)	($1,813,150)
[4 29]	C & I Demand TOD Off-Peak [2b 13]x[4 6]x10	($565,651)	($1,850,220)	$1,981,076	($537,766)	($39,664)	$341,756	($107,999)	($2,883,386)	($570,738)	($1,346,515)	($848,492)	($1,862,592)
[4 30]	Outdoor Lighting [2b 14]x[4 7]x10	($5,939)	($24,870)	$38,360	($10,288)	($1,169)	$9,761	($3,038)	($71,743)	($12,446)	($22,484)	($12,263)	($26,239)
[4 31]	Total Sum[4 25]..[4 30]	($3,146,296)	($10,587,940)	$10,305,820	($2,724,227)	($213,672)	$1,890,266	($605,700)	($16,074,812)	($3,104,374)	($6,770,106)	($4,404,889)	($10,676,368)
[4 32]	Margin Sharing Refund												
[4 33]	Residential [2b 16]x[4 2]x10	($712,089)	($812,305)	($836,103)	($213,944)	($561,766)	($393,357)	($1,141,752)	($766,024)	($323,246)	($696,838)	($319,205)	($462,016)
[4 34]	C & I Non-Demand [2b 17]x[4 3]x10	($61,889)	($68,002)	($82,637)	($22,310)	($51,693)	($41,419)	($116,784)	($85,149)	($39,175)	($85,754)	($36,744)	($43,810)
[4 35]	C & I Demand Non-TOD [2b 18]x[4 4]x10	($683,360)	($750,352)	($920,293)	($253,897)	($584,321)	($409,614)	($1,065,333)	($739,621)	($373,369)	($824,249)	($393,075)	($483,494)
[4 36]	C & I Demand TOD On-Peak [2b 19]x[4 5]x10	($386,348)	($426,119)	($562,658)	($151,513)	($357,014)	($221,425)	($539,619)	($416,504)	($206,964)	($492,325)	($221,416)	($257,196)
[4 37]	C & I Demand TOD Off-Peak [2b 20]x[4 6]x10	($405,047)	($436,765)	($574,185)	($158,563)	($356,785)	($236,721)	($625,163)	($441,154)	($213,416)	($523,329)	($232,331)	($264,206)
[4 38]	Outdoor Lighting [2b 21]x[4 7]x10	($4,253)	($5,871)	($11,118)	($3,034)	($10,514)	($6,761)	($17,584)	($10,977)	($4,654)	($8,739)	($3,358)	($3,722)
[4 39]	Total Sum[4 33]..[4 38]	($2,252,986)	($2,499,414)	($2,986,994)	($803,261)	($1,922,093)	($1,309,297)	($3,506,235)	($2,459,429)	($1,160,824)	($2,631,234)	($1,206,129)	($1,514,444)
[4 40]	Total Fuel Clause Revenues												
[4 41]	Residential [4 9]+[4 17]	$27,369,387	$26,007,964	$19,139,045	$17,304,540	$17,596,683	$20,111,493	$22,869,586	$19,121,734	$19,163,406	$17,051,532	$18,642,568	$21,198,701
[4 42]	C & I Non-Demand [4 10]+[4 18]	$2,378,726	$2,177,262	$1,891,624	$1,804,516	$1,619,229	$2,117,636	$2,339,222	$2,125,514	$2,322,442	$2,098,391	$2,146,010	$2,010,162
[4 43]	C & I Demand Non-TOD [4 11]+[4 19]	$26,265,059	$24,024,424	$21,066,131	$20,535,740	$18,303,126	$20,942,658	$21,338,896	$18,462,758	$22,134,643	$20,169,328	$22,956,746	$22,184,212
[4 44]	C & I Demand TOD On-Peak [4 12]+[4 20]	$14,849,410	$13,643,277	$12,879,633	$12,254,848	$11,182,996	$11,320,800	$10,808,667	$10,396,950	$12,269,652	$12,047,121	$12,931,327	$11,800,956
[4 45]	C & I Demand TOD Off-Peak [4 13]+[4 21]	$15,568,111	$13,984,186	$13,143,558	$12,825,150	$11,175,952	$12,102,861	$12,522,118	$11,012,258	$12,652,138	$12,805,793	$13,568,771	$12,122,752
[4 46]	Outdoor Lighting [4 14]+[4 22]	$163,460	$187,972	$254,503	$245,371	$329,345	$345,676	$352,207	$274,001	$275,895	$213,832	$196,110	$170,775
[4 47]	Total Sum[4 41]..[4 46]	$86,594,153	$80,025,085	$68,374,494	$64,970,165	$60,207,331	$66,941,124	$70,230,696	$61,393,215	$68,818,176	$64,385,997	$70,441,532	$69,487,558
[4 48]	Total Fuel Clause Revenues including True-Up & Refund												
[4 49]	Residential [4 33]+[4 41]	$26,657,298	$25,195,659	$18,302,942	$17,090,596	$17,034,917	$19,718,136	$21,727,834	$18,355,710	$18,840,160	$16,354,694	$18,323,363	$20,736,685
[4 50]	C & I Non-Demand [4 34]+[4 42]	$2,316,837	$2,109,260	$1,808,987	$1,782,206	$1,567,536	$2,076,217	$2,222,438	$2,040,365	$2,283,267	$2,012,637	$2,109,266	$1,966,352
[4 51]	C & I Demand Non-TOD [4 35]+[4 43]	$25,581,699	$23,274,072	$20,145,838	$20,281,843	$17,718,805	$20,533,044	$20,273,563	$17,723,137	$21,761,274	$19,345,079	$22,563,671	$21,700,718
[4 52]	C & I Demand TOD On-Peak [4 36]+[4 44]	$14,463,062	$13,217,158	$12,316,975	$12,103,335	$10,825,982	$11,099,375	$10,269,048	$9,980,446	$12,062,688	$11,554,796	$12,709,911	$11,543,760
[4 53]	C & I Demand TOD Off-Peak [4 37]+[4 45]	$15,163,064	$13,547,421	$12,569,373	$12,666,587	$10,819,167	$11,866,140	$11,896,955	$10,571,104	$12,438,722	$12,282,464	$13,336,440	$11,858,546
[4 54]	Outdoor Lighting [4 38]+[4 46]	$159,207	$182,101	$243,385	$242,337	$318,831	$338,915	$334,623	$263,024	$271,241	$205,093	$192,752	$167,053
[4 55]	Total Sum[4 49]..[4 54]	$84,341,167	$77,525,671	$65,387,500	$64,166,904	$58,285,238	$65,631,827	$66,724,461	$58,933,786	$67,657,352	$61,754,763	$69,235,403	$67,973,114

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
RULE 7825.2810 SUBPART 1 E: REVENUE COLLECTED FROM CUSTOMERS								
[4 1]	Minnesota MWh Retail Sales Subject to FCA (Cal. Mo) [1b 21]	2,833,643	2,626,874	2,390,888	2,254,254	2,224,067	2,390,240	44,138,803
[4 2]	Residential [3 17]	928,361	789,039	671,505	595,420	641,877	745,436	12,903,339
[4 3]	C & I Non-Demand [3 18]	75,422	70,564	64,921	60,282	67,420	74,052	1,269,306
[4 4]	C & I Demand Non-TOD [3 19]	862,228	799,840	763,539	724,118	712,932	734,640	13,727,286
[4 5]	C & I Demand TOD On-Peak [3 20]	368,518	382,028	342,774	339,086	312,068	307,876	6,189,288
[4 6]	C & I Demand TOD Off-Peak [3 21]	591,615	577,208	538,640	523,191	477,814	513,771	9,851,640
[4 7]	Outdoor Lighting [3 22]	7,499	8,195	9,509	12,157	11,956	14,465	197,944
[4 8]	Base Cost Revenues							
[4 9]	Residential [2a 8]x[4 2]x10	$25,320,452	$21,520,534	$18,314,869	$16,239,699	$17,506,784	$20,331,290	351,930,312
[4 10]	C & I Non-Demand [2a 9]x[4 3]x10	$2,082,960	$1,948,794	$1,792,949	$1,664,832	$1,861,965	$2,045,124	35,054,933
[4 11]	C & I Demand Non-TOD [2a 10]x[4 4]x10	$23,070,738	$21,401,415	$20,430,105	$19,375,312	$19,076,007	$19,656,851	367,302,639
[4 12]	C & I Demand TOD On-Peak [2a 11]x[4 5]x10	$12,331,526	$12,783,604	$11,470,068	$11,346,658	$10,442,569	$10,302,294	207,108,924
[4 13]	C & I Demand TOD Off-Peak [2a 12]x[4 6]x10	$12,947,423	$12,632,128	$11,788,072	$11,449,972	$10,456,902	$11,243,817	215,601,961
[4 14]	Outdoor Lighting [2a 13]x[4 7]x10	$160,296	$175,174	$203,261	$259,864	$255,568	$309,199	$4,231,189
[4 15]	Total Sum[4 9]..[4 14]	$75,913,395	$70,461,649	$63,999,324	$60,336,337	$59,599,795	$63,888,575	$1,181,229,958
	Fuel Clause Revenues							
[4 16]	Fuel Cost Excess of Base							
[4 17]	Residential [2b 2]x[4 2]x10	$2,021,877	$1,501,620	$389,540	$599,886	($894,905)	($1,843,463)	$14,654,510
[4 18]	C & I Non-Demand [2b 2]x[4 3]x10	$166,328	$135,977	$38,135	$61,500	($95,184)	($185,434)	$1,493,747
[4 19]	C & I Demand Non-TOD [2b 2]x[4 4]x10	$1,842,236	$1,493,301	$434,530	$715,718	($975,148)	($1,782,310)	$15,819,837
[4 20]	C & I Demand TOD On-Peak [2b 2]x[4 5]x10	$984,680	$891,997	$243,952	$419,144	($533,824)	($934,127)	$9,025,254
[4 21]	C & I Demand TOD Off-Peak [2b 2]x[4 6]x10	$1,033,847	$881,397	$250,737	$422,948	($534,531)	($1,019,476)	$9,434,923
[4 22]	Outdoor Lighting [2b 2]x[4 7]x10	$12,800	$12,223	$4,323	$9,599	($13,064)	($28,036)	$139,165
[4 23]	Total Sum[4 17]..[4 22]	$6,061,768	$4,916,515	$1,361,217	$2,228,795	($3,046,656)	($5,792,846)	$50,567,436
[4 24]	True-Up							
[4 25]	Residential [2b 9]x[4 2]x10	$1,448,930	($1,424,941)	($2,271,466)	($2,553,542)	($1,518,322)	($2,326,714)	($22,701,100)
[4 26]	C & I Non-Demand [2b 10]x[4 3]x10	$119,195	($129,035)	($222,367)	($261,779)	($161,484)	($234,044)	($2,345,666)
[4 27]	C & I Demand Non-TOD [2b 11]x[4 4]x10	$1,320,200	($1,417,053)	($2,533,804)	($3,046,589)	($1,654,416)	($2,249,526)	($23,855,035)
[4 28]	C & I Demand TOD On-Peak [2b 12]x[4 5]x10	$705,657	($846,440)	($1,422,553)	($1,784,155)	($905,659)	($1,178,993)	($13,326,848)
[4 29]	C & I Demand TOD Off-Peak [2b 13]x[4 6]x10	$740,903	($836,409)	($1,461,993)	($1,800,400)	($906,901)	($1,286,739)	($13,841,730)
[4 30]	Outdoor Lighting [2b 14]x[4 7]x10	$9,173	($11,599)	($25,209)	($40,861)	($22,165)	($35,385)	($268,404)
[4 31]	Total Sum[4 25]..[4 30]	$4,344,058	($4,665,477)	($7,937,392)	($9,487,326)	($5,168,947)	($7,311,401)	($76,338,783)
[4 32]	Margin Sharing Refund							
[4 33]	Residential [2b 16]x[4 2]x10	($800,080)	($640,289)	($285,752)	($247,260)	($186,960)	($224,570)	($9,623,556)
[4 34]	C & I Non-Demand [2b 17]x[4 3]x10	($65,818)	($57,982)	($27,974)	($25,349)	($19,884)	($22,590)	($954,963)
[4 35]	C & I Demand Non-TOD [2b 18]x[4 4]x10	($728,997)	($636,745)	($318,755)	($295,006)	($203,713)	($217,123)	($9,881,317)
[4 36]	C & I Demand TOD On-Peak [2b 19]x[4 5]x10	($389,653)	($380,347)	($178,959)	($172,761)	($111,517)	($113,794)	($5,586,132)
[4 37]	C & I Demand TOD Off-Peak [2b 20]x[4 6]x10	($409,114)	($375,837)	($183,919)	($174,332)	($111,670)	($124,194)	($5,846,731)
[4 38]	Outdoor Lighting [2b 21]x[4 7]x10	($5,065)	($5,212)	($3,171)	($3,957)	($2,729)	($3,415)	($114,134)
[4 39]	Total Sum[4 33]..[4 38]	($2,398,727)	($2,096,412)	($998,530)	($918,665)	($636,473)	($705,686)	($32,006,833)
[4 40]	Total Fuel Clause Revenues							
[4 41]	Residential [4 9]+[4 17]	$27,342,329	$23,022,154	$18,704,409	$16,839,585	$16,611,879	$18,487,827	$366,584,822
[4 42]	C & I Non-Demand [4 10]+[4 18]	$2,249,288	$2,084,771	$1,831,084	$1,726,332	$1,766,781	$1,859,690	$36,548,680
[4 43]	C & I Demand Non-TOD [4 11]+[4 19]	$24,912,974	$22,894,716	$20,864,635	$20,091,030	$18,100,859	$17,874,541	$383,122,476
[4 44]	C & I Demand TOD On-Peak [4 12]+[4 20]	$13,316,206	$13,675,601	$11,714,020	$11,765,802	$9,908,745	$9,368,167	$216,134,178
[4 45]	C & I Demand TOD Off-Peak [4 13]+[4 21]	$13,981,270	$13,513,525	$12,038,809	$11,872,920	$9,922,371	$10,224,341	$225,036,884
[4 46]	Outdoor Lighting [4 14]+[4 22]	$173,096	$187,397	$207,584	$269,463	$242,504	$281,163	$4,370,354
[4 47]	Total Sum[4 41]..[4 46]	$81,975,163	$75,378,164	$65,360,541	$62,565,132	$56,553,139	$58,095,729	$1,231,797,394
[4 48]	Total Fuel Clause Revenues including True-Up & Refund							
[4 49]	Residential [4 33]+[4 41]	$26,542,249	$22,381,865	$18,418,657	$16,592,325	$16,424,919	$18,263,257	$356,961,266
[4 50]	C & I Non-Demand [4 34]+[4 42]	$2,183,470	$2,026,789	$1,803,110	$1,700,983	$1,746,897	$1,837,100	$35,593,717
[4 51]	C & I Demand Non-TOD [4 35]+[4 43]	$24,183,977	$22,257,971	$20,545,880	$19,796,024	$17,897,146	$17,657,418	$373,241,159
[4 52]	C & I Demand TOD On-Peak [4 36]+[4 44]	$12,926,553	$13,295,254	$11,535,061	$11,593,041	$9,797,228	$9,254,373	$210,548,046
[4 53]	C & I Demand TOD Off-Peak [4 37]+[4 45]	$13,572,156	$13,137,688	$11,854,890	$11,698,588	$9,810,701	$10,100,147	$219,190,153
[4 54]	Outdoor Lighting [4 38]+[4 46]	$168,031	$182,185	$204,413	$265,506	$239,775	$277,748	$4,256,220
[4 55]	Total Sum[4 49]..[4 54]	$79,576,436	$73,281,752	$64,362,011	$61,646,467	$55,916,666	$57,390,043	$1,199,790,561

RULE 7825.2810 SUBPART 1 G: AMOUNT OF REFUNDS CREDITED TO CUSTOMERS

	Refund Included in Fuel Cost Charge Month	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
[5a 1]	**System Asset Based Margins Sharing Refund**	($2,870,588)	($804,541)	($1,906,177)	($1,307,251)	($3,536,629)	($2,446,777)	($1,107,013)	($2,576,279)	($1,221,479)	($1,585,763)	($2,444,562)	($2,200,719)
[5a 2]	Forecasted Minnesota Jurisdiction MWh Sales	2,403,439	2,288,091	2,252,324	2,470,869	2,512,046	2,165,867	2,353,924	2,073,039	2,266,847	2,527,282	2,886,730	2,759,956
[5a 3]	Refund Factor [5a 1]/[5a 3]/10	-0.119¢	-0.035¢	-0.085¢	-0.053¢	-0.141¢	-0.113¢	-0.047¢	-0.124¢	-0.054¢	-0.063¢	-0.085¢	-0.080¢
	Class Refund Factors												
[5a 4]	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
[5a 5]	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
[5a 6]	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
[5a 7]	C & I Demand TOD 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
[5a 8]	C & I Demand TOD 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
[5a 9]	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
	Class Refund Factors												
[5a 10]	Residential [5a 3]x[5a 4]	-0.122¢	-0.036¢	-0.086¢	-0.054¢	-0.143¢	-0.115¢	-0.048¢	-0.126¢	-0.055¢	-0.064¢	-0.086¢	-0.081¢
[5a 11]	C & I Non-Demand [5a 3]x[5a 5]	-0.123¢	-0.036¢	-0.087¢	-0.055¢	-0.145¢	-0.116¢	-0.048¢	-0.128¢	-0.056¢	-0.065¢	-0.087¢	-0.082¢
[5a 12]	C & I Demand Non-TOD [5a 3]x[5a 6]	-0.119¢	-0.035¢	-0.084¢	-0.053¢	-0.141¢	-0.113¢	-0.047¢	-0.124¢	-0.054¢	-0.063¢	-0.085¢	-0.080¢
[5a 13]	C & I Demand TOD On-Peak [5a 3]x[5a 7]	-0.149¢	-0.044¢	-0.106¢	-0.066¢	-0.176¢	-0.141¢	-0.059¢	-0.155¢	-0.067¢	-0.078¢	-0.106¢	-0.100¢
[5a 14]	C & I Demand TOD Off-Peak [5a 3]x[5a 8]	-0.098¢	-0.029¢	-0.069¢	-0.043¢	-0.115¢	-0.092¢	-0.038¢	-0.101¢	-0.044¢	-0.051¢	-0.069¢	-0.065¢
[5a 15]	Outdoor Lighting [5a 3]x[5a 9]	-0.095¢	-0.028¢	-0.068¢	-0.042¢	-0.112¢	-0.090¢	-0.038¢	-0.099¢	-0.043¢	-0.050¢	-0.068¢	-0.064¢
	Minnesota MWh Retail Sales Subject to FCA (Cal. Mo)												
[5a 16]	Residential	914,118	953,925	687,862	597,876	652,230	730,563	796,873	666,282	675,399	550,969	582,088	723,516
[5a 17]	C & I Non-Demand	78,461	78,866	67,141	61,572	59,272	75,969	80,496	73,142	80,836	66,961	66,174	67,755
[5a 18]	C & I Demand Non-TOD	894,193	898,206	771,760	723,229	691,529	775,461	757,910	655,756	795,197	664,310	730,650	771,788
[5a 19]	C & I Demand TOD On-Peak	404,244	407,871	377,296	345,108	337,851	335,187	306,973	295,280	352,465	317,281	329,096	328,286
[5a 20]	C & I Demand TOD Off-Peak	648,013	639,228	588,714	552,235	516,256	547,914	543,776	478,210	555,728	515,681	528,001	515,645
[5a 21]	Outdoor Lighting	6,966	8,797	11,671	10,817	15,576	16,022	15,659	12,182	12,407	8,816	7,813	7,437
	Amount of Margin Sharing Refund Credited to Customers												
[5a 22]	Residential [5a 10]x[5a 16]x10	($1,111,120)	($341,353)	($592,456)	($321,914)	($934,509)	($839,928)	($381,383)	($842,680)	($370,375)	($351,832)	($501,655)	($587,119)
[5a 23]	C & I Non-Demand [5a 11]x[5a 17]x10	($96,570)	($28,576)	($58,556)	($33,570)	($85,992)	($88,440)	($39,010)	($93,669)	($44,886)	($43,297)	($57,747)	($55,674)
[5a 24]	C & I Demand Non-TOD [5a 12]x[5a 17]x10	($1,066,289)	($315,324)	($652,114)	($382,024)	($972,027)	($874,635)	($355,861)	($813,636)	($427,800)	($416,164)	($617,750)	($614,413)
[5a 25]	C & I Demand TOD On-Peak [5a 13]x[5a 18]x10	($602,845)	($179,068)	($398,696)	($227,978)	($593,898)	($472,795)	($180,251)	($458,186)	($237,138)	($248,574)	($347,970)	($326,842)
[5a 26]	C & I Demand TOD Off-Peak [5a 14]x[5a 19]x10	($632,020)	($183,542)	($406,860)	($238,588)	($593,524)	($505,456)	($208,826)	($485,302)	($244,531)	($264,225)	($365,123)	($335,752)
[5a 27]	Outdoor Lighting [5a 15]x[5a 20]x10	($6,636)	($2,467)	($7,878)	($4,565)	($17,491)	($14,437)	($5,874)	($12,075)	($5,332)	($4,412)	($5,277)	($4,730)
[5a 28]	Total Sum[5a 22]..[5a 28]	**($3,515,480)**	**($1,050,329)**	**($2,116,560)**	**($1,208,639)**	**($3,197,441)**	**($2,795,690)**	**($1,171,206)**	**($2,705,548)**	**($1,330,063)**	**($1,328,503)**	**($1,895,522)**	**($1,924,528)**
	Other Refunds to Customers	**[TRADE SECRET DATA BEGINS**											
[5b 1]	Sherco Outage Settlement Refund												
[5b 2]	Refund Factor [5b 1]/[5a 2]/10												
[5b 3]	Sherco Land Sale Gain Refund True Up												
[5b 4]	Refund Factor [5b 3]/[5a 2]/10												
[5b 5]	Inver Hills Asset Sales Gain Sharing Final ROE Adjustment												
[5b 6]	Refund Factor [5b 5]/[5a 2]/10												
[5b 7]	High Bridge Gas Cost Refund												
[5b 8]	Refund Factor [5b 5]/[5a 2]/10												
[5b 9]	Total of Other Refund Factors [5b 2]+[5b 4]+[5b 6]												
	Class Refund Factors												
[5b 10]	Residential [5b 9]x[5a 4]												
[5b 11]	C & I Non-Demand [5b 9]x[5a 5]												
[5b 12]	C & I Demand Non-TOD [5b 9]x[5a 6]												
[5b 13]	C & I Demand TOD On-Peak [5b 9]x[5a 7]												
[5b 14]	C & I Demand TOD Off-Peak [5b 9]x[5a 8]												
[5b 15]	Outdoor Lighting [5b 9]x[5a 9]												
	Amount of Other Refund Credited to Customers												
[5b 16]	Residential [5a 16]x[5b 10]												
[5b 17]	C & I Non-Demand [5a 17]x[5b 11]												
[5b 18]	C & I Demand Non-TOD [5a 18]x[5b 12]												
[5b 19]	C & I Demand TOD On-Peak [5a 19]x[5b 13]												
[5b 20]	C & I Demand TOD Off-Peak [5a 20]x[5b 14]												
[5b 21]	Outdoor Lighting [5a 21]x[5b 15]												
[5b 22]	Total Sum[5b 16]..[5b 22]												

TRADE SECRET DATA ENDS]

	Refund Included in Fuel Cost Charge Month	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
	RULE 7825.2810 SUBPART 1 G: AMOUNT OF REFUNDS CREDITED TO CUS							
[5a 1]	**System Asset Based Margins Sharing Refund**	($972,923)	($909,715)	($620,976)	($723,776)	($3,056,330)	($2,411,390)	($32,702,888)
[5a 2]	Forecasted Minnesota Jurisdiction MWh Sales	2,326,773	2,229,409	2,169,745	2,445,016	2,425,070	2,169,548	42,725,975
[5a 3]	Refund Factor [5a 1]/[5a 3]/10	-0.042¢	-0.041¢	-0.029¢	-0.030¢	-0.126¢	-0.111¢	-0.077¢
	Class Refund Factors							
[5a 4]	Residential	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177	1.0177
[5a 5]	C & I Non-Demand	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305	1.0305
[5a 6]	C & I Demand Non-TOD	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984	0.9984
[5a 7]	C & I Demand TOD On-Peak	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486	1.2486
[5a 8]	C & I Demand TOD Off-Peak	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166	0.8166
[5a 9]	Outdoor Lighting	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976	0.7976
	Class Refund Factors							
[5a 10]	Residential [5a 3]x[5a 4]	-0.043¢	-0.042¢	-0.029¢	-0.030¢	-0.128¢	-0.113¢	-0.078¢
[5a 11]	C & I Non-Demand [5a 3]x[5a 5]	-0.043¢	-0.042¢	-0.029¢	-0.031¢	-0.130¢	-0.115¢	-0.079¢
[5a 12]	C & I Demand Non-TOD [5a 3]x[5a 6]	-0.042¢	-0.041¢	-0.029¢	-0.030¢	-0.126¢	-0.111¢	-0.076¢
[5a 13]	C & I Demand TOD On-Peak [5a 3]x[5a 7]	-0.052¢	-0.051¢	-0.036¢	-0.037¢	-0.157¢	-0.139¢	-0.096¢
[5a 14]	C & I Demand TOD Off-Peak [5a 3]x[5a 8]	-0.034¢	-0.033¢	-0.023¢	-0.024¢	-0.103¢	-0.091¢	-0.063¢
[5a 15]	Outdoor Lighting [5a 3]x[5a 9]	-0.033¢	-0.033¢	-0.023¢	-0.024¢	-0.101¢	-0.089¢	-0.061¢
	Minnesota MWh Retail Sales Subject to FCA (Cal. Mo)							
[5a 16]	Residential	928,361	789,039	671,505	595,420	641,877	745,436	12,903,339
[5a 17]	C & I Non-Demand	75,422	70,564	64,921	60,282	67,420	74,052	1,269,306
[5a 18]	C & I Demand Non-TOD	862,228	799,840	763,539	724,118	712,932	734,640	13,727,286
[5a 19]	C & I Demand TOD On-Peak	368,518	382,028	342,774	339,086	312,068	307,876	6,189,288
[5a 20]	C & I Demand TOD Off-Peak	591,615	577,208	538,640	523,191	477,814	513,771	9,851,640
[5a 21]	Outdoor Lighting	7,499	8,195	9,509	12,157	11,956	14,465	197,944
	Amount of Margin Sharing Refund Credited to Customers							
[5a 22]	Residential [5a 10]x[5a 16]x10	($395,055)	($327,664)	($195,589)	($179,376)	($823,284)	($843,192)	($9,940,485)
[5a 23]	C & I Non-Demand [5a 11]x[5a 17]x10	($32,499)	($29,672)	($19,147)	($18,389)	($87,562)	($84,817)	($998,073)
[5a 24]	C & I Demand Non-TOD [5a 12]x[5a 17]x10	($359,954)	($325,855)	($218,174)	($214,013)	($897,075)	($815,223)	($10,338,331)
[5a 25]	C & I Demand TOD On-Peak [5a 13]x[5a 18]x10	($192,400)	($194,639)	($122,490)	($125,330)	($491,076)	($427,264)	($5,827,440)
[5a 26]	C & I Demand TOD Off-Peak [5a 14]x[5a 19]x10	($202,007)	($192,331)	($125,886)	($126,471)	($491,752)	($466,314)	($6,068,510)
[5a 27]	Outdoor Lighting [5a 15]x[5a 20]x10	($2,501)	($2,667)	($2,171)	($2,870)	($12,018)	($12,823)	($126,224)
[5a 28]	Total Sum[5a 22]..[5a 28]	**($1,184,415)**	**($1,072,829)**	**($683,457)**	**($666,449)**	**($2,802,768)**	**($2,649,634)**	**($33,299,063)**
	Other Refunds to Customers	**[TRADE SECRET DATA BEGINS**						
[5b 1]	Sherco Outage Settlement Refund							
[5b 2]	Refund Factor [5b 1]/[5a 2]/10							
[5b 3]	Sherco Land Sale Gain Refund True Up							
[5b 4]	Refund Factor [5b 3]/[5a 2]/10							
[5b 5]	Inver Hills Asset Sales Gain Sharing Final ROE Adjustment							
[5b 6]	Refund Factor [5b 5]/[5a 2]/10							
[5b 7]	High Bridge Gas Cost Refund							
[5b 8]	Refund Factor [5b 5]/[5a 2]/10							
[5b 9]	Total of Other Refund Factors [5b 2]+[5b 4]+[5b 6]							
	Class Refund Factors							
[5b 10]	Residential [5b 9]x[5a 4]							
[5b 11]	C & I Non-Demand [5b 9]x[5a 5]							
[5b 12]	C & I Demand Non-TOD [5b 9]x[5a 6]							
[5b 13]	C & I Demand TOD On-Peak [5b 9]x[5a 7]							
[5b 14]	C & I Demand TOD Off-Peak [5b 9]x[5a 8]							
[5b 15]	Outdoor Lighting [5b 9]x[5a 9]							
	Amount of Other Refund Credited to Customers							
[5b 16]	Residential [5a 16]x[5b 10]							
[5b 17]	C & I Non-Demand [5a 17]x[5b 11]							
[5b 18]	C & I Demand Non-TOD [5a 18]x[5b 12]							
[5b 19]	C & I Demand TOD On-Peak [5a 19]x[5b 13]							
[5b 20]	C & I Demand TOD Off-Peak [5a 20]x[5b 14]							
[5b 21]	Outdoor Lighting [5a 21]x[5b 15]							
[5b 22]	Total Sum[5b 16]..[5b 22]							
								TRADE SECRET DATA ENDS]

	Refund Included in Fuel Cost Charge Month	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
	Total Asset Based Margin Sharing and Other Refunds	**[TRADE SECRET DATA BEGINS**											
[5c 1]	Residential [5a 22]+[5b 16]												
[5c 2]	C & I Non-Demand [5a 23]+[5b 17]												
[5c 3]	C & I Demand Non-TOD [5a 24]+[5b 18]												
[5c 4]	C & I Demand TOD On-Peak [5a 25]+[5b 19]												
[5c 5]	C & I Demand TOD Off-Peak [5a 26]+[5b 20]												
[5c 6]	Outdoor Lighting [5a 27]+[5b 21]												
[5c 7]	Total Sum[5d 1]..[5d 6]												
													TRADE SECRET DATA ENDS]

	Refund Included in Fuel Cost Charge Month	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
	Total Asset Based Margin Sharing and Other Refunds	**[TRADE SECRET DATA BEGINS**						
[5c 1]	Residential [5a 22]+[5b 16]							
[5c 2]	C & I Non-Demand [5a 23]+[5b 17]							
[5c 3]	C & I Demand Non-TOD [5a 24]+[5b 18]							
[5c 4]	C & I Demand TOD On-Peak [5a 25]+[5b 19]							
[5c 5]	C & I Demand TOD Off-Peak [5a 26]+[5b 20]							
[5c 6]	Outdoor Lighting [5a 27]+[5b 21]							
[5c 7]	Total Sum[5d 1]..[5d 6]							
								TRADE SECRET DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2018 - December 2019
Fuel, Purchased Power and Other Costs

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
A.	**Actual Costs of Fuel Used by Company to Generate Electricity**												
	Account 151 Fossil Fuel												
[1]	Coal (5004001)	29,232,252	27,438,445	23,914,550	27,752,577	32,608,099	30,424,704	29,559,267	23,292,736	18,890,494	10,985,018	21,852,722	23,492,616
[2]	Wood/Refuse-Derived Fuel (5005001/5006001/4280161)	2,056,086	1,089,927	456,551	778,140	937,614	855,354	1,022,273	703,545	511,637	721,683	917,938	912,943
[3]	Natural Gas / Oil CC (5002041)	19,309,426	25,189,587	15,889,704	8,441,224	10,438,256	11,513,179	13,034,146	19,717,724	19,418,465	15,065,039	11,712,045	14,649,963
[4]	Natural Gas / Oil CT (5002001/5002021/5003001/500311)	2,705,789	1,713,146	1,593,714	1,518,562	970,089	252,554	1,959,289	1,296,599	402,481	1,789,701	2,598,914	1,869,009
[5]	Total Fossil Fuel	53,303,553	55,431,105	41,854,519	38,490,503	44,954,058	43,045,790	45,574,975	45,010,605	39,223,077	28,561,442	37,081,619	40,924,531
[6]	Account 518 Nuclear Fuel	10,476,560	10,359,705	8,491,311	7,591,732	10,212,886	10,920,319	10,475,575	9,289,472	9,929,308	7,509,241	8,912,307	10,281,039
[7]	Total Own Generation	63,780,114	65,790,809	50,345,830	46,082,235	55,166,944	53,966,109	56,050,550	54,300,077	49,152,384	36,070,682	45,993,926	51,205,570
B.	**Cost of Energy/Power Purchased by Company**												
	Account 555 Energy Purchases												
[8]	Long Term Energy Purchase Contract Total (5066001/5066011)	18,548,170	15,493,928	14,736,720	13,661,692	10,883,106	8,909,582	11,601,172	9,244,556	9,595,856	7,732,938	15,278,597	14,871,991
[8A]	MISO	10,882,166	9,905,515	10,698,951	13,244,185	8,428,409	8,601,275	14,222,903	7,557,412	8,269,525	8,798,089	8,053,098	1,863,697
[8B]	Less: MISO Schedule 16 and 17	(675,995)	(571,063)	(666,786)	(804,664)	(875,277)	(676,250)	(476,755)	(535,109)	(715,936)	(666,682)	(666,890)	(889,451)
[8C]	Less: MISO Schedule 24	(78,974)	(107,836)	(96,619)	(101,812)	(105,958)	(96,697)	(93,325)	(95,362)	(77,449)	(109,987)	(80,194)	(101,373)
[8D]	Less: RSG/RNU	(92,682)	(26,482)	(68,649)	(90,207)	(104,789)	(106,746)	(24,219)	(432,432)	(86,090)	(55,507)	(186,615)	(79,078)
[8E]	Less: MISO ARR												
[8F]	Less: MISO Congestion & Loss	(920,331)	(419,580)	(654,052)	(349,069)	(769,074)	(861,964)	(811,777)	(837,640)	(911,252)	(340,689)	(968,525)	(781,509)
[9]	SPP (5066021)	10,526	9,719	13,111	6,083	19,144	13,716	10,908	15,911	12,495	9,057	8,339	2,571
[10]	Others - Wind (5069001/5069006/5069011)	12,005,084	11,390,953	16,154,436	17,692,750	17,050,848	16,560,431	17,748,356	14,944,422	17,185,024	14,888,888	13,229,220	11,789,698
[11]	Others - Tolling (Plant Gas & Oil) (5066071/5066081)	1,679,775	2,063,289	643,471	828,732	580,192	612,767	1,357,275	1,330,820	1,829,534	1,845,108	841,646	2,725,076
[12]	Others - Qualifying Facilities (5067001)	164,065	204,525	50,723	191,706	26,018	113,664	117,306	83,279	95,397	201,040	156,083	190,300
[13]	Solar (5070001)	15,497,685	11,004,787	10,943,461	8,533,618	4,840,128	5,444,296	6,054,010	1,818,303	12,155,799	10,516,337	16,047,887	17,399,638
[14]	Other s - Highbridge Gas Cost Adjustment	0	(5,503,959)	500,360	500,360	500,360	500,360	500,360	500,360	500,360	500,360	500,360	500,360
[15]	Others - Asset Based Trading	3,031,594	1,749,874	1,661,005	1,335,421	1,843,545	18,897	1,707,744	(1,616,698)	1,112,604	1,268,154	2,373,509	3,322,702
[16]	Others - Non-Asset Based Trading	5,459,946	4,529,155	2,692,692	3,946,242	(706,628)	8,700,736	6,131,226	7,293,088	6,847,784	2,441,881	3,099,682	12,319,876
[17]	Other - Renewable*Connect Neutrality Charge	(52,573)	(74,542)	(78,516)	(75,550)	(66,458)	(75,990)	(73,826)	(74,063)	(74,244)	(72,719)	(69,823)	(71,672)
[18]	Other - REC Related Fuel Costs	(385,453)	(328,214)	(150,330)	(149,132)	(132,767)	(206,329)	(118,827)	(200,205)	(477,598)	546,184	(405,756)	(212,761)
[19]	Total Purchases	65,073,002	49,320,069	56,379,978	58,370,354	41,410,799	47,451,746	57,852,528	38,996,642	55,261,809	47,502,451	57,210,619	62,850,066
C.	**Fuel-Related Costs Recovered through Intersystem Sales**												
[20]	Estimated Energy Generated by Company Total	11,506,636	7,210,745	11,386,281	8,551,366	14,565,018	12,233,516	13,316,858	10,904,706	10,204,402	6,015,097	15,259,515	12,799,518
[21]	Estimated Energy Purchased by Company Total	8,491,540	6,279,029	4,353,697	5,281,663	1,136,917	8,719,632	7,838,969	5,676,390	7,960,388	3,710,035	5,473,191	15,642,578
[22]	Total	19,998,175	13,489,773	15,739,978	13,833,029	15,701,935	20,953,148	21,155,828	16,581,096	18,164,790	9,725,132	20,732,706	28,442,096
D.	**Other Deductions or Additions to Fuel Clause Adjustment Calculation ***												
	Deduction from Account 555												
[23]	Less Purchased Power for WindSource Program	590,730	519,105	379,240	508,761	449,845	458,531	421,276	419,600	1,057,041	(106,235)	891,063	520,244
[24]	Less Purchased Power for Renewable*Connect	346,072	501,015	562,807	509,959	474,959	487,146	499,600	486,911	507,766	481,103	466,286	472,317
[25]	Less Purchased Power Solar Gardens (Above Market)	7,605,211	4,829,734	5,750,742	5,028,980	3,934,869	2,832,154	3,609,067	540,406	7,518,534	5,175,210	9,376,285	10,051,617
[26]	Less Other - MISO Excess Congestion	65,001	0	(258,000)	(316)	0	0	0	0	0	2,851,747	0	0
E.	**TOTAL**												
[27]	Total [7]+[19]-[22]-[23]-[24]-[25]-[26]	100,247,925	95,771,252	84,551,042	84,572,175	76,016,136	76,686,875	88,217,307	75,268,706	77,166,063	65,446,176	71,738,204	74,569,362

* Excluded Biomass PPA Termination cost recovery and other one time refunds or recovery.

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2018 - December 2019
Fuel, Purchased Power and Other Costs

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
A.	**Actual Costs of Fuel Used by Company to Generate Electricity**							
	Account 151 Fossil Fuel							
[1]	Coal (5004001)	27,228,802	19,677,101	15,878,566	11,787,064	16,924,232	14,139,049	405,078,296
[2]	Wood/Refuse-Derived Fuel (5005001/5006001/4280161)	924,710	784,692	560,530	835,287	1,061,992	761,095	15,891,997
[3]	Natural Gas / Oil CC (5002041)	15,724,454	15,624,558	13,684,512	13,464,611	11,793,042	14,707,276	269,377,208
[4]	Natural Gas / Oil CT (5002001/5002021/5003001/500311)	3,766,874	2,804,536	1,532,462	2,043,330	998,237	664,601	30,479,885
[5]	Total Fossil Fuel	47,644,839	38,890,886	31,656,069	28,130,293	30,777,503	30,272,020	720,827,386
[6]	Account 518 Nuclear Fuel	10,479,546	10,448,677	9,232,488	7,967,255	10,395,029	10,765,431	173,737,881
[7]	Total Own Generation	58,124,385	49,339,564	40,888,558	36,097,548	41,172,532	41,037,452	894,565,267
B.	**Cost of Energy/Power Purchased by Company**							
	Account 555 Energy Purchases							
[8]	Long Term Energy Purchase Contract Total (5066001/5066011)	15,880,207	14,651,324	13,099,348	9,605,281	9,493,420	10,455,627	223,743,516
[8A]	MISO	8,134,883	5,183,714	7,444,485	8,454,557	7,626,324	7,497,212	154,866,400
[8B]	Less: MISO Schedule 16 and 17	(707,970)	(397,707)	(602,482)	(706,209)	(610,302)	(790,376)	(12,035,904)
[8C]	Less: MISO Schedule 24	(94,086)	(106,425)	(80,321)	(88,828)	(83,549)	(108,486)	(1,707,282)
[8D]	Less: RSG/RNU	(1,452,254)	(98,357)	(35,604)	(124,162)	(16,457)	(94,572)	(3,174,902)
[8E]	Less: MISO ARR							0
[8F]	Less: MISO Congestion & Loss	(120,152)	(1,166,395)	(973,374)	(934,993)	(999,722)	(849,909)	(13,670,007)
[9]	SPP (5066021)	8,019	8,066	6,379	4,368	16,405	15,992	190,808
[10]	Others - Wind (5069001/5069006/5069011)	8,987,104	9,198,844	14,750,901	20,013,701	18,164,711	14,767,627	266,522,997
[11]	Others - Tolling (Plant Gas & Oil) (5066071/5066081)	5,272,748	5,255,042	3,534,974	3,240,088	4,050,169	5,400,957	43,091,664
[12]	Others - Qualifying Facilities (5067001)	107,016	105,189	86,283	155,155	58,079	121,552	2,227,380
[13]	Solar (5070001)	19,089,841	18,476,621	14,272,282	12,475,353	5,232,550	6,712,778	196,515,373
[14]	Other s - Highbridge Gas Cost Adjustment	500,360	0	0	0	0	0	1
[15]	Others - Asset Based Trading	3,335,627	3,347,232	3,356,704	1,519,679	3,288,406	1,682,383	34,338,381
[16]	Others - Non-Asset Based Trading	18,014,342	13,927,716	12,661,015	8,431,686	8,896,278	11,779,309	136,466,027
[17]	Other - Renewable*Connect Neutrality Charge	(78,795)	(81,106)	(77,327)	(73,063)	(67,071)	(70,447)	(1,307,786)
[18]	Other - REC Related Fuel Costs	(467,043)	(592,955)	(519,498)	110,181	(180,371)	(183,497)	(4,054,373)
[19]	Total Purchases	76,409,846	67,710,802	66,923,765	62,082,794	54,868,871	56,336,150	1,022,012,291
C.	**Fuel-Related Costs Recovered through Intersystem Sales**							
[20]	Estimated Energy Generated by Company Total	15,903,304	12,572,699	12,626,873	10,773,627	11,339,320	11,259,795	208,429,275
[21]	Estimated Energy Purchased by Company Total	21,349,968	17,274,948	16,017,719	9,951,365	12,184,685	13,461,693	170,804,408
[22]	Total	37,253,272	29,847,648	28,644,592	20,724,992	23,524,005	24,721,487	379,233,682
D.	**Other Deductions or Additions to Fuel Clause Adjustment Calculation ***							
	Deduction from Account 555							
[23]	Less Purchased Power for WindSource Program	739,188	854,301	941,024	356,204	652,964	577,490	10,230,372
[24]	Less Purchased Power for Renewable*Connect	528,508	551,405	453,520	588,919	450,957	480,010	8,849,261
[25]	Less Purchased Power Solar Gardens (Above Market)	10,965,447	10,799,751	9,360,830	8,783,393	3,172,307	5,027,637	114,362,174
[26]	Less Other - MISO Excess Congestion	0	0	0	0	0	0	2,658,433
E.	**TOTAL**							
[27]	Total [7]+[19]-[22]-[23]-[24]-[25]-[26]	85,047,816	74,997,260	68,412,356	67,726,833	68,241,170	66,566,977	1,401,243,635

* Excluded Biomass PPA Termination cost recovery and other one time refunds or recovery.

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2018 - December 2019
Company Generation, Purchased and Other MWh

PUBLIC DOCUMENT -
NOT PUBLIC DATA HAS BEEN EXCISED

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
	F. MWh of Generation												
	Account 151 Fossil Fuel												
[1]	Coal (5004001)	1,010,155	1,014,563	795,844	1,040,742	1,027,259	1,128,948	942,786	825,697	562,651	387,450	515,772	910,929
[2]	Wood/Refuse-Derived Fuel (5005001/5006001/4280161)	42,092	42,529	23,478	35,995	42,120	125,229	46,224	35,165	30,134	41,062	44,206	43,731
[3]	Natural Gas / Oil CC (5002041)	679,457	644,933	424,166	208,171	100,896	89,239	289,762	567,164	475,030	612,947	332,187	372,674
[4]	Natural Gas / Oil CT (5002001/5002021/5003001/500311)	(52,728)	9,716	(115,297)	(62,528)	(44,100)	(32,236)	(46,838)	(54,867)	(89,965)	(74,164)	(115,744)	(101,441)
[5]	Total Fossil Fuel	1,678,976	1,711,741	1,128,191	1,222,380	1,126,175	1,311,180	1,231,934	1,373,159	977,850	967,295	776,421	1,225,893
[6]	Account 518 Nuclear Fuel	1,261,021	1,246,290	1,074,877	939,538	1,212,859	1,319,092	1,299,896	1,142,448	1,213,997	899,836	1,060,049	1,229,193
[7]	Total Own Generation	2,939,997	2,958,031	2,203,068	2,161,918	2,339,034	2,630,272	2,531,830	2,515,607	2,191,847	1,867,131	1,836,470	2,455,086
	G. Purchased Energy/Power MWh												
	Account 555 Energy Purchases	**[TRADE SECRET DATA BEGINS…**											
[8]	Long Term Energy Purchase Contract Total (5066001/5066011)												
[8A]	MISO												
[8B]	Less: MISO Schedule 16 and 17												
[8C]	Less: MISO Schedule 24												
[8D]	Less: RSG/RNU												
[8E]	Less: MISO ARR												
[8F]	Less: MISO Congestion & Loss												
[9]	SPP (5066021)												
[10]	Others - Wind (5069001/5069006/5069011)												
[11]	Others - Tolling (Plant Gas & Oil) (5066071/5066081)												
[12]	Others - Qualifying Facilities (5067001)												
[13]	Solar (5070001)												
[14]	Other s - Highbridge Gas Cost Adjustment												
[15]	Others - Asset Based Trading												
[16]	Others - Non-Asset Based Trading												
[17]	Other - Renewable*Connect Neutrality Charge												
[18]	Other - REC Related Fuel Costs												
[19]	Total Purchases												
	H. Intersystem Sales MWh												
[20]	Estimated Energy Generated by Company Total												
[21]	Estimated Energy Purchased by Company Total												
[22]	Total												
	I. MWh Related to Other Deductions or Additions to Fuel Clause Adjustment Calculation												
	Deduction from Account 555												
[23]	Purchased Power for WindSource Program												
[24]	Purchased Power for Renewable*Connect												
[25]	Purchased Power Solar Gardens (Above Market)												
[26]	Other - MISO Excess Congestion												**...TRADE SECRET DATA ENDS]**
	J. TOTAL MWH												
[27]	Total [7]+[19]-[22]-[23]-[24]+[25]-[26]	4,532,787	3,342,346	3,222,068	3,316,845	3,044,311	3,386,014	3,481,148	4,509,970	1,710,559	2,756,385	2,839,613	3,071,813

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2018 - December 2019
Company Generation, Purchased and Other MWh

PUBLIC DOCUMENT -
NOT PUBLIC DATA HAS BEEN EXCISED

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
F. MWh of Generation								
	Account 151 Fossil Fuel							
[1]	Coal (5004001)	739,888	480,452	1,128,348	882,319	1,438,086	1,493,774	16,325,663
[2]	Wood/Refuse-Derived Fuel (5005001/5006001/4280161)	42,987	45,392	28,688	46,910	42,409	35,732	794,083
[3]	Natural Gas / Oil CC (5002041)	789,030	801,925	1,103,609	947,944	587,973	1,106,698	10,133,805
[4]	Natural Gas / Oil CT (5002001/5002021/5003001/500311)	(50,823)	(40,835)	(31,420)	(69,294)	(103,228)	(149,139)	(1,224,931)
[5]	Total Fossil Fuel	1,521,082	1,286,934	2,229,225	1,807,879	1,965,240	2,487,065	26,028,620
[6]	Account 518 Nuclear Fuel	1,263,447	1,266,246	1,173,265	872,255	1,278,738	1,318,665	21,071,712
[7]	Total Own Generation	2,784,529	2,553,180	3,402,490	2,680,134	3,243,978	3,805,730	47,100,332
G. Purchased Energy/Power MWh								
	Account 555 Energy Purchases	**[TRADE SECRET DATA BEGINS…**						
[8]	Long Term Energy Purchase Contract Total (5066001/5066011)							
[8A]	MISO							
[8B]	Less: MISO Schedule 16 and 17							
[8C]	Less: MISO Schedule 24							
[8D]	Less: RSG/RNU							
[8E]	Less: MISO ARR							
[8F]	Less: MISO Congestion & Loss							
[9]	SPP (5066021)							
[10]	Others - Wind (5069001/5069006/5069011)							
[11]	Others - Tolling (Plant Gas & Oil) (5066071/5066081)							
[12]	Others - Qualifying Facilities (5067001)							
[13]	Solar (5070001)							
[14]	Other s - Highbridge Gas Cost Adjustment							
[15]	Others - Asset Based Trading							
[16]	Others - Non-Asset Based Trading							
[17]	Other - Renewable*Connect Neutrality Charge							
[18]	Other - REC Related Fuel Costs							
[19]	Total Purchases							
H. Intersystem Sales MWh								
[20]	Estimated Energy Generated by Company Total							
[21]	Estimated Energy Purchased by Company Total							
[22]	Total							
I. MWh Related to Other Deductions or Additions to Fuel Clause Adjustment Calculation								
	Deduction from Account 555							
[23]	Purchased Power for WindSource Program							
[24]	Purchased Power for Renewable*Connect							
[25]	Purchased Power Solar Gardens (Above Market)							
[26]	Other - MISO Excess Congestion							
								...TRADE SECRET DATA ENDS]
J. TOTAL MWH								
[27]	Total [7]+[19]-[22]-[23]-[24]+[25]-[26]	3,761,855	3,574,927	4,441,250	3,896,337	4,208,258	4,854,482	63,950,969

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2018 - December 2019
Estimated Fuel-Related Costs per MWh

PUBLIC DOCUMENT -
NOT PUBLIC DATA HAS BEEN EXCISED

Docket No. E999/AA-20-171
Part E, Section 5
Schedule 4

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
K.	**Estimated Company's Generated Electricity Sold to Retail Customers**												
	Account 151 Fossil Fuel												
[1]	Coal (5004001)	$28.94	$27.04	$30.05	$26.67	$31.74	$26.95	$31.35	$28.21	$33.57	$28.35	$42.37	$25.79
[2]	Wood/Refuse-Derived Fuel (5005001/5006001/4280161)	$48.85	$25.63	$19.45	$21.62	$22.26	$6.83	$22.12	$20.01	$16.98	$17.58	$20.77	$20.88
[3]	Natural Gas / Oil CC (5002041)	$28.42	$39.06	$37.46	$40.55	$103.46	$129.02	$44.98	$34.77	$40.88	$24.58	$35.26	$39.31
[4]	Natural Gas / Oil CT (5002001/5002021/5003001/500311)	($51.32)	$176.32	($13.82)	($24.29)	($22.00)	($7.83)	($41.83)	($23.63)	($4.47)	($24.13)	($22.45)	($18.42)
[5]	Total Fossil Fuel	$31.75	$32.38	$37.10	$31.49	$39.92	$32.83	$36.99	$32.78	$40.11	$29.53	$47.76	$33.38
[6]	Account 518 Nuclear Fuel	$8.31	$8.31	$7.90	$8.08	$8.42	$8.28	$8.06	$8.13	$8.18	$8.35	$8.41	$8.36
[7]	Total Own Generation	$21.69	$22.24	$22.85	$21.32	$23.59	$20.52	$22.14	$21.59	$22.43	$19.32	$25.04	$20.86
L.	**Estimated Purchased Energy/Power Sold to Retail Customers**												
	Account 555 Energy Purchases	[TRADE SECRET DATA BEGINS…											
[8]	Long Term Energy Purchase Contract Total (5066001/5066011)												
[8A]	MISO												
[8B]	Less: MISO Schedule 16 and 17												
[8C]	Less: MISO Schedule 24												
[8D]	Less: RSG/RNU												
[8E]	Less: MISO ARR												
[8F]	Less: MISO Congestion & Loss												
[9]	SPP (5066021)												
[10]	Others - Wind (5069001/5069006/5069011)												
[11]	Others - Tolling (Plant Gas & Oil) (5066071/5066081)												
[12]	Others - Qualifying Facilities (5067001)												
[13]	Solar (5070001)												
[14]	Other s - Highbridge Gas Cost Adjustment												
[15]	Others - Asset Based Trading												
[16]	Others - Non-Asset Based Trading												
[17]	Other - Renewable*Connect Neutrality Charge												
[18]	Other - REC Related Fuel Costs												
[19]	Total Purchases												
M.	**Estimated Intersystem Sales-Related**												
[20]	Estimated Energy Generated by Company Total												
[21]	Estimated Energy Purchased by Company Total												
[22]	Total												
N.	**Other Deductions or Additions**												
	Deduction from Account 555												
[23]	Purchased Power for WindSource Program												
[24]	Purchased Power for Renewable*Connect												
[25]	Purchased Power Solar Gardens (Above Market)												
[26]	Other - MISO Excess Congestion												**...TRADE SECRET DATA ENDS]**
O.	**SYSTEM TOTAL**												
[27]	Total [7]+[19]-[22]-[23]-[24]+[25]-[26]	$25.59	$31.73	$30.03	$28.77	$27.79	$24.52	$27.62	$17.07	$54.49	$27.81	$32.18	$31.05

Northern States Power Company | **PUBLIC DOCUMENT -** | Docket No. E999/AA-20-171
Electric Operations - State of Minnesota | **NOT PUBLIC DATA HAS BEEN EXCISED** | Part E, Section 5
Monthly Fuel Clause Adjustment July 2018 - December 2019 | Schedule 4
Estimated Fuel-Related Costs per MWh |

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
K.	**Estimated Company's Generated Electricity Sold to Retail Customers**							
	Account 151 Fossil Fuel							
[1]	Coal (5004001)	$36.80	$40.96	$14.07	$13.36	$11.77	$9.47	$24.81
[2]	Wood/Refuse-Derived Fuel (5005001/5006001/4280161)	$21.51	$17.29	$19.54	$17.81	$25.04	$21.30	$20.01
[3]	Natural Gas / Oil CC (5002041)	$19.93	$19.48	$12.40	$14.20	$20.06	$13.29	$26.58
[4]	Natural Gas / Oil CT (5002001/5002021/5003001/500311)	($74.12)	($68.68)	($48.77)	($29.49)	($9.67)	($4.46)	($24.88)
[5]	Total Fossil Fuel	$31.32	$30.22	$14.20	$15.56	$15.66	$12.17	$27.69
[6]	Account 518 Nuclear Fuel	$8.29	$8.25	$7.87	$9.13	$8.13	$8.16	$8.25
[7]	Total Own Generation	$20.87	$19.32	$12.02	$13.47	$12.69	$10.78	$18.99
L.	**Estimated Purchased Energy/Power Sold to Retail Customers**							
	Account 555 Energy Purchases	[TRADE SECRET DATA BEGINS…						
[8]	Long Term Energy Purchase Contract Total (5066001/5066011)							
[8A]	MISO							
[8B]	Less: MISO Schedule 16 and 17							
[8C]	Less: MISO Schedule 24							
[8D]	Less: RSG/RNU							
[8E]	Less: MISO ARR							
[8F]	Less: MISO Congestion & Loss							
[9]	SPP (5066021)							
[10]	Others - Wind (5069001/5069006/5069011)							
[11]	Others - Tolling (Plant Gas & Oil) (5066071/5066081)							
[12]	Others - Qualifying Facilities (5067001)							
[13]	Solar (5070001)							
[14]	Other s - Highbridge Gas Cost Adjustment							
[15]	Others - Asset Based Trading							
[16]	Others - Non-Asset Based Trading							
[17]	Other - Renewable*Connect Neutrality Charge							
[18]	Other - REC Related Fuel Costs							
[19]	Total Purchases							
M.	**Estimated Intersystem Sales-Related**							
[20]	Estimated Energy Generated by Company Total							
[21]	Estimated Energy Purchased by Company Total							
[22]	Total							
N.	**Other Deductions or Additions**							
	Deduction from Account 555							
[23]	Purchased Power for WindSource Program							
[24]	Purchased Power for Renewable*Connect							
[25]	Purchased Power Solar Gardens (Above Market)							
[26]	Other - MISO Excess Congestion							**...TRADE SECRET DATA ENDS]**
O.	**SYSTEM TOTAL**							
[27]	Total [7]+[19]-[22]-[23]-[24]+[25]-[26]	$28.63	$27.23	$19.80	$22.14	$17.93	$15.95	$25.70

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
Costs Recovered from Sales of Energy to Other Utilities													
		[TRADE SECRET DATA BEGINS…											
[1]	Generation												
[2]	Purchases												
[3]	Total												
[4]	Generation %												
[5]	Purchases %												
[6]	Total												
MWh Sales of Energy to Other Utilities													
[1]	Generation												
[2]	Purchases												
[3]	Total												
[4]	Generation %												
[5]	Purchases %												
[6]	Total												
													…TRADE SECRET DATA ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2018 - December 2019
Estimated Fuel-Related Costs per MWh

PUBLIC DOCUMENT -
NOT PUBLIC DATA HAS BEEN EXCISED

		Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Costs Recovered from Sales of Energy to Other Utilities		**[TRADE SECRET DATA BEGINS…**						
[1]	Generation							
[2]	Purchases							
[3]	Total							
[4]	Generation %							
[5]	Purchases %							
[6]	Total							
MWh Sales of Energy to Other Utilities								
[1]	Generation							
[2]	Purchases							
[3]	Total							
[4]	Generation %							
[5]	Purchases %							
[6]	Total							

…TRADE SECRET DATA ENDS]

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

PART F

AUDITOR'S REPORT

Xcel Energy℠

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

July 31, 2019

Andrew Pederson
Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

**RE: 2018 - 2019 ANNUAL AUTOMATIC ADJUSTMENT (AAA)
CHARGES REPORT – ELECTRIC OPERATION
DOCKET NO. E999/AA-20-___**

Dear Mr. Pederson:

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 ongoing and requirements established by the Minnesota Public Utilities Commission for the upcoming Annual Automatic Adjustment (AAA) of Charges Report – Electric Operations filing. The Company's 2018-2019 AAA Electric Report will be filed with the Commission and Minnesota Department of Commerce – Division of Energy Resources by March 1, 2020. We note that this report differs from past reports in that it will cover an 18-month 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 Report, among other things, will provide detailed results of the Company's fuel clause for the reporting period July 2018 to December 2019 The Department will then prepare a comprehensive analysis of the AAA reports filed by all regulated electric utilities, and the Commission will conduct a hearing to review and act on the AAA Report and the Department's recommendations.

<u>AAA Report Independent Audit Requirements</u>

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 approval of our 2005 electric rate case (Docket No. E002/GR-05-1428), the Fuel Clause

Adjustment (FCA) as of 2007 is based on Xcel Energy's monthly forecast of system energy costs and sales including a "true-up" 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.

On November 2, 2015 the Company filed a Petition to increase electric rates (Docket No. E002/GR-15-826). In the associated docket, E002/MR-15-827, a new Base Cost of Energy of $0.02680 per kWh was approved (a decrease of $0.0100 over the previous Base Cost of Energy) along with the interim rates that went into effect January 1, 2016. The current Base Cost of Energy became effective with the implementation of final rates in Docket No. E002/GR-15-826 on October 1, 2017.

The table below shows the current and prior effective Base Cost of Energy by the 6 customer class categories:

Customer Class Category	**Current Base Cost of Energy ($/kWh)[1]**	**Prior Base Cost of Energy ($/kWh)[2]**
Residential	$0.02727	$0.02730
C & I Non-Demand	$0.02762	$0.02812
C & I Demand	$0.02676	$0.02688
C & I Demand Time of Day On-Peak	$0.03346	$0.03412
C & I Demand Time of Day Off-Peak	$0.02188	$0.02141
Outdoor Lighting	$0.02138	$0.01996

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 A.

For the eighteen months ending December 31, 2019, 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

[1] As part of the most recent rate case (Docket No. E002/ GR-15-826) the new FAF ratios were approved by the MPUC in the Order dated June 12, 2017. The new FAF ratios became effective October 1, 2017.
[2] Effective January 1, 2016, pursuant to the MPUC's acceptance of the proposed Base Cost of Energy with the implementation of the interim rate (Docket Nos. E002/GR-15-826 and E002/MR-15-827).

agreements, Windsource exemption and end-of-life nuclear fuel accrual. Please see Appendix A for a list of dockets in which these additional items were approved.

The 2018-2019 Electric AAA 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.[3]

At the Department of Commerce's recommendation, in order to more promptly report REC purchases with Windsource energy needs, the Windsource "brown energy" credit is computed and returned to retail customers on a monthly basis.

Pursuant to the Commission's September 17, 2014 Order in Docket No. E002/M-13-867), we are authorized to recover the costs of the Solar*Rewards Community program through the FCA. These costs include customer bill credits, additional REC credits and unsubscribed energy. Currently there are 374 solar garden facilities generating energy. Each garden was added to the monthly FCA calculation in the month it went online.

Pursuant to the Commission's February 27, 2017 Order in Docket No. E002/M-15-985, the Renewable*Connect and Renewable*Connect Government programs have been in operations during the 2017-2018 AAA period Program energy utilized over the assigned level is credited back to the FCA through the monthly Neutrality Adjustment.

In compliance with the Commission's February 16, 2018 Order in Docket No. E002/PA-17-529, the Company credited the applicable transaction gains through the Minnesota FCA upon completion of our sale of the Inver Hills Generating Plant Facilities (land and oil tanks) to Flint Hills.

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 the auditor report to be submitted with the Company's 2018-2019 Electric AAA Report to be filed by March 1, 2020, the Company's external auditors should include a statement certifying the following:

[3] 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 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 27, 2020. We note that the audit may be conducted in two parts; one part to include the 12-month period of July 2018-June 2019 and the second part to include July – December 2019. 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 will be scheduling a follow-up meeting to ensure that all the audit requirements are understood.

Sincerely,

/s/

REBECCA D. EILERS
REGULATORY POLICY SPECIALIST

cc: Amy Liberkowski
Lisa Peterson
John Chow

Appendix A

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
- Forecast FCA – E002/M-00-420, E002/M-01-477, E,G002/M-01-838, E002/M-02-645, E002/M-03-585, E002/M-04-595, E002/M-05-613, E002/M-06-589, E002/M-07-484, E002/M-08-451, E002/M-14-364, and <u>E002/M-17-445</u>
- <u>Fuel Clause Reform – E999/CI-03-802, Orders dated December 19, 2017 and June 12, 2019</u>

For the 18 months ending December 31, 2019, 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, E002/M-09-1055, Notice of Approval dated October 12, 2009. <u>Amendment approved in E002/M-17-26, Order dated October 8, 2018.</u>
    - Winona, LLC, E002/M-09-1247, Notice of Approval dated December 1, 2009
    - Goodhue North, LLC, E002/M-09-1349, Order dated April 28, 2010[1]
    - Goodhue South, LLC, E002/M-09-1350, Order dated April 28, 2010[2]

[1] On July 24, 2013, the Company notified the MPUC that the PPAs with Goodhue North and Goodhue South had been terminated. The MPUC issued an Order closing the associated dockets on October 23, 2013.
[2] Id.

- 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, E002/M-09-1481, Order dated June 25, 2010[3]
- WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
- Big Blue, LLC, E002/M-10-733, Notice of Approval dated August 26, 2010[4]
- Community Wind North, LLC, E002/M-10-734, Order dated August 26, 2010
- 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, E002/M-08-1487, Order dated April 24, 2009. 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
- Jeffers Wind 20, LLC, E002/M-06-1234, 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

- WindSource Exemption – E002/M-01-1479, E002/M-09-1177 [5]
- 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

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[3] The amended PPA was approved by the Commission's September 8, 2014 Order in Docket No. E002/M-14-490.
[4] The amended PPA was approved by the Commission's February 27, 2014 Order in Docket No. E002/M-13-1002.
[5] ORDER ALLOWING ADDITION OF LIMITED SOLAR ENERGY TO WINDSOURCE PROGRAM, REQUIRING CUSTOMER NOTIFICATION AND REQUIRING COMPLIANCE FILING, June 21, 2010.

- Inver Hills Sales Gain Sharing Refund – E002/PA-17-529, Order dated February 16, 2018
- Sherco Land Sale Sharing Refund – E002/M-17-528, Order dated February 6, 2018
- Solar Energy Standard Exemption – E002/M-17-425, Order dated October 12, 2017
- Sherco 3 Outage Settlement – E002/GR-12-961, E002/GR-13-868, E999/AA-13-599, E999/AA-14-579, E999/AA-16-523, E999/AA-17-482 and E999/AA-18-373, Order dated April 11, 2019

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 July 1, 2018 to December 31, 2019, and Independent Accountants' Report on Applying Agreed-Upon Procedures

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INDEPENDENT ACCOUNTANTS' REPORT ON APPLYING AGREED-UPON PROCEDURES

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

We have performed the procedures enumerated below, which were agreed to by Northern States Power Company, a Minnesota Corporation (the "Company") and the Minnesota Public Utilities Commission (the "Commission"), solely to assist you with the compliance of 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 electric rates filed by the Company with the Commission, as well as with Docket No. E-999/AA-15-611 on the Schedule of Fuel Adjustment Clause Factors ("the Schedule"). The Company's management is responsible for maintaining compliance with those requirements. The sufficiency of these procedures is solely the responsibility of those parties specified in this report. Consequently, we make no representation regarding the sufficiency of the procedures enumerated below either for the purpose for which this report has been requested or for any other purpose.

Our procedures and findings are as follows:

a. On a sample basis, we compared the documentation in support of payments and invoices received from energy suppliers for the 47 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 Minnesota Public Utilities Commission, to the bases used by the Company 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 July 1, 2018 to December 31, 2019, 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 July 1, 2018 to December 31, 2019 and found them to be in agreement.

e. We randomly selected eighteen individual billings for each class of service for the period from July 1, 2018 to December 31, 2019, and recalculated the automatic adjustment charges and credits used by the Company and traced these amounts to the individual customer's subsidiary records to ensure that the calculated credit or charge was recorded, noting no exceptions.

f. We did not identify any corrections to FCA charges or other billing errors for the period from July 1, 2018 to December 31, 2019, with the exception of the following:

    i. The Minnesota asset-based margin sharing refund calculation for the months of February and April 2019 utilized billing month sales as compared to calendar month sales. As a result, the asset-based margins for February and April 2019 were over-refunded by a total of $54,840. The amounts were corrected upon identification by the Company in July 2019.

g. We reconciled and gained an understanding of total revenue and the cost of power to the Company's general ledger and found them to be in agreement, when considering applicable reconciling items, with the FCA calculation underlying detail.

h. We have recalculated the true-up calculation and have traced the related revenue and expense amounts to the Company's accounting records and found them to be in agreement with the amounts used in the true-up calculation.

i. Through inspection of a sample of twelve accounting records, we identified no exceptions with the accounting separation of retail and wholesale financial instruments.

j. On a sample basis, we inspected vendor invoices and traced gains and losses to the accounting records for one selection. We did not identify any wholesale electric financial instrument gains or losses recorded in Account 555 or Account 804.

This agreed-upon procedures engagement was conducted 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, the objective of which would be the expression of an opinion or conclusion, respectively, on the Schedule. 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.

This report is intended solely for the information and use of the Board of Directors 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, 2020

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION

STATE OF MINNESOTA RETAIL ELECTRIC CUSTOMERS
SCHEDULE OF FUEL ADJUSTMENT CLAUSE FACTORS
FOR THE PERIOD FROM JULY 1, 2018 TO DECEMBER 31, 2019
(CENTS PER KWH)

	Residential	C&I Non-Demand	C&I Demand Non-TOD	C&I Demand On-Peak	C&I Demand Off-Peak	Outdoor Lighting
July 1, 2018	2.807	2.843	2.754	3.444	2.252	2.201
August 1, 2018	2.280	2.309	2.238	2.798	1.829	1.788
September 1, 2018	3.080	3.119	3.022	3.779	2.471	2.414
October 1, 2018	2.737	2.772	2.686	3.358	2.196	2.146
November 1, 2018	2.602	2.635	2.553	3.192	2.088	2.040
December 1, 2018	2.776	2.812	2.724	3.406	2.227	2.176
January 1, 2019	2.702	2.736	2.651	3.315	2.168	2.118
February 1, 2019	2.003	2.029	1.966	2.458	1.607	1.571
March 1, 2019	2.661	2.695	2.612	3.265	2.135	2.087
April 1, 2019	2.642	2.676	2.593	3.242	2.120	2.072
May 1, 2019	2.947	2.985	2.892	3.616	2.365	2.311
June 1, 2019	2.416	2.447	2.371	2.964	1.938	1.894
July 1, 2019	3.015	3.053	2.958	3.699	2.419	2.363
August 1, 2019	2.656	2.690	2.606	3.258	2.131	2.082
September 1, 2019	2.404	2.435	2.359	2.950	1.929	1.885
October 1, 2019	2.357	2.388	2.313	2.892	1.891	1.848
November 1, 2019	2.322	2.352	2.279	2.849	1.863	1.821
December 1, 2019	2.137	2.165	2.098	2.623	1.715	1.676

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.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

PART G

FIVE-YEAR PROJECTION

ANNUAL FIVE-YEAR PROJECTION

In compliance with MN Rule 7825.2830, the following schedules were provided in our May 1, 2019 Petition in Docket No. E002/AA-19-293. The attachments contain the trade secret five-year (2020 - 2024) projection of fuel cost by energy source:

Part A, Attachment 1 – 2020 Year Fuel Cost Forecast – Per Unit Summary
Part E, Attachment 1 – 4-Year Fuel Cost Forecast – Per Unit Summary
Part A, Attachment 2 – 2020 Fuel Cost Forecast – Cost Summary
Part E, Attachment 2 – 4-Year Fuel Cost Forecast – Cost Summary
Part A, Attachment 3 – 2020 Fuel Cost Forecast – Energy Summary
Part E, Attachment 3 – 4-Year Fuel Cost Forecast – Energy Summary

The detailed trade secret information was provided in the May 1, 2019 Petition in Docket No. E002/AA-19-293 as follows:

Part B, Attachment 2 – 2020 Fossil Fuel Costs
Part E, Attachment 4 – 4-Year Fossil Fuel Costs
Part B, Attachment 3 – 2020 Coal Burn Expenses
Part E, Attachment 5 – 4-Year Coal Burn Expenses
Part B, Attachment 4 – 2020 Nuclear Fuel Expenses
Part E, Attachment 6 – 4-Year Nuclear Fuel Expenses

The energy and peak demand forecasts in Part A, Attachment 4 and Part E, Attachment 7 were used as assumptions in developing the projection of fossil and nuclear fuel costs. Fuel cost projections for 2020 through 2024 are based on Xcel Energy's February 2019 energy and peak demand forecasts. Part E, Attachment 8 includes the estimated load management impact for the same period.

Additional detail about the fuel forecast assumptions and inputs are included in the May 1, 2019 petition. We will include a 5-year fuel forecast with our 2021 fuel forecast to be filed by May 1, 2020.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

PART H

ADDITIONAL REPORTING REQUIREMENTS

ADDITIONAL REPORTING REQUIREMENTS (NON-MISO)

Part H contains the Company's various compliance reports required by Commission Orders in prior Company miscellaneous filings, investigations, and AAA Reports, other than the compliance reports required by Commission Order regarding the Company's participation in the MISO Day 1, Day 2 and ASM operations.

1. History of Nuclear Fuel Sinking Fund (Docket No. E002/M-81-306)

This reporting item was discontinued pursuant to the Commission's March 16, 2018 Order in Docket No. E999/AA-16-523.

2. Investigation of NSP's Practices Regarding Energy Marketing and Fuel Clause (Docket No. E002/CI-00-415)

On April 3, 2000, the Residential and Small Business Utilities Division of the Office of the Attorney General (OAG) filed a request that the Commission initiate a summary investigation into the Company's automatic adjustment of its electric rates (Docket No. E002/CI-00-415). The purpose of the investigation was to determine whether the Company's practices related to the costs included in its retail electric fuel adjustment clause and costs assigned to wholesale electric sales result in a rate that is just and reasonable. Through an Order issued on July 20, 2000, the Commission required the parties to meet and submit a report. In the period between the Commission's July 20, 2000 Order and April 20, 2001, the Commission issued three Orders accepting updates and setting due dates for further reports or updates. On April 20, 2001, the OAG filed its final report, in which it concluded that a formal Commission investigation was no longer warranted provided that the Company complied with reporting requirements set forth in the report.

On June 15, 2001, the Commission issued an Order accepting the final report submitted by the OAG and closed the docket. The Order also required the Company to provide with its AAA reports a monthly comparison of generation costs allocated to retail and wholesale for the months of June, July, and August. The Company has attached the data for 2019 as Part H, Section 2, Schedule 1. The data for 2018 was provided in Docket No. E999/AA-18-373, as supplemented on October 15, 2018.

3. Natural Gas Financial Instruments (Docket Nos. E002/M-01-1953 and E,G999/AA-02-950)

On March 20, 2002, the Commission issued an Order in the above-referenced dockets which 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.[1] The Company also proposed 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 and PGA submitted September 1, 2002. The Department agreed with this recommendation and the Commission included the requirement in its Order. We continue to comply with this requirement, and Part F, Schedule 1 contains a copy of the letter that was sent to facilitate the independent audit by Deloitte & Touche LLP in compliance with the Commission's Order. We note that 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. See Part F, Schedule 1.

4. Annual Transmission Transformers Report (Docket Nos. E,G999/AA-07-1130, E999/M-07-1028 and E999/M-09-602)

On August 31, 2009, the Commission issued an Order in the above-referenced dockets in regards to the 2006-2007 AAA Reports, as well as the 2007 and 2009 Minnesota Biennial Transmission Projects Report and Renewable Energy Standards Report. As a part of its decision, the Commission required all Minnesota electric utilities to report in their AAA reports, and their biennial transmission projects reports, the number of transformers over 100 kV (low side or distribution side) by size, and to assess whether they are maintaining in inventory or otherwise have access to a reasonable level of spare transformers in different sizes due to the increased cost of replacement power during outages.

The following table illustrates the NSP System spare transmission transformer inventory and planned deliveries:

[1] One purpose of the filing was to correctly account for and segregate the costs of financial instruments purchased to limit volatility in electric generation fuel costs from those purchased to limit volatility in the cost of natural gas purchased for the Company's retail local distribution company function.

Primary Voltage Class	Secondary Voltage Class	Maximum MVA	NSP Operating Company	Location	Status
345	115	672	Minnesota	Inver Hills	Storage
345	161	336	Minnesota	Maple Grove	Storage
345	115	672	Minnesota	Maple Grove	Storage
345	115	448	Minnesota	Maple Grove	Storage
230	115	336	Minnesota	Maple Grove	Storage
161	115	187	Minnesota	Maple Grove	Storage
118	34.5	120	Minnesota	Chanarambie	Storage
118	70.6	112	Minnesota	Maple Grove	Storage

The Company believes that it maintains a reasonable level of transformers in inventory in order to: (1) maintain the reliability of the system; (2) remain consistent with North American Electric Reliability Corporation (NERC) reliability criteria; and (3) balance the economic benefit to ratepayers.

However, while the Company believes it maintains a reasonable inventory, and while transmission transformers are typically designed to provide high reliability performance and durability, they do fail from time to time regardless of the efforts of the Company. Such failures may result, for example, from extreme weather conditions, exposure to excessive dust, or natural corrosion. Despite the Company's long-standing practice of improving and maintaining the transmission capability throughout the NSP System, when outages of individual transformers occur it can affect purchased energy costs.

Part H, Section 4, Schedule 1 contains a list of all NSP System transmission transformers exceeding 100 kV.

5. Wind Curtailment Report (Docket Nos. E002/M-00-622, E002/M-02-51, E002/M-04-404, E002/CN-01-1958, E002/M-04-864, E,G999/AA-04-1279, E002/M-05-1850, E002/M-05-1934 and E002/M-06-85)

The Company has been providing wind curtailment reporting in its monthly FCA reports since the May FCA report dated April 28, 2004. Additionally, the Commission's April 4, 2006 Order regarding curtailment payments to wind developers introduced a new element to the regulatory review of wind power purchases—projection of curtailment costs given existing and planned wind-generated energy purchases and the transmission system. Part H, Section 5, Schedule 1 contains a summary of wind production and curtailment payments during the July 1, 2018 – December 31, 2019 AAA reporting period.

Part H, Section 5, Schedule 2 contains an explanation of the factors affecting wind curtailment costs for the 2018-2019 AAA reporting period. We discussed wind curtailment forecasting in our May 1, 2019 Petition in Docket No. E002/AA-19-293 which presented our 2020 fuel forecast, and will update that discussion in our 2021 fuel forecast Petition to be filed on May 1, 2020. Actual curtailment expenses depend on the wind resource experienced at each turbine, the timing of outages of existing transmission facilities and construction of additional transmission facilities, and the operation of wind generators as Dispatchable Intermittent Resources (DIR) in the MISO energy market.

6. 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.

7. 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.

8. 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.

9. Community Solar Gardens (Docket No. E002/M-13-867)

In its September 17, 2014 ORDER APPROVING SOLAR-GARDEN PLAN WITH MODIFICATIONS, 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."

In the reporting period between July 2018 – December 31, 2019, there were 268 active Community Solar Gardens in-service and 158 of these came on-line during the July 2018 – December 2019 AAA reporting period. The location, start date and number of subscriptions for these gardens are detailed in Part H, Section 9, Schedule 1. The total system amount of expense related to the 268 solar gardens during this reporting period was $145,321,146, as shown in Part H, Section 9, Schedule 2. The corresponding subscribed and unsubscribed energy bill credits were $143,993,415 and $1,327,732, respectively. 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. The market costs are allocated to jurisdiction through normal allocations, and above market costs are direct assigned to Minnesota. 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 H, Section 9, Schedule 2 shows the breakdown of the total Minnesota Community Solar Garden market and above market expenses in the 2018-2019 AAA period:

	System	MN Amount[i]	Estimated MN Retail Allocator
Market	$29,355,206	$21,269,584	0.726456
Above Market	$115,965,941	$115,965,941	1.0000000
Total	$145,321,146	$137,235,525	

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, 2019 in Docket No. E002/M-13-867, and the next report is due on April 1, 2020.

10. FCA Rule Variance Dockets (Docket No. E999/AA-15-611)

The Commission's July 21, 2017 Order in the above-referenced docket 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). Please see Part H, Section 10, Schedule 1 for a list of relevant dockets.

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[i] $1,759,246 in solar gardens developer late fees were credited to the FCA. This credit has resulted in a net solar garden cost recovery of $135,476,279 during the AAA reporting period.

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Table 1: GENERATION COSTS ALLOCATION BETWEEN RETAIL & WHOLESALE CLASS

[PROTECTED DATA BEGINS

	Retail		Wholesale		Retail & Wholesale	
	MWh	Cost ($/MWh)	MWh	Cost ($/MWh)	MWh	Cost ($/MWh)
	[1]	[2]	[3]	[4]	[5] [1] + [3]	[6] {[1]x[2]+[3]x[4]}/[5]
June 2019						
July 2019						
August 2019						

PROTECTED DATA ENDS]

Source: Xcel Energy Commercial Accounting

	Primary Voltage Class	Secondary Voltage Class	Maximum MVA	Operating Company	Location	Status
1	345	161	300	Minnesota	Adams Substation	In-service standalone
2	230	115	336	Minnesota	Blue Lake Substation	In-service duplicate
3	345	115	336	Minnesota	Blue Lake Substation	In-service duplicate
4	345	161	448	Wisconsin	Briggs Road Substation	In-service standalone
5	345	115	448	Minnesota	Brookings County Substation	In-service duplicate
6	345	115	448	Minnesota	Brookings County Substation	In-service duplicate
7	345	115	448	Minnesota	Chisago County Substation	In-service duplicate
8	345	115	448	Minnesota	Chisago County Substation	In-service duplicate
9	500	345	1200	Minnesota	Chisago County Substation	In-service duplicate
10	500	345	1200	Minnesota	Chisago County Substation	In-service duplicate
11	161	115	187	Minnesota	Collville Substation	In-service standalone
12	345	115	672	Minnesota	Coon Creek Substation	In-service duplicate
13	345	115	672	Minnesota	Coon Creek Substation	In-service duplicate
14	161	115	186	Wisconsin	Crystal Cave Substation	In-service standalone
15	345	161	300	Wisconsin	Eau Claire Substation	In-service duplicate
16	345	161	300	Wisconsin	Eau Claire Substation	In-service duplicate
17	345	115	448	Minnesota	Eden Prairie Substation	In-service duplicate
18	345	115	448	Minnesota	Eden Prairie Substation	In-service duplicate
19	345	115	448	Minnesota	Elm Creek Substation	In-service standalone
20	161	115	187	Wisconsin	Gingles Substation	In-service standalone
21	345	230	336	Minnesota	Hazel Creek Substation	In-service standalone
22	161	115	187	Wisconsin	Hydro Lane Substation	In-service standalone
23	345	115	598	Minnesota	Inver Hills Substation	In-service standalone
24	345	115	448	Minnesota	King Substation	In-service standalone
25	345	115	448	Minnesota	Kohlman Lake Substation	In-service duplicate
26	345	115	450	Minnesota	Kohlman Lake Substation	In-service duplicate
27	161	115	336	Minnesota	Lawrence Creek	In-service standalone
28	345	115	448	Minnesota	Lyon County	In-service standalone
29	230	115	187	Minnesota	Maple River Substation	In-service duplicate
30	230	115	187	Minnesota	Maple River Substation	In-service duplicate
31	230	115	187	Minnesota	Minnesota Valley Substation	In-service duplicate
32	230	115	186	Minnesota	Minnesota Valley Substation	In-service duplicate
33	345	230	336	Minnesota	Monticello Substation	In-service duplicate
34	345	115	336	Minnesota	Monticello Substation	In-service duplicate
35	345	115	672	Minnesota	Nobles County Substation	In-service duplicate
36	345	115	672	Minnesota	Nobles County Substation	In-service duplicate
37	345	161	672	Minnesota	North Rochester	In-service standalone
38	161	115	178	Wisconsin	Osprey Substation	In-service standalone
39	345	115	450	Minnesota	Parkers Lake Substation	In-service duplicate
40	345	115	450	Minnesota	Parkers Lake Substation	In-service duplicate
41	230	115	336	Minnesota	Paynesville Transmission Substation	In-service standalone
42	161	115	112	Wisconsin	Pine Lake Substation	In-service standalone
43	345	161	224	Minnesota	Prairie Island Substation	In-service standalone
44	230	115	336	Minnesota	Prairie Substation	In-service duplicate
45	230	115	336	Minnesota	Prairie Substation	In-service duplicate
46	230	115	336	Minnesota	Prairie Substation	In-service duplicate
47	345	115	448	Minnesota	Quarry Substation	In-service standalone
48	345	230	336	Minnesota	Red Rock Substation	In-service duplicate
49	345	115	448	Minnesota	Red Rock Substation	In-service duplicate
50	345	115	448	Minnesota	Red Rock Substation	In-service duplicate
51	345	115	649	Minnesota	Scott County Substation	In-service duplicate
52	345	115	672	Minnesota	Scott County Substation	In-service duplicate
53	345	115	336	Minnesota	Sheas Lake Substation	In-service standalone
54	345	115	448	Minnesota	Sherco Substation	In-service standalone
55	230	115	187	Minnesota	Sheyenne Substation	In-service duplicate
56	230	115	187	Minnesota	Sheyenne Substation	In-service duplicate
57	161	115	187	Minnesota	Split Rock Substation	In-service duplicate
58	230	115	336	Minnesota	Split Rock Substation	In-service duplicate
59	345	115	358	Minnesota	Split Rock Substation	In-service duplicate
60	345	115	358	Minnesota	Split Rock Substation	In-service duplicate
61	161	115	187	Minnesota	South Bend Substation	In-service standalone
62	345	161	336	Wisconsin	Stone Lake Substation	In-service standalone
63	345	115	672	Minnesota	Terminal Substation	In-service duplicate
64	345	115	672	Minnesota	Terminal Substation	In-service duplicate
65	345	115	448	Minnesota	Wilmarth Substation	In-service duplicate
66	345	115	448	Minnesota	Wilmarth Substation	In-service duplicate
67	118	70.6	112	Minnesota	Pomerleau Lake Substation	In-service standalone
68	161	70.6	112	Wisconsin	Stone Lake Substation	In-service standalone

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
For January 2017 to October 2019

Docket No.E999/AA-20-171
Part H Section 5
Schedule 1
Page 1 of 5

	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-17			*430,915.00*	*16,121,114.26*	*3,697.00*	*157,640.79*	*$ 16,278,755.05*
Feb-17			*413,435.00*	*16,507,567.11*	*6,934.00*	*276,825.34*	*$ 16,784,392.45*
Mar-17			*416,890.00*	*16,715,428.81*	*11,980.00*	*523,111.92*	*$ 17,238,540.73*
Apr-17			*457,766.00*	*14,278,919.80*	*7,291.00*	*309,809.33*	*$ 14,588,729.13*
May-17			*419,789.00*	*15,783,918.29*	*5,970.00*	*243,464.35*	*$ 16,027,382.64*
Jun-17			*325,258.00*	*12,144,565.98*	*6,822.00*	*309,043.74*	*$ 12,453,609.72*
Jul-17			*225,540.00*	*8,477,405.53*	*277.00*	*14,625.98*	*$ 8,492,031.51*
Aug-17			*179,181.00*	*6,687,158.36*	*54.00*	*2,734.06*	*$ 6,689,892.42*
Sep-17			*348,409.00*	*13,076,351.03*	*1,268.00*	*65,237.53*	*$ 13,141,588.56*
Oct-17			*516,819.00*	*19,352,565.13*	*2,931.00*	*133,307.49*	*$ 19,485,872.62*
Nov-17			*496,866.00*	*18,739,626.55*	*435.00*	*18,782.21*	*$ 18,758,408.76*
Dec-17			*494,304.00*	*18,583,732.70*	*479.00*	*16,365.01*	*$ 18,600,097.71*
Total-17			***4,725,172.00***	***$ 176,468,353.55***	***48,138.00***	***$ 2,070,947.75***	***$ 178,539,301.30***
Jan-18			*517,112.61*	*19,554,286.92*	*1,511.09*	*61,457.59*	*$ 19,615,744.51*
Feb-18			*418,166.06*	*15,810,253.22*	*233.23*	*10,491.35*	*$ 15,820,744.57*
Mar-18			*456,664.46*	*17,253,894.46*	*826.10*	*34,676.33*	*$ 17,288,570.79*
Apr-18			*389,872.84*	*14,871,852.82*	*2,438.98*	*107,167.74*	*$ 14,979,020.56*
May-18			*321,602.85*	*12,231,504.86*	*479.79*	*20,960.61*	*$ 12,252,465.47*
Jun-18			*376,960.04*	*14,294,249.66*	*956.44*	*37,717.50*	*$ 14,331,967.16*
Jul-18			*252,109.41*	*9,524,606.84*	*558.38*	*25,341.15*	*$ 9,549,947.99*
Aug-18			*260,557.95*	*9,854,956.67*	*564.99*	*26,170.63*	*$ 9,881,127.30*
Sep-18			*372,900.25*	*14,204,082.85*	*1,483.22*	*64,512.97*	*$ 14,268,595.82*
Oct-18			*406,941.22*	*15,440,333.05*	*392.86*	*18,908.20*	*$ 15,459,241.25*
Nov-18			*391,946.75*	*14,949,146.73*	*1,497.05*	*66,292.63*	*$ 15,015,439.36*
Dec-18			*376,229.82*	*14,485,535.21*	*10,741.09*	*338,305.25*	*$ 14,823,840.46*
Total-18			***4,541,064.26***	***$ 172,474,703.29***	***21,683.23***	***$ 812,001.95***	***$ 173,286,705.24***
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			*406,299.72*	*15,084,183.21*	*1,869.04*	*93,395.08*	*$ 15,177,578.29*
Apr-19			*320,446.94*	*11,945,738.10*	*15,514.36*	*714,235.19*	*$ 12,659,973.29*
May-19			*414,641.04*	*14,673,983.37*	*8,719.31*	*367,154.52*	*$ 15,041,137.89*
Jun-19			*305,281.05*	*10,705,837.28*	*2,914.02*	*116,848.22*	*$ 10,822,685.50*
Jul-19			*259,723.46*	*9,131,537.69*	*5,882.20*	*225,357.99*	*$ 9,356,895.68*
Aug-19			*235,454.96*	*8,394,370.96*	*1,705.60*	*68,807.54*	*$ 8,463,178.50*
Sep-19			*417,454.67*	*14,926,240.55*	*1,016.19*	*47,264.76*	*$ 14,973,505.31*
Oct-19			*521,623.14*	*18,804,328.15*	*10,510.38*	*407,660.98*	*$ 19,211,989.13*
Nov-19			*473,817.83*	*16,580,511.84*	*1,818.16*	*77,049.29*	*$ 16,657,561.13*
Dec-19			*407,457.50*	*14,226,050.46*	*1,527.30*	*70,126.80*	*$ 14,296,177.26*
Total-19			***4,488,686.70***	***162,334,782.15***	***55,923.05***	***2,411,218.40***	***164,746,000.55***

Northern States Power Company
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	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-17			-	0.00	-	0.00	
Feb-17			-	0.00	-	0.00	
Mar-17			-	0.00	-	0.00	
Apr-17			-	0.00	-	0.00	
May-17			-	0.00	-	0.00	
Jun-17			-	0.00	-	0.00	
Jul-17			-	0.00	-	0.00	
Aug-17			-	0.00	-	0.00	
Sep-17			-	0.00	-	0.00	
Oct-17			-	0.00	-	0.00	
Nov-17			-	0.00	-	0.00	
Dec-17			-	0.00	-	0.00	
Total-17			-	0.00	-	0.00	
Jan-18			-	0.00	-	0.00	
Feb-18			-	0.00	-	0.00	
Mar-18			-	0.00	-	0.00	
Apr-18			-	0.00	-	0.00	
May-18			-	0.00	-	0.00	
Jun-18			-	0.00	-	0.00	
Jul-18			-	0.00	-	0.00	
Aug-18			-	0.00	-	0.00	
Sep-18			-	0.00	-	0.00	
Oct-18			-	0.00	-	0.00	
Nov-18			-	0.00	-	0.00	
Dec-18			-	0.00	-	0.00	
Total-18			-	0.00	-	0.00	
Jan-19			-	0.00	-	0.00	
Feb-19			-	0.00	-	0.00	
Mar-19			-	0.00	-	0.00	
Apr-19			-	0.00	-	0.00	
May-19			-	0.00	-	0.00	
Jun-19			-	0.00	-	0.00	
Jul-19			-	0.00	-	0.00	
Aug-19			-	0.00	-	0.00	
Sep-19			-	0.00	-	0.00	
Oct-19			-	0.00	-	0.00	
Nov-19			-	0.00	-	0.00	
Dec-19			-	0.00	-	0.00	
Total-19			-	0.00	-	0.00	

Northern States Power Company
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Wind Curtailment Summary Report - Total
For January 2017 to October 2019

	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-17			-	0.00	-	0.00	
Feb-17			-	0.00	-	0.00	
Mar-17			-	0.00	-	0.00	
Apr-17			-	0.00	-	0.00	
May-17			-	0.00	-	0.00	
Jun-17			-	0.00	-	0.00	
Jul-17			-	0.00	-	0.00	
Aug-17			-	0.00	-	0.00	
Sep-17			-	0.00	-	0.00	
Oct-17			-	0.00	-	0.00	
Nov-17			-	0.00	-	0.00	
Dec-17			-	0.00	-	0.00	
Total-17			-	0.00	-	0.00	
Jan-18			-	0.00	-	0.00	
Feb-18			-	0.00	-	0.00	
Mar-18			-	0.00	-	0.00	
Apr-18			-	0.00	-	0.00	
May-18			-	0.00	-	0.00	
Jun-18			-	0.00	-	0.00	
Jul-18			-	0.00	-	0.00	
Aug-18			-	0.00	-	0.00	
Sep-18			-	0.00	-	0.00	
Oct-18			-	0.00	-	0.00	
Nov-18			-	0.00	-	0.00	
Dec-18			-	0.00	-	0.00	
Total-18			-	0.00	-	0.00	
Jan-19			-	0.00	-	0.00	
Feb-19			-	0.00	-	0.00	
Mar-19			-	0.00	-	0.00	
Apr-19			-	0.00	-	0.00	
May-19			-	0.00	-	0.00	
Jun-19			-	0.00	-	0.00	
Jul-19			-	0.00	-	0.00	
Aug-19			-	0.00	-	0.00	
Sep-19			-	0.00	-	0.00	
Oct-19			-	0.00	-	0.00	
Nov-19			-	0.00	-	0.00	
Dec-19			-	0.00	-	0.00	
Total-19			-	0.00	-	0.00	

Northern States Power Company
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Wind Curtailment Summary Report - Total
For January 2017 to October 2019

	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-17			185,333.00	6,652,404.63	3,697.00	157,640.77	$ 6,810,045.40
Feb-17			186,522.00	7,471,418.20	6,934.00	276,825.34	$ 7,748,243.54
Mar-17			173,389.00	6,688,109.31	11,980.00	523,111.92	$ 7,211,221.23
Apr-17			208,551.00	8,133,830.65	7,291.00	309,809.33	$ 8,443,639.98
May-17			140,001.00	5,528,045.13	5,970.00	243,464.35	$ 5,771,509.48
Jun-17			142,504.00	5,704,337.23	6,822.00	309,043.74	$ 6,013,380.97
Jul-17			22,344.00	1,266,241.66	277.00	14,625.98	$ 1,280,867.64
Aug-17			22,910.00	1,180,091.68	54.00	2,734.06	$ 1,182,825.74
Sep-17			75,520.00	3,539,468.64	1,268.00	65,237.53	$ 3,604,706.17
Oct-17			109,037.00	5,029,142.90	2,931.00	133,307.49	$ 5,162,450.39
Nov-17			129,002.00	5,142,020.66	435.00	18,782.21	$ 5,160,802.87
Dec-17			97,506.00	4,362,695.93	479.00	16,365.01	$ 4,379,060.94
Total-17			1,492,619.00	$ 60,697,806.62	48,138.00	$ 2,070,947.73	$ 62,768,754.35
Jan-18			90,734.12	3,924,799.96	1,458.00	58,950.29	$ 3,983,750.25
Feb-18			54,843.51	2,785,838.57	134.82	5,843.30	$ 2,791,681.87
Mar-18			144,991.48	5,587,088.09	548.61	21,570.10	$ 5,608,658.19
Apr-18			93,370.50	4,258,543.18	2,303.34	100,761.56	$ 4,359,304.74
May-18			82,315.24	3,741,116.04	428.37	18,532.00	$ 3,759,648.04
Jun-18			109,000.47	4,749,778.23	852.99	32,831.32	$ 4,782,609.55
Jul-18			103,125.62	4,460,620.74	558.38	25,341.15	$ 4,485,961.89
Aug-18			77,691.31	3,449,696.45	126.02	5,438.28	$ 3,455,134.73
Sep-18			136,694.24	6,133,579.28	1,483.22	64,512.97	$ 6,198,092.25
Oct-18			55,002.98	2,166,371.84	392.86	18,908.20	$ 2,185,280.04
Nov-18			110,378.69	4,609,900.25	1,497.05	66,292.63	$ 4,676,192.88
Dec-18			157,458.72	6,744,439.49	10,741.09	338,305.25	$ 7,082,744.74
Total-18			1,215,606.87	$ 52,611,772.12	20,524.75	$ 757,287.05	$ 53,369,059.17
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	15,485.07	711,886.77	$ 6,330,516.53
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	1,392.87	53,668.43	$ 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			184,977.48	8,039,287.04	10,510.38	407,660.98	$ 8,446,948.02
Nov-19			74,659.60	2,611,621.36	1,818.16	77,049.29	$ 2,688,670.65
Dec-19			135,153.03	5,868,631.62	1,527.30	70,126.80	$ 5,938,758.42
Total-19			1,271,208.27	$ 52,991,197.89	55,581.03	$ 2,393,730.87	55,384,928.76

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
For January 2017 to October 2019

	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-17			-	0.00	-	0.00	
Feb-17			-	0.00	-	0.00	
Mar-17			-	0.00	-	0.00	
Apr-17			-	0.00	-	0.00	
May-17			-	0.00	-	0.00	
Jun-17			-	0.00	-	0.00	
Jul-17			-	0.00	-	0.00	
Aug-17			-	0.00	-	0.00	
Sep-17			-	0.00	-	0.00	
Oct-17			-	0.00	-	0.00	
Nov-17			-	0.00	-	0.00	
Dec-17			-	0.00	-	0.00	
Total-17			-	0.00	-	0.00	
Jan-18			-	0.00	-	0.00	
Feb-18			-	0.00	-	0.00	
Mar-18			-	0.00	-	0.00	
Apr-18			-	0.00	-	0.00	
May-18			-	0.00	-	0.00	
Jun-18			-	0.00	-	0.00	
Jul-18			-	0.00	-	0.00	
Aug-18			-	0.00	-	0.00	
Sep-18			-	0.00	-	0.00	
Oct-18			-	0.00	-	0.00	
Nov-18			-	0.00	-	0.00	
Dec-18			-	0.00	-	0.00	
Total-17			-	0.00	-	0.00	
Jan-19			-	0.00	-	0.00	
Feb-19			-	0.00	-	0.00	
Mar-19			-	0.00	-	0.00	
Apr-19			-	0.00	-	0.00	
May-19			-	0.00	-	0.00	
Jun-19			-	0.00	-	0.00	
Jul-19			-	0.00	-	0.00	
Aug-19			-	0.00	-	0.00	
Sep-19			-	0.00	-	0.00	
Oct-19			-	0.00	-	0.00	
Nov-19			-	0.00	-	0.00	
Dec-19			-	0.00	-	0.00	
Total-19			-	0.00	-	0.00	

2018 – 2019 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. In compliance with the Commission's Order, this report provides a summary of the Company's experience regarding wind curtailment payments. The estimate of potential curtailment payments, and the assumptions used to develop our forecast, will be provided in our 2021 fuel forecast Petition to be filed on May 1, 2020. We previously discussed and provided our 2020 wind curtailment forecasting in our May 1, 2019 Petition in Docket No. E002/AA-19-293.

II. CURTAILMENT UPDATE

In past AAA Curtailment Reports, the Company has worked with the Department and made efforts to improve communications about the events and activity that cause wind generation curtailment. The Department's review and evaluation over the years has helped identify areas where our reports could be more descriptive of the reasons for wind curtailment and efforts made to minimize resulting costs. In addition, the Company continues to utilize initiatives to reduce curtailment which we believe are having a positive impact on curtailment or costs associated with curtailment. Examples include, where possible, scheduling transmission activities which can impact curtailment during low wind months.

The Company expects that some level of wind curtailment from Power Purchase Agreement (PPA) facilities will occur during 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) and a number of 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 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.

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 existing PPA wind facilities associated with this report that are registered and operate as DIR.

Table 1
DIR PPA Facilities

Wind Project	MW
Fenton	200
Odell	200
Prairie Rose	200
MinnDakota	150
Mower County	100
Moraine II	50
Big Blue	36
Zephyr	30
Valley View	10
Total	976

The federal Production Tax Credit (PTC), which provides tax benefits to wind generating plants, is scheduled to expire 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 5,500 MW of planned wind generation in Minnesota, North Dakota, South Dakota and Iowa that has recently gone into service, or is expected to go into service in in the next two years. This includes 1,800 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 Date
NSP	1800	ND, SD, MN	2019-2021
Alliant Energy	1000	Iowa	2019-2020
Great River Energy	300	ND	2019-2020
MidAmerican	2000	Iowa	2019-2020
Minnesota Power	250	MN	2020
Ottertail Power	150	ND	2020
Total	5500		

The required transmission upgrades for these wind projects will likely not all be in-service by the time the projects begin producing energy. In addition, a number of transmission facilities that were identified in the interconnection studies as overloaded will be taken out of service and rebuilt.[2] This will have a negative effect on LMP pricing in the MISO energy market that could potentially impact real-time wind generation on the NSP System. This potential impact will lessen due to mitigation measures such as: (1) the use of DIR and set-point control technology, (2) placing in service the required transmission facilities and transmission system improvements, and (3) improved transmission outage scheduling.

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

[1] This does not include the wind repowering projects that NSP is pursueing.
[2] This is especially true in the area around Big Stone in South Dakota. A significant number of 115 kV and 230 kV lines, mostly owned by Otter Tail Power Company are being taken out of service and rebuilt. Xcel Energy will also be rebuilding an existing 345 kV that connects to the Twin Cities.

meet this need, the Company, often in cooperation with other utilities, has planned, engineered and constructed a number of projects designed to increase the transmission capacity in that area. Table 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 transmission projects developed by the Company, MISO has identified and approved a number of new transmission infrastructure projects, including 17 MVPs, designed to accommodate the planned and expected generation expansion in the MISO footprint.[3] The MVPs will help 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

[3] The MISO Board of Directors approved the new transmission projects, which included the CapX2020 Brookings County – Southeast Twin Citites 345 kV line as an MVP, on December 13, 2012.

completion of the MVP projects, particularly the ones listed in the following table, 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	Ottertail 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	Ottertail Power Company, Montana Dakota Utilities	February 5, 2019
North Madison - Cardinal - Spring Green - Dubuque area 345 kV Line	American Transmission Company, ITC Midwest	End 2023

IV. Wind Generation, Curtailment and Curtailment Projections

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

Chart 1
NSP Wind Development
(1993 – 2019)

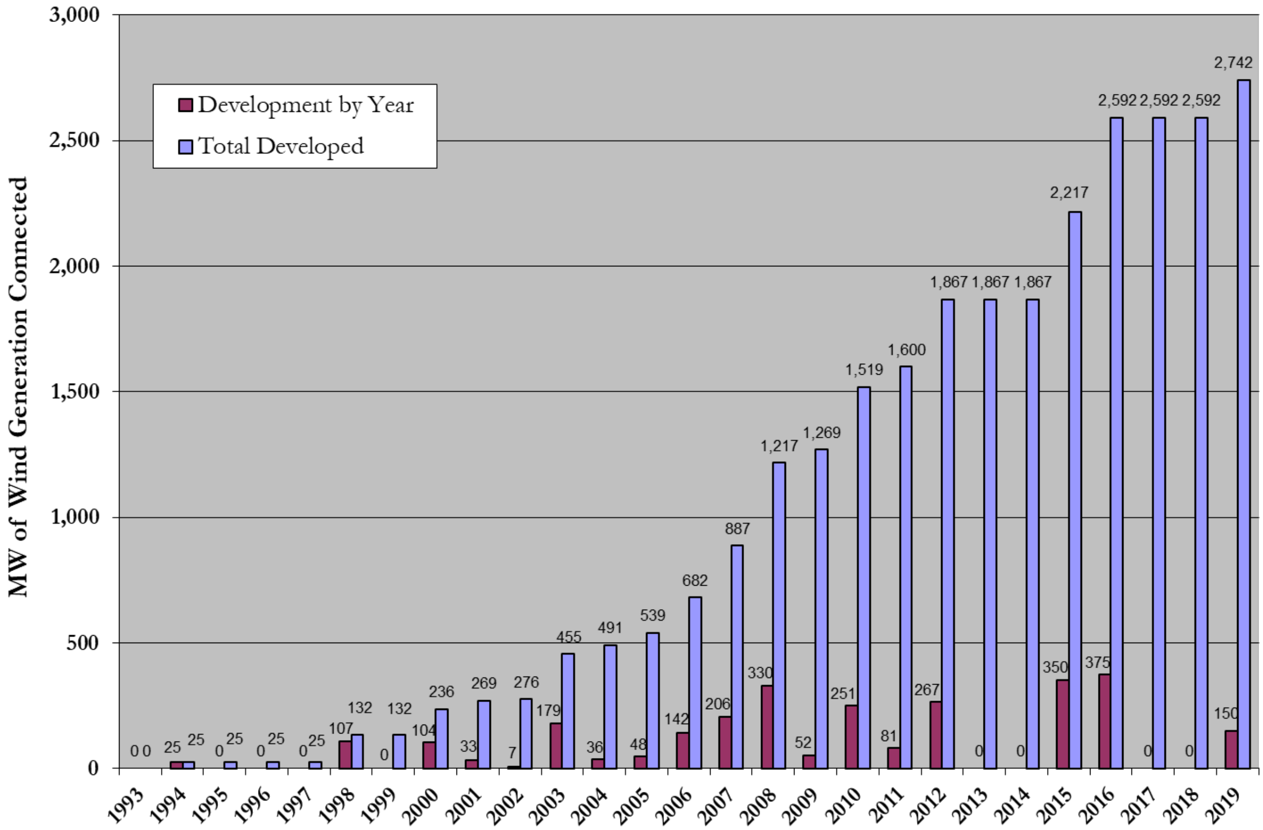
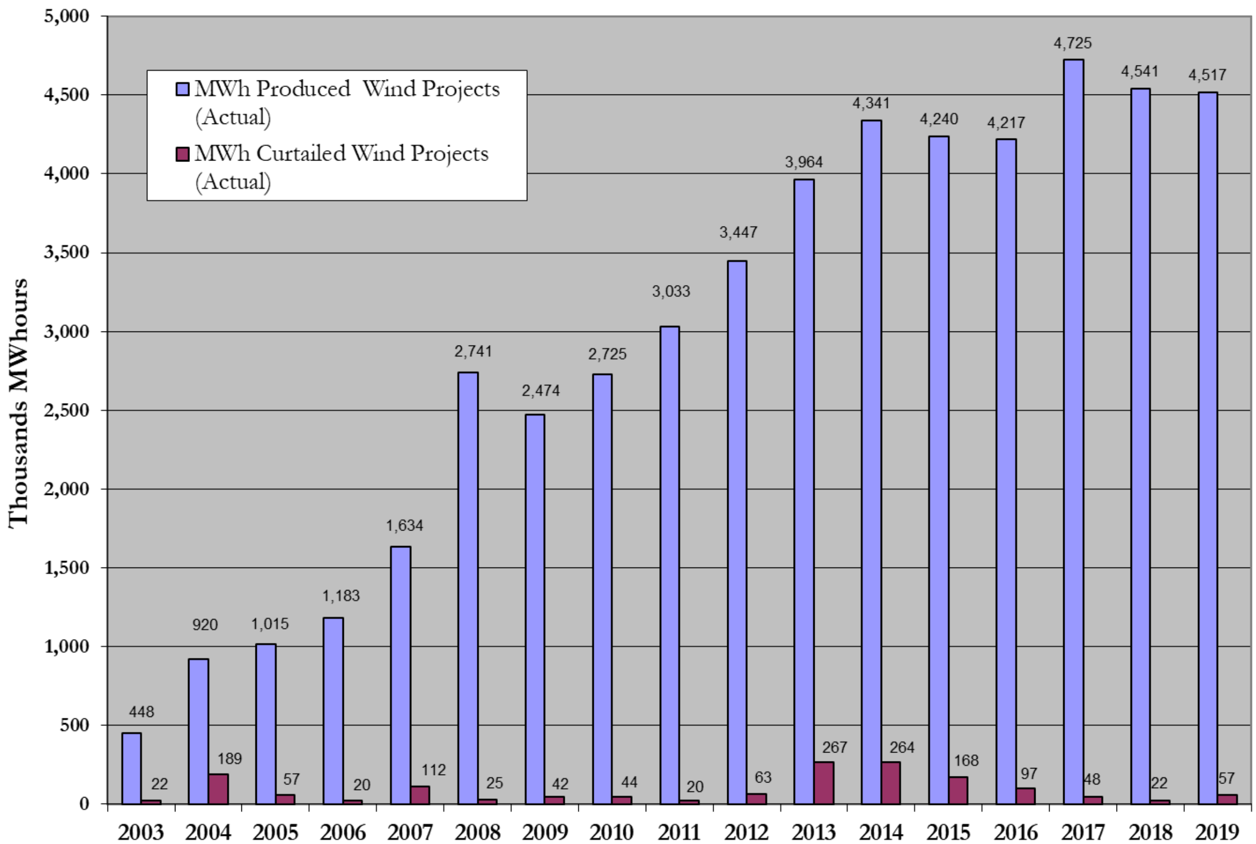


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through December 2019[4]. Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation 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.

[4] AAA Part H, Section 5, Schedule 1.

Chart 2
NSP Wind Production & Curtailment (MWh)
(2003 – 2019)



Curtailment during July 2018 through December 2019 was broken up into two categories to better explain the reasons for the curtailment and its cause. To support the analysis the Company identified hours during the 2018/2019 AAA period where transmission-related outages impacted wind projects. These hours were assigned as Transmission Curtailment. During hours where transmission outages did not occur, or where transmission outages did not impact a specific wind farm, the hours were assigned as DIR Curtailment[5] based on if a project was registered as a DIR. This hourly information was then compared to hourly curtailment data for each of the reporting wind farms and total MWh and curtailment costs were calculated. It should be noted that the hourly data was only assigned one category and did not overlap.

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[5] The Company stopped performing manual curtailment of non-DIR PPA wind facilities during the 2018/2019 AAA period since analysis of the economic impact of manual curtailment showed minimal customer economic value.

A total of $2,947,317 in curtailment payments[6] were made during this reporting period for the twocategories:

1) Transmission Curtailment Events ($610,781). This includes all outages listed below; and
2) DIR Curtailments Events ($2,336,535). This was driven by negative LMP related reasons

The MWh and curtailment costs determined during the curtailment analysis are compiled in Table 6 and Table 7 below. These results are further separated to show MWh and curtailment costs for projects that are still eligible for the PTC and those that are not. Note: the curtailment values in this section do not exactly match the curtailment values shown in AAA Part H, Section 5, Schedule 1. This data is based on the Company's analysis and estimated volumes from curtailment events and not based on the customer submitted invoices.

Table 6
2018/2019 Wind Curtailment MWh

Events	MWh		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	19,116	19,116	0
DIR Curtailment Events	51,669	50,150	0
Totals	70,786	70,786	0

Table 7
2018/2019 Wind Curtailment Costs

Events	Payments		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	$610,781	$610,781	$0
DIR Curtailment Events	$2,336,535	$2,252,324	$0
Totals	$2,947,317	$2,947,317	$0

[6] The curtailment analysis in this section used Company data – not AAA Part H, Section 5, Schedule 1 data.

As can be seen in Tables 6 and 7, the majority of the curtailment was related to DIR Curtailment Events and occurred at projects that are no longer eligible for the PTC.

It is important to note that of the $2,947,317 in total curtailment costs, the vast majority of these total 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.[7]

Transmission Curtailment Events

Wind curtailment costs totaling $610,781 were due to the transmission events described below.

The primary goal when planning construction and maintenance work that will impact wind generation output is to perform multiple outages at the same time, and schedule 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. For example, from September through the end of 2013, there were unavoidable transmission outages taken which resulted in significantly increased levels of curtailment than had been experienced in a number of years. Summer months are also high load months and transmission outages may not be possible due to load serving needs.

It should be noted that only specific wind generation facilities are used to manage the different transmission events. For example, a Split Rock – Nobles County 345 kV line outage could be managed by limiting output of Lake Benton II, Chanarambie Power Partners, Fenton, Ridgewind, Moraine I, and/or Moraine II while a Brookings County transformer outage could be managed by limiting output of MinnDakota.

The Company experienced planned and unplanned outages of the Split Rock – Nobles County 345 kV line, Nobles County Lakefield Junction 345 kV line, Chanarambie – Fenton 115 kV line, Fenton – Nobles County 115 kV line and Brookings County TR10 Transformer that contributed to curtailment during this period. The facilities were taken out of service as the result of adverse weather conditions, for NSP and other utility maintenance activies, and to accommodate upgrades related to interconnecting new generating facilities.

[7] The PPA contract language can generally be described as "take or pay" in which NSP must pay for the wind energy that could be produced, regardless of whether it actually is produced or if it is curtailed.

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. It should be noted that not all DIR farms are equipped with setpoint controls. In such situations, a phone call or e-mail is required to initiate a DIR curtailment. Non-DIR units are not equipped with setpoint control.

DIR Curtailment Events
Wind curtailment costs totaling $2,336,535 were due to the MISO-directed DIR control as described below.

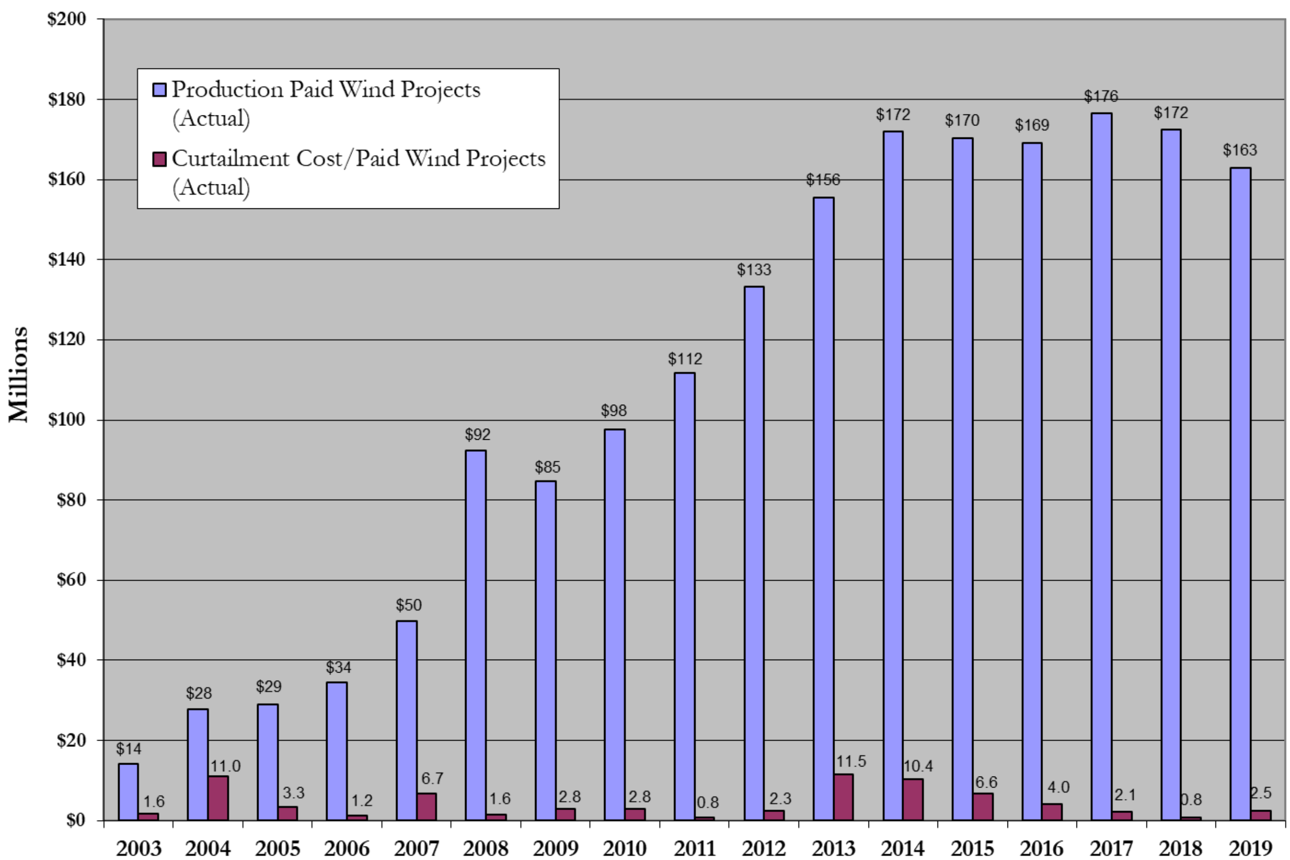
DIR related curtailment was due to negative LMP prices associated with congestion throughout the Minnesota and Iowa region due to regional transmission outages, or local congestion due to local transmission outages, as well as the higher levels of wind generation present where all required transmission improvements have not been completed or where sufficient transmission outlets did not exist.

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.

V. Wind Production and Curtailment Payments

Chart 3 shows the corresponding production and curtailment costs from July 1, 2018 through December 30, 2019.[8] 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
NSP Wind Production & Curtailment Payments
(2003 – 2019)



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 on May 1, 2020. 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

[8] AAA Part H, Section 5, Schedule 1

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

Future wind generation additions and completion of the MVP transmission projects will likely impact the amount of future curtailment experienced. While it is reasonable to expect curtailment levels will be reduced once the new transmission lines are in service, the reduction will likely be off-set by the new wind projects going into service. In the Company's recent filing for Acquisition of Wind Generation under Docket No. E002/M-16-777, a detailed discussion on wind curtailment was also provided. The filing stated that the Company expects wind curtailment to be higher when the new projects first go into service, and then decline as new transmission and other changes on the MISO system occur to better accommodate increased wind penetration. While we continue to believe that this will be the case, there is no certainty as to when, and if, the numerous wind generation projects currently in the development queue will actually come to fruition.

VI. CONCLUSION

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. 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 AAA reports.

Location (County)	Meter Install Date (s)	Rated AC Power Output (MW)	# of Subscriptions* (Dec. 2019)
Benton	9/29/2017	2.000	143
Benton	10/30/2017	5.000	306
Benton	8/14/2018	4.950	165
Benton	5/13/2019	5.000	12
Benton	3/25/2018	2.000	9
Benton	10/30/2018	1.000	16
Benton	12/17/2018	1.000	12
Benton	12/17/2018	1.000	14
Blue Earth	10/16/2018	5.000	10
Blue Earth	5/23/2017	3.000	16
Blue Earth	8/7/2018	3.540	11
Blue Earth	11/20/2017	5.000	20
Blue Earth	3/5/2019	0.240	21
Blue Earth	5/30/2018	1.000	13
Blue Earth	9/24/2019	0.620	19
Blue Earth	9/27/2019	0.620	22
Blue Earth	12/18/2019	1.000	N/A
Carver	3/14/2018	0.998	28
Carver	2/26/2018	1.996	42
Carver	8/16/2018	4.000	26
Carver	2/28/2017	4.860	14
Carver	12/15/2017	5.000	35
Carver	3/6/2018	3.000	41
Carver	12/21/2017	4.360	13
Carver	1/16/2018	3.000	13
Carver	8/29/2019	1.000	12
Carver	7/22/2019	1.000	26
Carver	7/25/2019	1.000	37
Carver	5/1/2019	1.000	18
Chippewa	3/25/2018 & 6/15/2018	4.000	33
Chippewa	10/25/2017 & 11/14/2017	3.000	10
Chippewa	8/29/2017	2.000	11
Chippewa	11/14/2018	1.000	39
Chippewa	12/18/2018	1.000	575
Chippewa	8/26/2019	1.000	406
Chisago	4/30/2018	3.000	293
Chisago	12/18/2017	5.000	682
Chisago	8/9/2018	5.000	1090
Chisago	3/13/2018	5.000	455
Chisago	12/14/2016	5.000	454
Chisago	8/22/2017	3.000	1185

Chisago	12/15/2016	4.000	498
Chisago	1/13/2017	3.890	29
Chisago	2/27/2019	2.000	1203
Chisago	4/22/2019	3.000	17
Chisago	8/16/2019	0.998	14
Chisago	12/13/2017	5.000	31
Chisago	9/28/2018	1.000	6
Chisago	8/1/2018	1.000	31
Chisago	9/28/2018	1.000	11
Chisago	8/30/2018	1.000	83
Chisago	11/26/2018	1.000	14
Chisago	12/11/2018	0.500	302
Chisago	11/29/2018	1.000	82
Chisago	11/27/2018	1.000	529
Chisago	11/28/2018	1.000	22
Chisago	7/3/2019	1.000	12
Chisago	9/3/2019	1.000	16
Chisago	11/28/2018	1.000	15
Chisago	12/7/2018	1.000	155
Chisago	5/21/2019	1.000	425
Chisago	12/19/2019	1.000	N/A
Dakota	6/7/2019	5.000	506
Dakota	6/7/2019	5.000	463
Dakota	1/13/2017	5.000	204
Dakota	12/20/2016	5.000	305
Dakota	1/23/2018	4.950	198
Dakota	2/13/17 & 3/15/2017	5.000	187
Dakota	7/27/2018	5.000	273
Dakota	8/31/2017	5.000	13
Dakota	12/1/2016	5.000	35
Dakota	11/30/2017	2.700	23
Dakota	9/17/2018	0.750	123
Dakota	8/6/2019	1.000	10
Dakota	12/11/2019	1.000	N/A
Dodge	9/27/2017	4.000	34
Dodge	7/18/2017	5.000	14
Dodge	12/18/2017	5.000	15
Dodge	5/15/2019	1.000	16
Dodge	5/15/2019	0.396	14
Dodge	1/9/2019	1.000	705
Douglas	8/2/2018	5.000	12
DOUGLAS	12/11/2019	1.000	N/A
Douglas	12/27/2019	1.000	N/A
Faribault	3/2/2018	1.840	11
Freeborn	6/18/2019	0.250	32

Goodhue	7/19/2018	5.000	154
Goodhue	9/27/2019	4.400	24
Goodhue	7/30/2018	2.000	38
Goodhue	4/11/2019	5.000	6
Goodhue	2/13/2017 & 3/2/2017	4.000	46
Goodhue	4/12/2018	0.800	22
Goodhue	1/12/2017	4.860	50
Goodhue	4/26/2018	0.998	7
Goodhue	5/11/2018	1.000	100
Goodhue	5/22/2018	1.000	10
Goodhue	9/14/2018	1.000	16
Goodhue	9/19/2018	1.000	25
Goodhue	12/31/2019	0.590	N/A
Hennepin	1/11/2019	5.000	12
Hennepin	10/25/2017	5.000	19
Hennepin	8/22/2016	0.004	12
Hennepin	6/6/2018	0.180	698
Hennepin	11/28/2018	0.527	12
Hennepin	7/30/2019	0.180	13
Hennepin	9/18/2019	0.960	7
Hennepin	9/28/2018	0.320	12
Kandiyohi	11/14/2018	1.000	26
Kandiyohi	5/21/2019	1.000	24
Kaniyohi	8/14/2017	2.000	23
Le Sueur	2/28/2018	5.000	14
Le Sueur	8/6/2018	5.000	9
Le Sueur	2/23/2018	3.000	187
Le Sueur	9/9/2015	0.036	173
Le Sueur	6/29/2018	3.000	26
Le Sueur	1/18/2018	3.000	44
Le Sueur	12/19/2018	1.000	39
Lincoln	9/14/2017	0.200	277
Lincoln	4/25/2016	0.204	48
Lyon	6/15/2018	3.000	34
Lyon	5/3/2019	1.000	127
McLeod	3/12/2019	3.000	210
McLeod	10/25/2017	3.000	161
McLeod	10/26/2017	5.000	57
McLeod	10/25/2018	1.000	112
McLeod	12/18/2019	1.000	N/A
McLeod	12/27/2019	1.000	N/A
McLeod	8/30/2019	1.000	13
Meeker	1/23/2019	0.760	295
Meeker	12/13/2019	1.000	N/A
Meeker	12/11/2019	1.000	N/A

Murray	12/20/2018	1.000	30
Murray	12/20/2018	1.000	13
Nicollet	11/20/2017	5.000	21
Nicollet	1/31/2019	1.000	29
Nicollet	12/18/2019	1.000	N/A
Olmsted	7/19/2017	5.000	134
Olmsted	9/9/2019	1.000	20
Paynesville	12/21/2016 & 1/31/2017	5.000	6
Pipestone	10/30/2017	5.000	12
Pipestone	8/18/2017	2.000	136
Pipestone	1/31/2018	4.700	13
Pope	9/13/2017	5.000	32
Pope	3/15/2018	5.000	11
Pope	4/19/2018	3.000	15
Pope	11/16/2018	1.000	73
Pope	3/26/2019	1.000	7
Pope	3/28/2019	1.000	9
Pope	12/16/2019	1.000	N/A
Pope	9/11/2019	1.000	16
Pope	9/11/2019	1.000	10
Ramsey	5/12/2016	0.125	9
Ramsey	1/8/2019	0.540	11
Redwood	5/2/2017	3.000	12
Renville	12/28/2017	3.000	6
Renville	3/29/2019	1.000	27
Renville	5/16/2018	1.000	10
Renville	5/17/2018	1.000	148
Renville	12/30/2019	1.000	N/A
Rice	2/14/2018	0.998	27
Rice	2/28/2018	5.000	8
Rice	6/30/2017	5.000	50
Rice	3/2/2018	3.000	28
Rice	11/30/2017	5.000	12
Rice	6/20/2018	1.000	7
Rice	8/8/2019	1.000	24
Rice	10/9/2019	1.000	21
Rice	4/30/2019	1.000	6
Rice	12/13/2019	1.000	N/A
Rice	9/18/2019	1.000	86
Rosemount	12/22/2016	5.000	9
Scott	3/28/2018	4.950	12
Scott	12/20/2017	3.000	6
Scott	11/30/2017	4.700	6
Scott	11/30/2017	0.700	12
Scott	11/28/2018	0.823	163

Scott	12/19/2016 & 12/22/2016	3.000	159
Scott	11/28/2018	1.000	12
Scott	7/24/2019	0.598	24
Scott	8/13/2019	1.000	10
Scott	10/30/2019	0.400	10
Sherburne	3/14/2018	5.000	18
Sherburne	7/13/2018	5.000	10
Sherburne	9/22/2017	5.000	7
Sherburne	6/29/2018	5.000	11
Sherburne	12/10/2018	4.800	19
Sherburne	12/3/2018	5.000	11
Sherburne	3/28/2019	5.000	10
Sherburne	2/12/2018	3.250	6
Sherburne	4/30/2018	4.000	83
Sherburne	11/16/2018	1.000	19
Sherburne	7/31/2019	0.996	9
Sherburne	12/23/2019	1.000	N/A
Sherburne	7/26/2019	3.000	38
Sherburne	11/26/2019	1.000	133
Sherburne	10/29/2019	1.000	13
Sherburne	12/26/2019	1.000	N/A
Sherburne	12/30/2019	0.940	N/A
Sibley	6/14/2019	3.250	12
Stearns	11/9/2017	5.000	9
Stearns	8/24/2017	2.000	21
Stearns	1/4/2017	3.000	124
Stearns	1/5/2017	3.000	18
Stearns	12/15/2016 & 12/21/2016	5.000	17
Stearns	11/16/2017	4.000	35
Stearns	12/13/2017	5.000	159
Stearns	9/13/2017	2.200	66
Stearns	9/13/2017	4.860	14
Stearns	10/30/2017	3.000	6
Stearns	10/25/2019	4.750	12
Stearns	8/16/2019	0.998	123
Stearns	4/30/2018	5.000	31
Stearns	6/18/2019	3.000	9
Stearns	6/3/2019	5.000	194
Stearns	4/16/2019	1.000	6
Stearns	8/16/2019	1.000	50
Stearns	3/4/2019	0.720	12
Stearns	3/4/2019	1.000	14
Stearns	1/28/2019	0.324	11
Stearns	3/25/2019	1.000	91
Stearns	12/17/2018	1.000	63

Stearns	12/27/2019	1.000	N/A
Stearns	12/23/2019	1.000	N/A
Stearns	12/16/2019	1.000	N/A
Stearns	10/23/2019	1.000	137
Stearns	12/3/2019	1.000	N/A
Steele	3/5/2018	3.400	31
Steele	7/18/2018	1.000	16
Steele	6/5/2018	1.000	10
Wabasha	3/13/2017	3.000	15
Wabasha	1/29/2018	4.000	7
Wabasha	3/26/2019	0.850	144
Wabasha	8/20/2019	1.000	19
Wabasha	8/22/2019	1.000	8
Wabasha	8/20/2019	1.000	#N/A
Waseca	2/26/2018	5.000	#N/A
Waseca	11/1/2018	1.000	#N/A
Waseca	10/25/2018	1.000	#N/A
Waseca	9/27/2018	1.000	#N/A
Waseca	11/18/2019	1.000	#N/A
Waseca	2/13/2019	1.000	#N/A
Waseca	9/6/2019	1.000	12
Washington	4/20/2018	5.000	8
Washington	7/16/2018	2.500	#N/A
Washington	9/4/2018	5.000	#N/A
Washington	7/18/2017	5.000	#N/A
Washington	10/29/2018	4.875	#N/A
Washington	1/10/2018	5.000	#N/A
Washington	2/28/2018	4.000	12
Washington	4/13/2018, 5/31/18 & 7/24/18	3.000	7
Washington	3/10/2017	0.036	9
Washington	9/7/2018	0.750	#N/A
Washington	4/22/2019	1.000	#N/A
Washington	3/22/2019	1.000	#N/A
Watonwan	7/2/2018	0.250	15
Winona	4/28/2017	0.250	#N/A
Winona	8/21/2019	5.000	14
Winona	8/22/2019	1.000	12
Winona	8/22/2019	1.000	10
Wright	4/29/2019	5.000	12
Wright	8/27/2018	5.000	14
Wright	11/13/2017	5.000	13
Wright	11/3/2017	5.000	#N/A
Wright	11/28/2018	5.000	#N/A
Wright	5/31/2019	5.000	26

Wright	10/17/2018	4.000	#N/A
Wright	8/14/2018	0.972	#N/A
Yellow Medicine	12/21/2018	5.000	#N/A

Northern States Power Company
Electric Operations - State of Minnesota
Derivation of Adjustment for Fuel Clause Rider
Minnesota Jurisdictional Solar Gardens Program Cost Recovery

		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
	System Portion of Bill Credits & Unsubscribed Energy Payments (Market Amount Allocated to All Jurisdictions)																			
[1]	Solar Gardens Subscribed Energy	$2,518,226	$2,093,572	$1,534,255	$1,202,635	($340,978)	$1,703,849	$1,082,391	$434,940	$1,741,967	$1,745,334	$2,074,459	$2,212,515	$3,007,476	$2,681,051	$1,783,659	$1,261,176	$726,108	$564,602	$28,027,237
[2]	Solar Gardens Unsubscribed Energy <40 KW	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$63	$124	$0	$45	$5	$237
[3]	Solar Gardens Unsubscribed Energy > 40 KW	$66,790	$84,366	$169,116	$171,051	$86,045	$65,306	$16,402	$26,651	$26,803	$5,575	$78,809	$85,431	$104,661	$131,695	$51,827	$64,380	$65,645	$27,179	$1,327,732
[4]	Total Costs (System) [1]+[2]+[3]	$2,585,016	$2,177,938	$1,703,371	$1,373,686	($254,933)	$1,769,155	$1,098,793	$461,591	$1,768,771	$1,750,909	$2,153,267	$2,297,946	$3,112,137	$2,812,809	$1,835,609	$1,325,556	$791,798	$591,786	$29,355,206
	Above Market Amount Recoverable in Minnesota Jurisdiction																			
[5]	Minnesota Direct Assigned Above Market Amount	$7,826,811	$4,911,139	$5,731,902	$5,050,152	$3,994,342	$2,828,022	$3,657,470	$734,935	$7,664,181	$5,175,210	$9,494,967	$10,051,617	$10,965,447	$10,781,126	$9,519,667	$8,805,427	$3,320,733	$5,452,794	$115,965,941
[6]	Total Bill Credits & Unsubscribed Energy Payments [4]+[5]	**$10,411,827**	**$7,089,077**	**$7,435,273**	**$6,423,838**	**$3,739,409**	**$4,597,177**	**$4,756,263**	**$1,196,526**	**$9,432,952**	**$6,926,118**	**$11,648,235**	**$12,349,563**	**$14,077,584**	**$13,593,935**	**$11,355,276**	**$10,130,984**	**$4,112,531**	**$6,044,580**	**$145,321,146**
	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]	**$7,826,811**	**$4,911,139**	**$5,731,902**	**$5,050,152**	**$3,994,342**	**$2,828,022**	**$3,657,470**	**$734,935**	**$7,664,181**	**$5,175,210**	**$9,494,967**	**$10,051,617**	**$10,965,447**	**$10,781,126**	**$9,519,667**	**$8,805,427**	**$3,320,733**	**$5,452,794**	**$115,965,941**
	MWh Sales Weighting																			
[8]	Minnesota Jurisdiction Retail MWh Subject to FCA	2,945,995	2,986,893	2,504,444	2,290,837	2,272,715	2,481,116	2,501,689	2,180,852	2,472,032	2,124,018	2,243,822	2,414,427	2,833,642	2,626,874	2,390,888	2,254,255	2,224,067	2,390,240	44,138,806
[9]	NSP System MWh Sales Exclude Windsource & Renewable*Connect	3,979,207	4,076,681	3,416,109	3,192,783	3,173,434	3,468,339	3,515,256	3,077,029	3,447,371	2,964,863	3,119,984	3,322,970	3,883,223	3,616,879	3,266,218	3,162,141	3,102,154	3,348,905	61,133,546
[10]	Allocation Weighting [8]/[9]	74.0347%	73.2678%	73.3128%	71.7505%	71.6169%	71.5361%	71.1666%	70.8753%	71.7077%	71.6397%	71.9177%	72.6587%	72.9714%	72.6282%	73.2005%	71.2889%	71.6943%	71.3738%	72.2006%
	Market Bill Credits and Payments Allocated to MN Fuel Clause Recovery																			
[11]	Total Solar Gardens Costs Allocation [6]*[10]	$7,708,367	$5,194,008	$5,451,004	$4,609,134	$2,678,049	$3,288,644	$3,384,871	$848,041	$6,764,157	$4,961,848	$8,377,147	$8,973,033	$10,272,609	$9,873,030	$8,312,119	$7,222,265	$2,948,449	$4,314,245	$105,181,021
[12]	Allocated Solar Gardens Costs in Excess of Avoided LMP [7]*[10]	($5,794,558)	($3,598,282)	($4,202,216)	($3,623,508)	($2,860,624)	($2,023,058)	($2,602,898)	($520,887)	($5,495,811)	($3,707,503)	($6,828,566)	($7,303,375)	($8,001,639)	($7,830,137)	($6,968,444)	($6,277,291)	($2,380,776)	($3,891,865)	($83,911,437)
[13]	Allocated Avoided LMP (Allocated System Portion) [11]+[12]	**$1,913,810**	**$1,595,726**	**$1,248,788**	**$985,627**	**($182,575)**	**$1,265,585**	**$781,974**	**$327,154**	**$1,268,346**	**$1,254,345**	**$1,548,581**	**$1,669,658**	**$2,270,970**	**$2,042,893**	**$1,343,675**	**$944,974**	**$567,674**	**$422,380**	**$21,269,584**
	Total Solar Gardens Costs Recovery Included in MN Fuel Cost Charge																			
[14]	Market and Above Market Allocated Amount [17]+[13]	**$9,740,620**	**$6,506,865**	**$6,980,690**	**$6,035,778**	**$3,811,767**	**$4,093,608**	**$4,439,443**	**$1,062,088**	**$8,932,526**	**$6,429,555**	**$11,043,549**	**$11,721,275**	**$13,236,417**	**$12,824,019**	**$10,863,342**	**$9,750,402**	**$3,888,407**	**$5,875,174**	**$137,235,525**
[15]	**Solar Gardens Developer Late Fees (Credit Back to MN Customers)**	**$221,600**	**$95,400**	**$0**	**$30,838**	**$65,400**	**$0**	**$55,000**	**$197,800**	**$165,250**	**$0**	**$141,000**	**$0**	**$0**	**$0**	**$171,800**	**$32,744**	**$154,614**	**$427,800**	**$1,759,246**
[16]	**Net Solar Gardens Costs Recovery Included in MN Fuel Cost Charge [14]-[15]**	$9,519,020	$6,411,465	$6,980,690	$6,004,941	$3,746,367	$4,093,608	$4,384,443	$864,288	$8,767,276	$6,429,555	$10,902,549	$11,721,275	$13,236,417	$12,824,019	$10,691,542	$9,717,658	$3,733,793	$5,447,374	$135,476,279
	Market Bill Credits and Payments Allocated to Other Jurisdictions																			
[17]	Cost Allocated to Other Jurisdictions (Market Portion Based on LMP) [4]-[13]	$671,207	$582,212	$454,583	$388,060	($72,358)	$503,570	$316,819	$134,437	$500,425	$496,563	$604,686	$628,288	$841,167	$769,917	$491,934	$380,582	$224,124	$169,406	$8,085,622
	Direct Assigned Minnesota Cost Removed from System Cost																			
[18]	Minnesota Direct Assigned Above Market Amount [5]	$7,826,811	$4,911,139	$5,731,902	$5,050,152	$3,994,342	$2,828,022	$3,657,470	$734,935	$7,664,181	$5,175,210	$9,494,967	$10,051,617	$10,965,447	$10,781,126	$9,519,667	$8,805,427	$3,320,733	$5,452,794	$115,965,941
[19]	Solar Gardens Developer Late Fees (Credit Back to MN Customers) [15]	$221,600	$95,400	$0	$30,838	$65,400	$0	$55,000	$197,800	$165,250	$0	$141,000	$0	$0	$0	$171,800	$32,744	$154,614	$427,800	$1,759,246
[20]	Direct Assigned Minnesota Cost Removed from System Cost [18]-[19]	**$7,605,211**	**$4,815,739**	**$5,731,902**	**$5,019,314**	**$3,928,942**	**$2,828,022**	**$3,602,470**	**$537,135**	**$7,498,931**	**$5,175,210**	**$9,353,967**	**$10,051,617**	**$10,965,447**	**$10,781,126**	**$9,347,867**	**$8,772,683**	**$3,166,119**	**$5,024,994**	**$114,206,695**

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, includes variances authorized by the MPUC. The variances and dockets are listed below.

<u>General Fuel Clause Rules and Tariffs</u>

- Fuel Clause Terms – E002/M-95-244 (Order dated September 5, 1995)
- Variance to Include Certain Fuels and Purchased Power Costs – E002/M-96-934 (Order dated November 12, 1996)
- Tariff Updates – E,G002/M-97-985 (Order dated February 3, 1998)
- Forecast FCA
  - E002/M-00-420 (Order dated June 27, 2000)
  - E002/M-01-477 (Order dated July 27, 2001)
  - E,G002/M-01-838 (Order dated December 23, 2002)
  - E002/M-02-645 (Order dated July 17, 2002)
  - E002/M-03-585 (Order dated July 10, 2003)
  - E002/M-04-595 (Order dated August 13, 2004)
  - E002/M-05-613 (Order dated July 27, 2005)
  - E002/M-06-589 (Order dated July 17, 2006)
  - E002/M-07-484 (Order dated July 6, 2007)
  - E002/M-08-451 (Order dated July 16, 2008)
  - E002/M-14-364 (Order dated October 24, 2014)
  - E002/M-17-445 (Order dated December 1, 2017)
- Fuel Clause Reform – E999/CI-03-802 (Orders dated December 19, 2017 and June 12, 2019)
- 2020 Fuel Forecast – E002/AA-19-293 (Order dated November 14, 2019)

For the eighteen months ending December 31, 2019, computations of the monthly fuel clause adjustment factors also reflected the recovery of MISO Day 2 and ASM charges, wind contract curtailment payments, power purchase agreements, biomass terminations, Windsource and other renewable energy program exemptions, and gain sharing. These additional components of the FCA were approved by the MPUC in the following dockets:

- MISO ASM – E002/M-08-528 (Orders dated February 26, 2009; March 17, 2009; and August 23, 2010)
- MISO Day 2 – E002/M-04-1970 (Orders dated April 7, 2005, December 21, 2005, February 24, 2006, December 20, 2006 and February 7, 2008)

- Wind Power Purchase Agreements and Curtailment:
    - Chanarambie – E002/M-00-622, (Order dated July 17, 2002)
    - Navitas Energy – E002/M-02-51 (Order dated July 17, 2002)
    - Ivanhoe Wind – E002/M-04-404 (Order dated October 4, 2004)
    - Velva Wind – E002/M-04-864 (Order dated July 19, 2006)
    - Buffalo Ridge – E002/CN-01-1958 (Order dated March 11, 2003)
    - 2003-2204 Electric AAA Docket – E,G999/AA-04-1279 (Order dated April 4, 2006)
    - Fenton Power Partners – E002/M-05-1850 (Order dated March 31, 2006)
    - FPL/Mower County – E002/M-05-1934 (Order dated March 31, 2006)
    - MinnDakota Wind – E002/M-06-85 (Order dated May 3, 2006)
    - Woodstock, LLC – E002/M-09-1055 (Notice of Approval dated October 12, 2009)[1]
    - Winona, LLC – E002/M-09-1247 (Notice of Approval dated December 1, 2009)
    - Goodhue North, LLC – E002/M-09-1349 (Order dated April 28, 2010)[2]
    - Goodhue South, LLC – E002/M-09-1350 (Order dated April 28, 2010)[3]
    - 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)
    - Big Blue, LLC – E002/M-10-733 (Notice of Approval dated August 26, 2010)[4]
    - Community Wind North, LLC – E002/M-10-734 (Order dated August 26, 2010)
    - 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 – E002/M-08-1487 (Order dated April 24, 2009)[5]

[1] The amended PPA was approved by the Commission's October 8, 2018 Order in Docket No. E002/M-17-26.
[2] On July 24, 2013, the Company notified the MPUC that the PPAs with Goodhue North and Goodhue South had been terminated. The MPUC issued an Order closing the associated dockets on October 23, 2013.
[3] Id.
[4] The amended PPA was approved by the Commission's February 27, 2014 Order in Docket No. E002/M-13-1002.
[5] The amended PPA was approved by the Commission's March 25, 2019 Order in Docket No. E002/M-19-58.

  - Ewington Energy Systems LLC – E002/M-06-1472 (Notice of Approval dated November 30, 2006)
  - Jeffers Wind 20, LLC – E002/M-06-1234 (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)
  - Dakota Range I & II – E002/M-17-694 (Order dated May 17, 2018)
  - Dakota Range III – E002/M-18-765 (Order dated July 19, 2019)
- Solar Power Purchase Agreements
  - Best Power, LLC – E002/M-09-1481 (Order dated June 25, 2010)[6]
  - 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)
- Biomass and Other Power Purchase Agreements
  - KODA Energy, LLC – E002/M-08-1098 (Order dated January 29, 2009)
  - WM Renewable Energy, LLC, E002/M-10-161 (Order dated April 30, 2010)
  - Diamond K Dairy – E002/M-10-486 (Order dated August 26, 2010)
  - HERC – E002/M-17-532 (Order dated December 28, 2017)
- Biomass Terminations
  - Benson – E002/M-17-530 (Order dated January 23, 2018)
  - Laurentian – E002/M-17-551 (Order dated January 23, 2018)
  - Pine Bend – E002/M-17-531 (Order dated February 16, 2018)
- WindSource Exemption – E002/M-01-1479 (Orders dated February 26, 2002 and May 7, 2002) and E002/M-09-1177 (Order dated June 21, 2010)[7]
- Community Solar Gardens Program – E002/M-13-867 (Order dated September 17, 2014)
- Renewable*Connect Government Program – E002/M-15-985 (Order dated February 27, 2017)

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[6] The amended PPA was approved by the Commission's September 8, 2014 Order in Docket No. E002/M-14-490.

[7] ORDER ALLOWING ADDITION OF LIMITED SOLAR ENERGY TO WINDSOURCE PROGRAM, REQUIRING CUSTOMER NOTIFICATION AND REQUIRING COMPLIANCE FILING, June 21, 2010.

- Renewable*Connect – E002/M-19-33 (Order dated August 12, 2019)
- Sherco Land Sale – E002/M-17-528 (Order dated February 6, 2018)
- 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)
- Sherco 3 Outage Settlement – E002/GR-12-961, E002/GR-13-868, E999/AA-13-599, E999/AA-14-579, E999/AA-16-523, E999/AA-17-482 and E999/AA-18-373 (Order dated April 11, 2019)

ADDITIONAL REPORTING REQUIREMENT - HERC PPA

We made a commitment in a February 1, 2018 letter in Docket No. E002/M-17-532 to provide 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 desires 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 will purchase 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. The pricing under the Interim Agreement is subject to retroactive adjustment upon approval by the Commission of permanent pricing for the Extension Term.

NSP and HERC executed an amendment to the Interim Agreement on November 28, 2018, which extended the Interim Agreement through December 31, 2019. LMP pricing was used throughout the July 2018-December 2019 AAA reporting period.

Part H, Section 11, Schedule 1 shows the production and invoiced amounts under the interim HERC agreement for the eighteen month AAA reporting period. As shown in Schedule 1, the total cost paid during reporting period was $6,912,656, which is an average cost of $23.40/MWh.

Covanta Hennepin Energy Resource Co LP

PPA Cost and Vols	Cost	MWh	$/MWH
July	$507,562.97	19,437.71	$26.11
August	$461,616.07	17,950.40	$25.72
September	$432,324.62	17,732.96	$24.38
October	$278,654.56	9,549.64	$29.18
November	$585,375.92	20,805.86	$28.14
December	$480,317.11	18,220.62	$26.36
January	$529,146.22	19,269.53	$27.46
February	$367,679.02	13,239.65	$27.77
March	$280,724.14	10,446.17	$26.87
April	$123,919.27	5,210.00	$23.78
May	$380,008.24	19,772.10	$19.22
June	$331,724.08	18,289.83	$18.14
July	$388,570.88	17,252.94	$22.52
August	$461,851.42	19,233.99	$24.01
September	$286,598.66	14,158.19	$20.24
October	$351,465.10	18,850.59	$18.64
November	$391,836.89	19,346.44	$20.25
December	$273,279.68	16,685.18	$16.38
TOTAL	$6,912,654.85	295,451.80	
AVERAGE			$23.40

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

Xcel Energy®

PART I

MISO DAY 1 OPERATIONS IMPACT

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. DAY 1 OPERATIONS IMPACT
(Docket No. E002/M-00-257 et al.)

Part I contains the Company's various compliance reports required by Commission Orders issued in prior Company miscellaneous filings, rate cases, and Annual Automatic Adjustment of Charges Reports associated with the Company's participation in the Midcontinent Independent System Operator, Inc. (MISO).

Background

On May 9, 2002, the Commission issued an Order approving the Company's petition to transfer functional control of certain transmission facilities (those at 100 kV and above) to MISO. In compliance with the Order, the Company provides the following information:

1. Section 2, Item C, Part 3(a): Schedule 10 Administrative Charges Paid to MISO Under MISO Tariff

2018-2019 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
July 2018	$1,133,706.91	87.6880%	84.2615%	$ 837,664.57
August 2018	$1,015,644.93	87.6880%	84.2615%	$ 750,431.85
September 2018	$952,869.21	87.6880%	84.2615%	$ 704,048.61
October 2018	$881,163.10	87.6880%	84.2615%	$ 651,066.95
November 2018	$774,664.71	87.6880%	84.2615%	$ 572,378.25
December 2018	$908,469.86	87.6880%	84.2615%	$ 671,243.16
January 2019	$1,079,382.45	87.0633%	83.8864%	$ 788,319.07
February 2019	$803,802.44	87.0633%	83.8864%	$ 587,051.23
March 2019	$1,014,495.24	87.0633%	83.8864%	$ 740,929.17
April 2019	$946,324.88	87.0633%	83.8864%	$ 691,141.45
May 2019	$916,927.37	87.0633%	83.8864%	$ 669,671.19
June 2019	$966,529.75	87.0633%	83.8864%	$ 705,897.93
Total	**$11,393,980.85**			**$ 8,369,843.43**

*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.

July – December 2019

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
July 2019	$836,241.49	87.0633%	83.8864%	$ 610,742.85
August 2019	$928,299.84	87.0633%	83.8864%	$ 677,976.99
September 2019	$1,112,281.31	87.0633%	83.8864%	$ 812,346.51
October 2019	$937,600.10	87.0633%	83.8864%	$ 684,769.37
November 2019	$833,525.66	87.0633%	83.8864%	$ 608,759.37
December 2019	$960,801.27	87.0633%	83.8864%	$ 701,714.18
	$5,608,749.67			**$ 4,096,309.27**

*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.

2017-2018 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
July 2017	$1,091,627.19	87.4350%	84.2464%	$804,101.76
August 2017	$1,007,193.95	87.4350%	84.2464%	$741,907.52
September 2017	$1,133,189.01	87.4350%	84.2464%	$834,716.54
October 2017	$947,789.47	87.4350%	84.2464%	$698,149.68
November 2017	$940,127.90	87.4350%	84.2464%	$692,506.11
December 2017	$956,640.09	87.4350%	84.2464%	$704,669.12
January 2018	$1,016,481.13	87.6880%	84.2615%	$751,049.69
February 2018	$896,812.46	87.6880%	84.2615%	$662,629.83
March 2018	$1,017,318.98	87.6880%	84.2615%	$751,668.75
April 2018	$923,179.62	87.6880%	84.2615%	$682,111.79
May 2018	$1,118,523.81	87.6880%	84.2615%	$826,446.19
June 2018	$1,076,530.52	87.6880%	84.2615%	$795,418.52
Total	**$12,125,414.13**			**$8,945,375.52**

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

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

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

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

The Company allocates costs recorded in these accounts between the NSP-Minnesota and NSP-Wisconsin Companies, as well as to NSP-Minnesota jurisdictions (Minnesota, North Dakota and South Dakota), based on a demand allocator. The Interchange Agreement demand allocator (36 month coincident peak demand) increased the NSP System allocation to the Company effective January 1, 2018, pursuant to the annual update to the Interchange Agreement allocation factors accepted by FERC in Docket No. ER18-1117-000, letter order dated April 24, 2018. The 2019 Interchange Agreement demand allocator was approved in FERC Docket No. ER19-1340-000, and the letter order approving that filing was issued on May 1, 2019.

The State of Minnesota jurisdictional demand allocator (12 month coincident peak demand) increased effective January 1, 2018 based on State of Minnesota demands. The net impact of the increase in the 2018 Interchange Agreement demand allocator and the increase in the 2018 State of Minnesota jurisdictional demand allocator is an increase in the 2018 NSP System allocation to the Minnesota jurisdiction.

Order Point 18 of the Commission's August 16, 2013 Order in Docket No. E999/AA-11-792 (the 2011 AAA docket) requires utilities to

> *…provide in the initial filing of all future electric AAA reports the Minnesota jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the electric utilities shall 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.*

For comparison purposes, the 2017-2018 amount invoiced for MISO Schedule 10 administrative charges was $12.13 million. The amount invoiced for the 12-month 2018-2019 AAA reporting period was $11.39 million.[1]

2. Section 2, Item C, Part 3(b):
MISO Administrative Charges Deferred by MISO for Later Recovery

MISO deferred costs associated with the integration of the Entergy Operating Companies, Cleco Power LLC, South Mississippi Electric Power Association, Lafayette Utilities Systems and East Texas Electric Cooperative and recovered the costs over a five-year period, beginning on January 1, 2014, the date of the integration of the first Entergy Operating Company.

3. Section 2, Item C, Part 5(c):
Each Instance Where MISO Directed NSP to Curtail NSP's Own Generation for Reliability Reasons that Resulted in an Interruption of Firm Retail Electric Service to NSP's Retail Customers in Minnesota

There was no instance of said conditions occurring during this reporting period.

4. Section 2, Item C, Part 5(d):
Each Instance Where MISO Directed the Curtailment of a Delivery of a Firm Purchased Power Supply that Subsequently Resulted in an Interruption of Firm Retail Electric Service to NSP's Retail Customers in Minnesota

There was no instance of said conditions occurring during this reporting period.

5. Section 2, Item C, Part 8(b):
Changes to MISO Tariffs That May Ultimately Affect the Rates of Retail Customers in Minnesota, and on NSP's Efforts to Minimize MISO Transmission Service Costs

In the period July 1, 2018 to December 31, 2019, MISO submitted a significant number of filings to FERC, including proposed tariff changes to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff, compliance

[1] For comparison purposes, we are comparing the prior 12-month reporting period to only 12-months of the current reporting period. The remaining six months of the current reporting period are presented in a separate table above.

filings, generation interconnection agreements, answers to complaints, and various other filings. Many of the proposed tariff changes and other filings may ultimately affect the rates of our retail electric customers in Minnesota in some manner. All MISO filings to FERC during the reporting period are available (cataloged by month) at the MISO web site (www.misoenergy.org), at the "FERC Filings and Orders" tab available under the "Legal" tab at the MISO home page. NSP endeavors to minimize costs associated with these changes by being an active participant in MISO and by intervening in MISO dockets at FERC.

6. Section 2, Item C, Part 8(c)
Annual Analysis of How the Transfer of Operational Control to the MISO Has Affected NSP's Transmission and Energy Costs and Revenues

a. Overall Transmission Costs and Revenues

As a result of the transfer of operational control of NSP's transmission assets (and the transmission assets of numerous neighboring utilities) to MISO and participation in MISO's regional Tariff, the Company has realized savings on the cost of transmission services purchased to deliver energy supplies purchased to serve our native load customers. This benefit stems primarily from the broad region covered by the MISO Tariff and the conversion of point-to-point transmission service under MAPP Schedule F or individual provider OATTs to network integration transmission service under the MISO Tariff beginning in 2002. This change also had the effect of eliminating most rate "pancaking" (the accumulation of transmission rates assessed by adjacent or distant transmission systems or control areas) for purchased power transactions with delivery points within the MISO region.

These benefits are particularly important to the Company, since it purchases a substantial portion of energy supplies to serve our native load customers. The benefits of this change were discussed in the Direct and Rebuttal testimony of Mr. Stephen Beuning in the 2005 NSP electric rate case (Docket No. E002/GR-05-1428).[2] Mr. Beuning's testimony is incorporated by reference.

On the transmission revenue side of the equation, participating in the MISO regional tariff initially reduced the Company's third party transmission service tariff revenues

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[2] On November 3, 2008, Mr. Beuning provided additional testimony regarding the benefits received by the Company as a result of MISO operations. The testimony was provided as a part of the Company's 2008 rate case in Docket No. E002/GR-08-1065.

due to the adoption of the MISO regional tariff. Just as the Company in MISO Day 1 operations could contract for network transmission service under license plate rates to deliver power to our system, other MISO members could transmit power across our transmission system without paying the Company directly for this use. Revenues from MISO point-to-point service also decreased due to lower volumes of point-to-point service associated with bilateral transactions since the start of the Day 2 energy market in 2005, and the FERC-mandated elimination of "regional through and out" charges (RTOR) for transactions crossing the border between MISO and PJM Interconnection L.L.C. in late 2004. Transmission service revenue has increased as the Company has invested in new transmission facilities and reflected the cost of the new facilities in its annual updates to the Attachment O – NSP formula transmission rate contained in the MISO Tariff.

Overall transmission costs and revenues were discussed at length in the Direct Testimony of Mr. Ian Benson in the most recent NSP electric rate case (Docket No. E002/GR-15-826. Mr. Benson's testimony is also incorporated by reference.

b. Overall Energy Costs for Retail Customers, Including Analysis of How MISO Membership Has Affected NSP's Ability to Use Its Own Generating Sources When They Are the Least-Cost Power Source

On April 1, 2005, MISO began operation of the Day 2 wholesale Day Ahead and Real Time energy markets, pursuant to its Tariff. MISO initiated regional security constrained economic dispatch with the day-ahead and real-time energy markets. Under the Day 2 tariffs, all MISO participants that own or operate generation are now required to submit offers for their generation resources (either owned generation or purchases) that are "Network Resources" belonging to the market. At the same time, each MISO load serving entity (LSE) must bid their load requirements into the market. Since the Company is a market participant with generation and also an LSE, the Company participates with both bids and offers. After receipt of the generation offers and load bids, MISO performs a supply cost optimization analysis that evaluates and reflects delivery constraints on the transmission grid. MISO "clears" the day-ahead and real-time markets over its entire footprint based on participants' bids and offers and the limitations of the transmission system, with optimized cost of supply.

The impact of MISO Day 2 market operations was discussed in the testimony of Mr. Beuning in the Company's 2005 electric rate case, and that testimony is incorporated by reference. The impact was also discussed in the June 22, 2006 Joint Report to the Commission in Docket No. E002/M-04-1970 *et al.*, and in the Company's Reply Comments to the 2007 AAA report (Docket No. E,G999/AA-07-1130). The discussion in those documents is also incorporated by reference.

On January 6, 2009, MISO further enhanced their market by incorporating ancillary services in their market design (Day 3). The Ancillary Services Market (ASM) allowed for further optimization of supply for energy, as well as for regulating reserves, spinning reserves, and supplemental reserves. MISO uses a co-optimitized algorithm that finds the least cost solution for supplying both energy and the reserves. This allows the Company to more fully use its own generation to serve native load when it is least cost. It also allows the Company to procure energy and reserves at a lower cost when the Company's own generation is not least cost.

Along with the launch of the ASM, MISO allows demand response to be offered into its market. These consist of demand response for emergencies as well as economic demand response. MISO allows the Company to include its demand response programs in MISO's resource adequacy construct and these programs will be available for system emergencies that include the NSP System. The emergency procedures that describe the circumstances where MISO can call on the Company's demand response programs can be found on MISO's website (www.misoenergy.org).

In summary, NSP makes available to MISO both its Company-owned and purchased resources for regional dispatch optimization. NSP uses proprietary resource trading methods to ensure that least cost resources remain available for native supply, while ensuring that competitive regional supply alternatives have the opportunity to clear when they can provide energy at lower costs.

In general, operation of the Day 2 and ASM market has not negatively affected the Company's ability to use its own resources (Company-owned generation or bilateral purchased power) when those native resources are the least cost power resource. In particular, the Day 2 market has facilitated the integration of wind energy resources in the regional dispatch much more efficiently than would be the case if NSP system operations had continued on a stand-alone basis.

c. Overall Energy Costs for Retail Customers, Including ….NSP's Ability to Access Low-Cost Power on the Wholesale Market for Its Retail Customers

The Company continues to experience the benefits and efficiencies of the MISO Day 2 and Day 3 Markets, which enhanced NSP's ability to access low-cost power and ancillary services. On a qualitative basis, our experience with the regional generation dispatch market operated by MISO shows benefits related to integration of wind generation resources in the regional economic dispatch. Absent MISO's provision of access to generation on a large regional basis, NSP would experience more disruptive local dispatch requirements, increasing costs for our customers.

7. Section 2, Item C, Part 8(d)
Each Instance Where MISO Directed NSP to Redispatch NSP's Owned Generation for Reliability Reasons, Including an Explanation of Financial Impact on Rates, if Any, and the Reason for the Redispatch, if Known.

Pursuant to the Commission's February 6, 2008 Order on the Company's 2006 AAA report (Docket No. E,G999/AA-06-1208), this reporting item is no longer required.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

PART J

MISO DAY 2 AND ASM

Midcontinent Independent System Operator, Inc. (MISO) Day 2 Accounting and Recovery (Docket No. E002/M-04-1970 *et al.*), Electric Rate Case Settlement Agreement (Docket No. E002/M-05-1428), and 2006 AAA Order (Docket No. E,G999/AA-06-1208) Compliance Report

1. Background

On December 21, 2005, the Commission issued its ORDER ESTABLISHING SECOND INTERIM ACCOUNTING FOR MISO DAY 2 COSTS, PROVIDING FOR REFUNDS, AND INITIATING INVESTIGATION in Docket No. E002/M-04-1970 *et al.* In compliance with the Order the Company is required to report the following information as part of its AAA report:

- Order Item 5:
  Each petitioner shall limit its level of activity in the real-time market to five percent of total purchases for retail customers, or make real-time market activities subject to prudence review on an annual basis in the annual automatic adjustment of charges docket arising pursuant to Minnesota Rules part 7825.2810.
- Order Item 7, Part C:
  In annual reports regarding the automatic adjustment of charges, each petitioner shall provide the following:
  - Information on the net cost of congestion costs and financial transmission rights (FTR) revenues from serving ratepayers. The report should also include information on the amount of excess FTR revenues recovered from MISO as calculated in the FTR Monthly Allocation Amount and the FTR Yearly Allocation Amount.
  - A summary of the effects of each of the thirty-two MISO Day 2 charges on ratepayers and/or the petitioner over the course of the year.

On December 20, 2006, the Commission issued a second order in Docket No. E002/M-04-1970, its ORDER ESTABLISHING ACCOUNTING TREATMENT FOR MISO DAY 2 COSTS (MISO Day 2 Order). In this Order, all Minnesota electric utilities are required to report additional information in their monthly FCA filings and AAA reports. Specifically for Xcel Energy, certain reporting requirements are similar to the ones included in the Company's 2005 Electric Rate Case Settlement in Docket No. E002/M-05-1428. And on February 6, 2008, the Commission issued its Order in Docket No. E,G999/AA-06-1208, *In the Matter of the Review of the 2006 Annual*

Automatic Adjustment of Charges for All Electric and Gas Utilities (2006 AAA Order), which also established additional reporting requirements for the Company's AAA Report. The following table is a side by side comparison of the reporting requirements from the MISO Day 2 Order, 2005 Rate Case Settlement, and 2006 AAA Order applicable to this AAA Report:

MISO Day 2 Order	2005 Rate Case Settlement	2006 AAA Order	Descriptions	Report In	Xcel Energy's Compliance
7A	Item 1		Overview of anticipated events, planned action and fuel cost minimization plans	AAA	Part J, Section 4
7B	Item 2		Annual FCA forecast and explanation of previous year's forecast deviation (Note: Quarterly for Xcel Energy per FCA Settlement Agreement)[1]	AAA (FCA)	Quarterly FCA forecast provided to customers who signed the protective agreement. Monthly deviation explained in FCA filings and during meeting with customers.[2]
7C	Item 3		Provide to customers who signed protective agreement summary of AAA filing stating key factors affecting costs and FCA forecast	Same Time as AAA	Separate mailing to customers who signed protective agreement after September AAA filing.
7G		Paragraphs 21, 22 & 24	Monthly MISO reporting	FCA and AAA	Part J, Section 5, Schedules 1-16 of this AAA report provide MISO reporting in several formats as originally requested and later requested by parties.
		Paragraph 18	Actual and budget comparison of generation plant maintenance		Part K, Section 1, Schedule 1 of this AAA report

[1] As noted in Part J, Section 4, under Fuel Clause Reform, as approved by the Commission's June 12, 2019 Order in Docket No. E999/CI-03-802, the Company will no longer file quarterly forecast reports.
[2] Pursuant to Settlement Agreement item 4, the Company shall meet at least twice yearly with interested parties to discuss the FCA forecast. A similar requirement is also cited in paragraph 7D in the December 20, 2006 Order in Docket No. E002/M-04-1970 *et al.*

2. Real-Time Market: Compliance with December 21, 2005 MISO Day 2 Order Paragraph 5

The Company's real-time market strategy currently is **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]. The Company believes that this strategy meets the intent of the Commission's Order in Docket No. E002/M-04-1970 **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS].

3. Compliance with MISO Order Paragraphs 7A and 7C and FCA Settlement Agreement Items 1 & 3

As a result of the MISO Day 2 Order and 2005 Rate Case Settlement referenced above, the Company is required to provide additional information in its AAA reports on its plans to hedge volatility in fuel and purchased energy costs. The Company provided details about our plans to manage price risk volatility, including our hedging strategy, in our May 1, 2019 Annual Forecast of Rates filing in Docket No. E002/AA-19-293. We will continue to comply with this reporting requirement in future May 1 Annual Forecast of Rates filings, in compliance with the Commission's June 12, 2019 Order which approved the Company's proposed disposition of AAA reporting items as delineated in Attachment 3 of the March 1, 2019 joint comments.

In addition, the main factors contributing to changes in forecast fuel and purchase power expense for 2020 as compared to actual and forecast costs for 2018 are discussed in Docket No. E002/AA-19-293. The Commission approved our 2020 fuel forecast in that docket in its November 14, 2019 Order. Future May 1 Annual Forecast of Rates filings will contain details relating to forecasted fuel and purchased energy costs.

QUARTERLY FORECAST OF 12 MONTHLY FCC AND DEVIATION ANALYSIS

For this AAA reporting period, the Company has prepared and distributed six proprietary quarterly forecasts dated July 5, 2018, October 9, 2018, January 15, 2019, April 10, 2010, July 11, 2019, and October 4, 2019 to interested parties who have signed a protective agreement with the Company. These quarterly forecasts are included as Part J, Section 4 Schedule 1. Seventeen customer representatives have signed protective agreements. The Company has been providing the forecast versus actual information, and when necessary, an explanation of deviation in the monthly FCC filing, pursuant to the requirements in the FCA Forecast Settlement approved by the Commission. A summary of the deviation analysis for the period July 2018 to December 2019 is included in Part J, Section 4 Schedule 2.

Under Fuel Clause Reform, we will present the required 24 month forecast in our May 1 annual fuel forecast filing. As approved by the Commission's June 12, 2019 Order in Docket No. E999/CI-03-802 setting reporting requirements under the new fuel clause process, the Company will no longer file quarterly forecast reports.

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchases Energy Costs
(October 1, 2018)

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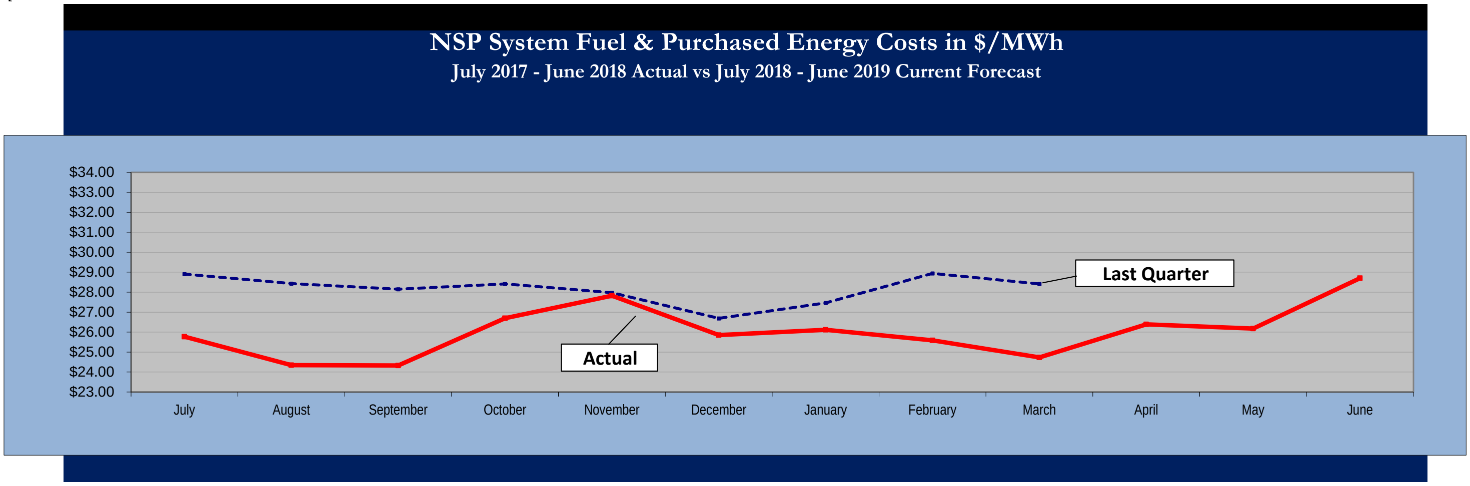

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		Quarterly Forecast				Prior Year			Deviation
		Current [PROTECTED DATA BEGINS	Last Quarter	Change [PROTECTED DATA BEGINS		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current Forecast [PROTECTED DATA BEGINS
July	2018		$28.91		2017	$25.77	$28.71	-10.2%	
August	2018		$28.43		2017	$24.35	$26.77	-9.0%	
September	2018		$28.15		2017	$24.33	$26.66	-8.7%	
October	2018		$28.41		2017	$26.70	$27.73	-3.7%	
November	2018		$27.97		2017	$27.82	$27.86	-0.1%	
December	2018		$26.69		2017	$25.85	$26.22	-1.4%	
January	2019		$27.46		2018	$26.12	$27.62	-5.4%	
February	2019		$28.94		2018	$25.59	$28.74	-11.0%	
March	2019		$28.41		2018	$24.73	$26.99	-8.4%	
April	2019				2018	$26.39	$28.67	-8.0%	
May	2019				2018	$26.18	$29.69	-11.8%	
June	2019				2018 *	$28.70	$28.70	0.0%	
Average (Unweighted)						$26.04	$27.86	-6.5%	
		PROTECTED DATA ENDS]		PROTECTED DATA ENDS]					PROTECTED DATA ENDS]

* From June 2018 FCC Forecast

Forecast Assumption Highlights

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Disclaimer

The forecast of monthly fuel and purchased power costs, in $/MWh, provided in the FCA Forecast are forecasts only. NSP's actual electric rates are linked to the often-unpredictable current market prices for fuel (coal, natural gas, oil, nuclear fuel) and the cost of wholesale energy from third party suppliers (other utilities, independent power producers, wind generating plants, etc.), which are affected by current market conditions at the time. The energy supply market is highly variable, and market prices for both generation fuel and purchased energy go up and down over time. It is not possible to definitely predict what the wholesale market will do over a period of time. The forecasts provided in a FCA Forecast, which are based on projected supply and demand information currently available to the Company, should be considered general estimates of possible future prices. Actual costs will vary.

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchases Energy Costs
(October 1, 2018)

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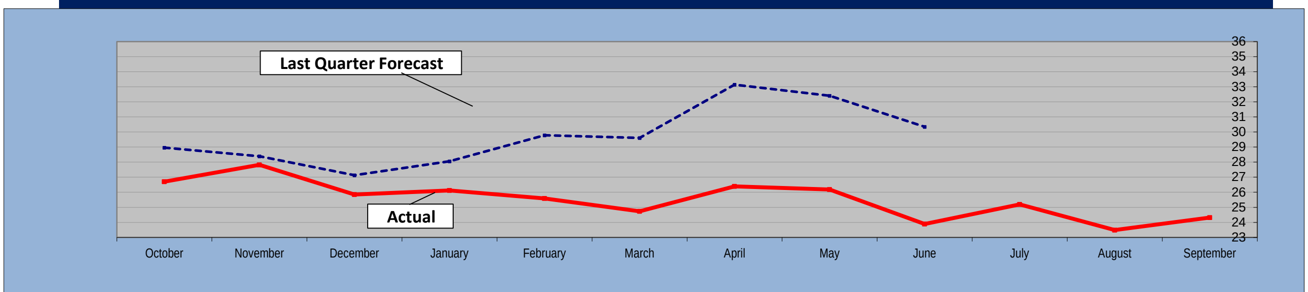
NSP System Fuel & Purchased Energy Costs in $/MWh

October 2017 - September 2018 Actual vs October 2018 - September 2019 Current Forecast



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		Quarterly Forecast				Prior Year			Deviation
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current Forecast
		[PROTECTED DATA BEGINS		[PROTECTED DATA BEGINS					[PROTECTED DATA BEGINS
October	2018		$28.96		2017	$26.70	$27.73	-3.7%	
November	2018		$28.39		2017	$27.82	$28.07	-0.9%	
December	2018		$27.13		2017	$25.85	$26.29	-1.7%	
January	2019		$28.05		2018	$26.12	$27.62	-5.4%	
February	2019		$29.78		2018	$25.59	$28.75	-11.0%	
March	2019		$29.61		2018	$24.73	$27.97	-11.6%	
April	2019		$33.14		2018	$26.39	$30.32	-13.0%	
May	2019		$32.41		2018	$26.18	$30.40	-13.9%	
June	2019		$30.34		2018	$23.89	$29.54	-19.1%	
July	2019				2018	$25.19	$29.71	-15.2%	
August	2019				2018	$23.49	$29.12	-19.3%	
September	2019				2018 *	$24.32	$28.60	-15.0%	
Average (Unweighted)						$25.52	$28.68	-11.0%	
		PROTECTED DATA ENDS]		PROTECTED DATA ENDS]					PROTECTED DATA ENDS]

* From September 2018 FCC Forecast

Forecast Assumption Highlights

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Disclaimer

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PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchases Energy Costs
(January 2019)

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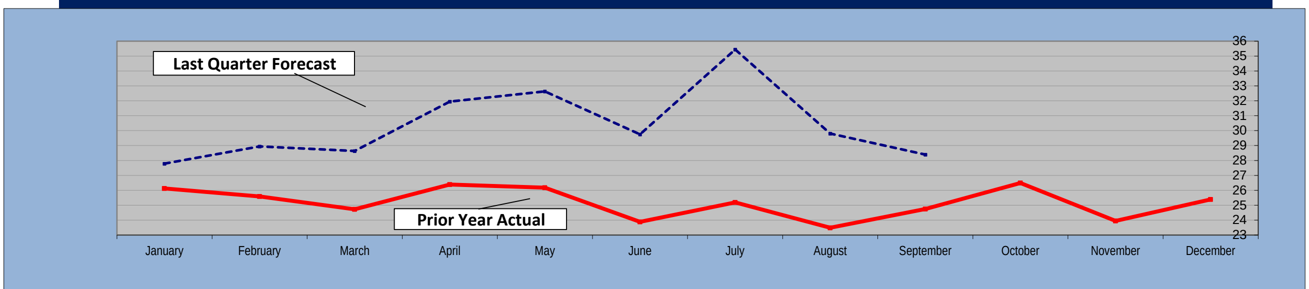
NSP System Fuel & Purchased Energy Costs in $/MWh

January 2018 - December 2018 Actual vs January 2019 - December 2018 Current Forecast



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		MN Jurisdiction Quarterly Forecast				Prior Year System Fuel Costs		
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast
		[PROTECTED DATA BEGINS		[PROTECTED DATA BEGINS				
January	2019		$27.79		2018	$26.12	$27.62	-5.4%
February	2019		$28.94		2018	$25.59	$28.34	-9.7%
March	2019		$28.64		2018	$24.73	$27.66	-10.6%
April	2019		$31.95		2018	$26.39	$29.32	-10.0%
May	2019		$32.63		2018	$26.18	$29.37	-10.9%
June	2019		$29.75		2018	$23.89	$28.82	-17.1%
July	2019		$35.44		2018	$25.19	$29.25	-13.9%
August	2019		$29.80		2018	$23.49	$28.67	-18.1%
September	2019		$28.40		2018	$24.75	$28.74	-13.9%
October	2019				2018	$26.49	$28.40	-6.7%
November	2019				2018	$23.95	$28.51	-16.0%
December	2019				2018 *	$25.39	$26.79	-5.2%
Average (Unweighted)						$25.18	$28.46	-11.5%
		PROTECTED DATA ENDS]		PROTECTED DATA ENDS]				

* From December 2018 FCC Forecast

Forecast Assumption Highlights

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Disclaimer

The forecast of monthly fuel and purchased power costs, in $/MWh, provided in the FCA Forecast are forecasts only. NSP's actual electric rates are linked to the often-unpredictable current market prices for fuel (coal, natural gas, oil, nuclear fuel) and the cost of wholesale energy from third party suppliers (other utilities, independent power producers, wind generating plants, etc.), which are affected by current market conditions at the time. The energy supply market is highly variable, and market prices for both generation fuel and purchased energy go up and down over time. It is not possible to definitely predict what the wholesale market will do over a period of time. The forecasts provided in a FCA Forecast, which are based on projected supply and demand information currently available to the Company, should be considered general estimates of possible future prices. Actual costs will vary.

PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchases Energy Costs
(April 2019)

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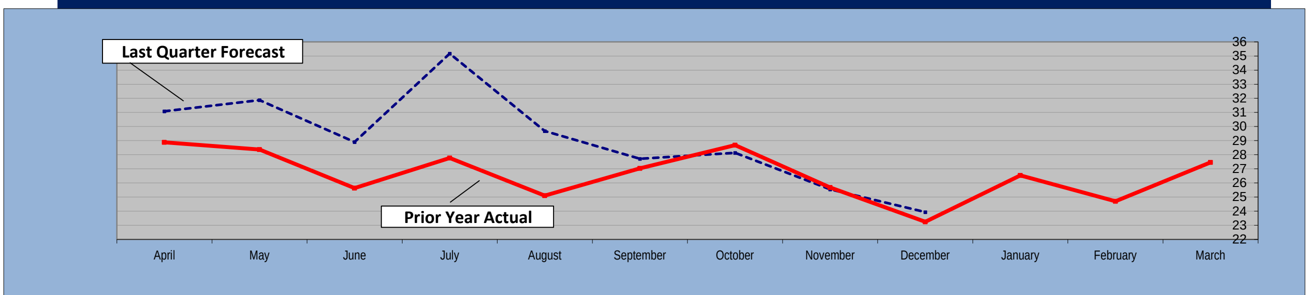
NSP System Fuel & Purchased Energy Costs in $/MWh

April 2018 - March 2019 Actual vs April 2019 - March 2020 Current Forecast



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		MN Jurisdiction Quarterly Forecast				Prior Year MN Jurisdiction Cost **		
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast
		[PROTECTED DATA BEGINS		[PROTECTED DATA BEGINS				
April	2019		$31.08		2018	$28.88	$28.67	0.7%
May	2019		$31.87		2018	$28.38	$29.68	-4.4%
June	2019		$28.91		2018	$25.63	$28.49	-10.0%
July	2019		$35.17		2018	$27.77	$28.91	-3.9%
August	2019		$29.68		2018	$25.10	$28.43	-11.7%
September	2019		$27.72		2018	$27.04	$28.15	-3.9%
October	2019		$28.14		2018	$28.68	$28.41	1.0%
November	2019		$25.55		2018	$25.68	$27.97	-8.2%
December	2019		$23.94		2018	$23.25	$26.69	-12.9%
January	2020				2019	$26.54	$27.46	-3.4%
February	2020				2019	$24.71	$28.94	-14.6%
March	2020				2019 *	$27.46	$28.41	-3.4%
Average (Unweighted)						$26.59	$28.35	-6.2%
		PROTECTED DATA ENDS]		PROTECTED DATA ENDS]				

* From March 2019 FCC Forecast ** Excluded Biomass PPA Termination Cost Recovery

Forecast Assumption Highlights

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Disclaimer

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PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchases Energy Costs
(July 2019)

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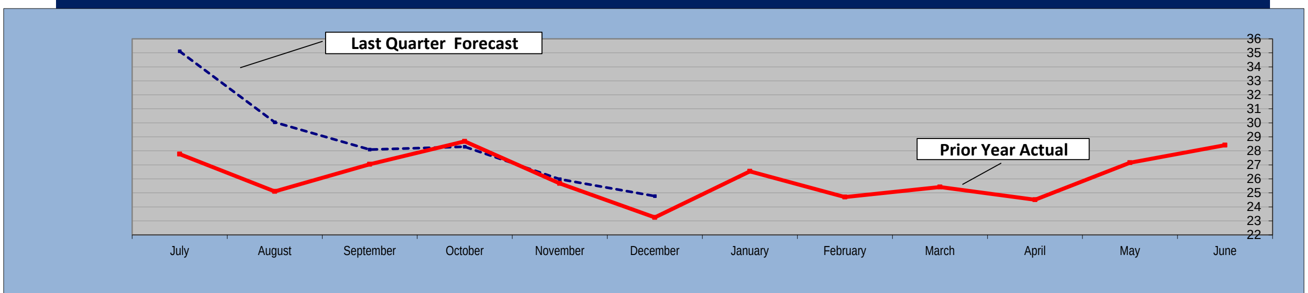
NSP System Fuel & Purchased Energy Costs in $/MWh

July 2018 - June 2019 Actual vs July 2019 - June 2020 Current Forecast



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		MN Jurisdiction Quarterly Forecast				Prior Year MN Jurisdiction Cost **		
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast
		[PROTECTED DATA BEGINS		[PROTECTED DATA BEGINS				
July	**2019**		**$35.11**		**2018**	**$27.77**	**$29.42**	**-5.6%**
August	**2019**		**$30.04**		**2018**	**$25.10**	**$28.71**	**-12.6%**
September	**2019**		**$28.09**		**2018**	**$27.04**	**$28.77**	**-6.0%**
October	**2019**		**$28.30**		**2018**	**$28.68**	**$28.96**	**-1.0%**
November	**2019**		**$25.98**		**2018**	**$25.68**	**$28.39**	**-9.6%**
December	**2019**		**$24.77**		**2018**	**$23.25**	**$27.13**	**-14.3%**
January	**2020**				**2019**	**$26.54**	**$28.05**	**-5.4%**
February	**2020**				**2019**	**$24.71**	**$29.78**	**-17.0%**
March	**2020**				**2019**	**$25.42**	**$29.61**	**-14.1%**
April	**2020**				**2019**	**$24.51**	**$33.14**	**-26.1%**
May	**2020**				**2019**	**$27.16**	**$32.41**	**-16.2%**
June	**2020**				**2019 ***	**$28.40**	**$30.34**	**-6.4%**
Average (Unweighted)						**$26.19**	**$29.56**	**-11.4%**
		...TRADE SECRET DATA ENDS]		*...TRADE SECRET DATA ENDS]*				

* From june 2019 FCC Forecast ** Excluded Biomass PPA Termination Cost Recovery

Forecast Assumption Highlights

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Disclaimer

The forecast of monthly fuel and purchased power costs, in $/MWh, provided in the FCA Forecast are forecasts only. NSP's actual electric rates are linked to the often-unpredictable current market prices for fuel (coal, natural gas, oil, nuclear fuel) and the cost of wholesale energy from third party suppliers (other utilities, independent power producers, wind generating plants, etc.), which are affected by current market conditions at the time. The energy supply market is highly variable, and market prices for both generation fuel and purchased energy go up and down over time. It is not possible to definitely predict what the wholesale market will do over a period of time. The forecasts provided in a FCA Forecast, which are based on projected supply and demand information currently available to the Company, should be considered general estimates of possible future prices. Actual costs will vary.

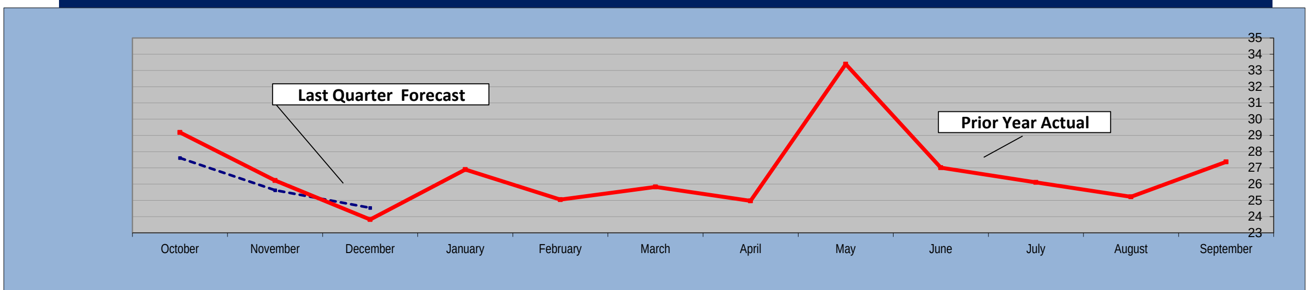
PUBLIC DOCUMENT - NOT PUBLIC DATA HAS BEEN EXCISED

Quarterly Forecast of Fuel & Purchases Energy Costs
(October 1, 2019)

[PROTECTED DATA BEGINS

NSP System Fuel & Purchased Energy Costs in $/MWh

October 2018 - September 2019 Actual vs October 2019 - September 2020 Current Forecast



PROTECTED DATA ENDS]

		MN Jurisdiction Quarterly Forecast				Prior Year MN Jurisdiction Cost **		
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast
		[PROTECTED DATA BEGINS		[PROTECTED DATA BEGINS				
October	2019		$27.61		2018	$29.18	$28.44	2.6%
November	2019		$25.63		2018	$26.22	$26.22	0.0%
December	2019		$24.54		2018	$23.82	$25.99	-8.3%
January	2020				2019	$26.90	$27.79	-3.2%
February	2020				2019	$25.05	$28.94	-13.4%
March	2020				2019	$25.83	$28.64	-9.8%
April	2020				2019	$24.97	$31.95	-21.8%
May	2020				2019	$33.39	$32.63	2.3%
June	2020				2019	$27.01	$29.75	-9.2%
July	2020				2019	$26.11	$35.44	-26.3%
August	2020				2019	$25.22	$29.80	-15.4%
September	2020				2019 *	$27.37	$28.40	-3.6%
Average (Unweighted)						$26.76	$29.50	-9.3%
		...TRADE SECRET DATA ENDS]		*...TRADE SECRET DATA ENDS]*				

* From june 2019 FCC Forecast   ** Included Biomass PPA Termination Cost Recovey

Forecast Assumption Highlights

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

Disclaimer

The forecast of monthly fuel and purchased power costs, in $/MWh, provided in the FCA Forecast are forecasts only. NSP's actual electric rates are linked to the often-unpredictable current market prices for fuel (coal, natural gas, oil, nuclear fuel) and the cost of wholesale energy from third party suppliers (other utilities, independent power producers, wind generating plants, etc.), which are affected by current market conditions at the time. The energy supply market is highly variable, and market prices for both generation fuel and purchased energy go up and down over time. It is not possible to definitely predict what the wholesale market will do over a period of time. The forecasts provided in a FCA Forecast, which are based on projected supply and demand information currently available to the Company, should be considered general estimates of possible future prices. Actual costs will vary.

Northern States Power Company — Docket No. E999/AA-20-171

Electric Operations - State of Minnesota — Part J, Section 4

Deviation Analysis — Schedule 2

Actual Costs and Projected Costs (July 2018 - December 2019) —

Monthly Forecast & Quarterly Forecast Deviation

Line		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
1	Monthly Forecast - Current Month	2.942¢	2.679¢	2.734¢	2.844¢	2.651¢	2.705¢	2.820¢	2.820¢	2.788¢	3.041¢	3.147¢	2.879¢	2.894¢	2.867¢	2.737¢	2.779¢	2.543¢	2.437¢
		2018 3rd Quarter			2018 4th Quarter			2019 1st Quarter			2019 2nd Quarter			2019 3rd Quarter			2019 4th Quarter		
2	Quarterly Forecast - Most Recent Quarter	2.942¢	2.871¢	2.877¢	2.844¢	2.622¢	2.599¢	2.810¢	2.845¢	2.833¢	3.041¢	3.197¢	2.940¢	2.894¢	2.846¢	2.739¢	2.779¢	2.546¢	2.450¢
3	Deviation	0.000	-0.192	-0.143	0.000	0.029	0.106	0.000	-0.025	-0.045	0.000	-0.050	-0.061	0.000	0.021	-0.002	0.000	-0.003	-0.013
4	In Percent	0.0%	-6.7%	-5.0%	0.0%	1.1%	4.1%	0.0%	-0.9%	-1.6%	0.0%	-1.6%	-2.1%	0.0%	0.7%	-0.1%	0.0%	-0.1%	-0.5%
		2018 2nd Quarter			2018 3rd Quarter			2018 4th Quarter			2019 1st Quarter			2019 2nd Quarter			2019 3rd Quarter		
5	Quarterly Forecast - Previous Quarter	2.891¢	2.843¢	2.815¢	2.896¢	2.839¢	2.713¢	2.779¢	2.894¢	2.864¢	3.108¢	3.187¢	2.891¢	3.511¢	3.004¢	2.809¢	2.761¢	2.536¢	2.454¢
6	Deviation	0.051	-0.164	-0.081	-0.052	-0.188	-0.008	0.041	-0.074	-0.076	-0.067	-0.040	-0.012	-0.617	-0.137	-0.072	0.018	0.007	-0.017
7	In Percent	1.8%	-5.8%	-2.9%	-1.8%	-6.6%	-0.3%	1.5%	-2.6%	-2.7%	-2.2%	-1.3%	-0.4%	-17.6%	-4.6%	-2.6%	0.7%	0.3%	-0.7%

Actual and Forecasted Cost Deviation

Line		Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
8	Actual System Costs	3.283¢	2.564¢	2.739¢	2.918¢	2.622¢	2.382¢	2.690¢	2.505¢	2.583¢	2.497¢	3.339¢	2.701¢	2.611¢	2.522¢	2.526¢	2.574¢	2.386¢	2.238¢
9	Forecasted System Costs (From Filing 2 Months Ago)	2.942¢	2.679¢	2.734¢	2.844¢	2.651¢	2.705¢	2.820¢	2.820¢	2.788¢	3.041¢	3.147¢	2.879¢	2.894¢	2.867¢	2.737¢	2.779¢	2.543¢	2.437¢
10	Deviation	0.341¢	-0.115¢	0.005¢	0.074¢	-0.029¢	-0.323¢	-0.130¢	-0.315¢	-0.205¢	-0.544¢	0.192¢	-0.178¢	-0.283¢	-0.345¢	-0.211¢	-0.205¢	-0.157¢	-0.199¢
11	In Percent	11.6%	-4.3%	0.2%	2.6%	-1.1%	-12.0%	-4.6%	-11.2%	-7.4%	-17.9%	6.1%	-6.2%	-9.8%	-12.0%	-7.7%	-7.4%	-6.2%	-8.2%

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	July 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (6,427,342.24)	$ 16,534,795.62	$ 10,107,453.38
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,614,903.69	$ (234,314.89)	$ 1,380,588.80
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,927,202.34	$ (424,723.22)	$ 2,502,479.12
1	Day-Ahead Asset Energy Amount	$ (1,885,236.21)	$ 15,875,757.51	$ 13,990,521.30
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,295.10)	$ -	$ (8,295.10)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (3,039.31)	$ -	$ (3,039.31)
4	Day-Ahead Market Administration Amount	$ 656,616.55	$ (45,158.58)	$ 611,457.97
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (7,596,662.58)	$ -	$ (7,596,662.58)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 992,591.94	$ (144,020.40)	$ 848,571.54
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 878,685.81	$ (127,493.16)	$ 751,192.65
5	Day-Ahead Non-Asset Energy Amount	$ (5,725,384.83)	$ (271,513.56)	$ (5,996,898.39)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,295.10	$ -	$ 8,295.10
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 3,039.31	$ -	$ 3,039.31
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 39,382.90	$ (5,714.27)	$ 33,668.63
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (28,978.79)	$ 27,159.57	$ (1,819.22)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,304,549.72)	$ 2,223,458.47	$ 918,908.75
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 132,109.20	$ 329.05	$ 132,438.25
13 c	Real-Time Asset Energy Amount - Loss Component	$ 123,291.50	$ 210.50	$ 123,502.00
13	Real-Time Asset Energy Amount	$ (1,049,149.02)	$ 2,223,998.02	$ 1,174,849.00
14	Real-Time Distribution of Losses Amount	$ (1,424,393.71)	$ -	$ (1,424,393.71)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 3.27	$ -	$ 3.27
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 5.08	$ -	$ 5.08
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (3.27)	$ -	$ (3.27)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (5.08)	$ -	$ (5.08)
19	Real-Time Market Administration Amount	$ 50,704.08	$ (6,262.88)	$ 44,441.20
20	Real-Time Miscellaneous Amount	$ 321,960.64	$ 10,703.99	$ 332,664.63
21	Real-time Net inadvertent Distribution	$ 220,572.75	$ -	$ 220,572.75
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 11,829.92	$ -	$ 11,829.92
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (2,267.85)	$ 20,829.58	$ 18,561.73
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,450.74)	$ 25,909.37	$ 24,458.63
22	Real-Time Non-Asset Energy Amount	$ 8,111.33	$ 46,738.95	$ 54,850.28
23	Real-Time Revenue Neutrality Uplift Amount	$ 185,822.99	$ (26,962.04)	$ 158,860.95
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 413,559.57	$ (60,005.54)	$ 353,554.03
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (209,141.97)	$ 129,812.92	$ (79,329.05)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,712,847.13)	$ -	$ (2,712,847.13)
29	Financial Transmission Rights Market Administration Amount	$ 20,096.24	$ -	$ 20,096.24
30	Financial Transmission Rights Monthly Allocation Amount	$ (3,582.30)	$ -	$ (3,582.30)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,499.39	$ (6,492.24)	$ 90,007.15
34	Real -Time Schedule 24 Allocation Amount	$ (84,960.45)	$ 73,927.61	$ (11,032.84)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (17,821.32)	$ -	$ (17,821.32)
37	Financial Transmission Guarantee Uplift Amount	$ 17,801.92	$ -	$ 17,801.92
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,270,304.83	$ -	$ 2,270,304.83
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,293,458.77)	$ 2,407.08	$ (2,291,051.69)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (320,148.19)	$ -	$ (320,148.19)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 41,430.89	$ -	$ 41,430.89
43	Real Time Price Volatility Make Whole Payment	$ (99,729.82)	$ 18,768.89	$ (80,960.93)
	TOTAL MISO CHARGES	**$ (11,511,968.43)**	**$ 17,987,165.43**	**$ 6,475,197.00**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 675,995.41**
	SCHEDULE 24 (FOR RETAIL)			**$ 78,974.31**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,720,227.28**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

	August 2018 Actual	System	Intersystem	System Retail
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 477,154.64	$ 8,672,225.62	$ 9,149,380.26
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 667,548.79	$ (53,516.10)	$ 614,032.69
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,087,706.54	$ (247,535.48)	$ 2,840,171.06
1	Day-Ahead Asset Energy Amount	$ 4,232,409.97	$ 8,371,174.05	$ 12,603,584.02
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 848.86	$ -	$ 848.86
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,912.34)	$ -	$ (2,912.34)
4	Day-Ahead Market Administration Amount	$ 537,904.16	$ (20,001.83)	$ 517,902.33
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (7,564,303.08)	$ -	$ (7,564,303.08)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 647,075.01	$ (51,874.76)	$ 595,200.25
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 926,635.36	$ (74,286.57)	$ 852,348.79
5	Day-Ahead Non-Asset Energy Amount	$ (5,990,592.71)	$ (126,161.32)	$ (6,116,754.03)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (848.86)	$ -	$ (848.86)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,912.35	$ -	$ 2,912.35
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 63,525.61	$ (5,092.73)	$ 58,432.88
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (30,490.54)	$ 62,347.80	$ 31,857.26
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,123,121.63)	$ 1,593,747.70	$ 470,626.07
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 527,854.56	$ 64.44	$ 527,919.00
13 c	Real-Time Asset Energy Amount - Loss Component	$ 260,532.92	$ 293.57	$ 260,826.49
13	Real-Time Asset Energy Amount	$ (334,734.15)	$ 1,594,105.71	$ 1,259,371.56
14	Real-Time Distribution of Losses Amount	$ (1,289,052.28)	$ -	$ (1,289,052.28)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 328.84	$ -	$ 328.84
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 97.69	$ -	$ 97.69
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (328.84)	$ -	$ (328.84)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (97.69)	$ -	$ (97.69)
19	Real-Time Market Administration Amount	$ 38,818.57	$ (3,745.54)	$ 35,073.03
20	Real-Time Miscellaneous Amount	$ 96,039.80	$ 10,703.99	$ 106,743.79
21	Real-time Net inadvertent Distribution	$ 11,705.02	$ -	$ 11,705.02
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 53,103.24	$ -	$ 53,103.24
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (803.75)	$ 46,513.78	$ 45,710.03
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (3,661.95)	$ 23,964.86	$ 20,302.91
22	Real-Time Non-Asset Energy Amount	$ 48,637.54	$ 70,478.63	$ 119,116.17
23	Real-Time Revenue Neutrality Uplift Amount	$ 53,787.45	$ (4,312.04)	$ 49,475.41
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 213,019.94	$ (17,077.40)	$ 195,942.54
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (99,818.34)	$ 112,764.97	$ 12,946.63
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (834,866.42)	$ -	$ (834,866.42)
29	Financial Transmission Rights Market Administration Amount	$ 18,087.28	$ -	$ 18,087.28
30	Financial Transmission Rights Monthly Allocation Amount	$ (37,459.65)	$ -	$ (37,459.65)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,356.87	$ (3,559.35)	$ 92,797.52
34	Real -Time Schedule 24 Allocation Amount	$ (69,865.97)	$ 84,904.57	$ 15,038.60
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (5,682.10)	$ -	$ (5,682.10)
37	Financial Transmission Guarantee Uplift Amount	$ 5,183.65	$ -	$ 5,183.65
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,270,304.83	$ -	$ 2,270,304.83
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,293,458.77)	$ 10,397.76	$ (2,283,061.01)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (320,148.49)	$ -	$ (320,148.49)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 41,430.89	$ -	$ 41,430.89
43	Real Time Price Volatility Make Whole Payment	$ (36,231.99)	$ 9,149.72	$ (27,082.27)
	TOTAL MISO CHARGES	**$ (3,615,189.82)**	**$ 10,146,076.99**	**$ 6,530,887.17**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 571,062.64**
	SCHEDULE 24 (FOR RETAIL)			**$ 107,836.12**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,851,988.41**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	September 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (7,186,012.70)	$ 14,250,345.33	$ 7,064,332.63
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 448,282.98	$ (68,644.11)	$ 379,638.87
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,204,337.92	$ (337,543.05)	$ 1,866,794.87
1	Day-Ahead Asset Energy Amount	$ (4,533,391.80)	$ 13,844,158.18	$ 9,310,766.38
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (18,283.58)	$ -	$ (18,283.58)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (6,980.25)	$ -	$ (6,980.25)
4	Day-Ahead Market Administration Amount	$ 647,893.53	$ (48,001.57)	$ 599,891.96
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,655,205.04)	$ -	$ (6,655,205.04)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 894,184.74	$ (136,923.58)	$ 757,261.16
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 817,936.28	$ (125,247.90)	$ 692,688.38
5	Day-Ahead Non-Asset Energy Amount	$ (4,943,084.02)	$ (262,171.49)	$ (5,205,255.51)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 18,283.58	$ -	$ 18,283.58
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 6,980.25	$ -	$ 6,980.25
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 62,311.02	$ (9,541.48)	$ 52,769.54
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (39,059.66)	$ 32,926.20	$ (6,133.46)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,167,857.12	$ 1,707,309.96	$ 2,875,167.08
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 171,379.30	$ 32.21	$ 171,411.51
13 c	Real-Time Asset Energy Amount - Loss Component	$ 24,291.11	$ 107.87	$ 24,398.98
13	Real-Time Asset Energy Amount	$ 1,363,527.53	$ 1,707,450.04	$ 3,070,977.57
14	Real-Time Distribution of Losses Amount	$ (1,026,632.15)	$ -	$ (1,026,632.15)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 56,094.68	$ (5,266.24)	$ 50,828.44
20	Real-Time Miscellaneous Amount	$ 202,080.96	$ 10,358.70	$ 212,439.66
21	Real-time Net inadvertent Distribution	$ (92,059.80)	$ -	$ (92,059.80)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 4,230.60	$ -	$ 4,230.60
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (210.35)	$ 38,501.34	$ 38,290.99
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (704.45)	$ 5,627.93	$ 4,923.48
22	Real-Time Non-Asset Energy Amount	$ 3,315.80	$ 44,129.27	$ 47,445.07
23	Real-Time Revenue Neutrality Uplift Amount	$ 28,294.23	$ (4,332.60)	$ 23,961.63
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 357,710.30	$ (54,775.01)	$ 302,935.29
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (178,197.87)	$ 108,960.59	$ (69,237.28)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (503,905.53)	$ -	$ (503,905.53)
29	Financial Transmission Rights Market Administration Amount	$ 16,066.00	$ -	$ 16,066.00
30	Financial Transmission Rights Monthly Allocation Amount	$ (44,253.83)	$ -	$ (44,253.83)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 107,122.00	$ (7,424.82)	$ 99,697.18
34	Real -Time Schedule 24 Allocation Amount	$ (93,731.13)	$ 90,652.58	$ (3,078.55)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 5,818.31	$ -	$ 5,818.31
37	Financial Transmission Guarantee Uplift Amount	$ (5,065.14)	$ -	$ (5,065.14)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,189,565.60	$ -	$ 2,189,565.60
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,190,703.62)	$ 10,541.26	$ (2,180,162.36)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (242,965.26)	$ -	$ (242,965.26)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 130,420.69	$ -	$ 130,420.69
43	Real Time Price Volatility Make Whole Payment	$ (162,966.54)	$ 12,531.14	$ (150,435.40)
	TOTAL MISO CHARGES	**$ (8,885,795.70)**	**$ 15,470,194.75**	**$ 6,584,399.05**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 666,786.40**
	SCHEDULE 24 (FOR RETAIL)			**$ 96,618.63**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,820,994.02**

		System	Intersystem	System Retail
	October 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (6,997,648.67)	$ 10,453,243.68	$ 3,455,595.01
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 348,422.11	$ (30,667.62)	$ 317,754.49
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,770,216.27	$ (243,830.52)	$ 2,526,385.75
1	Day-Ahead Asset Energy Amount	$ (3,879,010.29)	$ 10,178,745.54	$ 6,299,735.25
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (50.24)	$ -	$ (50.24)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (90.81)	$ -	$ (90.81)
4	Day-Ahead Market Administration Amount	$ 783,368.61	$ (39,523.79)	$ 743,844.82
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,536,574.59)	$ -	$ (6,536,574.59)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 260,094.46	$ (22,893.15)	$ 237,201.31
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 527,103.28	$ (46,394.89)	$ 480,708.39
5	Day-Ahead Non-Asset Energy Amount	$ (5,749,376.85)	$ (69,288.03)	$ (5,818,664.88)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 50.24	$ -	$ 50.24
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 90.81	$ -	$ 90.81
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 98,385.96	$ (8,659.79)	$ 89,726.17
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (15,835.89)	$ 33,357.48	$ 17,521.59
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 7,557,082.03	$ 1,306,700.28	$ 8,863,782.31
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 46,300.57	$ 1.73	$ 46,302.30
13 c	Real-Time Asset Energy Amount - Loss Component	$ 2,611.07	$ 1.37	$ 2,612.44
13	Real-Time Asset Energy Amount	$ 7,605,993.67	$ 1,306,703.38	$ 8,912,697.05
14	Real-Time Distribution of Losses Amount	$ (922,125.28)	$ -	$ (922,125.28)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 6.22	$ -	$ 6.22
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 1.14	$ -	$ 1.14
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (6.22)	$ -	$ (6.22)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (1.14)	$ -	$ (1.14)
19	Real-Time Market Administration Amount	$ 52,710.27	$ (6,406.62)	$ 46,303.65
20	Real-Time Miscellaneous Amount	$ 96,275.38	$ 10,703.99	$ 106,979.37
21	Real-time Net inadvertent Distribution	$ 77,626.14	$ -	$ 77,626.14
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (6,182.61)	$ -	$ (6,182.61)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (19.68)	$ 1,700.18	$ 1,680.50
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (15.55)	$ (2,681.33)	$ (2,696.88)
22	Real-Time Non-Asset Energy Amount	$ (6,217.84)	$ (981.14)	$ (7,198.98)
23	Real-Time Revenue Neutrality Uplift Amount	$ 655,240.42	$ (57,673.34)	$ 597,567.08
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 271,236.87	$ (23,873.89)	$ 247,362.98
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (300,760.84)	$ 127,695.78	$ (173,065.06)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (80,434.15)	$ -	$ (80,434.15)
29	Financial Transmission Rights Market Administration Amount	$ 14,516.00	$ -	$ 14,516.00
30	Financial Transmission Rights Monthly Allocation Amount	$ (48,652.72)	$ -	$ (48,652.72)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 103,289.24	$ (4,967.40)	$ 98,321.84
34	Real -Time Schedule 24 Allocation Amount	$ (84,513.82)	$ 88,003.93	$ 3,490.11
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (25,345.74)	$ -	$ (25,345.74)
37	Financial Transmission Guarantee Uplift Amount	$ 25,337.71	$ -	$ 25,337.71
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,189,565.60	$ -	$ 2,189,565.60
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,190,703.62)	$ (5,093.26)	$ (2,195,796.88)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (242,964.65)	$ -	$ (242,964.65)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 130,420.69	$ -	$ 130,420.69
43	Real Time Price Volatility Make Whole Payment	$ (43,614.46)	$ 15,386.86	$ (28,227.60)
	TOTAL MISO CHARGES	**$ (1,485,589.59)**	**$ 11,544,129.69**	**$ 10,058,540.10**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 804,664.47**
	SCHEDULE 24 (FOR RETAIL)			**$ 101,811.95**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 9,152,063.68**

Docket No. E999/AA-20-171
Part J, Section 5
Schedule 1

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	November 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (15,227,576.71)	$ 19,512,393.65	$ 4,284,816.94
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 187,285.79	$ (34,082.74)	$ 153,203.05
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,607,922.75	$ (656,578.81)	$ 2,951,343.94
1	Day-Ahead Asset Energy Amount	$ (11,432,368.17)	$ 18,821,732.10	$ 7,389,363.93
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (7,269.33)	$ -	$ (7,269.33)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,345.74	$ -	$ 2,345.74
4	Day-Ahead Market Administration Amount	$ 894,534.22	$ (79,283.01)	$ 815,251.21
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,876,510.04)	$ -	$ (3,876,510.04)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 185,495.14	$ (33,756.87)	$ 151,738.27
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 277,707.87	$ (50,537.97)	$ 227,169.90
5	Day-Ahead Non-Asset Energy Amount	$ (3,413,307.03)	$ (84,294.84)	$ (3,497,601.87)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 7,269.33	$ -	$ 7,269.33
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,345.74)	$ -	$ (2,345.74)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 111,056.42	$ (20,210.33)	$ 90,846.09
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (76,788.74)	$ 72,089.54	$ (4,699.20)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 146,572.78	$ 2,346,024.11	$ 2,492,596.89
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (23,629.14)	$ (0.95)	$ (23,630.09)
13 c	Real-Time Asset Energy Amount - Loss Component	$ (16,823.34)	$ (0.16)	$ (16,823.50)
13	Real-Time Asset Energy Amount	$ 106,120.30	$ 2,346,023.01	$ 2,452,143.31
14	Real-Time Distribution of Losses Amount	$ (1,121,300.12)	$ -	$ (1,121,300.12)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 62,294.73	$ (10,955.16)	$ 51,339.57
20	Real-Time Miscellaneous Amount	$ 173,251.92	$ 10,358.70	$ 183,610.62
21	Real-time Net inadvertent Distribution	$ (107,138.55)	$ -	$ (107,138.55)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (721.25)	$ -	$ (721.25)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 5.20	$ 2,006.10	$ 2,011.30
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 0.86	$ (3,484.22)	$ (3,483.36)
22	Real-Time Non-Asset Energy Amount	$ (715.19)	$ (1,478.12)	$ (2,193.31)
23	Real-Time Revenue Neutrality Uplift Amount	$ 295,464.55	$ (53,769.38)	$ 241,695.17
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 169,296.50	$ (30,809.00)	$ 138,487.50
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (378,364.21)	$ 233,878.08	$ (144,486.13)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ 151,905.71	$ -	$ 151,905.71
29	Financial Transmission Rights Market Administration Amount	$ 8,686.24	$ -	$ 8,686.24
30	Financial Transmission Rights Monthly Allocation Amount	$ (16,516.41)	$ -	$ (16,516.41)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 103,860.95	$ (9,527.73)	$ 94,333.22
34	Real -Time Schedule 24 Allocation Amount	$ (80,773.56)	$ 92,398.49	$ 11,624.93
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 40,298.85	$ -	$ 40,298.85
37	Financial Transmission Guarantee Uplift Amount	$ (40,641.55)	$ -	$ (40,641.55)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,189,565.60	$ -	$ 2,189,565.60
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,190,703.62)	$ 2,677.80	$ (2,188,025.82)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (242,964.65)	$ -	$ (242,964.65)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 130,420.69	$ -	$ 130,420.69
43	Real Time Price Volatility Make Whole Payment	$ (76,569.25)	$ 7,590.31	$ (68,978.94)
	TOTAL MISO CHARGES	**$ (14,741,394.37)**	**$ 21,296,420.47**	**$ 6,555,026.10**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 875,277.02**
	SCHEDULE 24 (FOR RETAIL)			**$ 105,958.15**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,573,790.93**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	December 2018 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (10,555,045.51)	$ 14,191,971.52	$ 3,636,926.01
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,507,770.72	$ (223,366.70)	$ 1,284,404.02
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,762,248.39	$ (557,353.31)	$ 3,204,895.08
1	Day-Ahead Asset Energy Amount	$ (5,285,026.40)	$ 13,411,251.51	$ 8,126,225.11
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (878.41)	$ -	$ (878.41)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,013.71	$ -	$ 3,013.71
4	Day-Ahead Market Administration Amount	$ 664,578.14	$ (43,489.12)	$ 621,089.02
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,534,295.08)	$ -	$ (3,534,295.08)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 158,918.96	$ (23,542.84)	$ 135,376.12
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 303,202.87	$ (44,917.59)	$ 258,285.28
5	Day-Ahead Non-Asset Energy Amount	$ (3,072,173.25)	$ (68,460.43)	$ (3,140,633.68)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 878.41	$ -	$ 878.41
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,013.71)	$ -	$ (3,013.71)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 119,041.48	$ (17,635.24)	$ 101,406.24
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (113,726.60)	$ 38,216.52	$ (75,510.08)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (245,591.13)	$ 2,325,052.41	$ 2,079,461.28
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 58,537.78	$ (0.39)	$ 58,537.39
13 c	Real-Time Asset Energy Amount - Loss Component	$ 15,682.86	$ 5.08	$ 15,687.94
13	Real-Time Asset Energy Amount	$ (171,370.49)	$ 2,325,057.10	$ 2,153,686.61
14	Real-Time Distribution of Losses Amount	$ (1,240,909.23)	$ -	$ (1,240,909.23)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 12.93	$ -	$ 12.93
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 3.23	$ -	$ 3.23
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (12.93)	$ -	$ (12.93)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (3.23)	$ -	$ (3.23)
19	Real-Time Market Administration Amount	$ 48,738.53	$ (9,532.65)	$ 39,205.88
20	Real-Time Miscellaneous Amount	$ 369,744.02	$ 10,703.99	$ 380,448.01
21	Real-time Net inadvertent Distribution	$ 99,169.58	$ -	$ 99,169.58
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 5,131.23	$ -	$ 5,131.23
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 2.66	$ (1,511.70)	$ (1,509.04)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (34.32)	$ (281.33)	$ (315.65)
22	Real-Time Non-Asset Energy Amount	$ 5,099.57	$ (1,793.03)	$ 3,306.54
23	Real-Time Revenue Neutrality Uplift Amount	$ 484,100.39	$ (71,716.41)	$ 412,383.98
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 117,415.06	$ (17,394.30)	$ 100,020.76
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (195,033.76)	$ 109,356.57	$ (85,677.19)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,167,361.77)	$ -	$ (1,167,361.77)
29	Financial Transmission Rights Market Administration Amount	$ 15,955.28	$ -	$ 15,955.28
30	Financial Transmission Rights Monthly Allocation Amount	$ (80,110.50)	$ -	$ (80,110.50)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 98,245.53	$ (6,421.29)	$ 91,824.24
34	Real -Time Schedule 24 Allocation Amount	$ (82,037.24)	$ 86,910.38	$ 4,873.14
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (97,314.32)	$ -	$ (97,314.32)
37	Financial Transmission Guarantee Uplift Amount	$ 94,933.31	$ -	$ 94,933.31
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,791,300.13	$ -	$ 1,791,300.13
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,791,548.83)	$ 3,108.27	$ (1,788,440.56)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (155,089.36)	$ -	$ (155,089.36)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,374.37	$ -	$ 42,374.37
43	Real Time Price Volatility Make Whole Payment	$ (38,980.18)	$ 10,485.88	$ (28,494.30)
	TOTAL MISO CHARGES	**$ (9,539,986.54)**	**$ 15,758,647.75**	**$ 6,218,661.21**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 676,250.18**
	SCHEDULE 24 (FOR RETAIL)			**$ 96,697.38**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,445,713.65**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	January 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (3,121,529.45)	$ 14,335,930.92	$ 11,214,401.47
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,996,616.80	$ (291,571.05)	$ 1,705,045.75
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,488,042.21	$ (509,367.71)	$ 2,978,674.50
1	Day-Ahead Asset Energy Amount	$ 2,363,129.56	$ 13,534,992.16	$ 15,898,121.72
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 11,650.90	$ -	$ 11,650.90
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,797.62	$ -	$ 1,797.62
4	Day-Ahead Market Administration Amount	$ 428,143.14	$ (30,063.74)	$ 398,079.40
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,760,059.53)	$ -	$ (2,760,059.53)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (35,883.01)	$ 5,240.09	$ (30,642.92)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 213,462.82	$ (31,172.52)	$ 182,290.30
5	Day-Ahead Non-Asset Energy Amount	$ (2,582,479.72)	$ (25,932.43)	$ (2,608,412.15)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (11,650.90)	$ -	$ (11,650.90)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,797.62)	$ -	$ (1,797.62)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 90,772.12	$ (13,255.68)	$ 77,516.44
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (88,258.02)	$ 55,618.70	$ (32,639.32)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,675,988.00)	$ 2,628,609.32	$ 952,621.32
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (168,205.37)	$ (0.01)	$ (168,205.38)
13 c	Real-Time Asset Energy Amount - Loss Component	$ (81,323.02)	$ (0.01)	$ (81,323.03)
13	Real-Time Asset Energy Amount	$ (1,925,516.39)	$ 2,628,609.31	$ 703,092.92
14	Real-Time Distribution of Losses Amount	$ (1,146,336.64)	$ -	$ (1,146,336.64)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 29,413.76	$ (4,356.47)	$ 25,057.29
20	Real-Time Miscellaneous Amount	$ 48,986.87	$ 10,703.99	$ 59,690.86
21	Real-time Net inadvertent Distribution	$ (50,899.18)	$ -	$ (50,899.18)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 1,842.64	$ -	$ 1,842.64
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 0.05	$ (20,547.83)	$ (20,547.78)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 0.04	$ (797.11)	$ (797.07)
22	Real-Time Non-Asset Energy Amount	$ 1,842.73	$ (21,344.94)	$ (19,502.21)
23	Real-Time Revenue Neutrality Uplift Amount	$ 11,044.93	$ (1,612.92)	$ 9,432.01
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 64,030.81	$ (9,350.58)	$ 54,680.23
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (114,702.05)	$ (5,564.92)	$ (120,266.97)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (381,905.51)	$ -	$ (381,905.51)
29	Financial Transmission Rights Market Administration Amount	$ 29,176.72	$ -	$ 29,176.72
30	Financial Transmission Rights Monthly Allocation Amount	$ (90,157.52)	$ -	$ (90,157.52)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (426,287.70)	$ -	$ (426,287.70)
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,842.77	$ (6,518.07)	$ 87,324.70
34	Real -Time Schedule 24 Allocation Amount	$ (78,210.62)	$ 84,211.35	$ 6,000.73
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 435,503.09	$ -	$ 435,503.09
37	Financial Transmission Guarantee Uplift Amount	$ (473,346.96)	$ -	$ (473,346.96)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,791,300.13	$ -	$ 1,791,300.13
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,791,548.83)	$ 116,443.80	$ (1,675,105.03)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (153,246.61)	$ -	$ (153,246.61)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,389.67	$ -	$ 42,389.67
43	Real Time Price Volatility Make Whole Payment	$ (55,970.79)	$ 11,208.30	$ (44,762.49)
	TOTAL MISO CHARGES	**$ (3,929,290.24)**	**$ 16,323,787.85**	**$ 12,394,497.61**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 452,313.41**
	SCHEDULE 24 (FOR RETAIL)			**$ 93,325.43**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 11,848,858.77**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	February 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (7,044,275.35)	$ 12,297,020.88	$ 5,252,745.53
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,482,893.85	$ (316,207.97)	$ 1,166,685.88
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,693,104.17	$ (574,269.71)	$ 2,118,834.46
1	Day-Ahead Asset Energy Amount	$ (2,868,277.33)	$ 11,406,543.20	$ 8,538,265.87
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 29,647.58	$ -	$ 29,647.58
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 7,326.99	$ -	$ 7,326.99
4	Day-Ahead Market Administration Amount	$ 551,980.86	$ (36,456.99)	$ 515,523.87
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,963,666.07)	$ -	$ (2,963,666.07)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (483,219.56)	$ 103,040.33	$ (380,179.23)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 55,088.20	$ (11,746.85)	$ 43,341.35
5	Day-Ahead Non-Asset Energy Amount	$ (3,391,797.43)	$ 91,293.49	$ (3,300,503.94)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (29,647.58)	$ -	$ (29,647.58)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (7,326.99)	$ -	$ (7,326.99)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 98,781.00	$ (21,063.77)	$ 77,717.23
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (70,178.46)	$ 35,346.36	$ (34,832.10)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (147,856.74)	$ 1,430,714.90	$ 1,282,858.16
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 16,808.99	$ -	$ 16,808.99
13 c	Real-Time Asset Energy Amount - Loss Component	$ (6,318.04)	$ -	$ (6,318.04)
13	Real-Time Asset Energy Amount	$ (137,365.79)	$ 1,430,714.90	$ 1,293,349.11
14	Real-Time Distribution of Losses Amount	$ (1,319,387.99)	$ -	$ (1,319,387.99)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 41,461.12	$ (5,411.46)	$ 36,049.66
20	Real-Time Miscellaneous Amount	$ 79,029.18	$ 9,668.12	$ 88,697.30
21	Real-time Net inadvertent Distribution	$ (133,686.51)	$ -	$ (133,686.51)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 151.42	$ -	$ 151.42
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ -	$ (24,658.41)	$ (24,658.41)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ (11,560.02)	$ (11,560.02)
22	Real-Time Non-Asset Energy Amount	$ 151.42	$ (36,218.44)	$ (36,067.02)
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,712,181.83	$ (365,100.68)	$ 1,347,081.15
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 216,975.93	$ (46,267.32)	$ 170,708.61
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (3,473,889.70)	$ 2,683,525.11	$ (790,364.59)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ 293,886.74	$ -	$ 293,886.74
29	Financial Transmission Rights Market Administration Amount	$ 7,976.88	$ -	$ 7,976.88
30	Financial Transmission Rights Monthly Allocation Amount	$ (94,015.01)	$ -	$ (94,015.01)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ 1.07	$ -	$ 1.07
33	Day-Ahead Schedule 24 Allocation Amount	$ 89,246.18	$ (5,906.96)	$ 83,339.22
34	Real -Time Schedule 24 Allocation Amount	$ (74,893.62)	$ 86,916.51	$ 12,022.89
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (81,675.23)	$ -	$ (81,675.23)
37	Financial Transmission Guarantee Uplift Amount	$ 102,923.50	$ -	$ 102,923.50
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,791,300.13	$ -	$ 1,791,300.13
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,791,548.83)	$ 58,738.32	$ (1,732,810.51)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (156,670.33)	$ -	$ (156,670.33)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,379.47	$ -	$ 42,379.47
43	Real Time Price Volatility Make Whole Payment	$ (94,587.85)	$ 7,006.23	$ (87,581.62)
	TOTAL MISO CHARGES	**$ (8,659,698.77)**	**$ 15,293,326.62**	**$ 6,633,627.85**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 559,550.41**
	SCHEDULE 24 (FOR RETAIL)			**$ 95,362.11**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,978,715.33**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	March 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (4,388,180.63)	$ 11,843,477.63	$ 7,455,297.00
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,061,684.44	$ (326,490.29)	$ 1,735,194.15
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,045,595.98	$ (482,303.45)	$ 2,563,292.53
1	Day-Ahead Asset Energy Amount	$ 719,099.79	$ 11,034,683.90	$ 11,753,783.69
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 2,675.57	$ -	$ 2,675.57
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 5,532.06	$ -	$ 5,532.06
4	Day-Ahead Market Administration Amount	$ 686,113.77	$ (45,682.80)	$ 640,430.97
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,650,021.92)	$ -	$ (3,650,021.92)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 450,167.94	$ (71,289.02)	$ 378,878.92
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 83,951.50	$ (13,294.64)	$ 70,656.86
5	Day-Ahead Non-Asset Energy Amount	$ (3,115,902.48)	$ (84,583.66)	$ (3,200,486.14)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2,675.57)	$ -	$ (2,675.57)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (5,532.06)	$ -	$ (5,532.06)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 90,530.24	$ (14,336.45)	$ 76,193.79
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (111,365.39)	$ 37,859.08	$ (73,506.31)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (705,137.65)	$ 1,871,750.40	$ 1,166,612.75
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 96,488.85	$ -	$ 96,488.85
13 c	Real-Time Asset Energy Amount - Loss Component	$ 47,058.99	$ -	$ 47,058.99
13	Real-Time Asset Energy Amount	$ (561,589.81)	$ 1,871,750.40	$ 1,310,160.59
14	Real-Time Distribution of Losses Amount	$ (793,578.25)	$ -	$ (793,578.25)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 56,279.14	$ (9,086.89)	$ 47,192.25
20	Real-Time Miscellaneous Amount	$ 155,878.10	$ 10,703.99	$ 166,582.09
21	Real-time Net inadvertent Distribution	$ 97,293.07	$ -	$ 97,293.07
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 0.47	$ -	$ 0.47
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ -	$ (4,185.22)	$ (4,185.22)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ 9,043.42	$ 9,043.42
22	Real-Time Non-Asset Energy Amount	$ 0.47	$ 4,858.20	$ 4,858.67
23	Real-Time Revenue Neutrality Uplift Amount	$ 249,977.97	$ (39,586.75)	$ 210,391.22
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 203,122.10	$ (32,166.61)	$ 170,955.49
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (273,885.54)	$ 24,624.91	$ (249,260.63)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,156,939.27)	$ -	$ (2,156,939.27)
29	Financial Transmission Rights Market Administration Amount	$ 28,312.64	$ -	$ 28,312.64
30	Financial Transmission Rights Monthly Allocation Amount	$ (112,020.04)	$ -	$ (112,020.04)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 99,517.54	$ (6,612.42)	$ 92,905.12
34	Real -Time Schedule 24 Allocation Amount	$ (84,071.29)	$ 68,614.93	$ (15,456.36)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (58,051.82)	$ -	$ (58,051.82)
37	Financial Transmission Guarantee Uplift Amount	$ 61,106.83	$ -	$ 61,106.83
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,547,181.68	$ -	$ 2,547,181.68
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,571,169.74)	$ 25,992.35	$ (2,545,177.39)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (90,957.73)	$ -	$ (90,957.73)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 55,175.45	$ -	$ 55,175.45
43	Real Time Price Volatility Make Whole Payment	$ (44,620.67)	$ 19,230.98	$ (25,389.69)
	TOTAL MISO CHARGES	**$ (4,924,563.24)**	**$ 12,866,263.16**	**$ 7,941,699.92**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 715,935.86**
	SCHEDULE 24 (FOR RETAIL)			**$ 77,448.76**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,148,315.30**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	April 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (656,753.91)	$ 7,367,799.79	$ 6,711,045.88
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,003,404.09	$ (117,007.49)	$ 886,396.60
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,032,461.42	$ (237,006.42)	$ 1,795,455.00
1	Day-Ahead Asset Energy Amount	$ 2,379,111.60	$ 7,013,785.87	$ 9,392,897.47
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (329.13)	$ -	$ (329.13)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,416.41	$ -	$ 2,416.41
4	Day-Ahead Market Administration Amount	$ 606,290.04	$ (29,858.45)	$ 576,431.59
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,391,705.22)	$ -	$ (2,391,705.22)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 210,874.36	$ (24,590.17)	$ 186,284.19
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 116,313.31	$ (13,563.36)	$ 102,749.95
5	Day-Ahead Non-Asset Energy Amount	$ (2,064,517.55)	$ (38,153.53)	$ (2,102,671.08)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 329.13	$ -	$ 329.13
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,416.41)	$ -	$ (2,416.41)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 82,593.70	$ (9,631.30)	$ 72,962.40
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (40,700.24)	$ 10,982.16	$ (29,718.08)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (49,991.23)	$ 2,021,122.26	$ 1,971,131.03
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 111,551.53	$ (783.31)	$ 110,768.22
13 c	Real-Time Asset Energy Amount - Loss Component	$ (5,167.08)	$ 28.98	$ (5,138.10)
13	Real-Time Asset Energy Amount	$ 56,393.22	$ 2,020,367.93	$ 2,076,761.15
14	Real-Time Distribution of Losses Amount	$ (675,750.58)	$ -	$ (675,750.58)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 58,805.28	$ (9,091.75)	$ 49,713.53
20	Real-Time Miscellaneous Amount	$ 192,235.93	$ 10,358.70	$ 202,594.63
21	Real-time Net inadvertent Distribution	$ (120,804.06)	$ -	$ (120,804.06)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,022.27	$ -	$ 8,022.27
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 6,717.36	$ 60,346.80	$ 67,064.16
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (248.56)	$ 4,291.82	$ 4,043.26
22	Real-Time Non-Asset Energy Amount	$ 14,491.07	$ 64,638.62	$ 79,129.69
23	Real-Time Revenue Neutrality Uplift Amount	$ 330,681.35	$ (38,560.93)	$ 292,120.42
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 62,726.92	$ (7,314.62)	$ 55,412.30
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (33,210.06)	$ 25,020.32	$ (8,189.74)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (97,019.43)	$ -	$ (97,019.43)
29	Financial Transmission Rights Market Administration Amount	$ 40,536.92	$ -	$ 40,536.92
30	Financial Transmission Rights Monthly Allocation Amount	$ (83,667.83)	$ -	$ (83,667.83)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,323.55	$ (4,676.52)	$ 88,647.03
34	Real -Time Schedule 24 Allocation Amount	$ (80,695.07)	$ 102,034.84	$ 21,339.77
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 30,592.69	$ -	$ 30,592.69
37	Financial Transmission Guarantee Uplift Amount	$ (16,787.49)	$ -	$ (16,787.49)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,547,181.68	$ -	$ 2,547,181.68
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,571,169.74)	$ 23,992.35	$ (2,547,177.39)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (90,957.87)	$ -	$ (90,957.87)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 55,175.45	$ -	$ 55,175.45
43	Real Time Price Volatility Make Whole Payment	$ (116,503.07)	$ 6,477.62	$ (110,025.45)
	TOTAL MISO CHARGES	**$ 558,356.41**	**$ 9,140,371.32**	**$ 9,698,727.73**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 666,682.04**
	SCHEDULE 24 (FOR RETAIL)			**$ 109,986.80**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 8,922,058.89**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	May 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (13,086,587.61)	$ 19,557,971.27	$ 6,471,383.66
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 526,019.77	$ (143,043.35)	$ 382,976.42
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,767,793.53	$ (480,725.47)	$ 1,287,068.06
1	Day-Ahead Asset Energy Amount	$ (10,792,774.31)	$ 18,934,202.45	$ 8,141,428.14
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (10,982.49)	$ -	$ (10,982.49)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (315.23)	$ -	$ (315.23)
4	Day-Ahead Market Administration Amount	$ 682,972.06	$ (96,535.04)	$ 586,437.02
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,752,237.09)	$ -	$ (5,752,237.09)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 937,003.39	$ (254,804.30)	$ 682,199.09
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 466,646.76	$ (126,897.73)	$ 339,749.03
5	Day-Ahead Non-Asset Energy Amount	$ (4,348,586.94)	$ (381,702.03)	$ (4,730,288.97)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 10,982.49	$ -	$ 10,982.49
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 315.23	$ -	$ 315.23
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 79,507.00	$ (21,620.76)	$ 57,886.24
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (92,547.73)	$ 56,963.70	$ (35,584.03)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,222,699.28)	$ 2,096,558.79	$ 873,859.51
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 71,887.25	$ 33.00	$ 71,920.25
13 c	Real-Time Asset Energy Amount - Loss Component	$ 59,320.44	$ 112.81	$ 59,433.25
13	Real-Time Asset Energy Amount	$ (1,091,491.59)	$ 2,096,704.60	$ 1,005,213.01
14	Real-Time Distribution of Losses Amount	$ (513,384.45)	$ -	$ (513,384.45)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 60,703.52	$ (12,999.03)	$ 47,704.49
20	Real-Time Miscellaneous Amount	$ (116,506.77)	$ 10,703.99	$ (105,802.78)
21	Real-time Net inadvertent Distribution	$ 147.75	$ -	$ 147.75
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 5,416.78	$ -	$ 5,416.78
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (121.36)	$ 33,834.78	$ 33,713.42
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (414.85)	$ 38,644.97	$ 38,230.12
22	Real-Time Non-Asset Energy Amount	$ 4,880.57	$ 72,479.74	$ 77,360.31
23	Real-Time Revenue Neutrality Uplift Amount	$ 463,508.81	$ (126,044.41)	$ 337,464.40
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 143,230.20	$ (38,949.35)	$ 104,280.85
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (15,698.46)	$ (29,282.76)	$ (44,981.22)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,259,506.68)	$ -	$ (1,259,506.68)
29	Financial Transmission Rights Market Administration Amount	$ 32,748.81	$ -	$ 32,748.81
30	Financial Transmission Rights Monthly Allocation Amount	$ (150,543.49)	$ -	$ (150,543.49)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 98,029.65	$ (10,304.06)	$ 87,725.59
34	Real -Time Schedule 24 Allocation Amount	$ (79,433.57)	$ 71,901.93	$ (7,531.64)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (23,950.27)	$ -	$ (23,950.27)
37	Financial Transmission Guarantee Uplift Amount	$ 6,700.83	$ -	$ 6,700.83
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,547,181.68	$ -	$ 2,547,181.68
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,571,169.74)	$ 25,169.16	$ (2,546,000.58)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (90,957.87)	$ -	$ (90,957.87)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 55,175.45	$ -	$ 55,175.45
43	Real Time Price Volatility Make Whole Payment	$ (56,103.03)	$ 14,122.11	$ (41,980.92)
	TOTAL MISO CHARGES	**$ (17,027,868.57)**	**$ 20,564,810.25**	**$ 3,536,941.68**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 666,890.32**
	SCHEDULE 24 (FOR RETAIL)			**$ 80,193.95**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,789,857.41**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	June 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,114,597.62)	$ 17,587,348.32	$ 3,472,750.70
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 435,190.70	$ (93,361.73)	$ 341,828.97
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,674,123.01	$ (359,150.63)	$ 1,314,972.38
1	Day-Ahead Asset Energy Amount	$ (12,005,283.91)	$ 17,134,835.97	$ 5,129,552.06
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,228.23)	$ -	$ (8,228.23)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,320.69)	$ -	$ (2,320.69)
4	Day-Ahead Market Administration Amount	$ 876,227.03	$ (86,139.05)	$ 790,087.98
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,979,711.15)	$ -	$ (4,979,711.15)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 684,043.94	$ (146,748.36)	$ 537,295.58
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 638,256.19	$ (136,925.49)	$ 501,330.70
5	Day-Ahead Non-Asset Energy Amount	$ (3,657,411.02)	$ (283,673.85)	$ (3,941,084.87)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,228.23	$ -	$ 8,228.23
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,320.69	$ -	$ 2,320.69
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 63,219.85	$ (13,562.59)	$ 49,657.26
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (62,870.47)	$ 32,777.65	$ (30,092.82)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,232,387.51)	$ 1,784,877.40	$ 552,489.89
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 72,788.08	$ 1,061.47	$ 73,849.55
13 c	Real-Time Asset Energy Amount - Loss Component	$ 97,746.49	$ 609.98	$ 98,356.47
13	Real-Time Asset Energy Amount	$ (1,061,852.94)	$ 1,786,548.85	$ 724,695.91
14	Real-Time Distribution of Losses Amount	$ (650,316.74)	$ -	$ (650,316.74)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 15.07	$ -	$ 15.07
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 7.25	$ -	$ 7.25
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (15.07)	$ -	$ (15.07)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (7.25)	$ -	$ (7.25)
19	Real-Time Market Administration Amount	$ 65,146.30	$ (8,970.33)	$ 56,175.97
20	Real-Time Miscellaneous Amount	$ 212,493.08	$ 11,894.10	$ 224,387.18
21	Real-time Net inadvertent Distribution	$ 43,454.12	$ -	$ 43,454.12
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 20,701.13	$ -	$ 20,701.13
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (4,947.87)	$ 21,407.74	$ 16,459.87
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (2,843.32)	$ (31,817.32)	$ (34,660.64)
22	Real-Time Non-Asset Energy Amount	$ 12,909.94	$ (10,409.58)	$ 2,500.36
23	Real-Time Revenue Neutrality Uplift Amount	$ 158,851.88	$ (34,078.59)	$ 124,773.29
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 146,536.63	$ (31,436.59)	$ 115,100.04
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (37,234.01)	$ 32,921.90	$ (4,312.11)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,129,744.04)	$ -	$ (1,129,744.04)
29	Financial Transmission Rights Market Administration Amount	$ 43,186.77	$ -	$ 43,186.77
30	Financial Transmission Rights Monthly Allocation Amount	$ (38,352.60)	$ -	$ (38,352.60)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,765.32	$ (12,125.24)	$ 81,640.08
34	Real -Time Schedule 24 Allocation Amount	$ (82,229.02)	$ 101,962.18	$ 19,733.16
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (66,727.21)	$ -	$ (66,727.21)
37	Financial Transmission Guarantee Uplift Amount	$ 51,872.13	$ -	$ 51,872.13
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,805,216.47	$ -	$ 1,805,216.47
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,805,445.07)	$ 8,792.80	$ (1,796,652.27)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (202,033.21)	$ -	$ (202,033.21)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,882.21	$ -	$ 25,882.21
43	Real Time Price Volatility Make Whole Payment	$ (40,310.38)	$ 12,454.92	$ (27,855.46)
	TOTAL MISO CHARGES	**$ (17,241,048.89)**	**$ 18,641,792.54**	**$ 1,400,743.65**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 889,450.72**
	SCHEDULE 24 (FOR RETAIL)			**$ 101,373.24**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 409,919.69**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	July 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (12,666,821.59)	$ 19,608,408.16	$ 6,941,586.57
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,569,518.59	$ (637,898.91)	$ 2,931,619.68
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,664,374.28	$ (476,143.04)	$ 2,188,231.24
1	Day-Ahead Asset Energy Amount	$ (6,432,928.72)	$ 18,494,366.21	$ 12,061,437.49
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 10,844.82	$ -	$ 10,844.82
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (3,035.09)	$ -	$ (3,035.09)
4	Day-Ahead Market Administration Amount	$ 695,556.87	$ (62,053.30)	$ 633,503.57
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,636,433.37)	$ -	$ (6,636,433.37)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,378,480.18	$ (246,344.42)	$ 1,132,135.76
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 816,261.80	$ (145,871.91)	$ 670,389.89
5	Day-Ahead Non-Asset Energy Amount	$ (4,441,691.39)	$ (392,216.34)	$ (4,833,907.73)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (10,844.82)	$ -	$ (10,844.82)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 3,035.09	$ -	$ 3,035.09
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 55,978.72	$ (10,003.80)	$ 45,974.92
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (18,013.28)	$ 9,339.95	$ (8,673.33)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,221,316.15)	$ 1,896,329.76	$ 675,013.61
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 176,597.75	$ 74.92	$ 176,672.67
13 c	Real-Time Asset Energy Amount - Loss Component	$ 119,784.67	$ 77.31	$ 119,861.98
13	Real-Time Asset Energy Amount	$ (924,933.73)	$ 1,896,482.00	$ 971,548.27
14	Real-Time Distribution of Losses Amount	$ (1,175,922.23)	$ -	$ (1,175,922.23)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 53,676.55	$ (6,252.35)	$ 47,424.20
20	Real-Time Miscellaneous Amount	$ 170,484.76	$ 12,290.57	$ 182,775.33
21	Real-time Net inadvertent Distribution	$ (2,930.86)	$ -	$ (2,930.86)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 7,709.67	$ -	$ 7,709.67
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (419.25)	$ 80,517.29	$ 80,098.04
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (432.62)	$ 26,300.70	$ 25,868.08
22	Real-Time Non-Asset Energy Amount	$ 6,857.80	$ 106,818.00	$ 113,675.80
23	Real-Time Revenue Neutrality Uplift Amount	$ 467,688.86	$ (83,579.40)	$ 384,109.46
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 148,671.41	$ (26,568.66)	$ 122,102.75
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (72,706.96)	$ 21,851.87	$ (50,855.09)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,460,660.10)	$ -	$ (4,460,660.10)
29	Financial Transmission Rights Market Administration Amount	$ 27,042.60	$ -	$ 27,042.60
30	Financial Transmission Rights Monthly Allocation Amount	$ (137,857.43)	$ -	$ (137,857.43)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 105,021.95	$ (9,323.59)	$ 95,698.36
34	Real -Time Schedule 24 Allocation Amount	$ (93,659.66)	$ 92,047.70	$ (1,611.96)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (264,018.18)	$ -	$ (264,018.18)
37	Financial Transmission Guarantee Uplift Amount	$ 194,543.93	$ -	$ 194,543.93
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,805,216.47	$ -	$ 1,805,216.47
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,805,445.07)	$ 9,069.71	$ (1,796,375.36)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (204,112.67)	$ -	$ (204,112.67)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,882.21	$ -	$ 25,882.21
43	Real Time Price Volatility Make Whole Payment	$ (62,129.15)	$ 11,499.08	$ (50,630.07)
	TOTAL MISO CHARGES	**$ (16,340,387.30)**	**$ 20,063,767.64**	**$ 3,723,380.34**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 707,970.37**
	SCHEDULE 24 (FOR RETAIL)			**$ 94,086.40**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,921,323.57**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	August 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (10,882,366.12)	$ 16,404,588.56	$ 5,522,222.44
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,141,545.63	$ (403,815.44)	$ 1,737,730.19
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,083,104.75	$ (392,795.68)	$ 1,690,309.07
1	Day-Ahead Asset Energy Amount	$ (6,657,715.74)	$ 15,607,977.44	$ 8,950,261.70
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 7,536.97	$ -	$ 7,536.97
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,674.69)	$ -	$ (2,674.69)
4	Day-Ahead Market Administration Amount	$ 400,654.06	$ (35,211.29)	$ 365,442.77
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,730,150.72)	$ -	$ (5,730,150.72)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,254,254.16	$ (236,505.44)	$ 1,017,748.72
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 706,449.61	$ (133,209.98)	$ 573,239.63
5	Day-Ahead Non-Asset Energy Amount	$ (3,769,446.95)	$ (369,715.43)	$ (4,139,162.38)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (7,536.97)	$ -	$ (7,536.97)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,674.69	$ -	$ 2,674.69
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 60,391.61	$ (11,387.60)	$ 49,004.01
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (22,016.00)	$ 13,882.00	$ (8,134.00)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,052,482.22)	$ 1,334,147.98	$ 281,665.76
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 22,656.96	$ 22,640.53	$ 45,297.49
13 c	Real-Time Asset Energy Amount - Loss Component	$ 110,044.98	$ 72.46	$ 110,117.44
13	Real-Time Asset Energy Amount	$ (919,780.28)	$ 1,356,860.98	$ 437,080.70
14	Real-Time Distribution of Losses Amount	$ (863,775.46)	$ -	$ (863,775.46)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 25,046.11	$ (3,217.88)	$ 21,828.23
20	Real-Time Miscellaneous Amount	$ 135,961.02	$ 12,635.86	$ 148,596.88
21	Real-time Net inadvertent Distribution	$ 74,327.00	$ -	$ 74,327.00
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,686.61	$ -	$ 8,686.61
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (120,069.05)	$ (7,267.96)	$ (127,337.01)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (384.30)	$ 9,509.09	$ 9,124.79
22	Real-Time Non-Asset Energy Amount	$ (111,766.74)	$ 2,241.14	$ (109,525.60)
23	Real-Time Revenue Neutrality Uplift Amount	$ 372,318.76	$ (70,205.40)	$ 302,113.36
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 88,903.98	$ (16,763.97)	$ 72,140.01
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (38,242.65)	$ 26,992.47	$ (11,250.18)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,699,105.15)	$ -	$ (3,699,105.15)
29	Financial Transmission Rights Market Administration Amount	$ 10,435.94	$ -	$ 10,435.94
30	Financial Transmission Rights Monthly Allocation Amount	$ (200,076.68)	$ -	$ (200,076.68)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,136.38	$ (8,160.66)	$ 84,975.72
34	Real -Time Schedule 24 Allocation Amount	$ (84,546.43)	$ 105,996.12	$ 21,449.69
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (174,203.01)	$ -	$ (174,203.01)
37	Financial Transmission Guarantee Uplift Amount	$ 267,173.35	$ -	$ 267,173.35
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,805,216.47	$ -	$ 1,805,216.47
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,805,445.07)	$ 7,307.84	$ (1,798,137.23)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (203,055.76)	$ -	$ (203,055.76)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,882.21	$ -	$ 25,882.21
43	Real Time Price Volatility Make Whole Payment	$ (128,885.19)	$ 15,583.16	$ (113,302.03)
	TOTAL MISO CHARGES	**$ (15,318,614.22)**	**$ 16,634,814.79**	**$ 1,316,200.57**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 397,706.94**
	SCHEDULE 24 (FOR RETAIL)			**$ 106,425.41**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 812,068.22**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	September 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (10,619,183.75)	$ 16,237,998.12	$ 5,618,814.37
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,605,403.91	$ (313,342.59)	$ 1,292,061.32
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,770,942.42	$ (345,652.38)	$ 1,425,290.04
1	Day-Ahead Asset Energy Amount	$ (7,242,837.42)	$ 15,579,003.16	$ 8,336,165.74
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (6,828.80)	$ -	$ (6,828.80)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (5,214.50)	$ -	$ (5,214.50)
4	Day-Ahead Market Administration Amount	$ 592,456.64	$ (60,877.89)	$ 531,578.75
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,526,254.85)	$ -	$ (5,526,254.85)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 933,569.28	$ (182,213.96)	$ 751,355.32
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 807,789.05	$ (157,664.19)	$ 650,124.86
5	Day-Ahead Non-Asset Energy Amount	$ (3,784,896.52)	$ (339,878.16)	$ (4,124,774.68)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 6,828.80	$ -	$ 6,828.80
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 5,214.50	$ -	$ 5,214.50
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 54,807.01	$ (10,697.23)	$ 44,109.78
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (142,948.39)	$ 72,086.44	$ (70,861.95)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (841,420.20)	$ 1,179,016.67	$ 337,596.47
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 218,626.21	$ 0.24	$ 218,626.45
13 c	Real-Time Asset Energy Amount - Loss Component	$ 122,175.29	$ 5.07	$ 122,180.36
13	Real-Time Asset Energy Amount	$ (500,618.70)	$ 1,179,021.98	$ 678,403.28
14	Real-Time Distribution of Losses Amount	$ (805,409.36)	$ -	$ (805,409.36)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 47,334.67	$ (4,998.25)	$ 42,336.42
20	Real-Time Miscellaneous Amount	$ 254,600.63	$ 11,894.10	$ 266,494.73
21	Real-time Net inadvertent Distribution	$ 15,768.18	$ -	$ 15,768.18
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 27.23	$ -	$ 27.23
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (1.23)	$ 54,372.98	$ 54,371.75
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (25.99)	$ 37,638.77	$ 37,612.78
22	Real-Time Non-Asset Energy Amount	$ 0.01	$ 92,011.75	$ 92,011.76
23	Real-Time Revenue Neutrality Uplift Amount	$ 71,452.24	$ (13,946.04)	$ 57,506.20
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 56,155.10	$ (10,960.35)	$ 45,194.75
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (83,337.48)	$ 14,622.71	$ (68,714.77)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,525,831.06)	$ -	$ (1,525,831.06)
29	Financial Transmission Rights Market Administration Amount	$ 28,566.79	$ -	$ 28,566.79
30	Financial Transmission Rights Monthly Allocation Amount	$ (63,914.41)	$ -	$ (63,914.41)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 90,286.38	$ (9,300.06)	$ 80,986.32
34	Real -Time Schedule 24 Allocation Amount	$ (83,068.01)	$ 82,402.24	$ (665.77)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 30,121.26	$ -	$ 30,121.26
37	Financial Transmission Guarantee Uplift Amount	$ (47,374.50)	$ -	$ (47,374.50)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,337,779.21	$ -	$ 1,337,779.21
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,340,179.39)	$ 1,824.04	$ (1,338,355.35)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (198,269.67)	$ -	$ (198,269.67)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 59,727.45	$ -	$ 59,727.45
43	Real Time Price Volatility Make Whole Payment	$ (87,380.70)	$ 22,219.01	$ (65,161.69)
	TOTAL MISO CHARGES	**$ (13,267,010.04)**	**$ 16,604,427.46**	**$ 3,337,417.42**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 602,481.96**
	SCHEDULE 24 (FOR RETAIL)			**$ 80,320.55**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,654,614.91**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	October 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (8,766,927.58)	$ 12,441,406.49	$ 3,674,478.91
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,262,762.43	$ (411,408.46)	$ 1,851,353.97
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,995,030.74	$ (362,730.31)	$ 1,632,300.43
1	Day-Ahead Asset Energy Amount	$ (4,509,134.41)	$ 11,667,267.72	$ 7,158,133.31
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (7,592.48)	$ -	$ (7,592.48)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (958.82)	$ -	$ (958.82)
4	Day-Ahead Market Administration Amount	$ 687,978.31	$ (61,916.89)	$ 626,061.42
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,249,260.05)	$ -	$ (3,249,260.05)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 552,425.65	$ (100,440.32)	$ 451,985.33
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 332,517.90	$ (60,457.38)	$ 272,060.52
5	Day-Ahead Non-Asset Energy Amount	$ (2,364,316.50)	$ (160,897.70)	$ (2,525,214.20)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 7,592.48	$ -	$ 7,592.48
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 958.82	$ -	$ 958.82
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 83,205.81	$ (15,128.22)	$ 68,077.59
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (182,534.20)	$ 101,557.29	$ (80,976.91)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 39,443.49	$ 1,453,982.13	$ 1,493,425.62
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 142,719.63	$ (798.81)	$ 141,920.82
13 c	Real-Time Asset Energy Amount - Loss Component	$ 9,758.39	$ (193.33)	$ 9,565.06
13	Real-Time Asset Energy Amount	$ 191,921.51	$ 1,452,989.98	$ 1,644,911.49
14	Real-Time Distribution of Losses Amount	$ (518,123.61)	$ -	$ (518,123.61)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 33.27	$ -	$ 33.27
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 12.56	$ -	$ 12.56
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (33.27)	$ -	$ (33.27)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (12.56)	$ -	$ (12.56)
19	Real-Time Market Administration Amount	$ 63,928.30	$ (7,702.88)	$ 56,225.42
20	Real-Time Miscellaneous Amount	$ 219,979.65	$ 12,290.57	$ 232,270.22
21	Real-time Net inadvertent Distribution	$ 14,735.95	$ -	$ 14,735.95
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 64,519.87	$ -	$ 64,519.87
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 4,393.50	$ 34,439.29	$ 38,832.79
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 1,063.34	$ (5,680.43)	$ (4,617.09)
22	Real-Time Non-Asset Energy Amount	$ 69,976.71	$ 28,758.86	$ 98,735.57
23	Real-Time Revenue Neutrality Uplift Amount	$ 517,573.18	$ (94,103.55)	$ 423,469.63
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 82,118.79	$ (14,930.58)	$ 67,188.21
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (52,982.12)	$ 34,369.65	$ (18,612.47)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (426,804.42)	$ -	$ (426,804.42)
29	Financial Transmission Rights Market Administration Amount	$ 23,921.89	$ -	$ 23,921.89
30	Financial Transmission Rights Monthly Allocation Amount	$ (37,459.02)	$ -	$ (37,459.02)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 86,324.07	$ (7,788.14)	$ 78,535.93
34	Real -Time Schedule 24 Allocation Amount	$ (78,878.80)	$ 89,170.83	$ 10,292.03
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (11,499.97)	$ -	$ (11,499.97)
37	Financial Transmission Guarantee Uplift Amount	$ 29,504.90	$ -	$ 29,504.90
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,337,779.21	$ -	$ 1,337,779.21
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,340,179.39)	$ 1,781.20	$ (1,338,398.19)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (198,206.91)	$ -	$ (198,206.91)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 59,727.45	$ -	$ 59,727.45
43	Real Time Price Volatility Make Whole Payment	$ (76,259.32)	$ 17,883.18	$ (58,376.14)
	TOTAL MISO CHARGES	**$ (6,327,702.94)**	**$ 13,043,601.32**	**$ 6,715,898.38**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 706,208.73**
	SCHEDULE 24 (FOR RETAIL)			**$ 88,827.96**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,920,861.69**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	November 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,003,311.03)	$ 16,543,375.21	$ 2,540,064.18
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,905,613.83	$ 399,019.77	$ 2,304,633.60
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,348,066.64	$ 491,665.72	$ 2,839,732.36
1	Day-Ahead Asset Energy Amount	$ (9,749,630.56)	$ 17,434,060.70	$ 7,684,430.14
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,906.58	$ -	$ 1,906.58
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (63.64)	$ -	$ (63.64)
4	Day-Ahead Market Administration Amount	$ 607,514.50	$ (64,267.99)	$ 543,246.51
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,661,404.19)	$ -	$ (2,661,404.19)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 187,215.31	$ 39,201.34	$ 226,416.65
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 284,331.79	$ 59,536.72	$ 343,868.51
5	Day-Ahead Non-Asset Energy Amount	$ (2,189,857.09)	$ 98,738.06	$ (2,091,119.03)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,906.58)	$ -	$ (1,906.58)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 63.64	$ -	$ 63.64
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 66,452.30	$ 13,914.56	$ 80,366.86
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (107,080.46)	$ 58,141.09	$ (48,939.37)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (460,598.94)	$ 3,108,167.34	$ 2,647,568.40
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 92,775.38	$ (20.49)	$ 92,754.89
13 c	Real-Time Asset Energy Amount - Loss Component	$ 48,784.95	$ (8.34)	$ 48,776.61
13	Real-Time Asset Energy Amount	$ (319,038.61)	$ 3,108,138.51	$ 2,789,099.90
14	Real-Time Distribution of Losses Amount	$ (657,043.93)	$ -	$ (657,043.93)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 60,308.87	$ (12,823.95)	$ 47,484.92
20	Real-Time Miscellaneous Amount	$ 606,534.59	$ 11,894.10	$ 618,428.69
21	Real-time Net inadvertent Distribution	$ 22,346.64	$ -	$ 22,346.64
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 215.56	$ -	$ 215.56
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (97.86)	$ (19,475.96)	$ (19,573.82)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (39.83)	$ 162.17	$ 122.34
22	Real-Time Non-Asset Energy Amount	$ 77.87	$ (19,313.79)	$ (19,235.92)
23	Real-Time Revenue Neutrality Uplift Amount	$ (70,454.99)	$ (14,752.69)	$ (85,207.68)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 82,598.89	$ 17,295.52	$ 99,894.41
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (108,771.54)	$ 56,398.90	$ (52,372.64)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,169,823.12)	$ -	$ (1,169,823.12)
29	Financial Transmission Rights Market Administration Amount	$ 19,570.56	$ -	$ 19,570.56
30	Financial Transmission Rights Monthly Allocation Amount	$ (42,276.61)	$ -	$ (42,276.61)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 84,740.12	$ (8,959.83)	$ 75,780.29
34	Real -Time Schedule 24 Allocation Amount	$ (74,091.80)	$ 81,860.75	$ 7,768.95
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (68,725.91)	$ -	$ (68,725.91)
37	Financial Transmission Guarantee Uplift Amount	$ 73,143.23	$ -	$ 73,143.23
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,337,779.21	$ -	$ 1,337,779.21
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,340,179.39)	$ 1,895.17	$ (1,338,284.22)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (198,218.84)	$ -	$ (198,218.84)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 59,727.45	$ -	$ 59,727.45
43	Real Time Price Volatility Make Whole Payment	$ (47,620.76)	$ 10,285.11	$ (37,335.65)
	TOTAL MISO CHARGES	**$ (13,122,019.38)**	**$ 20,772,504.22**	**$ 7,650,484.84**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 610,301.99**
	SCHEDULE 24 (FOR RETAIL)			**$ 83,549.24**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,956,633.61**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	December 2019 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (11,711,719.33)	$ 15,366,833.74	$ 3,655,114.41
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,545,634.06	$ (315,459.95)	$ 1,230,174.11
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,301,715.99	$ (469,774.33)	$ 1,831,941.66
1	Day-Ahead Asset Energy Amount	$ (7,864,369.28)	$ 14,581,599.46	$ 6,717,230.18
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 10,460.62	$ -	$ 10,460.62
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 212.07	$ -	$ 212.07
4	Day-Ahead Market Administration Amount	$ 780,267.99	$ (69,497.81)	$ 710,770.18
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,783,955.25)	$ -	$ (2,783,955.25)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (4,671.77)	$ 953.50	$ (3,718.27)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 229,674.02	$ (46,875.88)	$ 182,798.14
5	Day-Ahead Non-Asset Energy Amount	$ (2,558,953.00)	$ (45,922.38)	$ (2,604,875.38)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (10,460.62)	$ -	$ (10,460.62)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (212.07)	$ -	$ (212.07)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 69,143.39	$ (14,111.99)	$ 55,031.40
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (108,131.14)	$ 35,532.30	$ (72,598.84)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 110,686.34	$ 1,637,301.56	$ 1,747,987.90
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (778.56)	$ (203.62)	$ (982.18)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 16,816.94	$ (3.27)	$ 16,813.67
13	Real-Time Asset Energy Amount	$ 126,724.72	$ 1,637,094.67	$ 1,763,819.39
14	Real-Time Distribution of Losses Amount	$ (912,334.22)	$ -	$ (912,334.22)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -
19	Real-Time Market Administration Amount	$ 65,004.23	$ (10,024.89)	$ 54,979.34
20	Real-Time Miscellaneous Amount	$ 117,351.45	$ 12,290.57	$ 129,642.02
21	Real-time Net inadvertent Distribution	$ 14,831.50	$ -	$ 14,831.50
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (1,012.53)	$ -	$ (1,012.53)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 997.68	$ (12,914.89)	$ (11,917.21)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 16.02	$ (2,356.92)	$ (2,340.90)
22	Real-Time Non-Asset Energy Amount	$ 1.17	$ (15,271.81)	$ (15,270.64)
23	Real-Time Revenue Neutrality Uplift Amount	$ 352,729.16	$ (71,991.12)	$ 280,738.04
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 41,494.97	$ (8,469.02)	$ 33,025.95
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (59,419.98)	$ 38,925.77	$ (20,494.21)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (636,844.90)	$ -	$ (636,844.90)
29	Financial Transmission Rights Market Administration Amount	$ 24,626.30	$ -	$ 24,626.30
30	Financial Transmission Rights Monthly Allocation Amount	$ (39,365.46)	$ -	$ (39,365.46)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 98,214.55	$ (8,725.25)	$ 89,489.30
34	Real -Time Schedule 24 Allocation Amount	$ (67,971.70)	$ 86,968.43	$ 18,996.73
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (89,773.02)	$ -	$ (89,773.02)
37	Financial Transmission Guarantee Uplift Amount	$ 82,954.80	$ -	$ 82,954.80
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,123,444.70	$ -	$ 1,123,444.70
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,123,867.22)	$ 54,964.25	$ (1,068,902.97)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (207,296.32)	$ -	$ (207,296.32)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,660.70	$ -	$ 42,660.70
43	Real Time Price Volatility Make Whole Payment	$ (48,182.59)	$ 11,560.86	$ (36,621.73)
	TOTAL MISO CHARGES	**$ (10,777,059.20)**	**$ 16,214,922.04**	**$ 5,437,862.84**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 790,375.82**
	SCHEDULE 24 (FOR RETAIL)			**$ 108,486.03**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,539,000.99**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	July 2018 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (6,427,342.24)	$ 16,534,795.62	$ 10,107,453.38	$ 7,483,025.42
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,927,202.34	$ (424,723.22)	$ 2,502,479.12	$ 1,852,703.56
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (3,039.31)	$ -	$ (3,039.31)	$ (2,250.14)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (7,596,662.58)	$ -	$ (7,596,662.58)	$ (5,624,168.33)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 878,685.81	$ (127,493.16)	$ 751,192.65	$ 556,143.42
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 3,039.31	$ -	$ 3,039.31	$ 2,250.14
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,304,549.72)	$ 2,223,458.47	$ 918,908.75	$ 680,311.58
13 c	Real-Time Asset Energy Amount - Loss Component	$ 123,291.50	$ 210.50	$ 123,502.00	$ 91,434.36
14	Real-Time Distribution of Losses Amount	$ (1,424,393.71)	$ -	$ (1,424,393.71)	$ (1,054,545.98)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 5.08	$ -	$ 5.08	$ 3.76
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (5.08)	$ -	$ (5.08)	$ (3.76)
21	Real-time Net inadvertent Distribution	$ 220,572.75	$ -	$ 220,572.75	$ 163,300.43
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 11,829.92	$ -	$ 11,829.92	$ 8,758.25
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,450.74)	$ 25,909.37	$ 24,458.63	$ 18,107.88
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,614,903.69	$ (234,314.89)	$ 1,380,588.80	$ 1,022,115.13
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,295.10)	$ -	$ (8,295.10)	$ (6,141.25)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 992,591.94	$ (144,020.40)	$ 848,571.54	$ 628,237.62
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,295.10	$ -	$ 8,295.10	$ 6,141.25
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 132,109.20	$ 329.05	$ 132,438.25	$ 98,050.30
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 3.27	$ -	$ 3.27	$ 2.42
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (3.27)	$ -	$ (3.27)	$ (2.42)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (2,267.85)	$ 20,829.58	$ 18,561.73	$ 13,742.13
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,712,847.13)	$ -	$ (2,712,847.13)	$ (2,008,448.94)
30	Financial Transmission Rights Monthly Allocation Amount	$ (3,582.30)	$ -	$ (3,582.30)	$ (2,652.15)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (17,821.32)	$ -	$ (17,821.32)	$ (13,193.97)
37	Financial Transmission Guarantee Uplift Amount	$ 17,801.92	$ -	$ 17,801.92	$ 13,179.60
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 185,822.99	$ (26,962.04)	$ 158,860.95	$ 117,612.27
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 39,382.90	$ (5,714.27)	$ 33,668.63	$ 24,926.48
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (28,978.79)	$ 27,159.57	$ (1,819.22)	$ (1,346.85)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 413,559.57	$ (60,005.54)	$ 353,554.03	$ 261,752.76
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (209,141.97)	$ 129,812.92	$ (79,329.05)	$ (58,731.04)
43	Real Time Price Volatility Make Whole Payment	$ (99,729.82)	$ 18,768.89	$ (80,960.93)	$ (59,939.20)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 656,616.55	$ (45,158.58)	$ 611,457.97	$ 452,691.23
19	Real-Time Market Administration Amount	$ 50,704.08	$ (6,262.88)	$ 44,441.20	$ 32,901.92
29	Financial Transmission Rights Market Administration Amount	$ 20,096.24	$ -	$ 20,096.24	$ 14,878.20
33	Day-Ahead Schedule 24 Allocation Amount	$ 96,499.39	$ (6,492.24)	$ 90,007.15	$ 66,636.55
34	Real -Time Schedule 24 Allocation Amount	$ (84,960.45)	$ 73,927.61	$ (11,032.84)	$ (8,168.13)
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	$ 321,960.64	$ 10,703.99	$ 332,664.63	$ 246,287.35
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,270,304.83	$ -	$ 2,270,304.83	$ 1,680,813.96
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,293,458.77)	$ 2,407.08	$ (2,291,051.69)	$ (1,696,173.84)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (320,148.19)	$ -	$ (320,148.19)	$ (237,020.84)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 41,430.89	$ -	$ 41,430.89	$ 30,673.25
	TOTAL MISO CHARGES	**$ (11,511,968.43)**	**$ 17,987,165.43**	**$ 6,475,197.00**	**$ 4,793,894.36**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 675,995.41**	**$ 500,471.35**
	SCHEDULE 24 (FOR RETAIL)			**$ 78,974.31**	**$ 58,468.41**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,720,227.28**	**$ 4,234,954.60**

Docket No. E999/AA-20-171
Part J, Section 5
Schedule 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

			System		Intersystem		System Retail		Minnesota Retail
August 2018 Actual									
Energy and Loss Charges									
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	477,154.64	$	8,672,225.62	$	9,149,380.26	$	6,703,546.30
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	3,087,706.54	$	(247,535.48)	$	2,840,171.06	$	2,080,929.82
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	(2,912.34)	$	-	$	(2,912.34)	$	(2,133.81)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(7,564,303.08)	$	-	$	(7,564,303.08)	$	(5,542,195.70)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	926,635.36	$	(74,286.57)	$	852,348.79	$	624,496.90
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	2,912.35	$	-	$	2,912.35	$	2,133.81
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	(1,123,121.63)	$	1,593,747.70	$	470,626.07	$	344,817.20
13 c	Real-Time Asset Energy Amount - Loss Component	$	260,532.92	$	293.57	$	260,826.49	$	191,101.74
14	Real-Time Distribution of Losses Amount	$	(1,289,052.28)	$	-	$	(1,289,052.28)	$	(944,459.78)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	97.69	$	-	$	97.69	$	71.58
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	(97.69)	$	-	$	(97.69)	$	(71.58)
21	Real-time Net inadvertent Distribution	$	11,705.02	$	-	$	11,705.02	$	8,576.01
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	53,103.24	$	-	$	53,103.24	$	38,907.56
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	(3,661.95)	$	23,964.86	$	20,302.91	$	14,875.49
Congestion Related Charges									
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	667,548.79	$	(53,516.10)	$	614,032.69	$	449,888.02
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	848.86	$	-	$	848.86	$	621.94
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	647,075.01	$	(51,874.76)	$	595,200.25	$	436,089.92
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(848.86)	$	-	$	(848.86)	$	(621.94)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	527,854.56	$	64.44	$	527,919.00	$	386,794.44
15	Real-Time Financial Bilateral Transaction Congestion Amount	$	328.84	$	-	$	328.84	$	240.93
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$	(328.84)	$	-	$	(328.84)	$	(240.93)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$	(803.75)	$	46,513.78	$	45,710.03	$	33,490.71
FTR Related Charges									
28	Financial Transmission Rights Hourly Allocation Amount	$	(834,866.42)	$	-	$	(834,866.42)	$	(611,687.96)
30	Financial Transmission Rights Monthly Allocation Amount	$	(37,459.65)	$	-	$	(37,459.65)	$	(27,445.85)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$	-	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	(5,682.10)	$	-	$	(5,682.10)	$	(4,163.15)
37	Financial Transmission Guarantee Uplift Amount	$	5,183.65	$	-	$	5,183.65	$	3,797.94
38	Financial Transmission Rights Monthly Transaction Amount	$	-	$	-	$	-	$	-
Uplift (RNU) Charges									
23	Real-Time Revenue Neutrality Uplift Amount	$	53,787.45	$	(4,312.04)	$	49,475.41	$	36,249.53
Revenue Sufficiency Guarantee (RSG) Charges									
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	63,525.61	$	(5,092.73)	$	58,432.88	$	42,812.47
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(30,490.54)	$	62,347.80	$	31,857.26	$	23,341.10
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	213,019.94	$	(17,077.40)	$	195,942.54	$	143,562.72
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(99,818.34)	$	112,764.97	$	12,946.63	$	9,485.71
43	Real Time Price Volatility Make Whole Payment	$	(36,231.99)	$	9,149.72	$	(27,082.27)	$	(19,842.57)
Market Administration Charges									
4	Day-Ahead Market Administration Amount	$	537,904.16	$	(20,001.83)	$	517,902.33	$	379,455.46
19	Real-Time Market Administration Amount	$	38,818.57	$	(3,745.54)	$	35,073.03	$	25,697.22
29	Financial Transmission Rights Market Administration Amount	$	18,087.28	$	-	$	18,087.28	$	13,252.15
33	Day-Ahead Schedule 24 Allocation Amount	$	96,356.87	$	(3,559.35)	$	92,797.52	$	67,990.67
34	Real -Time Schedule 24 Allocation Amount	$	(69,865.97)	$	84,904.57	$	15,038.60	$	11,018.45
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	$	96,039.80	$	10,703.99	$	106,743.79	$	78,208.79
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-	$	-
Auction Revenue Rights (ARR)									
39	Auction Revenue Rights - FTR Auction Transactions	$	2,270,304.83	$	-	$	2,270,304.83	$	1,663,401.58
40	Auction Revenue Rights - Monthly ARR Revenue	$	(2,293,458.77)	$	10,397.76	$	(2,283,061.01)	$	(1,672,747.74)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(320,148.49)	$	-	$	(320,148.49)	$	(234,565.64)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	41,430.89	$	-	$	41,430.89	$	30,355.49
	TOTAL MISO CHARGES	**$**	**(3,615,189.82)**	**$**	**10,146,076.99**	**$**	**6,530,887.17**	**$**	**4,785,034.98**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**571,062.64**	**$**	**418,404.83**
	SCHEDULE 24 (FOR RETAIL)					**$**	**107,836.12**	**$**	**79,009.11**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**5,851,988.41**	**$**	**4,287,621.04**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	September 2018 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (7,186,012.70)	$ 14,250,345.33	$ 7,064,332.63	$ 5,179,057.66
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,204,337.92	$ (337,543.05)	$ 1,866,794.87	$ 1,368,598.96
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (6,980.25)	$ -	$ (6,980.25)	$ (5,117.41)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,655,205.04)	$ -	$ (6,655,205.04)	$ (4,879,114.90)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 817,936.28	$ (125,247.90)	$ 692,688.38	$ 507,829.01
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 6,980.25	$ -	$ 6,980.25	$ 5,117.41
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,167,857.12	$ 1,707,309.96	$ 2,875,167.08	$ 2,107,864.52
13 c	Real-Time Asset Energy Amount - Loss Component	$ 24,291.11	$ 107.87	$ 24,398.98	$ 17,887.57
14	Real-Time Distribution of Losses Amount	$ (1,026,632.15)	$ -	$ (1,026,632.15)	$ (752,652.43)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (92,059.80)	$ -	$ (92,059.80)	$ (67,491.59)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 4,230.60	$ -	$ 4,230.60	$ 3,101.57
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (704.45)	$ 5,627.93	$ 4,923.48	$ 3,609.54
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 448,282.98	$ (68,644.11)	$ 379,638.87	$ 278,323.76
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (18,283.58)	$ -	$ (18,283.58)	$ (13,404.20)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 894,184.74	$ (136,923.58)	$ 757,261.16	$ 555,169.10
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 18,283.58	$ -	$ 18,283.58	$ 13,404.20
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 171,379.30	$ 32.21	$ 171,411.51	$ 125,666.52
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	$ (210.35)	$ 38,501.34	$ 38,290.99	$ 28,072.19
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (503,905.53)	$ -	$ (503,905.53)	$ (369,427.08)
30	Financial Transmission Rights Monthly Allocation Amount	$ (44,253.83)	$ -	$ (44,253.83)	$ (32,443.71)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 5,818.31	$ -	$ 5,818.31	$ 4,265.56
37	Financial Transmission Guarantee Uplift Amount	$ (5,065.14)	$ -	$ (5,065.14)	$ (3,713.39)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 28,294.23	$ (4,332.60)	$ 23,961.63	$ 17,566.93
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 62,311.02	$ (9,541.48)	$ 52,769.54	$ 38,686.81
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (39,059.66)	$ 32,926.20	$ (6,133.46)	$ (4,496.61)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 357,710.30	$ (54,775.01)	$ 302,935.29	$ 222,090.24
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (178,197.87)	$ 108,960.59	$ (69,237.28)	$ (50,759.77)
43	Real Time Price Volatility Make Whole Payment	$ (162,966.54)	$ 12,531.14	$ (150,435.40)	$ (110,288.35)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 647,893.53	$ (48,001.57)	$ 599,891.96	$ 439,797.39
19	Real-Time Market Administration Amount	$ 56,094.68	$ (5,266.24)	$ 50,828.44	$ 37,263.74
29	Financial Transmission Rights Market Administration Amount	$ 16,066.00	$ -	$ 16,066.00	$ 11,778.43
33	Day-Ahead Schedule 24 Allocation Amount	$ 107,122.00	$ (7,424.82)	$ 99,697.18	$ 73,090.76
34	Real -Time Schedule 24 Allocation Amount	$ (93,731.13)	$ 90,652.58	$ (3,078.55)	$ (2,256.97)
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	$ 202,080.96	$ 10,358.70	$ 212,439.66	$ 155,745.39
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,189,565.60	$ -	$ 2,189,565.60	$ 1,605,231.11
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,190,703.62)	$ 10,541.26	$ (2,180,162.36)	$ (1,598,337.33)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (242,965.26)	$ -	$ (242,965.26)	$ (178,124.55)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 130,420.69	$ -	$ 130,420.69	$ 95,615.02
	TOTAL MISO CHARGES	**$ (8,885,795.70)**	**$ 15,470,194.75**	**$ 6,584,399.05**	**$ 4,827,205.07**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 666,786.40**	**$ 488,839.55**
	SCHEDULE 24 (FOR RETAIL)			**$ 96,618.63**	**$ 70,833.79**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,820,994.02**	**$ 4,267,531.73**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
October 2018 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (6,997,648.67)	$ 10,453,243.68	$ 3,455,595.01	$ 2,479,405.87
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,770,216.27	$ (243,830.52)	$ 2,526,385.75	$ 1,812,693.80
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (90.81)	$ -	$ (90.81)	$ (65.16)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,536,574.59)	$ -	$ (6,536,574.59)	$ (4,690,023.38)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 527,103.28	$ (46,394.89)	$ 480,708.39	$ 344,910.56
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 90.81	$ -	$ 90.81	$ 65.16
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 7,557,082.03	$ 1,306,700.28	$ 8,863,782.31	$ 6,359,806.00
13 c	Real-Time Asset Energy Amount - Loss Component	$ 2,611.07	$ 1.37	$ 2,612.44	$ 1,874.44
14	Real-Time Distribution of Losses Amount	$ (922,125.28)	$ -	$ (922,125.28)	$ (661,629.28)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 1.14	$ -	$ 1.14	$ 0.82
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (1.14)	$ -	$ (1.14)	$ (0.82)
21	Real-time Net inadvertent Distribution	$ 77,626.14	$ -	$ 77,626.14	$ 55,697.12
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (6,182.61)	$ -	$ (6,182.61)	$ (4,436.05)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (15.55)	$ (2,681.33)	$ (2,696.88)	$ (1,935.02)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 348,422.11	$ (30,667.62)	$ 317,754.49	$ 227,990.36
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (50.24)	$ -	$ (50.24)	$ (36.05)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 260,094.46	$ (22,893.15)	$ 237,201.31	$ 170,193.07
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 50.24	$ -	$ 50.24	$ 36.05
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 46,300.57	$ 1.73	$ 46,302.30	$ 33,222.12
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 6.22	$ -	$ 6.22	$ 4.46
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (6.22)	$ -	$ (6.22)	$ (4.46)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (19.68)	$ 1,700.18	$ 1,680.50	$ 1,205.77
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (80,434.15)	$ -	$ (80,434.15)	$ (57,711.89)
30	Financial Transmission Rights Monthly Allocation Amount	$ (48,652.72)	$ -	$ (48,652.72)	$ (34,908.56)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (25,345.74)	$ -	$ (25,345.74)	$ (18,185.69)
37	Financial Transmission Guarantee Uplift Amount	$ 25,337.71	$ -	$ 25,337.71	$ 18,179.93
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 655,240.42	$ (57,673.34)	$ 597,567.08	$ 428,757.23
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 98,385.96	$ (8,659.79)	$ 89,726.17	$ 64,378.95
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (15,835.89)	$ 33,357.48	$ 17,521.59	$ 12,571.82
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 271,236.87	$ (23,873.89)	$ 247,362.98	$ 177,484.12
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (300,760.84)	$ 127,695.78	$ (173,065.06)	$ (124,175.00)
43	Real Time Price Volatility Make Whole Payment	$ (43,614.46)	$ 15,386.86	$ (28,227.60)	$ (20,253.44)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 783,368.61	$ (39,523.79)	$ 743,844.82	$ 533,712.20
19	Real-Time Market Administration Amount	$ 52,710.27	$ (6,406.62)	$ 46,303.65	$ 33,223.09
29	Financial Transmission Rights Market Administration Amount	$ 14,516.00	$ -	$ 14,516.00	$ 10,415.30
33	Day-Ahead Schedule 24 Allocation Amount	$ 103,289.24	$ (4,967.40)	$ 98,321.84	$ 70,546.39
34	Real -Time Schedule 24 Allocation Amount	$ (84,513.82)	$ 88,003.93	$ 3,490.11	$ 2,504.17
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	$ 96,275.38	$ 10,703.99	$ 106,979.37	$ 76,758.21
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,189,565.60	$ -	$ 2,189,565.60	$ 1,571,023.74
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,190,703.62)	$ (5,093.26)	$ (2,195,796.88)	$ (1,575,494.71)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (242,964.65)	$ -	$ (242,964.65)	$ (174,328.29)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 130,420.69	$ -	$ 130,420.69	$ 93,577.47
	TOTAL MISO CHARGES	**$ (1,485,589.59)**	**$ 11,544,129.69**	**$ 10,058,540.10**	**$ 7,217,050.40**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 804,664.47**	**$ 577,350.59**
	SCHEDULE 24 (FOR RETAIL)			**$ 101,811.95**	**$ 73,050.56**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 9,152,063.68**	**$ 6,566,649.26**

Docket No. E999/AA-20-171
Part J, Section 5
Schedule 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	November 2018 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (15,227,576.71)	$ 19,512,393.65	$ 4,284,816.94	$ 3,062,803.86
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,607,922.75	$ (656,578.81)	$ 2,951,343.94	$ 2,109,632.16
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,345.74	$ -	$ 2,345.74	$ 1,676.74
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,876,510.04)	$ -	$ (3,876,510.04)	$ (2,770,944.50)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 277,707.87	$ (50,537.97)	$ 227,169.90	$ 162,381.93
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,345.74)	$ -	$ (2,345.74)	$ (1,676.74)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 146,572.78	$ 2,346,024.11	$ 2,492,596.89	$ 1,781,717.98
13 c	Real-Time Asset Energy Amount - Loss Component	$ (16,823.34)	$ (0.16)	$ (16,823.50)	$ (12,025.50)
14	Real-Time Distribution of Losses Amount	$ (1,121,300.12)	$ -	$ (1,121,300.12)	$ (801,509.70)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (107,138.55)	$ -	$ (107,138.55)	$ (76,583.05)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (721.25)	$ -	$ (721.25)	$ (515.55)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 0.86	$ (3,484.22)	$ (3,483.36)	$ (2,489.92)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 187,285.79	$ (34,082.74)	$ 153,203.05	$ 109,510.14
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (7,269.33)	$ -	$ (7,269.33)	$ (5,196.15)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 185,495.14	$ (33,756.87)	$ 151,738.27	$ 108,463.11
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 7,269.33	$ -	$ 7,269.33	$ 5,196.15
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (23,629.14)	$ (0.95)	$ (23,630.09)	$ (16,890.88)
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	$ 5.20	$ 2,006.10	$ 2,011.30	$ 1,437.69
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ 151,905.71	$ -	$ 151,905.71	$ 108,582.79
30	Financial Transmission Rights Monthly Allocation Amount	$ (16,516.41)	$ -	$ (16,516.41)	$ (11,805.99)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 40,298.85	$ -	$ 40,298.85	$ 28,805.78
37	Financial Transmission Guarantee Uplift Amount	$ (40,641.55)	$ -	$ (40,641.55)	$ (29,050.74)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 295,464.55	$ (53,769.38)	$ 241,695.17	$ 172,764.65
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 111,056.42	$ (20,210.33)	$ 90,846.09	$ 64,937.14
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (76,788.74)	$ 72,089.54	$ (4,699.20)	$ (3,359.01)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 169,296.50	$ (30,809.00)	$ 138,487.50	$ 98,991.40
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (378,364.21)	$ 233,878.08	$ (144,486.13)	$ (103,279.25)
43	Real Time Price Volatility Make Whole Payment	$ (76,569.25)	$ 7,590.31	$ (68,978.94)	$ (49,306.42)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 894,534.22	$ (79,283.01)	$ 815,251.21	$ 582,744.74
19	Real-Time Market Administration Amount	$ 62,294.73	$ (10,955.16)	$ 51,339.57	$ 36,697.72
29	Financial Transmission Rights Market Administration Amount	$ 8,686.24	$ -	$ 8,686.24	$ 6,208.96
33	Day-Ahead Schedule 24 Allocation Amount	$ 103,860.95	$ (9,527.73)	$ 94,333.22	$ 67,429.75
34	Real -Time Schedule 24 Allocation Amount	$ (80,773.56)	$ 92,398.49	$ 11,624.93	$ 8,309.55
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	$ 173,251.92	$ 10,358.70	$ 183,610.62	$ 131,245.59
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,189,565.60	$ -	$ 2,189,565.60	$ 1,565,110.03
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,190,703.62)	$ 2,677.80	$ (2,188,025.82)	$ (1,564,009.39)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (242,964.65)	$ -	$ (242,964.65)	$ (173,672.08)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 130,420.69	$ -	$ 130,420.69	$ 93,225.22
	TOTAL MISO CHARGES	**$ (14,741,394.37)**	**$ 21,296,420.47**	**$ 6,555,026.10**	**$ 4,685,558.22**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 875,277.02**	**$ 625,651.43**
	SCHEDULE 24 (FOR RETAIL)			**$ 105,958.15**	**$ 75,739.30**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,573,790.93**	**$ 3,984,167.49**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
December 2018 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (10,555,045.51)	$ 14,191,971.52	$ 3,636,926.01	$ 2,601,716.65
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,762,248.39	$ (557,353.31)	$ 3,204,895.08	$ 2,292,658.38
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,013.71	$ -	$ 3,013.71	$ 2,155.89
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,534,295.08)	$ -	$ (3,534,295.08)	$ (2,528,298.44)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 303,202.87	$ (44,917.59)	$ 258,285.28	$ 184,767.33
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,013.71)	$ -	$ (3,013.71)	$ (2,155.89)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (245,591.13)	$ 2,325,052.41	$ 2,079,461.28	$ 1,487,566.43
13 c	Real-Time Asset Energy Amount - Loss Component	$ 15,682.86	$ 5.08	$ 15,687.94	$ 11,222.55
14	Real-Time Distribution of Losses Amount	$ (1,240,909.23)	$ -	$ (1,240,909.23)	$ (887,698.62)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 3.23	$ -	$ 3.23	$ 2.31
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (3.23)	$ -	$ (3.23)	$ (2.31)
21	Real-time Net inadvertent Distribution	$ 99,169.58	$ -	$ 99,169.58	$ 70,942.09
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 5,131.23	$ -	$ 5,131.23	$ 3,670.68
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (34.32)	$ (281.33)	$ (315.65)	$ (225.81)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,507,770.72	$ (223,366.70)	$ 1,284,404.02	$ 918,813.12
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (878.41)	$ -	$ (878.41)	$ (628.38)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 158,918.96	$ (23,542.84)	$ 135,376.12	$ 96,842.86
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 878.41	$ -	$ 878.41	$ 628.38
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 58,537.78	$ (0.39)	$ 58,537.39	$ 41,875.39
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 12.93	$ -	$ 12.93	$ 9.25
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (12.93)	$ -	$ (12.93)	$ (9.25)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 2.66	$ (1,511.70)	$ (1,509.04)	$ (1,079.51)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,167,361.77)	$ -	$ (1,167,361.77)	$ (835,085.60)
30	Financial Transmission Rights Monthly Allocation Amount	$ (80,110.50)	$ -	$ (80,110.50)	$ (57,307.96)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (97,314.32)	$ -	$ (97,314.32)	$ (69,614.91)
37	Financial Transmission Guarantee Uplift Amount	$ 94,933.31	$ -	$ 94,933.31	$ 67,911.63
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 484,100.39	$ (71,716.41)	$ 412,383.98	$ 295,003.60
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 119,041.48	$ (17,635.24)	$ 101,406.24	$ 72,542.11
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (113,726.60)	$ 38,216.52	$ (75,510.08)	$ (54,017.00)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 117,415.06	$ (17,394.30)	$ 100,020.76	$ 71,551.00
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (195,033.76)	$ 109,356.57	$ (85,677.19)	$ (61,290.16)
43	Real Time Price Volatility Make Whole Payment	$ (38,980.18)	$ 10,485.88	$ (28,494.30)	$ (20,383.72)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 664,578.14	$ (43,489.12)	$ 621,089.02	$ 444,303.14
19	Real-Time Market Administration Amount	$ 48,738.53	$ (9,532.65)	$ 39,205.88	$ 28,046.37
29	Financial Transmission Rights Market Administration Amount	$ 15,955.28	$ -	$ 15,955.28	$ 11,413.79
33	Day-Ahead Schedule 24 Allocation Amount	$ 98,245.53	$ (6,421.29)	$ 91,824.24	$ 65,687.52
34	Real -Time Schedule 24 Allocation Amount	$ (82,037.24)	$ 86,910.38	$ 4,873.14	$ 3,486.06
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	$ 369,744.02	$ 10,703.99	$ 380,448.01	$ 272,157.84
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,791,300.13	$ -	$ 1,791,300.13	$ 1,281,427.05
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,791,548.83)	$ 3,108.27	$ (1,788,440.56)	$ (1,279,381.42)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (155,089.36)	$ -	$ (155,089.36)	$ (110,944.95)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,374.37	$ -	$ 42,374.37	$ 30,312.99
	TOTAL MISO CHARGES	**$ (9,539,986.54)**	**$ 15,758,647.75**	**$ 6,218,661.21**	**$ 4,448,590.47**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 676,250.18**	**$ 483,763.31**
	SCHEDULE 24 (FOR RETAIL)			**$ 96,697.38**	**$ 69,173.58**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,445,713.65**	**$ 3,895,653.59**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
January 2019 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (3,121,529.45)	$ 14,335,930.92	$ 11,214,401.47	$ 7,980,910.86
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,488,042.21	$ (509,367.71)	$ 2,978,674.50	$ 2,119,822.07
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,797.62	$ -	$ 1,797.62	$ 1,279.31
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,760,059.53)	$ -	$ (2,760,059.53)	$ (1,964,241.17)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 213,462.82	$ (31,172.52)	$ 182,290.30	$ 129,729.85
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,797.62)	$ -	$ (1,797.62)	$ (1,279.31)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,675,988.00)	$ 2,628,609.32	$ 952,621.32	$ 677,948.43
13 c	Real-Time Asset Energy Amount - Loss Component	$ (81,323.02)	$ (0.01)	$ (81,323.03)	$ (57,874.85)
14	Real-Time Distribution of Losses Amount	$ (1,146,336.64)	$ -	$ (1,146,336.64)	$ (815,809.08)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (50,899.18)	$ -	$ (50,899.18)	$ (36,223.23)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 1,842.64	$ -	$ 1,842.64	$ 1,311.34
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 0.04	$ (797.11)	$ (797.07)	$ (567.25)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,996,616.80	$ (291,571.05)	$ 1,705,045.75	$ 1,213,423.49
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 11,650.90	$ -	$ 11,650.90	$ 8,291.55
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (35,883.01)	$ 5,240.09	$ (30,642.92)	$ (21,807.53)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (11,650.90)	$ -	$ (11,650.90)	$ (8,291.55)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (168,205.37)	$ (0.01)	$ (168,205.38)	$ (119,706.09)
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	$ 0.05	$ (20,547.83)	$ (20,547.78)	$ (14,623.16)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (381,905.51)	$ -	$ (381,905.51)	$ (271,789.26)
30	Financial Transmission Rights Monthly Allocation Amount	$ (90,157.52)	$ -	$ (90,157.52)	$ (64,162.06)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (426,287.70)	$ -	$ (426,287.70)	$ (303,374.56)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 435,503.09	$ -	$ 435,503.09	$ 309,932.84
37	Financial Transmission Guarantee Uplift Amount	$ (473,346.96)	$ -	$ (473,346.96)	$ (336,865.05)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 11,044.93	$ (1,612.92)	$ 9,432.01	$ 6,712.44
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 90,772.12	$ (13,255.68)	$ 77,516.44	$ 55,165.83
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (88,258.02)	$ 55,618.70	$ (32,639.32)	$ (23,228.30)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 64,030.81	$ (9,350.58)	$ 54,680.23	$ 38,914.07
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (114,702.05)	$ (5,564.92)	$ (120,266.97)	$ (85,589.94)
43	Real Time Price Volatility Make Whole Payment	$ (55,970.79)	$ 11,208.30	$ (44,762.49)	$ (31,855.95)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 428,143.14	$ (30,063.74)	$ 398,079.40	$ 283,299.67
19	Real-Time Market Administration Amount	$ 29,413.76	$ (4,356.47)	$ 25,057.29	$ 17,832.43
29	Financial Transmission Rights Market Administration Amount	$ 29,176.72	$ -	$ 29,176.72	$ 20,764.09
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,842.77	$ (6,518.07)	$ 87,324.70	$ 62,146.04
34	Real -Time Schedule 24 Allocation Amount	$ (78,210.62)	$ 84,211.35	$ 6,000.73	$ 4,270.52
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	$ 48,986.87	$ 10,703.99	$ 59,690.86	$ 42,479.97
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,791,300.13	$ -	$ 1,791,300.13	$ 1,274,807.82
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,791,548.83)	$ 116,443.80	$ (1,675,105.03)	$ (1,192,115.69)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (153,246.61)	$ -	$ (153,246.61)	$ (109,060.44)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,389.67	$ -	$ 42,389.67	$ 30,167.30
	TOTAL MISO CHARGES	**$ (3,929,290.24)**	**$ 16,323,787.85**	**$ 12,394,497.61**	**$ 8,820,745.44**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 452,313.41**	**$ 321,896.18**
	SCHEDULE 24 (FOR RETAIL)			**$ 93,325.43**	**$ 66,416.56**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 11,848,858.77**	**$ 8,432,432.70**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

			System		Intersystem		System Retail		Minnesota Retail
	February 2019 Actual								
Energy and Loss Charges									
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	(7,044,275.35)	$	12,297,020.88	$	5,252,745.53	$	3,722,896.53
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	2,693,104.17	$	(574,269.71)	$	2,118,834.46	$	1,501,729.23
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	7,326.99	$	-	$	7,326.99	$	5,193.02
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(2,963,666.07)	$	-	$	(2,963,666.07)	$	(2,100,505.74)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	55,088.20	$	(11,746.85)	$	43,341.35	$	30,718.29
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	(7,326.99)	$	-	$	(7,326.99)	$	(5,193.02)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	(147,856.74)	$	1,430,714.90	$	1,282,858.16	$	909,228.93
13 c	Real-Time Asset Energy Amount - Loss Component	$	(6,318.04)	$	-	$	(6,318.04)	$	(4,477.93)
14	Real-Time Distribution of Losses Amount	$	(1,319,387.99)	$	-	$	(1,319,387.99)	$	(935,119.54)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$	-	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
21	Real-time Net inadvertent Distribution	$	(133,686.51)	$	-	$	(133,686.51)	$	(94,750.65)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	151.42	$	-	$	151.42	$	107.32
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	-	$	(11,560.02)	$	(11,560.02)	$	(8,193.19)
Congestion Related Charges									
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	1,482,893.85	$	(316,207.97)	$	1,166,685.88	$	826,891.53
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	29,647.58	$	-	$	29,647.58	$	21,012.80
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	(483,219.56)	$	103,040.33	$	(380,179.23)	$	(269,452.98)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(29,647.58)	$	-	$	(29,647.58)	$	(21,012.80)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	16,808.99	$	-	$	16,808.99	$	11,913.41
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	$	-	$	(24,658.41)	$	(24,658.41)	$	(17,476.71)
FTR Related Charges									
28	Financial Transmission Rights Hourly Allocation Amount	$	293,886.74	$	-	$	293,886.74	$	208,292.96
30	Financial Transmission Rights Monthly Allocation Amount	$	(94,015.01)	$	-	$	(94,015.01)	$	(66,633.37)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	1.07	$	-	$	1.07	$	0.76
36	Financial Transmission Rights Full Funding Guarantee Amount	$	(81,675.23)	$	-	$	(81,675.23)	$	(57,887.52)
37	Financial Transmission Guarantee Uplift Amount	$	102,923.50	$	-	$	102,923.50	$	72,947.29
38	Financial Transmission Rights Monthly Transaction Amount	$	-	$	-	$	-	$	-
Uplift (RNU) Charges									
23	Real-Time Revenue Neutrality Uplift Amount	$	1,712,181.83	$	(365,100.68)	$	1,347,081.15	$	954,747.14
Revenue Sufficiency Guarantee (RSG) Charges									
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	98,781.00	$	(21,063.77)	$	77,717.23	$	55,082.28
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(70,178.46)	$	35,346.36	$	(34,832.10)	$	(24,687.34)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	216,975.93	$	(46,267.32)	$	170,708.61	$	120,990.16
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(3,473,889.70)	$	2,683,525.11	$	(790,364.59)	$	(560,172.88)
43	Real Time Price Volatility Make Whole Payment	$	(94,587.85)	$	7,006.23	$	(87,581.62)	$	(62,073.69)
Market Administration Charges									
4	Day-Ahead Market Administration Amount	$	551,980.86	$	(36,456.99)	$	515,523.87	$	365,378.83
19	Real-Time Market Administration Amount	$	41,461.12	$	(5,411.46)	$	36,049.66	$	25,550.29
29	Financial Transmission Rights Market Administration Amount	$	7,976.88	$	-	$	7,976.88	$	5,653.63
33	Day-Ahead Schedule 24 Allocation Amount	$	89,246.18	$	(5,906.96)	$	83,339.22	$	59,066.88
34	Real -Time Schedule 24 Allocation Amount	$	(74,893.62)	$	86,916.51	$	12,022.89	$	8,521.25
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	$	79,029.18	$	9,668.12	$	88,697.30	$	62,864.43
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-	$	-
Auction Revenue Rights (ARR)									
39	Auction Revenue Rights - FTR Auction Transactions	$	1,791,300.13	$	-	$	1,791,300.13	$	1,269,588.45
40	Auction Revenue Rights - Monthly ARR Revenue	$	(1,791,548.83)	$	58,738.32	$	(1,732,810.51)	$	(1,228,133.78)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(156,670.33)	$	-	$	(156,670.33)	$	(111,040.49)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	42,379.47	$	-	$	42,379.47	$	30,036.56
	TOTAL MISO CHARGES	**$**	**(8,659,698.77)**	**$**	**15,293,326.62**	**$**	**6,633,627.85**	**$**	**4,701,600.33**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**559,550.41**	**$**	**396,582.75**
	SCHEDULE 24 (FOR RETAIL)					**$**	**95,362.11**	**$**	**67,588.13**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**5,978,715.33**	**$**	**4,237,429.45**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	March 2019 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (4,388,180.63)	$ 11,843,477.63	$ 7,455,297.00	$ 5,346,025.35
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,045,595.98	$ (482,303.45)	$ 2,563,292.53	$ 1,838,079.27
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 5,532.06	$ -	$ 5,532.06	$ 3,966.92
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,650,021.92)	$ -	$ (3,650,021.92)	$ (2,617,348.40)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 83,951.50	$ (13,294.64)	$ 70,656.86	$ 50,666.44
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (5,532.06)	$ -	$ (5,532.06)	$ (3,966.92)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (705,137.65)	$ 1,871,750.40	$ 1,166,612.75	$ 836,551.69
13 c	Real-Time Asset Energy Amount - Loss Component	$ 47,058.99	$ -	$ 47,058.99	$ 33,744.94
14	Real-Time Distribution of Losses Amount	$ (793,578.25)	$ -	$ (793,578.25)	$ (569,057.07)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 97,293.07	$ -	$ 97,293.07	$ 69,766.67
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 0.47	$ -	$ 0.47	$ 0.34
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ 9,043.42	$ 9,043.42	$ 6,484.84
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,061,684.44	$ (326,490.29)	$ 1,735,194.15	$ 1,244,268.59
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 2,675.57	$ -	$ 2,675.57	$ 1,918.59
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 450,167.94	$ (71,289.02)	$ 378,878.92	$ 271,685.53
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2,675.57)	$ -	$ (2,675.57)	$ (1,918.59)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 96,488.85	$ -	$ 96,488.85	$ 69,189.98
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	$ -	$ (4,185.22)	$ (4,185.22)	$ (3,001.13)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,156,939.27)	$ -	$ (2,156,939.27)	$ (1,546,692.51)
30	Financial Transmission Rights Monthly Allocation Amount	$ (112,020.04)	$ -	$ (112,020.04)	$ (80,327.04)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (58,051.82)	$ -	$ (58,051.82)	$ (41,627.65)
37	Financial Transmission Guarantee Uplift Amount	$ 61,106.83	$ -	$ 61,106.83	$ 43,818.33
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 249,977.97	$ (39,586.75)	$ 210,391.22	$ 150,866.80
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 90,530.24	$ (14,336.45)	$ 76,193.79	$ 54,636.85
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (111,365.39)	$ 37,859.08	$ (73,506.31)	$ (52,709.72)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 203,122.10	$ (32,166.61)	$ 170,955.49	$ 122,588.33
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (273,885.54)	$ 24,624.91	$ (249,260.63)	$ (178,739.18)
43	Real Time Price Volatility Make Whole Payment	$ (44,620.67)	$ 19,230.98	$ (25,389.69)	$ (18,206.37)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 686,113.77	$ (45,682.80)	$ 640,430.97	$ 459,238.61
19	Real-Time Market Administration Amount	$ 56,279.14	$ (9,086.89)	$ 47,192.25	$ 33,840.50
29	Financial Transmission Rights Market Administration Amount	$ 28,312.64	$ -	$ 28,312.64	$ 20,302.36
33	Day-Ahead Schedule 24 Allocation Amount	$ 99,517.54	$ (6,612.42)	$ 92,905.12	$ 66,620.17
34	Real -Time Schedule 24 Allocation Amount	$ (84,071.29)	$ 68,614.93	$ (15,456.36)	$ (11,083.41)
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	$ 155,878.10	$ 10,703.99	$ 166,582.09	$ 119,452.26
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,547,181.68	$ -	$ 2,547,181.68	$ 1,826,526.54
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,571,169.74)	$ 25,992.35	$ (2,545,177.39)	$ (1,825,089.31)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (90,957.73)	$ -	$ (90,957.73)	$ (65,223.74)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 55,175.45	$ -	$ 55,175.45	$ 39,565.07
	TOTAL MISO CHARGES	**$ (4,924,563.24)**	**$ 12,866,263.16**	**$ 7,941,699.92**	**$ 5,694,813.92**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 715,935.86**	**$ 513,381.46**
	SCHEDULE 24 (FOR RETAIL)			**$ 77,448.76**	**$ 55,536.76**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,148,315.30**	**$ 5,125,895.70**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

			System		Intersystem		System Retail		Minnesota Retail
April 2019 Actual									
Energy and Loss Charges									
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	(656,753.91)	$	7,367,799.79	$	6,711,045.88	$	4,807,770.97
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	2,032,461.42	$	(237,006.42)	$	1,795,455.00	$	1,286,257.99
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	2,416.41	$	-	$	2,416.41	$	1,731.11
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(2,391,705.22)	$	-	$	(2,391,705.22)	$	(1,713,409.67)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	116,313.31	$	(13,563.36)	$	102,749.95	$	73,609.72
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	(2,416.41)	$	-	$	(2,416.41)	$	(1,731.11)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	(49,991.23)	$	2,021,122.26	$	1,971,131.03	$	1,412,111.72
13 c	Real-Time Asset Energy Amount - Loss Component	$	(5,167.08)	$	28.98	$	(5,138.10)	$	(3,680.91)
14	Real-Time Distribution of Losses Amount	$	(675,750.58)	$	-	$	(675,750.58)	$	(484,105.47)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$	-	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
21	Real-time Net inadvertent Distribution	$	(120,804.06)	$	-	$	(120,804.06)	$	(86,543.63)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	8,022.27	$	-	$	8,022.27	$	5,747.13
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	(248.56)	$	4,291.82	$	4,043.26	$	2,896.58
Congestion Related Charges									
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	1,003,404.09	$	(117,007.49)	$	886,396.60	$	635,011.58
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	(329.13)	$	-	$	(329.13)	$	(235.79)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	210,874.36	$	(24,590.17)	$	186,284.19	$	133,453.37
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	329.13	$	-	$	329.13	$	235.79
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	111,551.53	$	(783.31)	$	110,768.22	$	79,353.98
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	$	6,717.36	$	60,346.80	$	67,064.16	$	48,044.54
FTR Related Charges									
28	Financial Transmission Rights Hourly Allocation Amount	$	(97,019.43)	$	-	$	(97,019.43)	$	(69,504.40)
30	Financial Transmission Rights Monthly Allocation Amount	$	(83,667.83)	$	-	$	(83,667.83)	$	(59,939.36)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$	-	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	30,592.69	$	-	$	30,592.69	$	21,916.50
37	Financial Transmission Guarantee Uplift Amount	$	(16,787.49)	$	-	$	(16,787.49)	$	(12,026.50)
38	Financial Transmission Rights Monthly Transaction Amount	$	-	$	-	$	-	$	-
Uplift (RNU) Charges									
23	Real-Time Revenue Neutrality Uplift Amount	$	330,681.35	$	(38,560.93)	$	292,120.42	$	209,274.10
Revenue Sufficiency Guarantee (RSG) Charges									
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	82,593.70	$	(9,631.30)	$	72,962.40	$	52,270.02
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(40,700.24)	$	10,982.16	$	(29,718.08)	$	(21,289.93)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	62,726.92	$	(7,314.62)	$	55,412.30	$	39,697.19
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(33,210.06)	$	25,020.32	$	(8,189.74)	$	(5,867.10)
43	Real Time Price Volatility Make Whole Payment	$	(116,503.07)	$	6,477.62	$	(110,025.45)	$	(78,821.87)
Market Administration Charges									
4	Day-Ahead Market Administration Amount	$	606,290.04	$	(29,858.45)	$	576,431.59	$	412,953.68
19	Real-Time Market Administration Amount	$	58,805.28	$	(9,091.75)	$	49,713.53	$	35,614.61
29	Financial Transmission Rights Market Administration Amount	$	40,536.92	$	-	$	40,536.92	$	29,040.51
33	Day-Ahead Schedule 24 Allocation Amount	$	93,323.55	$	(4,676.52)	$	88,647.03	$	63,506.44
34	Real -Time Schedule 24 Allocation Amount	$	(80,695.07)	$	102,034.84	$	21,339.77	$	15,287.74
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	$	192,235.93	$	10,358.70	$	202,594.63	$	145,138.12
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-	$	-
Auction Revenue Rights (ARR)									
39	Auction Revenue Rights - FTR Auction Transactions	$	2,547,181.68	$	-	$	2,547,181.68	$	1,824,792.49
40	Auction Revenue Rights - Monthly ARR Revenue	$	(2,571,169.74)	$	23,992.35	$	(2,547,177.39)	$	(1,824,789.42)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(90,957.87)	$	-	$	(90,957.87)	$	(65,161.92)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	55,175.45	$	-	$	55,175.45	$	39,527.51
	TOTAL MISO CHARGES	**$**	**558,356.41**	**$**	**9,140,371.32**	**$**	**9,698,727.73**	**$**	**6,948,136.31**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**666,682.04**	**$**	**477,608.80**
	SCHEDULE 24 (FOR RETAIL)					**$**	**109,986.80**	**$**	**78,794.18**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**8,922,058.89**	**$**	**6,391,733.33**

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

			System		Intersystem		System Retail		Minnesota Retail
	May 2019 Actual								
Energy and Loss Charges									
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	(13,086,587.61)	$	19,557,971.27	$	6,471,383.66	$	4,654,072.91
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	1,767,793.53	$	(480,725.47)	$	1,287,068.06	$	925,630.27
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	(315.23)	$	-	$	(315.23)	$	(226.71)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(5,752,237.09)	$	-	$	(5,752,237.09)	$	(4,136,878.95)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	466,646.76	$	(126,897.73)	$	339,749.03	$	244,339.83
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	315.23	$	-	$	315.23	$	226.71
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	(1,222,699.28)	$	2,096,558.79	$	873,859.51	$	628,460.02
13 c	Real-Time Asset Energy Amount - Loss Component	$	59,320.44	$	112.81	$	59,433.25	$	42,743.05
14	Real-Time Distribution of Losses Amount	$	(513,384.45)	$	-	$	(513,384.45)	$	(369,214.50)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$	-	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
21	Real-time Net inadvertent Distribution	$	147.75	$	-	$	147.75	$	106.26
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	5,416.78	$	-	$	5,416.78	$	3,895.63
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	(414.85)	$	38,644.97	$	38,230.12	$	27,494.24
Congestion Related Charges									
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	526,019.77	$	(143,043.35)	$	382,976.42	$	275,427.99
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	(10,982.49)	$	-	$	(10,982.49)	$	(7,898.36)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	937,003.39	$	(254,804.30)	$	682,199.09	$	490,622.17
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	10,982.49	$	-	$	10,982.49	$	7,898.36
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	71,887.25	$	33.00	$	71,920.25	$	51,723.42
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	$	(121.36)	$	33,834.78	$	33,713.42	$	24,245.93
FTR Related Charges									
28	Financial Transmission Rights Hourly Allocation Amount	$	(1,259,506.68)	$	-	$	(1,259,506.68)	$	(905,808.75)
30	Financial Transmission Rights Monthly Allocation Amount	$	(150,543.49)	$	-	$	(150,543.49)	$	(108,267.48)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$	-	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	(23,950.27)	$	-	$	(23,950.27)	$	(17,224.49)
37	Financial Transmission Guarantee Uplift Amount	$	6,700.83	$	-	$	6,700.83	$	4,819.09
38	Financial Transmission Rights Monthly Transaction Amount	$	-	$	-	$	-	$	-
Uplift (RNU) Charges									
23	Real-Time Revenue Neutrality Uplift Amount	$	463,508.81	$	(126,044.41)	$	337,464.40	$	242,696.77
Revenue Sufficiency Guarantee (RSG) Charges									
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	79,507.00	$	(21,620.76)	$	57,886.24	$	41,630.48
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(92,547.73)	$	56,963.70	$	(35,584.03)	$	(25,591.23)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	143,230.20	$	(38,949.35)	$	104,280.85	$	74,996.43
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(15,698.46)	$	(29,282.76)	$	(44,981.22)	$	(32,349.48)
43	Real Time Price Volatility Make Whole Payment	$	(56,103.03)	$	14,122.11	$	(41,980.92)	$	(30,191.73)
Market Administration Charges									
4	Day-Ahead Market Administration Amount	$	682,972.06	$	(96,535.04)	$	586,437.02	$	421,752.25
19	Real-Time Market Administration Amount	$	60,703.52	$	(12,999.03)	$	47,704.49	$	34,307.99
29	Financial Transmission Rights Market Administration Amount	$	32,748.81	$	-	$	32,748.81	$	23,552.20
33	Day-Ahead Schedule 24 Allocation Amount	$	98,029.65	$	(10,304.06)	$	87,725.59	$	63,090.26
34	Real -Time Schedule 24 Allocation Amount	$	(79,433.57)	$	71,901.93	$	(7,531.64)	$	(5,416.59)
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	$	(116,506.77)	$	10,703.99	$	(105,802.78)	$	(76,090.97)
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-	$	-
Auction Revenue Rights (ARR)									
39	Auction Revenue Rights - FTR Auction Transactions	$	2,547,181.68	$	-	$	2,547,181.68	$	1,831,875.51
40	Auction Revenue Rights - Monthly ARR Revenue	$	(2,571,169.74)	$	25,169.16	$	(2,546,000.58)	$	(1,831,026.09)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(90,957.87)	$	-	$	(90,957.87)	$	(65,414.85)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	55,175.45	$	-	$	55,175.45	$	39,680.94
	TOTAL MISO CHARGES	**$**	**(17,027,868.57)**	**$**	**20,564,810.25**	**$**	**3,536,941.68**	**$**	**2,543,688.54**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**666,890.32**	**$**	**479,612.45**
	SCHEDULE 24 (FOR RETAIL)					**$**	**80,193.95**	**$**	**57,673.68**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**2,789,857.41**	**$**	**2,006,402.42**

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	June 2019 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,114,597.62)	$ 17,587,348.32	$ 3,472,750.70	$ 2,523,255.72
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,674,123.01	$ (359,150.63)	$ 1,314,972.38	$ 955,441.92
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,320.69)	$ -	$ (2,320.69)	$ (1,686.18)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,979,711.15)	$ -	$ (4,979,711.15)	$ (3,618,193.68)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 638,256.19	$ (136,925.49)	$ 501,330.70	$ 364,260.40
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,320.69	$ -	$ 2,320.69	$ 1,686.18
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,232,387.51)	$ 1,784,877.40	$ 552,489.89	$ 401,432.00
13 c	Real-Time Asset Energy Amount - Loss Component	$ 97,746.49	$ 609.98	$ 98,356.47	$ 71,464.54
14	Real-Time Distribution of Losses Amount	$ (650,316.74)	$ -	$ (650,316.74)	$ (472,511.73)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 7.25	$ -	$ 7.25	$ 5.27
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (7.25)	$ -	$ (7.25)	$ (5.27)
21	Real-time Net inadvertent Distribution	$ 43,454.12	$ -	$ 43,454.12	$ 31,573.20
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 20,701.13	$ -	$ 20,701.13	$ 15,041.17
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (2,843.32)	$ (31,817.32)	$ (34,660.64)	$ (25,183.97)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 435,190.70	$ (93,361.73)	$ 341,828.97	$ 248,368.51
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,228.23)	$ -	$ (8,228.23)	$ (5,978.53)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 684,043.94	$ (146,748.36)	$ 537,295.58	$ 390,392.01
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,228.23	$ -	$ 8,228.23	$ 5,978.53
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 72,788.08	$ 1,061.47	$ 73,849.55	$ 53,658.13
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 15.07	$ -	$ 15.07	$ 10.95
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (15.07)	$ -	$ (15.07)	$ (10.95)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (4,947.87)	$ 21,407.74	$ 16,459.87	$ 11,959.53
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,129,744.04)	$ -	$ (1,129,744.04)	$ (820,857.40)
30	Financial Transmission Rights Monthly Allocation Amount	$ (38,352.60)	$ -	$ (38,352.60)	$ (27,866.50)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (66,727.21)	$ -	$ (66,727.21)	$ (48,483.13)
37	Financial Transmission Guarantee Uplift Amount	$ 51,872.13	$ -	$ 51,872.13	$ 37,689.62
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 158,851.88	$ (34,078.59)	$ 124,773.29	$ 90,658.66
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 63,219.85	$ (13,562.59)	$ 49,657.26	$ 36,080.32
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (62,870.47)	$ 32,777.65	$ (30,092.82)	$ (21,865.05)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 146,536.63	$ (31,436.59)	$ 115,100.04	$ 83,630.20
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (37,234.01)	$ 32,921.90	$ (4,312.11)	$ (3,133.12)
43	Real Time Price Volatility Make Whole Payment	$ (40,310.38)	$ 12,454.92	$ (27,855.46)	$ (20,239.42)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 876,227.03	$ (86,139.05)	$ 790,087.98	$ 574,067.70
19	Real-Time Market Administration Amount	$ 65,146.30	$ (8,970.33)	$ 56,175.97	$ 40,816.73
29	Financial Transmission Rights Market Administration Amount	$ 43,186.77	$ -	$ 43,186.77	$ 31,378.95
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,765.32	$ (12,125.24)	$ 81,640.08	$ 59,318.63
34	Real -Time Schedule 24 Allocation Amount	$ (82,229.02)	$ 101,962.18	$ 19,733.16	$ 14,337.86
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	$ 212,493.08	$ 11,894.10	$ 224,387.18	$ 163,036.82
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,805,216.47	$ -	$ 1,805,216.47	$ 1,311,646.93
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,805,445.07)	$ 8,792.80	$ (1,796,652.27)	$ (1,305,424.29)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (202,033.21)	$ -	$ (202,033.21)	$ (146,794.72)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,882.21	$ -	$ 25,882.21	$ 18,805.68
	TOTAL MISO CHARGES	**$ (17,241,048.89)**	**$ 18,641,792.54**	**$ 1,400,743.65**	**$ 1,017,762.21**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 889,450.72**	**$ 646,263.38**
	SCHEDULE 24 (FOR RETAIL)			**$ 101,373.24**	**$ 73,656.48**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 409,919.69**	**$ 297,842.34**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System		Intersystem		System Retail		Minnesota Retail
July 2019 Actual								
Energy and Loss Charges								
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	(12,666,821.59)	$	19,608,408.16	$	6,941,586.57	$	5,065,372.57
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	2,664,374.28	$	(476,143.04)	$	2,188,231.24	$	1,596,782.86
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	(3,035.09)	$	-	$	(3,035.09)	$	(2,214.75)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(6,636,433.37)	$	-	$	(6,636,433.37)	$	(4,842,698.02)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	816,261.80	$	(145,871.91)	$	670,389.89	$	489,192.85
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	3,035.09	$	-	$	3,035.09	$	2,214.75
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	(1,221,316.15)	$	1,896,329.76	$	675,013.61	$	492,566.85
13 c	Real-Time Asset Energy Amount - Loss Component	$	119,784.67	$	77.31	$	119,861.98	$	87,464.96
14	Real-Time Distribution of Losses Amount	$	(1,175,922.23)	$	-	$	(1,175,922.23)	$	(858,086.86)
16	Real-Time Financial Bilateral Transaction Loss Amount	$	-	$	-	$	-	$	-
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$	-	$	-	$	-	$	-
21	Real-time Net inadvertent Distribution	$	(2,930.86)	$	-	$	(2,930.86)	$	(2,138.69)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	7,709.67	$	-	$	7,709.67	$	5,625.85
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	(432.62)	$	26,300.70	$	25,868.08	$	18,876.30
Congestion Related Charges								
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	3,569,518.59	$	(637,898.91)	$	2,931,619.68	$	2,139,243.78
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	10,844.82	$	-	$	10,844.82	$	7,913.62
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	1,378,480.18	$	(246,344.42)	$	1,132,135.76	$	826,135.26
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(10,844.82)	$	-	$	(10,844.82)	$	(7,913.62)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$	-	$	-	$	-	$	-
13 b	Real-Time Asset Energy Amount - Congestion Component	$	176,597.75	$	74.92	$	176,672.67	$	128,920.51
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	$	(419.25)	$	80,517.29	$	80,098.04	$	58,448.66
FTR Related Charges								
28	Financial Transmission Rights Hourly Allocation Amount	$	(4,460,660.10)	$	-	$	(4,460,660.10)	$	(3,255,005.91)
30	Financial Transmission Rights Monthly Allocation Amount	$	(137,857.43)	$	-	$	(137,857.43)	$	(100,596.49)
31	Financial Transmission Rights Transaction Amount	$	-	$	-	$	-	$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	-	$	-	$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	(264,018.18)	$	-	$	(264,018.18)	$	(192,657.75)
37	Financial Transmission Guarantee Uplift Amount	$	194,543.93	$	-	$	194,543.93	$	141,961.42
38	Financial Transmission Rights Monthly Transaction Amount	$	-	$	-	$	-	$	-
Uplift (RNU) Charges								
23	Real-Time Revenue Neutrality Uplift Amount	$	467,688.86	$	(83,579.40)	$	384,109.46	$	280,290.03
Revenue Sufficiency Guarantee (RSG) Charges								
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$	55,978.72	$	(10,003.80)	$	45,974.92	$	33,548.54
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(18,013.28)	$	9,339.95	$	(8,673.33)	$	(6,329.05)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	148,671.41	$	(26,568.66)	$	122,102.75	$	89,100.08
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(72,706.96)	$	21,851.87	$	(50,855.09)	$	(37,109.67)
43	Real Time Price Volatility Make Whole Payment	$	(62,129.15)	$	11,499.08	$	(50,630.07)	$	(36,945.47)
Market Administration Charges								
4	Day-Ahead Market Administration Amount	$	695,556.87	$	(62,053.30)	$	633,503.57	$	462,276.39
19	Real-Time Market Administration Amount	$	53,676.55	$	(6,252.35)	$	47,424.20	$	34,606.10
29	Financial Transmission Rights Market Administration Amount	$	27,042.60	$	-	$	27,042.60	$	19,733.36
33	Day-Ahead Schedule 24 Allocation Amount	$	105,021.95	$	(9,323.59)	$	95,698.36	$	69,832.43
34	Real -Time Schedule 24 Allocation Amount	$	(93,659.66)	$	92,047.70	$	(1,611.96)	$	(1,176.27)
35	Schedule 24 Admin Allocation	$	-	$	-	$	-	$	-
Virtual Energy Charges								
12	Day-Ahead Virtual Energy Amount	$	-	$	-	$	-	$	-
27	Real-Time Virtual Energy Amount	$	-	$	-	$	-	$	-
Other MISO Charges								
20	Real-Time Miscellaneous Amount	$	170,484.76	$	12,290.57	$	182,775.33	$	133,373.71
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-	$	-
Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	$	1,805,216.47	$	-	$	1,805,216.47	$	1,317,291.64
40	Auction Revenue Rights - Monthly ARR Revenue	$	(1,805,445.07)	$	9,069.71	$	(1,796,375.36)	$	(1,310,840.16)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(204,112.67)	$	-	$	(204,112.67)	$	(148,943.86)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	25,882.21	$	-	$	25,882.21	$	18,886.61
	TOTAL MISO CHARGES	**$**	**(16,340,387.30)**	**$**	**20,063,767.64**	**$**	**3,723,380.34**	**$**	**2,717,002.58**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**707,970.37**	**$**	**516,615.86**
	SCHEDULE 24 (FOR RETAIL)					**$**	**94,086.40**	**$**	**68,656.16**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**2,921,323.57**	**$**	**2,131,730.57**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	August 2019 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (10,882,366.12)	$ 16,404,588.56	$ 5,522,222.44	$ 4,010,690.58
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,083,104.75	$ (392,795.68)	$ 1,690,309.07	$ 1,227,641.00
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,674.69)	$ -	$ (2,674.69)	$ (1,942.58)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,730,150.72)	$ -	$ (5,730,150.72)	$ (4,161,705.14)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 706,449.61	$ (133,209.98)	$ 573,239.63	$ 416,333.60
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,674.69	$ -	$ 2,674.69	$ 1,942.58
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,052,482.22)	$ 1,334,147.98	$ 281,665.76	$ 204,568.76
13 c	Real-Time Asset Energy Amount - Loss Component	$ 110,044.98	$ 72.46	$ 110,117.44	$ 79,976.31
14	Real-Time Distribution of Losses Amount	$ (863,775.46)	$ -	$ (863,775.46)	$ (627,344.54)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 74,327.00	$ -	$ 74,327.00	$ 53,982.36
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,686.61	$ -	$ 8,686.61	$ 6,308.93
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (384.30)	$ 9,509.09	$ 9,124.79	$ 6,627.17
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,141,545.63	$ (403,815.44)	$ 1,737,730.19	$ 1,262,082.10
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 7,536.97	$ -	$ 7,536.97	$ 5,473.97
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,254,254.16	$ (236,505.44)	$ 1,017,748.72	$ 739,172.54
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (7,536.97)	$ -	$ (7,536.97)	$ (5,473.97)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 22,656.96	$ 22,640.53	$ 45,297.49	$ 32,898.75
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	$ (120,069.05)	$ (7,267.96)	$ (127,337.01)	$ (92,482.57)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,699,105.15)	$ -	$ (3,699,105.15)	$ (2,686,593.37)
30	Financial Transmission Rights Monthly Allocation Amount	$ (200,076.68)	$ -	$ (200,076.68)	$ (145,312.09)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (174,203.01)	$ -	$ (174,203.01)	$ (126,520.51)
37	Financial Transmission Guarantee Uplift Amount	$ 267,173.35	$ -	$ 267,173.35	$ 194,043.19
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 372,318.76	$ (70,205.40)	$ 302,113.36	$ 219,419.49
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 60,391.61	$ (11,387.60)	$ 49,004.01	$ 35,590.73
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (22,016.00)	$ 13,882.00	$ (8,134.00)	$ (5,907.58)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 88,903.98	$ (16,763.97)	$ 72,140.01	$ 52,393.99
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (38,242.65)	$ 26,992.47	$ (11,250.18)	$ (8,170.80)
43	Real Time Price Volatility Make Whole Payment	$ (128,885.19)	$ 15,583.16	$ (113,302.03)	$ (82,289.22)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 400,654.06	$ (35,211.29)	$ 365,442.77	$ 265,414.49
19	Real-Time Market Administration Amount	$ 25,046.11	$ (3,217.88)	$ 21,828.23	$ 15,853.45
29	Financial Transmission Rights Market Administration Amount	$ 10,435.94	$ -	$ 10,435.94	$ 7,579.44
33	Day-Ahead Schedule 24 Allocation Amount	$ 93,136.38	$ (8,160.66)	$ 84,975.72	$ 61,716.33
34	Real -Time Schedule 24 Allocation Amount	$ (84,546.43)	$ 105,996.12	$ 21,449.69	$ 15,578.52
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	$ 135,961.02	$ 12,635.86	$ 148,596.88	$ 107,923.23
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,805,216.47	$ -	$ 1,805,216.47	$ 1,311,096.17
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,805,445.07)	$ 7,307.84	$ (1,798,137.23)	$ (1,305,954.65)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (203,055.76)	$ -	$ (203,055.76)	$ (147,475.74)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,882.21	$ -	$ 25,882.21	$ 18,797.78
	TOTAL MISO CHARGES	**$ (15,318,614.22)**	**$ 16,634,814.79**	**$ 1,316,200.57**	**$ 955,932.74**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 397,706.94**	**$ 288,847.38**
	SCHEDULE 24 (FOR RETAIL)			**$ 106,425.41**	**$ 77,294.86**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 812,068.22**	**$ 589,790.50**

Docket No. E999/AA-20-171
Part J, Section 5
Schedule 2

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	September 2019 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (10,619,183.75)	$ 16,237,998.12	$ 5,618,814.37	$ 4,113,000.37
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,770,942.42	$ (345,652.38)	$ 1,425,290.04	$ 1,043,319.48
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (5,214.50)	$ -	$ (5,214.50)	$ (3,817.04)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,526,254.85)	$ -	$ (5,526,254.85)	$ (4,045,246.34)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 807,789.05	$ (157,664.19)	$ 650,124.86	$ 475,894.67
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 5,214.50	$ -	$ 5,214.50	$ 3,817.04
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (841,420.20)	$ 1,179,016.67	$ 337,596.47	$ 247,122.31
13 c	Real-Time Asset Energy Amount - Loss Component	$ 122,175.29	$ 5.07	$ 122,180.36	$ 89,436.64
14	Real-Time Distribution of Losses Amount	$ (805,409.36)	$ -	$ (805,409.36)	$ (589,563.70)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 15,768.18	$ -	$ 15,768.18	$ 11,542.39
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 27.23	$ -	$ 27.23	$ 19.93
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (25.99)	$ 37,638.77	$ 37,612.78	$ 27,532.74
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,605,403.91	$ (313,342.59)	$ 1,292,061.32	$ 945,795.39
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (6,828.80)	$ -	$ (6,828.80)	$ (4,998.72)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 933,569.28	$ (182,213.96)	$ 751,355.32	$ 549,995.87
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 6,828.80	$ -	$ 6,828.80	$ 4,998.72
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 218,626.21	$ 0.24	$ 218,626.45	$ 160,035.66
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	$ (1.23)	$ 54,372.98	$ 54,371.75	$ 39,800.39
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,525,831.06)	$ -	$ (1,525,831.06)	$ (1,116,916.01)
30	Financial Transmission Rights Monthly Allocation Amount	$ (63,914.41)	$ -	$ (63,914.41)	$ (46,785.67)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 30,121.26	$ -	$ 30,121.26	$ 22,048.91
37	Financial Transmission Guarantee Uplift Amount	$ (47,374.50)	$ -	$ (47,374.50)	$ (34,678.37)
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 71,452.24	$ (13,946.04)	$ 57,506.20	$ 42,094.83
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 54,807.01	$ (10,697.23)	$ 44,109.78	$ 32,288.58
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (142,948.39)	$ 72,086.44	$ (70,861.95)	$ (51,871.30)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 56,155.10	$ (10,960.35)	$ 45,194.75	$ 33,082.79
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (83,337.48)	$ 14,622.71	$ (68,714.77)	$ (50,299.56)
43	Real Time Price Volatility Make Whole Payment	$ (87,380.70)	$ 22,219.01	$ (65,161.69)	$ (47,698.68)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 592,456.64	$ (60,877.89)	$ 531,578.75	$ 389,118.32
19	Real-Time Market Administration Amount	$ 47,334.67	$ (4,998.25)	$ 42,336.42	$ 30,990.47
29	Financial Transmission Rights Market Administration Amount	$ 28,566.79	$ -	$ 28,566.79	$ 20,911.03
33	Day-Ahead Schedule 24 Allocation Amount	$ 90,286.38	$ (9,300.06)	$ 80,986.32	$ 59,282.39
34	Real -Time Schedule 24 Allocation Amount	$ (83,068.01)	$ 82,402.24	$ (665.77)	$ (487.35)
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	$ 254,600.63	$ 11,894.10	$ 266,494.73	$ 195,075.48
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,337,779.21	$ -	$ 1,337,779.21	$ 979,261.11
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,340,179.39)	$ 1,824.04	$ (1,338,355.35)	$ (979,682.85)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (198,269.67)	$ -	$ (198,269.67)	$ (145,134.40)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 59,727.45	$ -	$ 59,727.45	$ 43,720.79
	TOTAL MISO CHARGES	**$ (13,267,010.04)**	**$ 16,604,427.46**	**$ 3,337,417.42**	**$ 2,443,006.33**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 602,481.96**	**$ 441,019.82**
	SCHEDULE 24 (FOR RETAIL)			**$ 80,320.55**	**$ 58,795.05**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,654,614.91**	**$ 1,943,191.46**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	October 2019 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (8,766,927.58)	$ 12,441,406.49	$ 3,674,478.91	$ 2,619,494.97
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,995,030.74	$ (362,730.31)	$ 1,632,300.43	$ 1,163,648.74
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (958.82)	$ -	$ (958.82)	$ (683.53)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (3,249,260.05)	$ -	$ (3,249,260.05)	$ (2,316,361.20)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 332,517.90	$ (60,457.38)	$ 272,060.52	$ 193,948.91
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 958.82	$ -	$ 958.82	$ 683.53
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 39,443.49	$ 1,453,982.13	$ 1,493,425.62	$ 1,064,646.44
13 c	Real-Time Asset Energy Amount - Loss Component	$ 9,758.39	$ (193.33)	$ 9,565.06	$ 6,818.82
14	Real-Time Distribution of Losses Amount	$ (518,123.61)	$ -	$ (518,123.61)	$ (369,364.53)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 12.56	$ -	$ 12.56	$ 8.95
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (12.56)	$ -	$ (12.56)	$ (8.95)
21	Real-time Net inadvertent Distribution	$ 14,735.95	$ -	$ 14,735.95	$ 10,505.09
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 64,519.87	$ -	$ 64,519.87	$ 45,995.49
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 1,063.34	$ (5,680.43)	$ (4,617.09)	$ (3,291.47)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,262,762.43	$ (411,408.46)	$ 1,851,353.97	$ 1,319,809.57
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (7,592.48)	$ -	$ (7,592.48)	$ (5,412.59)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 552,425.65	$ (100,440.32)	$ 451,985.33	$ 322,215.29
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 7,592.48	$ -	$ 7,592.48	$ 5,412.59
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 142,719.63	$ (798.81)	$ 141,920.82	$ 101,173.77
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 33.27	$ -	$ 33.27	$ 23.72
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (33.27)	$ -	$ (33.27)	$ (23.72)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 4,393.50	$ 34,439.29	$ 38,832.79	$ 27,683.47
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (426,804.42)	$ -	$ (426,804.42)	$ (304,264.10)
30	Financial Transmission Rights Monthly Allocation Amount	$ (37,459.02)	$ -	$ (37,459.02)	$ (26,704.12)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (11,499.97)	$ -	$ (11,499.97)	$ (8,198.20)
37	Financial Transmission Guarantee Uplift Amount	$ 29,504.90	$ -	$ 29,504.90	$ 21,033.71
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 517,573.18	$ (94,103.55)	$ 423,469.63	$ 301,886.77
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 83,205.81	$ (15,128.22)	$ 68,077.59	$ 48,531.75
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (182,534.20)	$ 101,557.29	$ (80,976.91)	$ (57,727.53)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 82,118.79	$ (14,930.58)	$ 67,188.21	$ 47,897.72
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (52,982.12)	$ 34,369.65	$ (18,612.47)	$ (13,268.62)
43	Real Time Price Volatility Make Whole Payment	$ (76,259.32)	$ 17,883.18	$ (58,376.14)	$ (41,615.70)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 687,978.31	$ (61,916.89)	$ 626,061.42	$ 446,312.19
19	Real-Time Market Administration Amount	$ 63,928.30	$ (7,702.88)	$ 56,225.42	$ 40,082.47
29	Financial Transmission Rights Market Administration Amount	$ 23,921.89	$ -	$ 23,921.89	$ 17,053.65
33	Day-Ahead Schedule 24 Allocation Amount	$ 86,324.07	$ (7,788.14)	$ 78,535.93	$ 55,987.39
34	Real -Time Schedule 24 Allocation Amount	$ (78,878.80)	$ 89,170.83	$ 10,292.03	$ 7,337.07
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	$ 219,979.65	$ 12,290.57	$ 232,270.22	$ 165,582.85
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,337,779.21	$ -	$ 1,337,779.21	$ 953,687.86
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,340,179.39)	$ 1,781.20	$ (1,338,398.19)	$ (954,129.12)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (198,206.91)	$ -	$ (198,206.91)	$ (141,299.49)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 59,727.45	$ -	$ 59,727.45	$ 42,579.03
	TOTAL MISO CHARGES	**$ (6,327,702.94)**	**$ 13,043,601.32**	**$ 6,715,898.38**	**$ 4,787,688.94**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 706,208.73**	**$ 503,448.32**
	SCHEDULE 24 (FOR RETAIL)			**$ 88,827.96**	**$ 63,324.46**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,920,861.69**	**$ 4,220,916.16**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
	November 2019 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (14,003,311.03)	$ 16,543,375.21	$ 2,540,064.18	$ 1,821,080.75
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,348,066.64	$ 491,665.72	$ 2,839,732.36	$ 2,035,925.70
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (63.64)	$ -	$ (63.64)	$ (45.63)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,661,404.19)	$ -	$ (2,661,404.19)	$ (1,908,074.59)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 284,331.79	$ 59,536.72	$ 343,868.51	$ 246,534.06
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 63.64	$ -	$ 63.64	$ 45.63
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (460,598.94)	$ 3,108,167.34	$ 2,647,568.40	$ 1,898,155.12
13 c	Real-Time Asset Energy Amount - Loss Component	$ 48,784.95	$ (8.34)	$ 48,776.61	$ 34,970.04
14	Real-Time Distribution of Losses Amount	$ (657,043.93)	$ -	$ (657,043.93)	$ (471,062.92)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 22,346.64	$ -	$ 22,346.64	$ 16,021.26
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 215.56	$ -	$ 215.56	$ 154.54
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (39.83)	$ 162.17	$ 122.34	$ 87.71
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,905,613.83	$ 399,019.77	$ 2,304,633.60	$ 1,652,290.48
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,906.58	$ -	$ 1,906.58	$ 1,366.91
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 187,215.31	$ 39,201.34	$ 226,416.65	$ 162,327.79
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,906.58)	$ -	$ (1,906.58)	$ (1,366.91)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 92,775.38	$ (20.49)	$ 92,754.89	$ 66,499.95
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	$ (97.86)	$ (19,475.96)	$ (19,573.82)	$ (14,033.31)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,169,823.12)	$ -	$ (1,169,823.12)	$ (838,696.27)
30	Financial Transmission Rights Monthly Allocation Amount	$ (42,276.61)	$ -	$ (42,276.61)	$ (30,309.91)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (68,725.91)	$ -	$ (68,725.91)	$ (49,272.55)
37	Financial Transmission Guarantee Uplift Amount	$ 73,143.23	$ -	$ 73,143.23	$ 52,439.51
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ (70,454.99)	$ (14,752.69)	$ (85,207.68)	$ (61,089.03)
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 66,452.30	$ 13,914.56	$ 80,366.86	$ 57,618.44
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (107,080.46)	$ 58,141.09	$ (48,939.37)	$ (35,086.73)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 82,598.89	$ 17,295.52	$ 99,894.41	$ 71,618.58
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (108,771.54)	$ 56,398.90	$ (52,372.64)	$ (37,548.19)
43	Real Time Price Volatility Make Whole Payment	$ (47,620.76)	$ 10,285.11	$ (37,335.65)	$ (26,767.53)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 607,514.50	$ (64,267.99)	$ 543,246.51	$ 389,476.68
19	Real-Time Market Administration Amount	$ 60,308.87	$ (12,823.95)	$ 47,484.92	$ 34,043.97
29	Financial Transmission Rights Market Administration Amount	$ 19,570.56	$ -	$ 19,570.56	$ 14,030.97
33	Day-Ahead Schedule 24 Allocation Amount	$ 84,740.12	$ (8,959.83)	$ 75,780.29	$ 54,330.13
34	Real -Time Schedule 24 Allocation Amount	$ (74,091.80)	$ 81,860.75	$ 7,768.95	$ 5,569.89
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	$ 606,534.59	$ 11,894.10	$ 618,428.69	$ 443,378.00
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,337,779.21	$ -	$ 1,337,779.21	$ 959,111.18
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,340,179.39)	$ 1,895.17	$ (1,338,284.22)	$ (959,473.25)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (198,218.84)	$ -	$ (198,218.84)	$ (142,111.57)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 59,727.45	$ -	$ 59,727.45	$ 42,821.17
	TOTAL MISO CHARGES	**$ (13,122,019.38)**	**$ 20,772,504.22**	**$ 7,650,484.84**	**$ 5,484,960.09**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 610,301.99**	**$ 437,551.62**
	SCHEDULE 24 (FOR RETAIL)			**$ 83,549.24**	**$ 59,900.03**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,956,633.61**	**$ 4,987,508.44**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnesota Retail
December 2019 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (11,711,719.33)	$ 15,366,833.74	$ 3,655,114.41	$ 2,608,793.22
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,301,715.99	$ (469,774.33)	$ 1,831,941.66	$ 1,307,525.96
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 212.07	$ -	$ 212.07	$ 151.36
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (2,783,955.25)	$ -	$ (2,783,955.25)	$ (1,987,014.02)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 229,674.02	$ (46,875.88)	$ 182,798.14	$ 130,469.94
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (212.07)	$ -	$ (212.07)	$ (151.36)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 110,686.34	$ 1,637,301.56	$ 1,747,987.90	$ 1,247,604.99
13 c	Real-Time Asset Energy Amount - Loss Component	$ 16,816.94	$ (3.27)	$ 16,813.67	$ 12,000.55
14	Real-Time Distribution of Losses Amount	$ (912,334.22)	$ -	$ (912,334.22)	$ (651,167.40)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 14,831.50	$ -	$ 14,831.50	$ 10,585.80
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (1,012.53)	$ -	$ (1,012.53)	$ (722.68)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 16.02	$ (2,356.92)	$ (2,340.90)	$ (1,670.79)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,545,634.06	$ (315,459.95)	$ 1,230,174.11	$ 878,021.73
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 10,460.62	$ -	$ 10,460.62	$ 7,466.14
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (4,671.77)	$ 953.50	$ (3,718.27)	$ (2,653.87)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (10,460.62)	$ -	$ (10,460.62)	$ (7,466.14)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (778.56)	$ (203.62)	$ (982.18)	$ (701.02)
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	$ 997.68	$ (12,914.89)	$ (11,917.21)	$ (8,505.76)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (636,844.90)	$ -	$ (636,844.90)	$ (454,540.26)
30	Financial Transmission Rights Monthly Allocation Amount	$ (39,365.46)	$ -	$ (39,365.46)	$ (28,096.62)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (89,773.02)	$ -	$ (89,773.02)	$ (64,074.40)
37	Financial Transmission Guarantee Uplift Amount	$ 82,954.80	$ -	$ 82,954.80	$ 59,207.97
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 352,729.16	$ (71,991.12)	$ 280,738.04	$ 200,373.35
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 69,143.39	$ (14,111.99)	$ 55,031.40	$ 39,277.99
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (108,131.14)	$ 35,532.30	$ (72,598.84)	$ (51,816.53)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 41,494.97	$ (8,469.02)	$ 33,025.95	$ 23,571.87
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (59,419.98)	$ 38,925.77	$ (20,494.21)	$ (14,627.49)
43	Real Time Price Volatility Make Whole Payment	$ (48,182.59)	$ 11,560.86	$ (36,621.73)	$ (26,138.31)
Market Administration Charges					
4	Day-Ahead Market Administration Amount	$ 780,267.99	$ (69,497.81)	$ 710,770.18	$ 507,303.53
19	Real-Time Market Administration Amount	$ 65,004.23	$ (10,024.89)	$ 54,979.34	$ 39,240.83
29	Financial Transmission Rights Market Administration Amount	$ 24,626.30	$ -	$ 24,626.30	$ 17,576.72
33	Day-Ahead Schedule 24 Allocation Amount	$ 98,214.55	$ (8,725.25)	$ 89,489.30	$ 63,871.89
34	Real -Time Schedule 24 Allocation Amount	$ (67,971.70)	$ 86,968.43	$ 18,996.73	$ 13,558.68
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	$ 117,351.45	$ 12,290.57	$ 129,642.02	$ 92,530.41
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,123,444.70	$ -	$ 1,123,444.70	$ 801,844.92
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,123,867.22)	$ 54,964.25	$ (1,068,902.97)	$ (762,916.43)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (207,296.32)	$ -	$ (207,296.32)	$ (147,955.21)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 42,660.70	$ -	$ 42,660.70	$ 30,448.55
	TOTAL MISO CHARGES	**$ (10,777,059.20)**	**$ 16,214,922.04**	**$ 5,437,862.84**	**$ 3,881,208.12**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 790,375.82**	**$ 564,121.08**
	SCHEDULE 24 (FOR RETAIL)			**$ 108,486.03**	**$ 77,430.58**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,539,000.99**	**$ 3,239,656.46**

Northern States Power Company

Electric Operation - State of Minnesota

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - SYSTEM

	July 18	August 18	September 18	October 18	November 18	December 18	January 19	February 19	March 19	April 19	May 19	June 19
Day Ahead & Real Time Asset & Non-Asset Energy												
1 a Day-Ahead Asset Energy Amount - Energy Component	(6,427,342.24)	477,154.64	(7,186,012.70)	(6,997,648.67)	(15,227,576.71)	(10,555,045.51)	(3,121,529.45)	(7,044,275.35)	(4,388,180.63)	(656,753.91)	(13,086,587.61)	(14,114,597.62)
5 a Day-Ahead Non-Asset Energy Amount - Energy Component	(7,596,662.58)	(7,564,303.08)	(6,655,205.04)	(6,536,574.59)	(3,876,510.04)	(3,534,295.08)	(2,760,059.53)	(2,963,666.07)	(3,650,021.92)	(2,391,705.22)	(5,752,237.09)	(4,979,711.15)
13 a Real-Time Asset Energy Amount - Energy Component	(1,304,549.72)	(1,123,121.63)	1,167,857.12	7,557,082.03	146,572.78	(245,591.13)	(1,675,988.00)	(147,856.74)	(705,137.65)	(49,991.23)	(1,222,699.28)	(1,232,387.51)
22 a Real-Time Non-Asset Energy Amount - Energy Component	11,829.92	53,103.24	4,230.60	(6,182.61)	(721.25)	5,131.23	1,842.64	151.42	0.47	8,022.27	5,416.78	20,701.13
SUBTOTAL	(15,316,724.62)	(8,157,166.83)	(12,669,130.02)	(5,983,323.84)	(18,958,235.22)	(14,329,800.49)	(7,555,734.34)	(10,155,646.74)	(8,743,339.73)	(3,090,428.09)	(20,056,107.20)	(20,305,995.15)
Day Ahead & Real Time Energy Loss												
1 c Day-Ahead Asset Energy Amount - Loss Component	2,927,202.34	3,087,706.54	2,204,337.92	2,770,216.27	3,607,922.75	3,762,248.39	3,488,042.21	2,693,104.17	3,045,595.98	2,032,461.42	1,767,793.53	1,674,123.01
3 Day-Ahead Financial Bilateral Transaction Loss Amount	(3,039.31)	(2,912.34)	(6,980.25)	(90.81)	2,345.74	3,013.71	1,797.62	7,326.99	5,532.06	2,416.41	(315.23)	(2,320.69)
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	878,685.81	926,635.36	817,936.28	527,103.28	277,707.87	303,202.87	213,462.82	55,088.20	83,951.50	116,313.31	466,646.76	638,256.19
13 c Real-Time Asset Energy Amount - Loss Component	123,291.50	260,532.92	24,291.11	2,611.07	(16,823.34)	15,682.86	(81,323.02)	(6,318.04)	47,058.99	(5,167.08)	59,320.44	97,746.49
22 c Real-Time Non-Asset Energy Amount - Loss Component	(1,450.74)	(3,661.95)	(704.45)	(15.55)	0.86	(34.32)	0.04	-	-	(248.56)	(414.85)	(2,843.32)
14 Real-Time Distribution of Losses Amount	(1,424,393.71)	(1,289,052.28)	(1,026,632.15)	(922,125.28)	(1,121,300.12)	(1,240,909.23)	(1,146,336.64)	(1,319,387.99)	(793,578.25)	(675,750.58)	(513,384.45)	(650,316.74)
16 Real-Time Financial Bilateral Transaction Loss Amount	5.08	97.69	-	1.14	-	3.23	-	-	-	-	-	7.25
SUBTOTAL	2,500,300.97	2,979,345.94	2,012,248.46	2,377,700.12	2,749,853.76	2,843,207.51	2,475,643.03	1,429,813.33	2,388,560.28	1,470,024.92	1,779,646.20	1,754,652.19
Virtual Energy Charges												
12 Day-Ahead Virtual Energy Amount	-	-	-	-	-	-	-	-	-	-	-	-
27 Real-Time Virtual Energy Amount												
SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-
Market Administration Charges (Schedule 16 & 17)												
4 Day-Ahead Market Administration Amount	656,616.55	537,904.16	647,893.53	783,368.61	894,534.22	664,578.14	428,143.14	551,980.86	686,113.77	606,290.04	682,972.06	876,227.03
19 Real-Time Market Administration Amount	50,704.08	38,818.57	56,094.68	52,710.27	62,294.73	48,738.53	29,413.76	41,461.12	56,279.14	58,805.28	60,703.52	65,146.30
29 Financial Transmission Rights Market Administration Amount	20,096.24	18,087.28	16,066.00	14,516.00	8,686.24	15,955.28	29,176.72	7,976.88	28,312.64	40,536.92	32,748.81	43,186.77
33 Day-Ahead Schedule 24 Allocation Amount	96,499.39	96,356.87	107,122.00	103,289.24	103,860.95	98,245.53	93,842.77	89,246.18	99,517.54	93,323.55	98,029.65	93,765.32
34 Real -Time Schedule 24 Allocation Amount	(84,960.45)	(69,865.97)	(93,731.13)	(84,513.82)	(80,773.56)	(82,037.24)	(78,210.62)	(74,893.62)	(84,071.29)	(80,695.07)	(79,433.57)	(82,229.02)
35 Schedule 24 Admin Allocation												
SUBTOTAL	738,955.81	621,300.91	733,445.08	869,370.30	988,602.58	745,480.24	502,365.77	615,771.42	786,151.80	718,260.72	795,020.47	996,096.40
Congestion Related Charges												
1 b Day-Ahead Asset Energy Amount - Congestion Component	1,614,903.69	667,548.79	448,282.98	348,422.11	187,285.79	1,507,770.72	1,996,616.80	1,482,893.85	2,061,684.44	1,003,404.09	526,019.77	435,190.70
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	992,591.94	647,075.01	894,184.74	260,094.46	185,495.14	158,918.96	(35,883.01)	(483,219.56)	450,167.94	210,874.36	937,003.39	684,043.94
13 b Real-Time Asset Energy Amount - Congestion Component	132,109.20	527,854.56	171,379.30	46,300.57	(23,629.14)	58,537.78	(168,205.37)	16,808.99	96,488.85	111,551.53	71,887.25	72,788.08
22 b Real-Time Non-Asset Energy Amount - Congestion Component	(2,267.85)	(803.75)	(210.35)	(19.68)	5.20	2.66	0.05	-	-	6,717.36	(121.36)	(4,947.87)
2 Day-Ahead Financial Bilateral Transmission Congestion Amount	(8,295.10)	848.86	(18,283.58)	(50.24)	(7,269.33)	(878.41)	11,650.90	29,647.58	2,675.57	(329.13)	(10,982.49)	(8,228.23)
15 Real-Time Financial Bilateral Transaction Congestion Amount	3.27	328.84	-	6.22	-	12.93	-	-	-	-	-	15.07
28 Financial Transmission Rights Hourly Allocation Amount	(2,712,847.13)	(834,866.42)	(503,905.53)	(80,434.15)	151,905.71	(1,167,361.77)	(381,905.51)	293,886.74	(2,156,939.27)	(97,019.43)	(1,259,506.68)	(1,129,744.04)
30 Financial Transmission Rights Monthly Allocation Amount	(3,582.30)	(37,459.65)	(44,253.83)	(48,652.72)	(16,516.41)	(80,110.50)	(90,157.52)	(94,015.01)	(112,020.04)	(83,667.83)	(150,543.49)	(38,352.60)
32 Financial Transmission Rights Yearly Allocation Amount	-	-	-	-	-	-	(426,287.70)	1.07	-	-	-	-
31 Financial Transmission Rights Transaction Amount												
36 Financial Transmission Rights Full Funding Guarantee Amount	(17,821.32)	(5,682.10)	5,818.31	(25,345.74)	40,298.85	(97,314.32)	435,503.09	(81,675.23)	(58,051.82)	30,592.69	(23,950.27)	(66,727.21)
37 Financial Transmission Guarantee Uplift Amount	17,801.92	5,183.65	(5,065.14)	25,337.71	(40,641.55)	94,933.31	(473,346.96)	102,923.50	61,106.83	(16,787.49)	6,700.83	51,872.13
38 Financial Transmission Rights Monthly Transaction Amount												
SUBTOTAL	12,596.32	970,027.79	947,946.90	525,658.54	476,934.26	474,511.36	867,984.77	1,267,251.93	345,112.50	1,165,336.15	96,506.95	(4,090.03)
Revenue Sufficiency Guarantee (RSG) Charges												
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	39,382.90	63,525.61	62,311.02	98,385.96	111,056.42	119,041.48	90,772.12	98,781.00	90,530.24	82,593.70	79,507.00	63,219.85
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	(28,978.79)	(30,490.54)	(39,059.66)	(15,835.89)	(76,788.74)	(113,726.60)	(88,258.02)	(70,178.46)	(111,365.39)	(40,700.24)	(92,547.73)	(62,870.47)
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	413,559.57	213,019.94	357,710.30	271,236.87	169,296.50	117,415.06	64,030.81	216,975.93	203,122.10	62,726.92	143,230.20	146,536.63
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	(209,141.97)	(99,818.34)	(178,197.87)	(300,760.84)	(378,364.21)	(195,033.76)	(114,702.05)	(3,473,889.70)	(273,885.54)	(33,210.06)	(15,698.46)	(37,234.01)
43 Real Time Price Volatility Make Whole Payment	(99,729.82)	(36,231.99)	(162,966.54)	(43,614.46)	(76,569.25)	(38,980.18)	(55,970.79)	(94,587.85)	(44,620.67)	(116,503.07)	(56,103.03)	(40,310.38)
SUBTOTAL	115,091.89	110,004.68	39,797.25	9,411.64	(251,369.28)	(111,284.00)	(104,127.93)	(3,322,899.08)	(136,219.26)	(45,092.75)	58,387.98	69,341.62
Other MISO Charges												
20 Real-Time Miscellaneous Amount	321,960.64	96,039.80	202,080.96	96,275.38	173,251.92	369,744.02	48,986.87	79,029.18	155,878.10	192,235.93	(116,506.77)	212,493.08
21 Real-time Net inadvertent Distribution	220,572.75	11,705.02	(92,059.80)	77,626.14	(107,138.55)	99,169.58	(50,899.18)	(133,686.51)	97,293.07	(120,804.06)	147.75	43,454.12
23 Real-Time Revenue Neutrality Uplift Amount	185,822.99	53,787.45	28,294.23	655,240.42	295,464.55	484,100.39	11,044.93	1,712,181.83	249,977.97	330,681.35	463,508.81	158,851.88
26 Real-Time Uninstructed Deviation Amount												
SUBTOTAL	728,356.38	161,532.27	138,315.39	829,141.94	361,577.92	953,013.99	9,132.62	1,657,524.50	503,149.14	402,113.22	347,149.79	414,799.08
Auction Revenue Rights (ARR)												
39 Auction Revenue Rights - FTR Auction Transactions	2,270,304.83	2,270,304.83	2,189,565.60	2,189,565.60	2,189,565.60	1,791,300.13	1,791,300.13	1,791,300.13	2,547,181.68	2,547,181.68	2,547,181.68	1,805,216.47
40 Auction Revenue Rights - Monthly ARR Revenue	(2,293,458.77)	(2,293,458.77)	(2,190,703.62)	(2,190,703.62)	(2,190,703.62)	(1,791,548.83)	(1,791,548.83)	(1,791,548.83)	(2,571,169.74)	(2,571,169.74)	(2,571,169.74)	(1,805,445.07)
41 Auction Revenue Rights - ARR Stage 2 Distribution	(320,148.19)	(320,148.49)	(242,965.26)	(242,964.65)	(242,964.65)	(155,089.36)	(153,246.61)	(156,670.33)	(90,957.73)	(90,957.87)	(90,957.87)	(202,033.21)
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	41,430.89	41,430.89	130,420.69	130,420.69	130,420.69	42,374.37	42,389.67	42,379.47	55,175.45	55,175.45	55,175.45	25,882.21
SUBTOTAL	(301,871.24)	(301,871.54)	(113,682.59)	(113,681.98)	(113,681.98)	(112,963.69)	(111,105.64)	(114,539.56)	(59,770.34)	(59,770.48)	(59,770.48)	(176,379.60)
Grandfathered Charge Types												
6 Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	8,295.10	(848.86)	18,283.58	50.24	7,269.33	878.41	(11,650.90)	(29,647.58)	(2,675.57)	329.13	10,982.49	8,228.23
7 Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	3,039.31	2,912.35	6,980.25	90.81	(2,345.74)	(3,013.71)	(1,797.62)	(7,326.99)	(5,532.06)	(2,416.41)	315.23	2,320.69
8 Day-Ahead Congestion Rebate on Option B Grandfathered Agreements												
9 Day-Ahead Losses Rebate on Option B Grandfathered Agreements												
17 Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	(3.27)	(328.84)	-	(6.22)	-	(12.93)	-	-	-	-	-	(15.07)
18 Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	(5.08)	(97.69)	-	(1.14)	-	(3.23)	-	-	-	-	-	(7.25)
SUBTOTAL	11,326.06	1,636.96	25,263.83	133.69	4,923.59	(2,151.46)	(13,448.52)	(36,974.57)	(8,207.63)	(2,087.28)	11,297.72	10,526.60
TOTAL MISO DAY 2 CHARGES	(11,511,968.43)	(3,615,189.82)	(8,885,795.70)	(1,485,589.59)	(14,741,394.37)	(9,539,986.54)	(3,929,290.24)	(8,659,698.77)	(4,924,563.24)	558,356.41	(17,027,868.57)	(17,241,048.89)

		July 19	August 19	September 19	October 19	November 19	December 19	YTD
Day Ahead & Real Time Asset & Non-Asset Energy								
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (12,666,821.59)	$ (10,882,366.12)	$ (10,619,183.75)	$ (8,766,927.58)	$ (14,003,311.03)	$ (11,711,719.33)	$ (156,978,725.16)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,636,433.37)	$ (5,730,150.72)	$ (5,526,254.85)	$ (3,249,260.05)	$ (2,661,404.19)	$ (2,783,955.25)	$ (84,848,409.82)
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,221,316.15)	$ (1,052,482.22)	$ (841,420.20)	$ 39,443.49	$ (460,598.94)	$ 110,686.34	$ (2,261,498.64)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 7,709.67	$ 8,686.61	$ 27.23	$ 64,519.87	$ 215.56	$ (1,012.53)	$ 183,672.25
	SUBTOTAL	$ (20,516,861.44)	$ (17,656,312.45)	$ (16,986,831.57)	$ (11,912,224.27)	$ (17,125,098.60)	$ (14,386,000.77)	$ (243,904,961.37)
Day Ahead & Real Time Energy Loss								
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,664,374.28	$ 2,083,104.75	$ 1,770,942.42	$ 1,995,030.74	$ 2,348,066.64	$ 2,301,715.99	$ 46,223,989.35
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (3,035.09)	$ (2,674.69)	$ (5,214.50)	$ (958.82)	$ (63.64)	$ 212.07	$ (4,960.77)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 816,261.80	$ 706,449.61	$ 807,789.05	$ 332,517.90	$ 284,331.79	$ 229,674.02	$ 8,482,014.42
13 c	Real-Time Asset Energy Amount - Loss Component	$ 119,784.67	$ 110,044.98	$ 122,175.29	$ 9,758.39	$ 48,784.95	$ 16,816.94	$ 948,269.12
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (432.62)	$ (384.30)	$ (25.99)	$ 1,063.34	$ (39.83)	$ 16.02	$ (9,176.22)
14	Real-Time Distribution of Losses Amount	$ (1,175,922.23)	$ (863,775.46)	$ (805,409.36)	$ (518,123.61)	$ (657,043.93)	$ (912,334.22)	$ (17,055,776.23)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ 12.56	$ -	$ -	$ 126.95
	SUBTOTAL	$ 2,421,030.81	$ 2,032,764.89	$ 1,890,256.91	$ 1,819,300.50	$ 2,024,035.98	$ 1,636,100.82	$ 38,584,486.62
Virtual Energy Charges								
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount							$ -
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Administration Charges (Schedule 16 & 17)								
4	Day-Ahead Market Administration Amount	$ 695,556.87	$ 400,654.06	$ 592,456.64	$ 687,978.31	$ 607,514.50	$ 780,267.99	$ 11,781,050.48
19	Real-Time Market Administration Amount	$ 53,676.55	$ 25,046.11	$ 47,334.67	$ 63,928.30	$ 60,308.87	$ 65,004.23	$ 936,468.71
29	Financial Transmission Rights Market Administration Amount	$ 27,042.60	$ 10,435.94	$ 28,566.79	$ 23,921.89	$ 19,570.56	$ 24,626.30	$ 409,509.86
33	Day-Ahead Schedule 24 Allocation Amount	$ 105,021.95	$ 93,136.38	$ 90,286.38	$ 86,324.07	$ 84,740.12	$ 98,214.55	$ 1,730,822.44
34	Real -Time Schedule 24 Allocation Amount	$ (93,659.66)	$ (84,546.43)	$ (83,068.01)	$ (78,878.80)	$ (74,091.80)	$ (67,971.70)	$ (1,457,631.76)
35	Schedule 24 Admin Allocation							$ -
	SUBTOTAL	$ 787,638.31	$ 444,726.06	$ 675,576.47	$ 783,273.77	$ 698,042.25	$ 900,141.37	$ 13,400,219.73
Congestion Related Charges								
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,569,518.59	$ 2,141,545.63	$ 1,605,403.91	$ 2,262,762.43	$ 1,905,613.83	$ 1,545,634.06	$ 25,310,502.18
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,378,480.18	$ 1,254,254.16	$ 933,569.28	$ 552,425.65	$ 187,215.31	$ (4,671.77)	$ 9,202,620.12
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 176,597.75	$ 22,656.96	$ 218,626.21	$ 142,719.63	$ 92,775.38	$ (778.56)	$ 1,766,468.97
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (419.25)	$ (120,069.05)	$ (1.23)	$ 4,393.50	$ (97.86)	$ 997.68	$ (116,841.80)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 10,844.82	$ 7,536.97	$ (6,828.80)	$ (7,592.48)	$ 1,906.58	$ 10,460.62	$ 6,834.11
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ 33.27	$ -	$ -	$ 399.60
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,460,660.10)	$ (3,699,105.15)	$ (1,525,831.06)	$ (426,804.42)	$ (1,169,823.12)	$ (636,844.90)	$ (21,797,806.23)
30	Financial Transmission Rights Monthly Allocation Amount	$ (137,857.43)	$ (200,076.68)	$ (63,914.41)	$ (37,459.02)	$ (42,276.61)	$ (39,365.46)	$ (1,320,281.51)
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ (426,286.63)
31	Financial Transmission Rights Transaction Amount							$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (264,018.18)	$ (174,203.01)	$ 30,121.26	$ (11,499.97)	$ (68,725.91)	$ (89,773.02)	$ (442,453.90)
37	Financial Transmission Guarantee Uplift Amount	$ 194,543.93	$ 267,173.35	$ (47,374.50)	$ 29,504.90	$ 73,143.23	$ 82,954.80	$ 429,964.45
38	Financial Transmission Rights Monthly Transaction Amount							$ -
	SUBTOTAL	$ 467,030.31	$ (500,286.82)	$ 1,143,770.66	$ 2,508,483.49	$ 979,730.83	$ 868,613.45	$ 12,613,119.36
Revenue Sufficiency Guarantee (RSG) Charges								
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 55,978.72	$ 60,391.61	$ 54,807.01	$ 83,205.81	$ 66,452.30	$ 69,143.39	$ 1,389,086.14
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (18,013.28)	$ (22,016.00)	$ (142,948.39)	$ (182,534.20)	$ (107,080.46)	$ (108,131.14)	$ (1,351,524.00)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 148,671.41	$ 88,903.98	$ 56,155.10	$ 82,118.79	$ 82,598.89	$ 41,494.97	$ 2,878,803.97
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (72,706.96)	$ (38,242.65)	$ (83,337.48)	$ (52,982.12)	$ (108,771.54)	$ (59,419.98)	$ (5,725,397.54)
43	Real Time Price Volatility Make Whole Payment	$ (62,129.15)	$ (128,885.19)	$ (87,380.70)	$ (76,259.32)	$ (47,620.76)	$ (48,182.59)	$ (1,316,645.74)
	SUBTOTAL	$ 51,800.74	$ (39,848.25)	$ (202,704.46)	$ (146,451.04)	$ (114,421.57)	$ (105,095.35)	$ (4,125,677.17)
Other MISO Charges								
20	Real-Time Miscellaneous Amount	$ 170,484.76	$ 135,961.02	$ 254,600.63	$ 219,979.65	$ 606,534.59	$ 117,351.45	$ 3,336,381.21
21	Real-time Net inadvertent Distribution	$ (2,930.86)	$ 74,327.00	$ 15,768.18	$ 14,735.95	$ 22,346.64	$ 14,831.50	$ 184,458.74
23	Real-Time Revenue Neutrality Uplift Amount	$ 467,688.86	$ 372,318.76	$ 71,452.24	$ 517,573.18	$ (70,454.99)	$ 352,729.16	$ 6,340,264.01
26	Real-Time Uninstructed Deviation Amount							$ -
	SUBTOTAL	$ 635,242.76	$ 582,606.78	$ 341,821.05	$ 752,288.78	$ 558,426.24	$ 484,912.11	$ 9,861,103.96
Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,805,216.47	$ 1,805,216.47	$ 1,337,779.21	$ 1,337,779.21	$ 1,337,779.21	$ 1,123,444.70	$ 34,677,183.63
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,805,445.07)	$ (1,805,445.07)	$ (1,340,179.39)	$ (1,340,179.39)	$ (1,340,179.39)	$ (1,123,867.22)	$ (34,807,924.71)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (204,112.67)	$ (203,055.76)	$ (198,269.67)	$ (198,206.91)	$ (198,218.84)	$ (207,296.32)	$ (3,518,264.39)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,882.21	$ 25,882.21	$ 59,727.45	$ 59,727.45	$ 59,727.45	$ 42,660.70	$ 1,066,283.39
	SUBTOTAL	$ (178,459.06)	$ (177,402.15)	$ (140,942.40)	$ (140,879.64)	$ (140,891.57)	$ (165,058.14)	$ (2,582,722.08)
Grandfathered Charge Types								
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (10,844.82)	$ (7,536.97)	$ 6,828.80	$ 7,592.48	$ (1,906.58)	$ (10,460.62)	$ (6,834.11)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 3,035.09	$ 2,674.69	$ 5,214.50	$ 958.82	$ 63.64	$ (212.07)	$ 4,960.78
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements							$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements							$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ (33.27)	$ -	$ -	$ (399.60)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ (12.56)	$ -	$ -	$ (126.95)
	SUBTOTAL	$ (7,809.73)	$ (4,862.28)	$ 12,043.30	$ 8,505.47	$ (1,842.94)	$ (10,672.69)	$ (2,399.88)
								0
	TOTAL MISO DAY 2 CHARGES	$ (16,340,387.30)	$ (15,318,614.22)	$ (13,267,010.04)	$ (6,327,702.94)	$ (13,122,019.38)	$ (10,777,059.20)	$ (176,156,830.83)

Northern States Power Company
Electric Operation - State of Minnesota

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - INTERSYSTEM

Docket No. E999/AA-20-171
Part J, Section 5
Schedule 4

		July 18	August 18	September 18	October 18	November 18	December 18	January 19	February 19	March 19	April 19	May 19	June 19
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 16,534,795.62	$ 8,672,225.62	$ 14,250,345.33	$ 10,453,243.68	$ 19,512,393.65	$ 14,191,971.52	$ 14,335,930.92	$ 12,297,020.88	$ 11,843,477.63	$ 7,367,799.79	$ 19,557,971.27	$ 17,587,348.32
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component												
13 a	Real-Time Asset Energy Amount - Energy Component	$ 2,223,458.47	$ 1,593,747.70	$ 1,707,309.96	$ 1,306,700.28	$ 2,346,024.11	$ 2,325,052.41	$ 2,628,609.32	$ 1,430,714.90	$ 1,871,750.40	$ 2,021,122.26	$ 2,096,558.79	$ 1,784,877.40
22 a	Real-Time Non-Asset Energy Amount - Energy Component												
	SUBTOTAL	$ 18,758,254.09	$ 10,265,973.32	$ 15,957,655.29	$ 11,759,943.96	$ 21,858,417.76	$ 16,517,023.93	$ 16,964,540.24	$ 13,727,735.78	$ 13,715,228.03	$ 9,388,922.05	$ 21,654,530.06	$ 19,372,225.72
Day Ahead & Real Time Energy Loss													
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ (424,723.22)	$ (247,535.48)	$ (337,543.05)	$ (243,830.52)	$ (656,578.81)	$ (557,353.31)	$ (509,367.71)	$ (574,269.71)	$ (482,303.45)	$ (237,006.42)	$ (480,725.47)	$ (359,150.63)
3	Day-Ahead Financial Bilateral Transaction Loss Amount												
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ (127,493.16)	$ (74,286.57)	$ (125,247.90)	$ (46,394.89)	$ (50,537.97)	$ (44,917.59)	$ (31,172.52)	$ (11,746.85)	$ (13,294.64)	$ (13,563.36)	$ (126,897.73)	$ (136,925.49)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 210.50	$ 293.57	$ 107.87	$ 1.37	$ (0.16)	$ 5.08	$ (0.01)	$ -	$ -	$ 28.98	$ 112.81	$ 609.98
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 25,909.37	$ 23,964.86	$ 5,627.93	$ (2,681.33)	$ (3,484.22)	$ (281.33)	$ (797.11)	$ (11,560.02)	$ 9,043.42	$ 4,291.82	$ 38,644.97	$ (31,817.32)
14	Real-Time Distribution of Losses Amount												
16	Real-Time Financial Bilateral Transaction Loss Amount												
	SUBTOTAL	$ (526,096.52)	$ (297,563.62)	$ (457,055.16)	$ (292,905.37)	$ (710,601.16)	$ (602,547.15)	$ (541,337.35)	$ (597,576.58)	$ (486,554.66)	$ (246,248.98)	$ (568,865.42)	$ (527,283.46)
Virtual Energy Charges													
12	Day-Ahead Virtual Energy Amount												
27	Real-Time Virtual Energy Amount												
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Administration Charges (Schedule 16 & 17)													
4	Day-Ahead Market Administration Amount	$ (45,158.58)	$ (20,001.83)	$ (48,001.57)	$ (39,523.79)	$ (79,283.01)	$ (43,489.12)	$ (30,063.74)	$ (36,456.99)	$ (45,682.80)	$ (29,858.45)	$ (96,535.04)	$ (86,139.05)
19	Real-Time Market Administration Amount	$ (6,262.88)	$ (3,745.54)	$ (5,266.24)	$ (6,406.62)	$ (10,955.16)	$ (9,532.65)	$ (4,356.47)	$ (5,411.46)	$ (9,086.89)	$ (9,091.75)	$ (12,999.03)	$ (8,970.33)
29	Financial Transmission Rights Market Administration Amount												
33	Day-Ahead Schedule 24 Allocation Amount	$ (6,492.24)	$ (3,559.35)	$ (7,424.82)	$ (4,967.40)	$ (9,527.73)	$ (6,421.29)	$ (6,518.07)	$ (5,906.96)	$ (6,612.42)	$ (4,676.52)	$ (10,304.06)	$ (12,125.24)
34	Real -Time Schedule 24 Allocation Amount	$ 73,927.61	$ 84,904.57	$ 90,652.58	$ 88,003.93	$ 92,398.49	$ 86,910.38	$ 84,211.35	$ 86,916.51	$ 68,614.93	$ 102,034.84	$ 71,901.93	$ 101,962.18
35	Schedule 24 Admin Allocation												
	SUBTOTAL	$ 16,013.91	$ 57,597.85	$ 29,959.95	$ 37,106.12	$ (7,367.41)	$ 27,467.32	$ 43,273.07	$ 39,141.10	$ 7,232.82	$ 58,408.12	$ (47,936.20)	$ (5,272.44)
Congestion Related Charges													
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ (234,314.89)	$ (53,516.10)	$ (68,644.11)	$ (30,667.62)	$ (34,082.74)	$ (223,366.70)	$ (291,571.05)	$ (316,207.97)	$ (326,490.29)	$ (117,007.49)	$ (143,043.35)	$ (93,361.73)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (144,020.40)	$ (51,874.76)	$ (136,923.58)	$ (22,893.15)	$ (33,756.87)	$ (23,542.84)	$ 5,240.09	$ 103,040.33	$ (71,289.02)	$ (24,590.17)	$ (254,804.30)	$ (146,748.36)
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 329.05	$ 64.44	$ 32.21	$ 1.73	$ (0.95)	$ (0.39)	$ (0.01)	$ -	$ -	$ (783.31)	$ 33.00	$ 1,061.47
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 20,829.58	$ 46,513.78	$ 38,501.34	$ 1,700.18	$ 2,006.10	$ (1,511.70)	$ (20,547.83)	$ (24,658.41)	$ (4,185.22)	$ 60,346.80	$ 33,834.78	$ 21,407.74
2	Day-Ahead Financial Bilateral Transmission Congestion Amount												
15	Real-Time Financial Bilateral Transaction Congestion Amount												
28	Financial Transmission Rights Hourly Allocation Amount												
30	Financial Transmission Rights Monthly Allocation Amount												
32	Financial Transmission Rights Yearly Allocation Amount												
31	Financial Transmission Rights Transaction Amount												
36	Financial Transmission Rights Full Funding Guarantee Amount												
37	Financial Transmission Guarantee Uplift Amount												
38	Financial Transmission Rights Monthly Transaction Amount												
	SUBTOTAL	$ (357,176.65)	$ (58,812.64)	$ (167,034.13)	$ (51,858.85)	$ (65,834.45)	$ (248,421.63)	$ (306,878.80)	$ (237,826.05)	$ (401,964.53)	$ (82,034.18)	$ (363,979.87)	$ (217,640.88)
Revenue Sufficiency Guarantee (RSG) Charges													
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ (5,714.27)	$ (5,092.73)	$ (9,541.48)	$ (8,659.79)	$ (20,210.33)	$ (17,635.24)	$ (13,255.68)	$ (21,063.77)	$ (14,336.45)	$ (9,631.30)	$ (21,620.76)	$ (13,562.59)
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ 27,159.57	$ 62,347.80	$ 32,926.20	$ 33,357.48	$ 72,089.54	$ 38,216.52	$ 55,618.70	$ 35,346.36	$ 37,859.08	$ 10,982.16	$ 56,963.70	$ 32,777.65
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (60,005.54)	$ (17,077.40)	$ (54,775.01)	$ (23,873.89)	$ (30,809.00)	$ (17,394.30)	$ (9,350.58)	$ (46,267.32)	$ (32,166.61)	$ (7,314.62)	$ (38,949.35)	$ (31,436.59)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 129,812.92	$ 112,764.97	$ 108,960.59	$ 127,695.78	$ 233,878.08	$ 109,356.57	$ (5,564.92)	$ 2,683,525.11	$ 24,624.91	$ 25,020.32	$ (29,282.76)	$ 32,921.90
43	Real Time Price Volatility Make Whole Payment	$ 18,768.89	$ 9,149.72	$ 12,531.14	$ 15,386.86	$ 7,590.31	$ 10,485.88	$ 11,208.30	$ 7,006.23	$ 19,230.98	$ 6,477.62	$ 14,122.11	$ 12,454.92
	SUBTOTAL	$ 110,021.57	$ 162,092.37	$ 90,101.44	$ 143,906.44	$ 262,538.60	$ 123,029.43	$ 38,655.81	$ 2,658,546.61	$ 35,211.91	$ 25,534.18	$ (18,767.06)	$ 33,155.28
Other MISO Charges													
20	Real-Time Miscellaneous Amount	$ 10,703.99	$ 10,703.99	$ 10,358.70	$ 10,703.99	$ 10,358.70	$ 10,703.99	$ 10,703.99	$ 9,668.12	$ 10,703.99	$ 10,358.70	$ 10,703.99	$ 11,894.10
21	Real-time Net inadvertent Distribution												
23	Real-Time Revenue Neutrality Uplift Amount	$ (26,962.04)	$ (4,312.04)	$ (4,332.60)	$ (57,673.34)	$ (53,769.38)	$ (71,716.41)	$ (1,612.92)	$ (365,100.68)	$ (39,586.75)	$ (38,560.93)	$ (126,044.41)	$ (34,078.59)
26	Real-Time Uninstructed Deviation Amount												
	SUBTOTAL	$ (16,258.05)	$ 6,391.95	$ 6,026.10	$ (46,969.35)	$ (43,410.68)	$ (61,012.42)	$ 9,091.07	$ (355,432.56)	$ (28,882.76)	$ (28,202.23)	$ (115,340.42)	$ (22,184.49)
Auction Revenue Rights (ARR)													
39	Auction Revenue Rights - FTR Auction Transactions												
40	Auction Revenue Rights - Monthly ARR Revenue	$ 2,407.08	$ 10,397.76	$ 10,541.26	$ (5,093.26)	$ 2,677.80	$ 3,108.27	$ 116,443.80	$ 58,738.32	$ 25,992.35	$ 23,992.35	$ 25,169.16	$ 8,792.80
41	Auction Revenue Rights - ARR Stage 2 Distribution												
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue												
	SUBTOTAL	$ 2,407.08	$ 10,397.76	$ 10,541.26	$ (5,093.26)	$ 2,677.80	$ 3,108.27	$ 116,443.80	$ 58,738.32	$ 25,992.35	$ 23,992.35	$ 25,169.16	$ 8,792.80
Grandfathered Charge Types													
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements												
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements												
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements												
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements												
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements												
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements												
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TOTAL MISO DAY 2 CHARGES	$ 17,987,165.43	$ 10,146,076.99	$ 15,470,194.75	$ 11,544,129.69	$ 21,296,420.47	$ 15,758,647.75	$ 16,323,787.85	$ 15,293,326.62	$ 12,866,263.16	$ 9,140,371.32	$ 20,564,810.25	$ 18,641,792.54

Northern States Power Company
Electric Operation - State of Minnesota

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - INTERSYSTEM

No.	Description	July 19	August 19	September 19	October 19	November 19	December 19	YTD
	Day Ahead & Real Time Asset & Non-Asset Energy							
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 19,608,408.16	$ 16,404,588.56	$ 16,237,998.12	$ 12,441,406.49	$ 16,543,375.21	$ 15,366,833.74	$ 263,207,134.51
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component							$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,896,329.76	$ 1,334,147.98	$ 1,179,016.67	$ 1,453,982.13	$ 3,108,167.34	$ 1,637,301.56	$ 33,944,871.44
22 a	Real-Time Non-Asset Energy Amount - Energy Component							$ -
	SUBTOTAL	$ 21,504,737.92	$ 17,738,736.54	$ 17,417,014.79	$ 13,895,388.62	$ 19,651,542.55	$ 17,004,135.30	$ 297,152,005.95
	Day Ahead & Real Time Energy Loss							
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ (476,143.04)	$ (392,795.68)	$ (345,652.38)	$ (362,730.31)	$ (491,665.72)	$ (469,774.33)	$ (7,649,149.24)
3	Day-Ahead Financial Bilateral Transaction Loss Amount							$ -
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ (145,871.91)	$ (133,209.98)	$ (157,664.19)	$ (60,457.38)	$ (59,536.72)	$ (46,875.88)	$ (1,406,094.73)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 77.31	$ 72.46	$ 5.07	$ (193.33)	$ 8.34	$ (3.27)	$ 1,336.59
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 26,300.70	$ 9,509.09	$ 37,638.77	$ (5,680.43)	$ (162.17)	$ (2,356.92)	$ 122,110.07
14	Real-Time Distribution of Losses Amount							$ -
16	Real-Time Financial Bilateral Transaction Loss Amount							$ -
	SUBTOTAL	$ (595,636.94)	$ (516,424.10)	$ (465,672.72)	$ (429,061.45)	$ (551,356.28)	$ (519,010.41)	$ (8,931,797.31)
	Virtual Energy Charges							
12	Day-Ahead Virtual Energy Amount							$ -
27	Real-Time Virtual Energy Amount							$ -
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Market Administration Charges (Schedule 16 & 17)							
4	Day-Ahead Market Administration Amount	$ (62,053.30)	$ (35,211.29)	$ (60,877.89)	$ (61,916.89)	$ (64,267.99)	$ (69,497.81)	$ (954,019.14)
19	Real-Time Market Administration Amount	$ (6,252.35)	$ (3,217.88)	$ (4,998.25)	$ (7,702.88)	$ (12,823.95)	$ (10,024.89)	$ (137,105.22)
29	Financial Transmission Rights Market Administration Amount							$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ (9,323.59)	$ (8,160.66)	$ (9,300.06)	$ (7,788.14)	$ (8,959.83)	$ (8,725.25)	$ (136,793.63)
34	Real -Time Schedule 24 Allocation Amount	$ 92,047.70	$ 105,996.12	$ 82,402.24	$ 89,170.83	$ 81,860.75	$ 86,968.43	$ 1,570,885.37
35	Schedule 24 Admin Allocation							$ -
	SUBTOTAL	$ 14,418.46	$ 59,406.29	$ 7,226.04	$ 11,762.92	$ (4,191.02)	$ (1,279.52)	$ 342,967.38
	Congestion Related Charges							
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ (637,898.91)	$ (403,815.44)	$ (313,342.59)	$ (411,408.46)	$ (399,019.77)	$ (315,459.95)	$ (4,413,219.14)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (246,344.42)	$ (236,505.44)	$ (182,213.96)	$ (100,440.32)	$ (39,201.34)	$ 953.50	$ (1,605,915.02)
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 74.92	$ 22,640.53	$ 0.24	$ (798.81)	$ 20.49	$ (203.62)	$ 22,470.99
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 80,517.29	$ (7,267.96)	$ 54,372.98	$ 34,439.29	$ 19,475.96	$ (12,914.89)	$ 342,859.84
2	Day-Ahead Financial Bilateral Transmission Congestion Amount							$ -
15	Real-Time Financial Bilateral Transaction Congestion Amount							$ -
28	Financial Transmission Rights Hourly Allocation Amount							$ -
30	Financial Transmission Rights Monthly Allocation Amount							$ -
32	Financial Transmission Rights Yearly Allocation Amount							$ -
31	Financial Transmission Rights Transaction Amount							$ -
36	Financial Transmission Rights Full Funding Guarantee Amount							$ -
37	Financial Transmission Guarantee Uplift Amount							$ -
38	Financial Transmission Rights Monthly Transaction Amount							$ -
	SUBTOTAL	$ (803,651.11)	$ (624,948.30)	$ (441,183.33)	$ (478,208.30)	$ (418,724.65)	$ (327,624.96)	$ (5,653,803.33)
	Revenue Sufficiency Guarantee (RSG) Charges							
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ (10,003.80)	$ (11,387.60)	$ (10,697.23)	$ (15,128.22)	$ (13,914.56)	$ (14,111.99)	$ (235,567.81)
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ 9,339.95	$ 13,882.00	$ 72,086.44	$ 101,557.29	$ 58,141.09	$ 35,532.30	$ 786,183.83
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (26,568.66)	$ (16,763.97)	$ (10,960.35)	$ (14,930.58)	$ (17,295.52)	$ (8,469.02)	$ (464,408.30)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 21,851.87	$ 26,992.47	$ 14,622.71	$ 34,369.65	$ 56,398.90	$ 38,925.77	$ 3,746,874.84
43	Real Time Price Volatility Make Whole Payment	$ 11,499.08	$ 15,583.16	$ 22,219.01	$ 17,883.18	$ 10,285.11	$ 11,560.86	$ 233,443.36
	SUBTOTAL	$ 6,118.43	$ 28,306.06	$ 87,270.59	$ 123,751.31	$ 93,615.01	$ 63,437.92	$ 4,066,525.93
	Other MISO Charges							
20	Real-Time Miscellaneous Amount	$ 12,290.57	$ 12,635.86	$ 11,894.10	$ 12,290.57	$ 11,894.10	$ 12,290.57	$ 200,862.02
21	Real-time Net inadvertent Distribution							$ -
23	Real-Time Revenue Neutrality Uplift Amount	$ (83,579.40)	$ (70,205.40)	$ (13,946.04)	$ (94,103.55)	$ 14,752.69	$ (71,991.12)	$ (1,142,822.89)
26	Real-Time Uninstructed Deviation Amount							$ -
	SUBTOTAL	$ (71,288.83)	$ (57,569.54)	$ (2,051.94)	$ (81,812.98)	$ 26,646.79	$ (59,700.55)	$ (941,960.87)
	Auction Revenue Rights (ARR)							
39	Auction Revenue Rights - FTR Auction Transactions							$ -
40	Auction Revenue Rights - Monthly ARR Revenue	$ 9,069.71	$ 7,307.84	$ 1,824.04	$ 1,781.20	$ 1,895.17	$ 54,964.25	$ 360,009.90
41	Auction Revenue Rights - ARR Stage 2 Distribution							$ -
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue							$ -
	SUBTOTAL	$ 9,069.71	$ 7,307.84	$ 1,824.04	$ 1,781.20	$ 1,895.17	$ 54,964.25	$ 360,009.90
	Grandfathered Charge Types							
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements							$ -
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements							$ -
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements							$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements							$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements							$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements							$ -
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	TOTAL MISO DAY 2 CHARGES	$ 20,063,767.64	$ 16,634,814.79	$ 16,604,427.46	$ 13,043,601.32	$ 18,799,427.58	$ 16,214,922.04	$ 286,393,947.65

Northern States Power Company
Electric Operation - State of Minnesota

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - RETAIL

		July 18	August 18	September 18	October 18	November 18	December 18	January 19	February 19	March 19	April 19	May 19	June 19
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a	Day-Ahead Asset Energy Amount - Energy Component	10,107,453.38	9,149,380.26	7,064,332.63	3,455,595.01	4,284,816.94	3,636,926.01	11,214,401.47	5,252,745.53	7,455,297.00	6,711,045.88	6,471,383.66	3,472,750.70
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	(7,596,662.58)	(7,564,303.08)	(6,655,205.04)	(6,536,574.59)	(3,876,510.04)	(3,534,295.08)	(2,760,059.53)	(2,963,666.07)	(3,650,021.92)	(2,391,705.22)	(5,752,237.09)	(4,979,711.15)
13 a	Real-Time Asset Energy Amount - Energy Component	918,908.75	470,626.07	2,875,167.08	8,863,782.31	2,492,596.89	2,079,461.28	952,621.32	1,282,858.16	1,166,612.75	1,971,131.03	873,859.51	552,489.89
22 a	Real-Time Non-Asset Energy Amount - Energy Component	11,829.92	53,103.24	4,230.60	(6,182.61)	(721.25)	5,131.23	1,842.64	151.42	0.47	8,022.27	5,416.78	20,701.13
	SUBTOTAL	3,441,529.47	2,108,806.49	3,288,525.27	5,776,620.12	2,900,182.54	2,187,223.44	9,408,805.90	3,572,089.04	4,971,888.30	6,298,493.96	1,598,422.86	(933,769.43)
Day Ahead & Real Time Energy Loss													
1 c	Day-Ahead Asset Energy Amount - Loss Component	2,502,479.12	2,840,171.06	1,866,794.87	2,526,385.75	2,951,343.94	3,204,895.08	2,978,674.50	2,118,834.46	2,563,292.53	1,795,455.00	1,287,068.06	1,314,972.38
3	Day-Ahead Financial Bilateral Transaction Loss Amount	(3,039.31)	(2,912.34)	(6,980.25)	(90.81)	2,345.74	3,013.71	1,797.62	7,326.99	5,532.06	2,416.41	(315.23)	(2,320.69)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	751,192.65	852,348.79	692,688.38	480,708.39	227,169.90	258,285.28	182,290.30	43,341.35	70,656.86	102,749.95	339,749.03	501,330.70
13 c	Real-Time Asset Energy Amount - Loss Component	123,502.00	260,826.49	24,398.98	2,612.44	(16,823.50)	15,687.94	(81,323.03)	(6,318.04)	47,058.99	(5,138.10)	59,433.25	98,356.47
22 c	Real-Time Non-Asset Energy Amount - Loss Component	24,458.63	20,302.91	4,923.48	(2,696.88)	(3,483.36)	(315.65)	(797.07)	(11,560.02)	9,043.42	4,043.26	38,230.12	(34,660.64)
14	Real-Time Distribution of Losses Amount	(1,424,393.71)	(1,289,052.28)	(1,026,632.15)	(922,125.28)	(1,121,300.12)	(1,240,909.23)	(1,146,336.64)	(1,319,387.99)	(793,578.25)	(675,750.58)	(513,384.45)	(650,316.74)
16	Real-Time Financial Bilateral Transaction Loss Amount	5.08	97.69	-	1.14	-	3.23	-	-	-	-	-	7.25
	SUBTOTAL	1,974,204.45	2,681,782.32	1,555,193.30	2,084,794.75	2,039,252.60	2,240,660.36	1,934,305.68	832,236.75	1,902,005.62	1,223,775.94	1,210,780.78	1,227,368.73
Virtual Energy Charges													
12	Day-Ahead Virtual Energy Amount	-	-	-	-	-	-	-	-	-	-	-	-
27	Real-Time Virtual Energy Amount	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-
Market Administration Charges (Schedule 16 & 17)													
4	Day-Ahead Market Administration Amount	611,457.97	517,902.33	599,891.96	743,844.82	815,251.21	621,089.02	398,079.40	515,523.87	640,430.97	576,431.59	586,437.02	790,087.98
19	Real-Time Market Administration Amount	44,441.20	35,073.03	50,828.44	46,303.65	51,339.57	39,205.88	25,057.29	36,049.66	47,192.25	49,713.53	47,704.49	56,175.97
29	Financial Transmission Rights Market Administration Amount	20,096.24	18,087.28	16,066.00	14,516.00	8,686.24	15,955.28	29,176.72	7,976.88	28,312.64	40,536.92	32,748.81	43,186.77
33	Day-Ahead Schedule 24 Allocation Amount	90,007.15	92,797.52	99,697.18	98,321.84	94,333.22	91,824.24	87,324.70	83,339.22	92,905.12	88,647.03	87,725.59	81,640.08
34	Real -Time Schedule 24 Allocation Amount	(11,032.84)	15,038.60	(3,078.55)	3,490.11	11,624.93	4,873.14	6,000.73	12,022.89	(15,456.36)	21,339.77	(7,531.64)	19,733.16
35	Schedule 24 Admin Allocation	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTOTAL	754,969.72	678,898.76	763,405.03	906,476.42	981,235.17	772,947.56	545,638.84	654,912.52	793,384.62	776,668.84	747,084.27	990,823.96
Congestion Related Charges													
1 b	Day-Ahead Asset Energy Amount - Congestion Component	1,380,588.80	614,032.69	379,638.87	317,754.49	153,203.05	1,284,404.02	1,705,045.75	1,166,685.88	1,735,194.15	886,396.60	382,976.42	341,828.97
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	848,571.54	595,200.25	757,261.16	237,201.31	151,738.27	135,376.12	(30,642.92)	(380,179.23)	378,878.92	186,284.19	682,199.09	537,295.58
13 b	Real-Time Asset Energy Amount - Congestion Component	132,438.25	527,919.00	171,411.51	46,302.30	(23,630.09)	58,537.39	(168,205.38)	16,808.99	96,488.85	110,768.22	71,920.25	73,849.55
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	18,561.73	45,710.03	38,290.99	1,680.50	2,011.30	(1,509.04)	(20,547.78)	(24,658.41)	(4,185.22)	67,064.16	33,713.42	16,459.87
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	(8,295.10)	848.86	(18,283.58)	(50.24)	(7,269.33)	(878.41)	11,650.90	29,647.58	2,675.57	(329.13)	(10,982.49)	(8,228.23)
15	Real-Time Financial Bilateral Transaction Congestion Amount	3.27	328.84	-	6.22	-	12.93	-	-	-	-	-	15.07
28	Financial Transmission Rights Hourly Allocation Amount	(2,712,847.13)	(834,866.42)	(503,905.53)	(80,434.15)	151,905.71	(1,167,361.77)	(381,905.51)	293,886.74	(2,156,939.27)	(97,019.43)	(1,259,506.68)	(1,129,744.04)
30	Financial Transmission Rights Monthly Allocation Amount	(3,582.30)	(37,459.65)	(44,253.83)	(48,652.72)	(16,516.41)	(80,110.50)	(90,157.52)	(94,015.01)	(112,020.04)	(83,667.83)	(150,543.49)	(38,352.60)
32	Financial Transmission Rights Yearly Allocation Amount	-	-	-	-	-	-	(426,287.70)	1.07	-	-	-	-
31	Financial Transmission Rights Transaction Amount	-	-	-	-	-	-	-	-	-	-	-	-
36	Financial Transmission Rights Full Funding Guarantee Amount	(17,821.32)	(5,682.10)	5,818.31	(25,345.74)	40,298.85	(97,314.32)	435,503.09	(81,675.23)	(58,051.82)	30,592.69	(23,950.27)	(66,727.21)
37	Financial Transmission Guarantee Uplift Amount	17,801.92	5,183.65	(5,065.14)	25,337.71	(40,641.55)	94,933.31	(473,346.96)	102,923.50	61,106.83	(16,787.49)	6,700.83	51,872.13
38	Financial Transmission Rights Monthly Transaction Amount	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTOTAL	(344,580.33)	911,215.15	780,912.77	473,799.69	411,099.81	226,089.73	561,105.97	1,029,425.88	(56,852.03)	1,083,301.97	(267,472.92)	(221,730.91)
Revenue Sufficiency Guarantee (RSG) Charges													
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	33,668.63	58,432.88	52,769.54	89,726.17	90,846.09	101,406.24	77,516.44	77,717.23	76,193.79	72,962.40	57,886.24	49,657.26
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	(1,819.22)	31,857.26	(6,133.46)	17,521.59	(4,699.20)	(75,510.08)	(32,639.32)	(34,832.10)	(73,506.31)	(29,718.08)	(35,584.03)	(30,092.82)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	353,554.03	195,942.54	302,935.29	247,362.98	138,487.50	100,020.76	54,680.23	170,708.61	170,955.49	55,412.30	104,280.85	115,100.04
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	(79,329.05)	12,946.63	(69,237.28)	(173,065.06)	(144,486.13)	(85,677.19)	(120,266.97)	(790,364.59)	(249,260.63)	(8,189.74)	(44,981.22)	(4,312.11)
43	Real Time Price Volatility Make Whole Payment	(80,960.93)	(27,082.27)	(150,435.40)	(28,227.60)	(68,978.94)	(28,494.30)	(44,762.49)	(87,581.62)	(25,389.69)	(110,025.45)	(41,980.92)	(27,855.46)
	SUBTOTAL	225,113.46	272,097.05	129,898.69	153,318.08	11,169.32	11,745.43	(65,472.12)	(664,352.47)	(101,007.35)	(19,558.57)	39,620.92	102,496.90
Other MISO Charges													
20	Real-Time Miscellaneous Amount	332,664.63	106,743.79	212,439.66	106,979.37	183,610.62	380,448.01	59,690.86	88,697.30	166,582.09	202,594.63	(105,802.78)	224,387.18
21	Real-time Net inadvertent Distribution	220,572.75	11,705.02	(92,059.80)	77,626.14	(107,138.55)	99,169.58	(50,899.18)	(133,686.51)	97,293.07	(120,804.06)	147.75	43,454.12
23	Real-Time Revenue Neutrality Uplift Amount	158,860.95	49,475.41	23,961.63	597,567.08	241,695.17	412,383.98	9,432.01	1,347,081.15	210,391.22	292,120.42	337,464.40	124,773.29
26	Real-Time Uninstructed Deviation Amount	-	-	-	-	-	-	-	-	-	-	-	-
	SUBTOTAL	712,098.33	167,924.22	144,341.49	782,172.59	318,167.24	892,001.57	18,223.69	1,302,091.94	474,266.38	373,910.99	231,809.37	392,614.59
Auction Revenue Rights (ARR)													
39	Auction Revenue Rights - FTR Auction Transactions	2,270,304.83	2,270,304.83	2,189,565.60	2,189,565.60	2,189,565.60	1,791,300.13	1,791,300.13	1,791,300.13	2,547,181.68	2,547,181.68	2,547,181.68	1,805,216.47
40	Auction Revenue Rights - Monthly ARR Revenue	(2,291,051.69)	(2,283,061.01)	(2,180,162.36)	(2,195,796.88)	(2,188,025.82)	(1,788,440.56)	(1,675,105.03)	(1,732,810.51)	(2,545,177.39)	(2,547,177.39)	(2,546,000.58)	(1,796,652.27)
41	Auction Revenue Rights - ARR Stage 2 Distribution	(320,148.19)	(320,148.49)	(242,965.26)	(242,964.65)	(242,964.65)	(155,089.36)	(153,246.61)	(156,670.33)	(90,957.73)	(90,957.87)	(90,957.87)	(202,033.21)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	41,430.89	41,430.89	130,420.69	130,420.69	130,420.69	42,374.37	42,389.67	42,379.47	55,175.45	55,175.45	55,175.45	25,882.21
	SUBTOTAL	(299,464.16)	(291,473.78)	(103,141.33)	(118,775.24)	(111,004.18)	(109,855.42)	5,338.16	(55,801.24)	(33,777.99)	(35,778.13)	(34,601.32)	(167,586.80)
Grandfathered Charge Types													
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	8,295.10	(848.86)	18,283.58	50.24	7,269.33	878.41	(11,650.90)	(29,647.58)	(2,675.57)	329.13	10,982.49	8,228.23
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	3,039.31	2,912.35	6,980.25	90.81	(2,345.74)	(3,013.71)	(1,797.62)	(7,326.99)	(5,532.06)	(2,416.41)	315.23	2,320.69
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	-	-	-	-	-	-	-	-	-	-	-	-
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	-	-	-	-	-	-	-	-	-	-	-	-
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	(3.27)	(328.84)	-	(6.22)	-	(12.93)	-	-	-	-	-	(15.07)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	(5.08)	(97.69)	-	(1.14)	-	(3.23)	-	-	-	-	-	(7.25)
	SUBTOTAL	11,326.06	1,636.96	25,263.83	133.69	4,923.59	(2,151.46)	(13,448.52)	(36,974.57)	(8,207.63)	(2,087.28)	11,297.72	10,526.60
	TOTAL MISO DAY 2 CHARGES	6,475,197.00	6,530,887.17	6,584,399.05	10,058,540.10	6,555,026.10	6,218,661.21	12,394,497.61	6,633,627.85	7,941,699.92	9,698,727.73	3,536,941.68	1,400,743.65

Northern States Power Company
Electric Operation - State of Minnesota

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 5

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - RETAIL

		July 19	August 19	September 19	October 19	November 19	December 19	YTD
Day Ahead & Real Time Asset & Non-Asset Energy								
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 6,941,586.57	$ 5,522,222.44	$ 5,618,814.37	$ 3,674,478.91	$ 2,540,064.18	$ 3,655,114.41	$ 106,228,409.35
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,636,433.37)	$ (5,730,150.72)	$ (5,526,254.85)	$ (3,249,260.05)	$ (2,661,404.19)	$ (2,783,955.25)	$ (84,848,409.82)
13 a	Real-Time Asset Energy Amount - Energy Component	$ 675,013.61	$ 281,665.76	$ 337,596.47	$ 1,493,425.62	$ 2,647,568.40	$ 1,747,987.90	$ 31,683,372.80
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 7,709.67	$ 8,686.61	$ 27.23	$ 64,519.87	$ 215.56	$ (1,012.53)	$ 183,672.25
	SUBTOTAL	$ 987,876.48	$ 82,424.09	$ 430,183.22	$ 1,983,164.35	$ 2,526,443.95	$ 2,618,134.53	$ 53,247,044.58
Day Ahead & Real Time Energy Loss								
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,188,231.24	$ 1,690,309.07	$ 1,425,290.04	$ 1,632,300.43	$ 1,856,400.92	$ 1,831,941.66	$ 38,574,840.11
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (3,035.09)	$ (2,674.69)	$ (5,214.50)	$ (958.82)	$ (63.64)	$ 212.07	$ (4,960.77)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 670,389.89	$ 573,239.63	$ 650,124.86	$ 272,060.52	$ 224,795.07	$ 182,798.14	$ 7,075,919.69
13 c	Real-Time Asset Energy Amount - Loss Component	$ 119,861.98	$ 110,117.44	$ 122,180.36	$ 9,565.06	$ 48,793.29	$ 16,813.67	$ 949,605.71
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 25,868.08	$ 9,124.79	$ 37,612.78	$ (4,617.09)	$ (202.00)	$ (2,340.90)	$ 112,933.85
14	Real-Time Distribution of Losses Amount	$ (1,175,922.23)	$ (863,775.46)	$ (805,409.36)	$ (518,123.61)	$ (657,043.93)	$ (912,334.22)	$ (17,055,776.23)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ 12.56	$ -	$ -	$ 126.95
	SUBTOTAL	$ 1,825,393.87	$ 1,516,340.79	$ 1,424,584.19	$ 1,390,239.05	$ 1,472,679.70	$ 1,117,090.41	$ 29,652,689.31
Virtual Energy Charges								
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Administration Charges (Schedule 16 & 17)								
4	Day-Ahead Market Administration Amount	$ 633,503.57	$ 365,442.77	$ 531,578.75	$ 626,061.42	$ 543,246.51	$ 710,770.18	$ 10,827,031.34
19	Real-Time Market Administration Amount	$ 47,424.20	$ 21,828.23	$ 42,336.42	$ 56,225.42	$ 47,484.92	$ 54,979.34	$ 799,363.49
29	Financial Transmission Rights Market Administration Amount	$ 27,042.60	$ 10,435.94	$ 28,566.79	$ 23,921.89	$ 19,570.56	$ 24,626.30	$ 409,509.86
33	Day-Ahead Schedule 24 Allocation Amount	$ 95,698.36	$ 84,975.72	$ 80,986.32	$ 78,535.93	$ 75,780.29	$ 89,489.30	$ 1,594,028.81
34	Real -Time Schedule 24 Allocation Amount	$ (1,611.96)	$ 21,449.69	$ (665.77)	$ 10,292.03	$ 7,768.95	$ 18,996.73	$ 113,253.61
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 802,056.77	$ 504,132.35	$ 682,802.51	$ 795,036.69	$ 693,851.23	$ 898,861.85	$ 13,743,187.11
Congestion Related Charges								
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,931,619.68	$ 1,737,730.19	$ 1,292,061.32	$ 1,851,353.97	$ 1,506,594.06	$ 1,230,174.11	$ 20,897,283.04
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,132,135.76	$ 1,017,748.72	$ 751,355.32	$ 451,985.33	$ 148,013.97	$ (3,718.27)	$ 7,596,705.10
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 176,672.67	$ 45,297.49	$ 218,626.45	$ 141,920.82	$ 92,795.87	$ (982.18)	$ 1,788,939.96
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 80,098.04	$ (127,337.01)	$ 54,371.75	$ 38,832.79	$ 19,378.10	$ (11,917.21)	$ 226,018.04
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 10,844.82	$ 7,536.97	$ (6,828.80)	$ (7,592.48)	$ 1,906.58	$ 10,460.62	$ 6,834.11
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ 33.27	$ -	$ -	$ 399.60
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,460,660.10)	$ (3,699,105.15)	$ (1,525,831.06)	$ (426,804.42)	$ (1,169,823.12)	$ (636,844.90)	$ (21,797,806.23)
30	Financial Transmission Rights Monthly Allocation Amount	$ (137,857.43)	$ (200,076.68)	$ (63,914.41)	$ (37,459.02)	$ (42,276.61)	$ (39,365.46)	$ (1,320,281.51)
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ (426,286.63)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (264,018.18)	$ (174,203.01)	$ 30,121.26	$ (11,499.97)	$ (68,725.91)	$ (89,773.02)	$ (442,453.90)
37	Financial Transmission Guarantee Uplift Amount	$ 194,543.93	$ 267,173.35	$ (47,374.50)	$ 29,504.90	$ 73,143.23	$ 82,954.80	$ 429,964.45
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ (336,620.80)	$ (1,125,235.12)	$ 702,587.33	$ 2,030,275.19	$ 561,006.18	$ 540,988.49	$ 6,959,316.03
Revenue Sufficiency Guarantee (RSG) Charges								
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 45,974.92	$ 49,004.01	$ 44,109.78	$ 68,077.59	$ 52,537.74	$ 55,031.40	$ 1,153,518.33
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (8,673.33)	$ (8,134.00)	$ (70,861.95)	$ (80,976.91)	$ (48,939.37)	$ (72,598.84)	$ (565,340.17)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 122,102.75	$ 72,140.01	$ 45,194.75	$ 67,188.21	$ 65,303.37	$ 33,025.95	$ 2,414,395.67
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (50,855.09)	$ (11,250.18)	$ (68,714.77)	$ (18,612.47)	$ (52,372.64)	$ (20,494.21)	$ (1,978,522.70)
43	Real Time Price Volatility Make Whole Payment	$ (50,630.07)	$ (113,302.03)	$ (65,161.69)	$ (58,376.14)	$ (37,335.65)	$ (36,621.73)	$ (1,083,202.38)
	SUBTOTAL	$ 57,919.17	$ (11,542.19)	$ (115,433.87)	$ (22,699.73)	$ (20,806.56)	$ (41,657.43)	$ (59,151.24)
Other MISO Charges								
20	Real-Time Miscellaneous Amount	$ 182,775.33	$ 148,596.88	$ 266,494.73	$ 232,270.22	$ 618,428.69	$ 129,642.02	$ 3,537,243.23
21	Real-time Net inadvertent Distribution	$ (2,930.86)	$ 74,327.00	$ 15,768.18	$ 14,735.95	$ 22,346.64	$ 14,831.50	$ 184,458.74
23	Real-Time Revenue Neutrality Uplift Amount	$ 384,109.46	$ 302,113.36	$ 57,506.20	$ 423,469.63	$ (55,702.30)	$ 280,738.04	$ 5,197,441.12
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 563,953.93	$ 525,037.24	$ 339,769.11	$ 670,475.80	$ 585,073.03	$ 425,211.56	$ 8,919,143.09
Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,805,216.47	$ 1,805,216.47	$ 1,337,779.21	$ 1,337,779.21	$ 1,337,779.21	$ 1,123,444.70	$ 34,677,183.63
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,796,375.36)	$ (1,798,137.23)	$ (1,338,355.35)	$ (1,338,398.19)	$ (1,338,284.22)	$ (1,068,902.97)	$ (34,447,914.81)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (204,112.67)	$ (203,055.76)	$ (198,269.67)	$ (198,206.91)	$ (198,218.84)	$ (207,296.32)	$ (3,518,264.39)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 25,882.21	$ 25,882.21	$ 59,727.45	$ 59,727.45	$ 59,727.45	$ 42,660.70	$ 1,066,283.39
	SUBTOTAL	$ (169,389.35)	$ (170,094.31)	$ (139,118.36)	$ (139,098.44)	$ (138,996.40)	$ (110,093.89)	$ (2,222,712.18)
Grandfathered Charge Types								
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (10,844.82)	$ (7,536.97)	$ 6,828.80	$ 7,592.48	$ (1,906.58)	$ (10,460.62)	$ (6,834.11)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 3,035.09	$ 2,674.69	$ 5,214.50	$ 958.82	$ 63.64	$ (212.07)	$ 4,960.78
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ (33.27)	$ -	$ -	$ (399.60)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ (12.56)	$ -	$ -	$ (126.95)
	SUBTOTAL	$ (7,809.73)	$ (4,862.28)	$ 12,043.30	$ 8,505.47	$ (1,842.94)	$ (10,672.69)	$ (2,399.88)
	TOTAL MISO DAY 2 CHARGES	$ 3,723,380.34	$ 1,316,200.57	$ 3,337,417.42	$ 6,715,898.38	$ 5,677,408.20	$ 5,437,862.84	$ 110,237,116.82

SUMMARY OF DAY 2 MARKET SETTLEMENT BY CATEGORIES - MINNESOTA RETAIL (WEIGHTED BY MWH SALES)

		July 18	August 18	September 18	October 18	November 18	December 18	January 19	February 19	March 19	April 19	May 19	June 19
	Day Ahead & Real Time Asset & Non-Asset Energy												
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 7,483,025.42	$ 6,703,546.30	$ 5,179,057.66	$ 2,479,405.87	$ 3,062,803.86	$ 2,601,716.65	$ 7,980,910.86	$ 3,722,896.53	$ 5,346,025.35	$ 4,807,770.97	$ 4,654,072.91	$ 2,523,255.72
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,624,168.33)	$ (5,542,195.70)	$ (4,879,114.90)	$ (4,690,023.38)	$ (2,770,944.50)	$ (2,528,298.44)	$ (1,964,241.17)	$ (2,100,505.74)	$ (2,617,348.40)	$ (1,713,409.67)	$ (4,136,878.95)	$ (3,618,193.68)
13 a	Real-Time Asset Energy Amount - Energy Component	$ 680,311.58	$ 344,817.20	$ 2,107,864.52	$ 6,359,806.00	$ 1,781,717.98	$ 1,487,566.43	$ 677,948.43	$ 909,228.93	$ 836,551.69	$ 1,412,111.72	$ 628,460.02	$ 401,432.00
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,758.25	$ 38,907.56	$ 3,101.57	$ (4,436.05)	$ (515.55)	$ 3,670.68	$ 1,311.34	$ 107.32	$ 0.34	$ 5,747.13	$ 3,895.63	$ 15,041.17
	SUBTOTAL	$ 2,547,926.91	$ 1,545,075.36	$ 2,410,908.84	$ 4,144,752.43	$ 2,073,061.79	$ 1,564,655.32	$ 6,695,929.46	$ 2,531,727.04	$ 3,565,228.98	$ 4,512,220.14	$ 1,149,549.61	$ (678,464.78)
	Day Ahead & Real Time Energy Loss												
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,852,703.56	$ 2,080,929.82	$ 1,368,598.96	$ 1,812,693.80	$ 2,109,632.16	$ 2,292,658.38	$ 2,119,822.07	$ 1,501,729.23	$ 1,838,079.27	$ 1,286,257.99	$ 925,630.27	$ 955,441.92
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,250.14)	$ (2,133.81)	$ (5,117.41)	$ (65.16)	$ 1,676.74	$ 2,155.89	$ 1,279.31	$ 5,193.02	$ 3,966.92	$ 1,731.11	$ (226.71)	$ (1,686.18)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 556,143.42	$ 624,496.90	$ 507,829.01	$ 344,910.56	$ 162,381.93	$ 184,767.33	$ 129,729.85	$ 30,718.29	$ 50,666.44	$ 73,609.72	$ 244,339.83	$ 364,260.40
13 c	Real-Time Asset Energy Amount - Loss Component	$ 91,434.36	$ 191,101.74	$ 17,887.57	$ 1,874.44	$ (12,025.50)	$ 11,222.55	$ (57,874.85)	$ (4,477.93)	$ 33,744.94	$ (3,680.91)	$ 42,743.05	$ 71,464.54
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 18,107.88	$ 14,875.49	$ 3,609.54	$ (1,935.02)	$ (2,489.92)	$ (225.81)	$ (567.25)	$ (8,193.19)	$ 6,484.84	$ 2,896.58	$ 27,494.24	$ (25,183.97)
14	Real-Time Distribution of Losses Amount	$ (1,054,545.98)	$ (944,459.78)	$ (752,652.43)	$ (661,629.28)	$ (801,509.70)	$ (887,698.62)	$ (815,809.08)	$ (935,119.54)	$ (569,057.07)	$ (484,105.47)	$ (369,214.50)	$ (472,511.73)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 3.76	$ 71.58	$ -	$ 0.82	$ -	$ 2.31	$ -	$ -	$ -	$ -	$ -	$ 5.27
	SUBTOTAL	$ 1,461,596.86	$ 1,964,881.94	$ 1,140,155.23	$ 1,495,850.16	$ 1,457,665.71	$ 1,602,882.04	$ 1,376,580.04	$ 589,849.88	$ 1,363,885.34	$ 876,709.02	$ 870,766.18	$ 891,790.24
	Virtual Energy Charges												
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Market Administration Charges (Schedule 16 & 17)												
4	Day-Ahead Market Administration Amount	$ 452,691.23	$ 379,455.46	$ 439,797.39	$ 533,712.20	$ 582,744.74	$ 444,303.14	$ 283,299.67	$ 365,378.83	$ 459,238.61	$ 412,953.68	$ 421,752.25	$ 574,067.70
19	Real-Time Market Administration Amount	$ 32,901.92	$ 25,697.22	$ 37,263.74	$ 33,223.09	$ 36,697.72	$ 28,046.37	$ 17,832.43	$ 25,550.29	$ 33,840.50	$ 35,614.61	$ 34,307.99	$ 40,816.73
29	Financial Transmission Rights Market Administration Amount	$ 14,878.20	$ 13,252.15	$ 11,778.43	$ 10,415.30	$ 6,208.96	$ 11,413.79	$ 20,764.09	$ 5,653.63	$ 20,302.36	$ 29,040.51	$ 23,552.20	$ 31,378.95
33	Day-Ahead Schedule 24 Allocation Amount	$ 66,636.55	$ 67,990.67	$ 73,090.76	$ 70,546.39	$ 67,429.75	$ 65,687.52	$ 62,146.04	$ 59,066.88	$ 66,620.17	$ 63,506.44	$ 63,090.26	$ 59,318.63
34	Real -Time Schedule 24 Allocation Amount	$ (8,168.13)	$ 11,018.45	$ (2,256.97)	$ 2,504.17	$ 8,309.55	$ 3,486.06	$ 4,270.52	$ 8,521.25	$ (11,083.41)	$ 15,287.74	$ (5,416.59)	$ 14,337.86
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 558,939.76	$ 497,413.94	$ 559,673.34	$ 650,401.15	$ 701,390.73	$ 552,936.88	$ 388,312.74	$ 464,170.89	$ 568,918.22	$ 556,402.98	$ 537,286.13	$ 719,919.87
	Congestion Related Charges												
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,022,115.13	$ 449,888.02	$ 278,323.76	$ 227,990.36	$ 109,510.14	$ 918,813.12	$ 1,213,423.49	$ 826,891.53	$ 1,244,268.59	$ 635,011.58	$ 275,427.99	$ 248,368.51
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 628,237.62	$ 436,089.92	$ 555,169.10	$ 170,193.07	$ 108,463.11	$ 96,842.86	$ (21,807.53)	$ (269,452.98)	$ 271,685.53	$ 133,453.37	$ 490,622.17	$ 390,392.01
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 98,050.30	$ 386,794.44	$ 125,666.52	$ 33,222.12	$ (16,890.88)	$ 41,875.39	$ (119,706.09)	$ 11,913.41	$ 69,189.98	$ 79,353.98	$ 51,723.42	$ 53,658.13
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 13,742.13	$ 33,490.71	$ 28,072.19	$ 1,205.77	$ 1,437.69	$ (1,079.51)	$ (14,623.16)	$ (17,476.71)	$ (3,001.13)	$ 48,044.54	$ 24,245.93	$ 11,959.53
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (6,141.25)	$ 621.94	$ (13,404.20)	$ (36.05)	$ (5,196.15)	$ (628.38)	$ 8,291.55	$ 21,012.80	$ 1,918.59	$ (235.79)	$ (7,898.36)	$ (5,978.53)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 2.42	$ 240.93	$ -	$ 4.46	$ -	$ 9.25	$ -	$ -	$ -	$ -	$ -	$ 10.95
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,008,448.94)	$ (611,687.96)	$ (369,427.08)	$ (57,711.89)	$ 108,582.79	$ (835,085.60)	$ (271,789.26)	$ 208,292.96	$ (1,546,692.51)	$ (69,504.40)	$ (905,808.75)	$ (820,857.40)
30	Financial Transmission Rights Monthly Allocation Amount	$ (2,652.15)	$ (27,445.85)	$ (32,443.71)	$ (34,908.56)	$ (11,805.99)	$ (57,307.96)	$ (64,162.06)	$ (66,633.37)	$ (80,327.04)	$ (59,939.36)	$ (108,267.48)	$ (27,866.50)
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ (303,374.56)	$ 0.76	$ -	$ -	$ -	$ -
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (13,193.97)	$ (4,163.15)	$ 4,265.56	$ (18,185.69)	$ 28,805.78	$ (69,614.91)	$ 309,932.84	$ (57,887.52)	$ (41,627.65)	$ 21,916.50	$ (17,224.49)	$ (48,483.13)
37	Financial Transmission Guarantee Uplift Amount	$ 13,179.60	$ 3,797.94	$ (3,713.39)	$ 18,179.93	$ (29,050.74)	$ 67,911.63	$ (336,865.05)	$ 72,947.29	$ 43,818.33	$ (12,026.50)	$ 4,819.09	$ 37,689.62
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ (255,109.10)	$ 667,626.96	$ 572,508.75	$ 339,953.53	$ 293,855.75	$ 161,735.88	$ 399,320.17	$ 729,608.16	$ (40,767.31)	$ 776,073.93	$ (192,360.48)	$ (161,106.81)
	Revenue Sufficiency Guarantee (RSG) Charges												
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 24,926.48	$ 42,812.47	$ 38,686.81	$ 64,378.95	$ 64,937.14	$ 72,542.11	$ 55,165.83	$ 55,082.28	$ 54,636.85	$ 52,270.02	$ 41,630.48	$ 36,080.32
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (1,346.85)	$ 23,341.10	$ (4,496.61)	$ 12,571.82	$ (3,359.01)	$ (54,017.00)	$ (23,228.30)	$ (24,687.34)	$ (52,709.72)	$ (21,289.93)	$ (25,591.23)	$ (21,865.05)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 261,752.76	$ 143,562.72	$ 222,090.24	$ 177,484.12	$ 98,991.40	$ 71,551.00	$ 38,914.07	$ 120,990.16	$ 122,588.33	$ 39,697.19	$ 74,996.43	$ 83,630.20
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (58,731.04)	$ 9,485.71	$ (50,759.77)	$ (124,175.00)	$ (103,279.25)	$ (61,290.16)	$ (85,589.94)	$ (560,172.88)	$ (178,739.18)	$ (5,867.10)	$ (32,349.48)	$ (3,133.12)
43	Real Time Price Volatility Make Whole Payment	$ (59,939.20)	$ (19,842.57)	$ (110,288.35)	$ (20,253.44)	$ (49,306.42)	$ (20,383.72)	$ (31,855.95)	$ (62,073.69)	$ (18,206.37)	$ (78,821.87)	$ (30,191.73)	$ (20,239.42)
	SUBTOTAL	$ 166,662.13	$ 199,359.42	$ 95,232.32	$ 110,006.45	$ 7,983.88	$ 8,402.23	$ (46,594.30)	$ (470,861.47)	$ (72,430.09)	$ (14,011.69)	$ 28,494.47	$ 74,472.92
	Other MISO Charges												
20	Real-Time Miscellaneous Amount	$ 246,287.35	$ 78,208.79	$ 155,745.39	$ 76,758.21	$ 131,245.59	$ 272,157.84	$ 42,479.97	$ 62,864.43	$ 119,452.26	$ 145,138.12	$ (76,090.97)	$ 163,036.82
21	Real-time Net inadvertent Distribution	$ 163,300.43	$ 8,576.01	$ (67,491.59)	$ 55,697.12	$ (76,583.05)	$ 70,942.09	$ (36,223.23)	$ (94,750.65)	$ 69,766.67	$ (86,543.63)	$ 106.26	$ 31,573.20
23	Real-Time Revenue Neutrality Uplift Amount	$ 117,612.27	$ 36,249.53	$ 17,566.93	$ 428,757.23	$ 172,764.65	$ 295,003.60	$ 6,712.44	$ 954,747.14	$ 150,866.80	$ 209,274.10	$ 242,696.77	$ 90,658.66
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 527,200.05	$ 123,034.32	$ 105,820.74	$ 561,212.56	$ 227,427.19	$ 638,103.53	$ 12,969.19	$ 922,860.92	$ 340,085.73	$ 267,868.59	$ 166,712.06	$ 285,268.68
	Auction Revenue Rights (ARR)												
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,680,813.96	$ 1,663,401.58	$ 1,605,231.11	$ 1,571,023.74	$ 1,565,110.03	$ 1,281,427.05	$ 1,274,807.82	$ 1,269,588.45	$ 1,826,526.54	$ 1,824,792.49	$ 1,831,875.51	$ 1,311,646.93
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,696,173.84)	$ (1,672,747.74)	$ (1,598,337.33)	$ (1,575,494.71)	$ (1,564,009.39)	$ (1,279,381.42)	$ (1,192,115.69)	$ (1,228,133.78)	$ (1,825,089.31)	$ (1,824,789.42)	$ (1,831,026.09)	$ (1,305,424.29)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (237,020.84)	$ (234,565.64)	$ (178,124.55)	$ (174,328.29)	$ (173,672.08)	$ (110,944.95)	$ (109,060.44)	$ (111,040.49)	$ (65,223.74)	$ (65,161.92)	$ (65,414.85)	$ (146,794.72)
42	Auction Revenue Rights - Monthly infeasible ARR Revenue	$ 30,673.25	$ 30,355.49	$ 95,615.02	$ 93,577.47	$ 93,225.22	$ 30,312.99	$ 30,167.30	$ 30,036.56	$ 39,565.07	$ 39,527.51	$ 39,680.94	$ 18,805.68
	SUBTOTAL	$ (221,707.47)	$ (213,556.32)	$ (75,615.76)	$ (85,221.80)	$ (79,346.22)	$ (78,586.33)	$ 3,798.99	$ (39,549.27)	$ (24,221.43)	$ (25,631.33)	$ (24,884.49)	$ (121,766.40)
	Grandfathered Charge Types												
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 6,141.25	$ (621.94)	$ 13,404.20	$ 36.05	$ 5,196.15	$ 628.38	$ (8,291.55)	$ (21,012.80)	$ (1,918.59)	$ 235.79	$ 7,898.36	$ 5,978.53
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,250.14	$ 2,133.81	$ 5,117.41	$ 65.16	$ (1,676.74)	$ (2,155.89)	$ (1,279.31)	$ (5,193.02)	$ (3,966.92)	$ (1,731.11)	$ 226.71	$ 1,686.18
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (2.42)	$ (240.93)	$ -	$ (4.46)	$ -	$ (9.25)	$ -	$ -	$ -	$ -	$ -	$ (10.95)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (3.76)	$ (71.58)	$ -	$ (0.82)	$ -	$ (2.31)	$ -	$ -	$ -	$ -	$ -	$ (5.27)
	SUBTOTAL	$ 8,385.22	$ 1,199.36	$ 18,521.61	$ 95.92	$ 3,519.40	$ (1,539.07)	$ (9,570.86)	$ (26,205.82)	$ (5,885.51)	$ (1,495.32)	$ 8,125.06	$ 7,648.49
	TOTAL MISO DAY 2 CHARGES	$ 4,793,894.36	$ 4,785,034.98	$ 4,827,205.07	$ 7,217,050.40	$ 4,685,558.22	$ 4,448,590.47	$ 8,820,745.44	$ 4,701,600.33	$ 5,694,813.92	$ 6,948,136.31	$ 2,543,688.54	$ 1,017,762.21

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 6

SUMMARY OF DAY 2 MARKET SETTLEMENT BY CATEGORIES - MINNESOTA RETAIL (WEIGHTED BY MWH SALES)

		July 19	August 19	September 19	October 19	November 19	December 19	YTD
Day Ahead & Real Time Asset & Non-Asset Energy								
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 5,065,372.57	$ 4,010,690.58	$ 4,113,000.37	$ 2,619,494.97	$ 1,821,080.75	$ 2,608,793.22	$ 76,782,920.56
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (4,842,698.02)	$ (4,161,705.14)	$ (4,045,246.34)	$ (2,316,361.20)	$ (1,908,074.59)	$ (1,987,014.02)	$ (61,446,422.18)
13 a	Real-Time Asset Energy Amount - Energy Component	$ 492,566.85	$ 204,568.76	$ 247,122.31	$ 1,064,646.44	$ 1,898,155.12	$ 1,247,604.99	$ 22,782,480.97
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 5,625.85	$ 6,308.93	$ 19.93	$ 45,995.49	$ 154.54	$ (722.68)	$ 132,971.45
	SUBTOTAL	$ 720,867.25	$ 59,863.13	$ 314,896.28	$ 1,413,775.71	$ 1,811,315.82	$ 1,868,661.51	$ 38,251,950.80
Day Ahead & Real Time Energy Loss								
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,596,782.86	$ 1,227,641.00	$ 1,043,319.48	$ 1,163,648.74	$ 1,330,933.29	$ 1,307,525.96	$ 27,814,028.74
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,214.75)	$ (1,942.58)	$ (3,817.04)	$ (683.53)	$ (45.63)	$ 151.36	$ (4,028.59)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 489,192.85	$ 416,333.60	$ 475,894.67	$ 193,948.91	$ 161,165.21	$ 130,469.94	$ 5,140,858.86
13 c	Real-Time Asset Energy Amount - Loss Component	$ 87,464.96	$ 79,976.31	$ 89,436.64	$ 6,818.82	$ 34,982.00	$ 12,000.55	$ 694,093.28
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 18,876.30	$ 6,627.17	$ 27,532.74	$ (3,291.47)	$ (144.82)	$ (1,670.79)	$ 82,802.52
14	Real-Time Distribution of Losses Amount	$ (858,086.86)	$ (627,344.54)	$ (589,563.70)	$ (369,364.53)	$ (471,062.92)	$ (651,167.40)	$ (12,314,903.11)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ 8.95	$ -	$ -	$ 92.69
	SUBTOTAL	$ 1,332,015.37	$ 1,101,290.97	$ 1,042,802.79	$ 991,085.89	$ 1,055,827.12	$ 797,309.63	$ 21,412,944.39
Virtual Energy Charges								
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Administration Charges (Schedule 16 & 17)								
4	Day-Ahead Market Administration Amount	$ 462,276.39	$ 265,414.49	$ 389,118.32	$ 446,312.19	$ 389,476.68	$ 507,303.53	$ 7,809,296.50
19	Real-Time Market Administration Amount	$ 34,606.10	$ 15,853.45	$ 30,990.47	$ 40,082.47	$ 34,043.97	$ 39,240.83	$ 576,609.91
29	Financial Transmission Rights Market Administration Amount	$ 19,733.36	$ 7,579.44	$ 20,911.03	$ 17,053.65	$ 14,030.97	$ 17,576.72	$ 295,523.74
33	Day-Ahead Schedule 24 Allocation Amount	$ 69,832.43	$ 61,716.33	$ 59,282.39	$ 55,987.39	$ 54,330.13	$ 63,871.89	$ 1,150,150.62
34	Real -Time Schedule 24 Allocation Amount	$ (1,176.27)	$ 15,578.52	$ (487.35)	$ 7,337.07	$ 5,569.89	$ 13,558.68	$ 81,191.05
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 585,272.01	$ 366,142.24	$ 499,814.87	$ 566,772.78	$ 497,451.65	$ 641,551.66	$ 9,912,771.82
Congestion Related Charges								
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,139,243.78	$ 1,262,082.10	$ 945,795.39	$ 1,319,809.57	$ 1,080,141.78	$ 878,021.73	$ 15,075,126.57
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 826,135.26	$ 739,172.54	$ 549,995.87	$ 322,215.29	$ 106,117.55	$ (2,653.87)	$ 5,530,870.89
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 128,920.51	$ 32,898.75	$ 160,035.66	$ 101,173.77	$ 66,529.33	$ (701.02)	$ 1,303,707.73
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 58,448.66	$ (92,482.57)	$ 39,800.39	$ 27,683.47	$ 13,892.99	$ (8,505.76)	$ 164,855.16
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 7,913.62	$ 5,473.97	$ (4,998.72)	$ (5,412.59)	$ 1,366.91	$ 7,466.14	$ 4,135.50
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ 23.72	$ -	$ -	$ 291.73
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,255,005.91)	$ (2,686,593.37)	$ (1,116,916.01)	$ (304,264.10)	$ (838,696.27)	$ (454,540.26)	$ (15,836,153.94)
30	Financial Transmission Rights Monthly Allocation Amount	$ (100,596.49)	$ (145,312.09)	$ (46,785.67)	$ (26,704.12)	$ (30,309.91)	$ (28,096.62)	$ (951,564.92)
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ (303,373.80)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (192,657.75)	$ (126,520.51)	$ 22,048.91	$ (8,198.20)	$ (49,272.55)	$ (64,074.40)	$ (324,134.31)
37	Financial Transmission Guarantee Uplift Amount	$ 141,961.42	$ 194,043.19	$ (34,678.37)	$ 21,033.71	$ 52,439.51	$ 59,207.97	$ 314,695.18
38	Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ (245,636.90)	$ (817,237.98)	$ 514,297.46	$ 1,447,360.51	$ 402,209.35	$ 386,123.92	$ 4,978,455.79
Revenue Sufficiency Guarantee (RSG) Charges								
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 33,548.54	$ 35,590.73	$ 32,288.58	$ 48,531.75	$ 37,666.55	$ 39,277.99	$ 830,053.88
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (6,329.05)	$ (5,907.58)	$ (51,871.30)	$ (57,727.53)	$ (35,086.73)	$ (51,816.53)	$ (405,416.85)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 89,100.08	$ 52,393.99	$ 33,082.79	$ 47,897.72	$ 46,818.78	$ 23,571.87	$ 1,749,113.84
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (37,109.67)	$ (8,170.80)	$ (50,299.56)	$ (13,268.62)	$ (37,548.19)	$ (14,627.49)	$ (1,415,625.55)
43	Real Time Price Volatility Make Whole Payment	$ (36,945.47)	$ (82,289.22)	$ (47,698.68)	$ (41,615.70)	$ (26,767.53)	$ (26,138.31)	$ (782,857.65)
	SUBTOTAL	$ 42,264.43	$ (8,382.88)	$ (84,498.18)	$ (16,182.38)	$ (14,917.11)	$ (29,732.48)	$ (24,732.33)
Other MISO Charges								
20	Real-Time Miscellaneous Amount	$ 133,373.71	$ 107,923.23	$ 195,075.48	$ 165,582.85	$ 443,378.00	$ 92,530.41	$ 2,555,147.47
21	Real-time Net inadvertent Distribution	$ (2,138.69)	$ 53,982.36	$ 11,542.39	$ 10,505.09	$ 16,021.26	$ 10,585.80	$ 138,867.86
23	Real-Time Revenue Neutrality Uplift Amount	$ 280,290.03	$ 219,419.49	$ 42,094.83	$ 301,886.77	$ (39,935.36)	$ 200,373.35	$ 3,727,039.22
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 411,525.05	$ 381,325.08	$ 248,712.70	$ 477,974.71	$ 419,463.90	$ 303,489.55	$ 6,421,054.55
Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions	$ 1,317,291.64	$ 1,311,096.17	$ 979,261.11	$ 953,687.86	$ 959,111.18	$ 801,844.92	$ 25,028,538.08
40	Auction Revenue Rights - Monthly ARR Revenue	$ (1,310,840.16)	$ (1,305,954.65)	$ (979,682.85)	$ (954,129.12)	$ (959,473.25)	$ (762,916.43)	$ (24,865,719.47)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (148,943.86)	$ (147,475.74)	$ (145,134.40)	$ (141,299.49)	$ (142,111.57)	$ (147,955.21)	$ (2,544,272.76)
42	Auction Revenue Rights - Monthly infeasible ARR Revenue	$ 18,886.61	$ 18,797.78	$ 43,720.79	$ 42,579.03	$ 42,821.17	$ 30,448.55	$ 768,796.41
	SUBTOTAL	$ (123,605.77)	$ (123,536.43)	$ (101,835.34)	$ (99,161.72)	$ (99,652.47)	$ (78,578.17)	$ (1,612,657.74)
Grandfathered Charge Types								
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (7,913.62)	$ (5,473.97)	$ 4,998.72	$ 5,412.59	$ (1,366.91)	$ (7,466.14)	$ (4,135.50)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,214.75	$ 1,942.58	$ 3,817.04	$ 683.53	$ 45.63	$ (151.36)	$ 4,028.59
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ (23.72)	$ -	$ -	$ (291.73)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ (8.95)	$ -	$ -	$ (92.69)
	SUBTOTAL	$ (5,698.87)	$ (3,531.39)	$ 8,815.76	$ 6,063.45	$ (1,321.28)	$ (7,617.50)	$ (491.33)
	TOTAL MISO DAY 2 CHARGES	$ 2,717,002.58	$ 955,932.74	$ 2,443,006.33	$ 4,787,688.94	$ 4,070,376.98	$ 3,881,208.12	$ 79,339,295.94

Docket No. E999/AA-20-171
Part J, Section 5
Schedule 7

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

July 2018	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	(282,428)	$ (6,427,342.24)	298,289	$ 10,107,453.38	(580,717)	$ (16,534,795.62)		
5a Day Ahead Non Asset Energy	(191,594)	$ (7,596,662.58)	(191,594)	$ (7,596,662.58)			11,688	$ 338,962.67
13a Real Time Asset Energy	(39,228)	$ (1,304,549.72)	41,286	$ 918,908.75	(80,514)	$ (2,223,458.47)		
22a Real Time Non Asset Energy	336	$ 11,829.92	336	$ 11,829.92				
SUBTOTAL	(512,914)	$ (15,316,724.62)	148,317	$ 3,441,529.47	(661,231)	$ (18,758,254.09)	11,688	$ 338,962.67
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,927,202.34		$ 2,502,479.12		$ 424,723.22		
5c Day Ahead Non Asset Loss		$ 878,685.81		$ 751,192.65		$ 127,493.16		
3 Day Ahead Financial Bilateral Transaction Loss		$ (3,039.31)		$ (3,039.31)		$ -		
13c Real Time Loss		$ 123,291.50		$ 123,502.00		$ (210.50)		
22c Real Time Non Asset Loss		$ (1,450.74)		$ 24,458.63		$ (25,909.37)		
14 Real Time Distribution Losses		$ (1,424,393.71)		$ (1,424,393.71)				
16 Real Time Financial Bilateral Loss		$ 5.08		$ 5.08				
SUBTOTAL	-	$ 2,500,300.97	-	$ 1,974,204.45	-	$ 526,096.52	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 656,616.55		$ 611,457.97		$ 45,158.58		$ 865.44
19 Real Time Market Administration (Schedule 17)		$ 50,704.08		$ 44,441.20		$ 6,262.88		
29 Financial Transmission Rights Administration (Schedule 16)		$ 20,096.24		$ 20,096.24		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 96,499.39		$ 90,007.15		$ 6,492.24		$ 127.68
34 Real -Time Schedule 24 Allocation Amount		$ (84,960.45)		$ (11,032.84)		$ (73,927.61)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 738,955.81	-	$ 754,969.72	-	$ (16,013.91)	-	$ 993.12
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,614,903.69		$ 1,380,588.80		$ 234,314.89		
5b Day Ahead Non Asset Congestion		$ 992,591.94		$ 848,571.54		$ 144,020.40		
13b Real Time Congestion		$ 132,109.20		$ 132,438.25		$ (329.05)		
22b Real Time Non Asset Congestion		$ (2,267.85)		$ 18,561.73		$ (20,829.58)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (8,295.10)		$ (8,295.10)				
15 Real Time Financial Bilateral Congestion		$ 3.27		$ 3.27				
28 Financial Transmission Rights Hourly Allocation		$ (2,712,847.13)		$ (2,712,847.13)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (3,582.30)		$ (3,582.30)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (17,821.32)		$ (17,821.32)				
37 Financial Transmission Guarantee Uplift Amount		$ 17,801.92		$ 17,801.92				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 12,596.32	-	$ (344,580.33)	-	$ 357,176.65	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 39,382.90		$ 33,668.63		$ 5,714.27		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (28,978.79)		$ (1,819.22)		$ (27,159.57)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 413,559.57		$ 353,554.03		$ 60,005.54		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (209,141.97)		$ (79,329.05)		$ (129,812.92)		
43 Real Time Price Volatility Make Whole Payment		$ (99,729.82)		$ (80,960.93)		$ (18,768.89)		
SUBTOTAL	-	$ 115,091.89	-	$ 225,113.46	-	$ (110,021.57)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 321,960.64		$ 332,664.63		$ (10,703.99)		
21 Real Time Net Inadvertent Distribution		$ 220,572.75		$ 220,572.75				$ 273.45
23 Real Time Revenue Neutrality Uplift Amount		$ 185,822.99		$ 158,860.95		$ 26,962.04		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 728,356.38	-	$ 712,098.33	-	$ 16,258.05	-	$ 273.45
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,270,304.83		$ 2,270,304.83				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,293,458.77)		$ (2,291,051.69)		$ (2,407.08)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (320,148.19)		$ (320,148.19)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 41,430.89		$ 41,430.89				
SUBTOTAL	-	$ (301,871.24)	-	($299,464)	-	($2,407)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,295.10		$ 8,295.10				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 3,039.31		$ 3,039.31				
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		$ (3.27)		$ (3.27)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (5.08)		$ (5.08)				
SUBTOTAL	-	$ 11,326.06	-	$ 11,326.06	-	$ -	-	$ -
Total MISO Day 2 Charges	(512,914)	$ (11,511,968.43)	148,317	$ 6,475,197.00	(661,231)	$ (17,987,165.43)	11,688	$ 340,229.24

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

Northern States Power Company

Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

August 2018	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	(71,376)	$ 477,154.64	246,785	$ 9,149,380.26	(318,161)	$ (8,672,225.62)		
5a Day Ahead Non Asset Energy	(195,291)	$ (7,564,303.08)	(195,291)	$ (7,564,303.08)			11,880	$ 328,644.20
13a Real Time Asset Energy	(14,803)	$ (1,123,121.63)	47,770	$ 470,626.07	(62,573)	$ (1,593,747.70)		
22a Real Time Non Asset Energy	1,649	$ 53,103.24	1,649	$ 53,103.24				
SUBTOTAL	(279,822)	$ (8,157,166.83)	100,912	$ 2,108,806.49	(380,734)	$ (10,265,973.32)	11,880	$ 328,644.20
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,087,706.54		$ 2,840,171.06		$ 247,535.48		
5c Day Ahead Non Asset Loss		$ 926,635.36		$ 852,348.79		$ 74,286.57		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,912.34)		$ (2,912.34)		$ -		
13c Real Time Loss		$ 260,532.92		$ 260,826.49		$ (293.57)		
22c Real Time Non Asset Loss		$ (3,661.95)		$ 20,302.91		$ (23,964.86)		
14 Real Time Distribution Losses		$ (1,289,052.28)		$ (1,289,052.28)				
16 Real Time Financial Bilateral Loss		$ 97.69		$ 97.69				
SUBTOTAL	-	$ 2,979,345.94	-	$ 2,681,782.32	-	$ 297,563.62	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 537,904.16		$ 517,902.33		$ 20,001.83		$ 749.92
19 Real Time Market Administration (Schedule 17)		$ 38,818.57		$ 35,073.03		$ 3,745.54		
29 Financial Transmission Rights Administration (Schedule 16)		$ 18,087.28		$ 18,087.28		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 96,356.87		$ 92,797.52		$ 3,559.35		$ 134.40
34 Real -Time Schedule 24 Allocation Amount		$ (69,865.97)		$ 15,038.60		$ (84,904.57)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 621,300.91	-	$ 678,898.76	-	$ (57,597.85)	-	$ 884.32
Congestion & FTRs								
1b Day Ahead Congestion		$ 667,548.79		$ 614,032.69		$ 53,516.10		
5b Day Ahead Non Asset Congestion		$ 647,075.01		$ 595,200.25		$ 51,874.76		
13b Real Time Congestion		$ 527,854.56		$ 527,919.00		$ (64.44)		
22b Real Time Non Asset Congestion		$ (803.75)		$ 45,710.03		$ (46,513.78)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 848.86		$ 848.86				
15 Real Time Financial Bilateral Congestion		$ 328.84		$ 328.84				
28 Financial Transmission Rights Hourly Allocation		$ (834,866.42)		$ (834,866.42)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (37,459.65)		$ (37,459.65)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (5,682.10)		$ (5,682.10)				
37 Financial Transmission Guarantee Uplift Amount		$ 5,183.65		$ 5,183.65				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 970,027.79	-	$ 911,215.15	-	$ 58,812.64	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 63,525.61		$ 58,432.88		$ 5,092.73		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (30,490.54)		$ 31,857.26		$ (62,347.80)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 213,019.94		$ 195,942.54		$ 17,077.40		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (99,818.34)		$ 12,946.63		$ (112,764.97)		
43 Real Time Price Volatility Make Whole Payment		$ (36,231.99)		$ (27,082.27)		$ (9,149.72)		
SUBTOTAL	-	$ 110,004.68	-	$ 272,097.05	-	$ (162,092.37)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 96,039.80		$ 106,743.79		$ (10,703.99)		$ (8.83)
21 Real Time Net Inadvertent Distribution		$ 11,705.02		$ 11,705.02				$ 21.57
23 Real Time Revenue Neutrality Uplift Amount		$ 53,787.45		$ 49,475.41		$ 4,312.04		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 161,532.27	-	$ 167,924.22	-	$ (6,391.95)	-	$ 12.74
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,270,304.83		$ 2,270,304.83				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,293,458.77)		$ (2,283,061.01)		$ (10,397.76)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (320,148.49)		$ (320,148.49)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 41,430.89		$ 41,430.89				
SUBTOTAL	-	$ (301,871.54)	-	($291,474)	-	($10,398)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (848.86)		$ (848.86)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,912.35		$ 2,912.35				
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		$ (328.84)		$ (328.84)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (97.69)		$ (97.69)				
SUBTOTAL	-	$ 1,636.96	-	$ 1,636.96	-	$ -	-	$ -
Total MISO Day 2 Charges	(279,822)	$ (3,615,189.82)	100,912	$ 6,530,887.17	(380,734)	$ (10,146,076.99)	11,880	$ 329,541.26

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

September 2018	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	(377,424)	$ (7,186,012.70)	178,477	$ 7,064,332.63	(555,901)	$ (14,250,345.33)		
5a Day Ahead Non Asset Energy	(167,316)	$ (6,655,205.04)	(167,316)	$ (6,655,205.04)			11,184	$ 290,251.53
13a Real Time Asset Energy	24,363	$ 1,167,857.12	84,638	$ 2,875,167.08	(60,275)	$ (1,707,309.96)		
22a Real Time Non Asset Energy	290	$ 4,230.60	290	$ 4,230.60				
SUBTOTAL	(520,087)	$ (12,669,130.02)	96,089	$ 3,288,525.27	(616,176)	$ (15,957,655.29)	11,184	$ 290,251.53
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,204,337.92		$ 1,866,794.87		$ 337,543.05		
5c Day Ahead Non Asset Loss		$ 817,936.28		$ 692,688.38		$ 125,247.90		
3 Day Ahead Financial Bilateral Transaction Loss		$ (6,980.25)		$ (6,980.25)		$ -		
13c Real Time Loss		$ 24,291.11		$ 24,398.98		$ (107.87)		
22c Real Time Non Asset Loss		$ (704.45)		$ 4,923.48		$ (5,627.93)		
14 Real Time Distribution Losses		$ (1,026,632.15)		$ (1,026,632.15)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,012,248.46	-	$ 1,555,193.30	-	$ 457,055.16	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 647,893.53		$ 599,891.96		$ 48,001.57		$ 964.48
19 Real Time Market Administration (Schedule 17)		$ 56,094.68		$ 50,828.44		$ 5,266.24		
29 Financial Transmission Rights Administration (Schedule 16)		$ 16,066.00		$ 16,066.00		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 107,122.00		$ 99,697.18		$ 7,424.82		$ 160.24
34 Real -Time Schedule 24 Allocation Amount		$ (93,731.13)		$ (3,078.55)		$ (90,652.58)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 733,445.08	-	$ 763,405.03	-	$ (29,959.95)	-	$ 1,124.72
Congestion & FTRs								
1b Day Ahead Congestion		$ 448,282.98		$ 379,638.87		$ 68,644.11		
5b Day Ahead Non Asset Congestion		$ 894,184.74		$ 757,261.16		$ 136,923.58		
13b Real Time Congestion		$ 171,379.30		$ 171,411.51		$ (32.21)		
22b Real Time Non Asset Congestion		$ (210.35)		$ 38,290.99		$ (38,501.34)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (18,283.58)		$ (18,283.58)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (503,905.53)		$ (503,905.53)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (44,253.83)		$ (44,253.83)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 5,818.31		$ 5,818.31				
37 Financial Transmission Guarantee Uplift Amount		$ (5,065.14)		$ (5,065.14)				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 947,946.90	-	$ 780,912.77	-	$ 167,034.13	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 62,311.02		$ 52,769.54		$ 9,541.48		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (39,059.66)		$ (6,133.46)		$ (32,926.20)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 357,710.30		$ 302,935.29		$ 54,775.01		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (178,197.87)		$ (69,237.28)		$ (108,960.59)		
43 Real Time Price Volatility Make Whole Payment		$ (162,966.54)		$ (150,435.40)		$ (12,531.14)		
SUBTOTAL	-	$ 39,797.25	-	$ 129,898.69	-	$ (90,101.44)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 202,080.96		$ 212,439.66		$ (10,358.70)		
21 Real Time Net Inadvertent Distribution		$ (92,059.80)		$ (92,059.80)				$ (111.25)
23 Real Time Revenue Neutrality Uplift Amount		$ 28,294.23		$ 23,961.63		$ 4,332.60		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 138,315.39	-	$ 144,341.49	-	$ (6,026.10)	-	$ (111.25)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,189,565.60		$ 2,189,565.60				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,190,703.62)		$ (2,180,162.36)		$ (10,541.26)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (242,965.26)		$ (242,965.26)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 130,420.69		$ 130,420.69				
SUBTOTAL	-	$ (113,682.59)	-	($103,141)	-	($10,541)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 18,283.58		$ 18,283.58				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 6,980.25		$ 6,980.25				
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	-	$ 25,263.83	-	$ 25,263.83	-	$ -	-	$ -
Total MISO Day 2 Charges	(520,087)	$ (8,885,795.70)	96,089	$ 6,584,399.05	(616,176)	$ (15,470,194.75)	11,184	$ 291,265.00

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

October 2018	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	(322,844)	$ (6,997,648.67)	(9,288)	$ 3,455,595.01	(313,556)	$ (10,453,243.68)		
5a Day Ahead Non Asset Energy	(165,588)	$ (6,536,574.59)	(165,588)	$ (6,536,574.59)			11,880	$ 359,007.62
13a Real Time Asset Energy	333,223	$ 7,557,082.03	382,973	$ 8,863,782.31	(49,750)	$ (1,306,700.28)		
22a Real Time Non Asset Energy	2	$ (6,182.61)	2	$ (6,182.61)				
SUBTOTAL	(155,207)	$ (5,983,323.84)	208,099	$ 5,776,620.12	(363,306)	$ (11,759,943.96)	11,880	$ 359,007.62
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,770,216.27		$ 2,526,385.75		$ 243,830.52		
5c Day Ahead Non Asset Loss		$ 527,103.28		$ 480,708.39		$ 46,394.89		
3 Day Ahead Financial Bilateral Transaction Loss		$ (90.81)		$ (90.81)		$ -		
13c Real Time Loss		$ 2,611.07		$ 2,612.44		$ (1.37)		
22c Real Time Non Asset Loss		$ (15.55)		$ (2,696.88)		$ 2,681.33		
14 Real Time Distribution Losses		$ (922,125.28)		$ (922,125.28)				
16 Real Time Financial Bilateral Loss		$ 1.14		$ 1.14				
SUBTOTAL	-	$ 2,377,700.12	-	$ 2,084,794.75	-	$ 292,905.37	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 783,368.61		$ 743,844.82		$ 39,523.79		$ 1,317.92
19 Real Time Market Administration (Schedule 17)		$ 52,710.27		$ 46,303.65		$ 6,406.62		
29 Financial Transmission Rights Administration (Schedule 16)		$ 14,516.00		$ 14,516.00		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 103,289.24		$ 98,321.84		$ 4,967.40		$ 170.80
34 Real -Time Schedule 24 Allocation Amount		$ (84,513.82)		$ 3,490.11		$ (88,003.93)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 869,370.30	-	$ 906,476.42	-	$ (37,106.12)	-	$ 1,488.72
Congestion & FTRs								
1b Day Ahead Congestion		$ 348,422.11		$ 317,754.49		$ 30,667.62		
5b Day Ahead Non Asset Congestion		$ 260,094.46		$ 237,201.31		$ 22,893.15		
13b Real Time Congestion		$ 46,300.57		$ 46,302.30		$ (1.73)		
22b Real Time Non Asset Congestion		$ (19.68)		$ 1,680.50		$ (1,700.18)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (50.24)		$ (50.24)				
15 Real Time Financial Bilateral Congestion		$ 6.22		$ 6.22				
28 Financial Transmission Rights Hourly Allocation		$ (80,434.15)		$ (80,434.15)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (48,652.72)		$ (48,652.72)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (25,345.74)		$ (25,345.74)				
37 Financial Transmission Guarantee Uplift Amount		$ 25,337.71		$ 25,337.71				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 525,658.54	-	$ 473,799.69	-	$ 51,858.85	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 98,385.96		$ 89,726.17		$ 8,659.79		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (15,835.89)		$ 17,521.59		$ (33,357.48)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 271,236.87		$ 247,362.98		$ 23,873.89		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (300,760.84)		$ (173,065.06)		$ (127,695.78)		
43 Real Time Price Volatility Make Whole Payment		$ (43,614.46)		$ (28,227.60)		$ (15,386.86)		
SUBTOTAL	-	$ 9,411.64	-	$ 153,318.08	-	$ (143,906.44)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 96,275.38		$ 106,979.37		$ (10,703.99)		
21 Real Time Net Inadvertent Distribution		$ 77,626.14		$ 77,626.14				$ 140.73
23 Real Time Revenue Neutrality Uplift Amount		$ 655,240.42		$ 597,567.08		$ 57,673.34		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 829,141.94	-	$ 782,172.59	-	$ 46,969.35	-	$ 140.73
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,189,565.60		$ 2,189,565.60				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,190,703.62)		$ (2,195,796.88)		$ 5,093.26		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (242,964.65)		$ (242,964.65)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 130,420.69		$ 130,420.69				
SUBTOTAL	-	$ (113,681.98)	-	($118,775)	-	$5,093	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 50.24		$ 50.24				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 90.81		$ 90.81				
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		$ (6.22)		$ (6.22)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (1.14)		$ (1.14)				
SUBTOTAL	-	$ 133.69	-	$ 133.69	-	$ -	-	$ -
Total MISO Day 2 Charges	(155,207)	$ (1,485,589.59)	208,099	$ 10,058,540.10	(363,306)	$ (11,544,129.69)	11,880	$ 360,637.07

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

Docket No. E999/AA-20-171
Part J, Section 5
Schedule 7

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

November 2018	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	(565,039)	$ (15,227,576.71)	99,509	$ 4,284,816.94	(664,548)	$ (19,512,393.65)		
5a Day Ahead Non Asset Energy	(97,764)	$ (3,876,510.04)	(97,764)	$ (3,876,510.04)			11,376	$ 359,154.78
13a Real Time Asset Energy	4,875	$ 146,572.78	94,915	$ 2,492,596.89	(90,040)	$ (2,346,024.11)		
22a Real Time Non Asset Energy	-	$ (721.25)	-	$ (721.25)				
SUBTOTAL	(657,927)	$ (18,958,235.22)	96,661	$ 2,900,182.54	(754,588)	$ (21,858,417.76)	11,376	$ 359,154.78
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,607,922.75		$ 2,951,343.94		$ 656,578.81		
5c Day Ahead Non Asset Loss		$ 277,707.87		$ 227,169.90		$ 50,537.97		
3 Day Ahead Financial Bilateral Transaction Loss		$ 2,345.74		$ 2,345.74		$ -		
13c Real Time Loss		$ (16,823.34)		$ (16,823.50)		$ 0.16		
22c Real Time Non Asset Loss		$ 0.86		$ (3,483.36)		$ 3,484.22		
14 Real Time Distribution Losses		$ (1,121,300.12)		$ (1,121,300.12)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,749,853.76	-	$ 2,039,252.60	-	$ 710,601.16	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 894,534.22		$ 815,251.21		$ 79,283.01		$ 1,357.92
19 Real Time Market Administration (Schedule 17)		$ 62,294.73		$ 51,339.57		$ 10,955.16		
29 Financial Transmission Rights Administration (Schedule 16)		$ 8,686.24		$ 8,686.24		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 103,860.95		$ 94,333.22		$ 9,527.73		$ 156.48
34 Real -Time Schedule 24 Allocation Amount		$ (80,773.56)		$ 11,624.93		$ (92,398.49)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 988,602.58	-	$ 981,235.17	-	$ 7,367.41	-	$ 1,514.40
Congestion & FTRs								
1b Day Ahead Congestion		$ 187,285.79		$ 153,203.05		$ 34,082.74		
5b Day Ahead Non Asset Congestion		$ 185,495.14		$ 151,738.27		$ 33,756.87		
13b Real Time Congestion		$ (23,629.14)		$ (23,630.09)		$ 0.95		
22b Real Time Non Asset Congestion		$ 5.20		$ 2,011.30		$ (2,006.10)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (7,269.33)		$ (7,269.33)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ 151,905.71		$ 151,905.71		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (16,516.41)		$ (16,516.41)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 40,298.85		$ 40,298.85				
37 Financial Transmission Guarantee Uplift Amount		$ (40,641.55)		$ (40,641.55)				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 476,934.26	-	$ 411,099.81	-	$ 65,834.45	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 111,056.42		$ 90,846.09		$ 20,210.33		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (76,788.74)		$ (4,699.20)		$ (72,089.54)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 169,296.50		$ 138,487.50		$ 30,809.00		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (378,364.21)		$ (144,486.13)		$ (233,878.08)		
43 Real Time Price Volatility Make Whole Payment		$ (76,569.25)		$ (68,978.94)		$ (7,590.31)		
SUBTOTAL	-	$ (251,369.28)	-	$ 11,169.32	-	$ (262,538.60)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 173,251.92		$ 183,610.62		$ (10,358.70)		
21 Real Time Net Inadvertent Distribution		$ (107,138.55)		$ (107,138.55)				$ (160.16)
23 Real Time Revenue Neutrality Uplift Amount		$ 295,464.55		$ 241,695.17		$ 53,769.38		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 361,577.92	-	$ 318,167.24	-	$ 43,410.68	-	$ (160.16)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,189,565.60		$ 2,189,565.60				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,190,703.62)		$ (2,188,025.82)		$ (2,677.80)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (242,964.65)		$ (242,964.65)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 130,420.69		$ 130,420.69				
SUBTOTAL	-	$ (113,681.98)	-	($111,004)	-	($2,678)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 7,269.33		$ 7,269.33				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (2,345.74)		$ (2,345.74)				
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	-	$ 4,923.59	-	$ 4,923.59	-	$ -	-	$ -
Total MISO Day 2 Charges	(657,927)	$ (14,741,394.37)	96,661	$ 6,555,026.10	(754,588)	$ (21,296,420.47)	11,376	$ 360,509.02

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

December 2018	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	(409,927)	$ (10,555,045.51)	91,168	$ 3,636,926.01	(501,095)	$ (14,191,971.52)		
5a Day Ahead Non Asset Energy	(96,419)	$ (3,534,295.08)	(96,419)	$ (3,534,295.08)			11,592	$ 332,847.45
13a Real Time Asset Energy	(9,915)	$ (245,591.13)	100,439	$ 2,079,461.28	(110,354)	$ (2,325,052.41)		
22a Real Time Non Asset Energy	3	$ 5,131.23	3	$ 5,131.23				
SUBTOTAL	(516,257)	$ (14,329,800.49)	95,192	$ 2,187,223.44	(611,449)	$ (16,517,023.93)	11,592	$ 332,847.45
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,762,248.39		$ 3,204,895.08		$ 557,353.31		
5c Day Ahead Non Asset Loss		$ 303,202.87		$ 258,285.28		$ 44,917.59		
3 Day Ahead Financial Bilateral Transaction Loss		$ 3,013.71		$ 3,013.71		$ -		
13c Real Time Loss		$ 15,682.86		$ 15,687.94		$ (5.08)		
22c Real Time Non Asset Loss		$ (34.32)		$ (315.65)		$ 281.33		
14 Real Time Distribution Losses		$ (1,240,909.23)		$ (1,240,909.23)				
16 Real Time Financial Bilateral Loss		$ 3.23		$ 3.23				
SUBTOTAL	-	$ 2,843,207.51	-	$ 2,240,660.36	-	$ 602,547.15	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 664,578.14		$ 621,089.02		$ 43,489.12		$ 999.68
19 Real Time Market Administration (Schedule 17)		$ 48,738.53		$ 39,205.88		$ 9,532.65		
29 Financial Transmission Rights Administration (Schedule 16)		$ 15,955.28		$ 15,955.28		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 98,245.53		$ 91,824.24		$ 6,421.29		$ 148.88
34 Real -Time Schedule 24 Allocation Amount		$ (82,037.24)		$ 4,873.14		$ (86,910.38)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 745,480.24	-	$ 772,947.56	-	$ (27,467.32)	-	$ 1,148.56
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,507,770.72		$ 1,284,404.02		$ 223,366.70		
5b Day Ahead Non Asset Congestion		$ 158,918.96		$ 135,376.12		$ 23,542.84		
13b Real Time Congestion		$ 58,537.78		$ 58,537.39		$ 0.39		
22b Real Time Non Asset Congestion		$ 2.66		$ (1,509.04)		$ 1,511.70		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (878.41)		$ (878.41)				
15 Real Time Financial Bilateral Congestion		$ 12.93		$ 12.93				
28 Financial Transmission Rights Hourly Allocation		$ (1,167,361.77)		$ (1,167,361.77)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (80,110.50)		$ (80,110.50)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (97,314.32)		$ (97,314.32)				
37 Financial Transmission Guarantee Uplift Amount		$ 94,933.31		$ 94,933.31				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 474,511.36	-	$ 226,089.73	-	$ 248,421.63	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 119,041.48		$ 101,406.24		$ 17,635.24		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (113,726.60)		$ (75,510.08)		$ (38,216.52)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 117,415.06		$ 100,020.76		$ 17,394.30		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (195,033.76)		$ (85,677.19)		$ (109,356.57)		
43 Real Time Price Volatility Make Whole Payment		$ (38,980.18)		$ (28,494.30)		$ (10,485.88)		
SUBTOTAL	-	$ (111,284.00)	-	$ 11,745.43	-	$ (123,029.43)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 369,744.02		$ 380,448.01		$ (10,703.99)		
21 Real Time Net Inadvertent Distribution		$ 99,169.58		$ 99,169.58				$ 143.22
23 Real Time Revenue Neutrality Uplift Amount		$ 484,100.39		$ 412,383.98		$ 71,716.41		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 953,013.99	-	$ 892,001.57	-	$ 61,012.42	-	$ 143.22
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,791,300.13		$ 1,791,300.13				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,791,548.83)		$ (1,788,440.56)		$ (3,108.27)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (155,089.36)		$ (155,089.36)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,374.37		$ 42,374.37				
SUBTOTAL	-	$ (112,963.69)	-	($109,855)	-	($3,108)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 878.41		$ 878.41				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,013.71)		$ (3,013.71)				
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		$ (12.93)		$ (12.93)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (3.23)		$ (3.23)				
SUBTOTAL	-	$ (2,151.46)	-	$ (2,151.46)	-	$ -	-	$ -
Total MISO Day 2 Charges	(516,257)	$ (9,539,986.54)	95,192	$ 6,218,661.21	(611,449)	$ (15,758,647.75)	11,592	$ 334,139.23

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

January 2019	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	(309,136)	$ (3,121,529.45)	242,264	$ 11,214,401.47	(551,400)	$ (14,335,930.92)		
5a Day Ahead Non Asset Energy	(88,555)	$ (2,760,059.53)	(88,555)	$ (2,760,059.53)			30,184	$ 899,853.50
13a Real Time Asset Energy	(29,959)	$ (1,675,988.00)	51,753	$ 952,621.32	(81,712)	$ (2,628,609.32)		
22a Real Time Non Asset Energy	-	$ 1,842.64	-	$ 1,842.64				
SUBTOTAL	(427,650)	$ (7,555,734.34)	205,462	$ 9,408,805.90	(633,112)	$ (16,964,540.24)	30,184	$ 899,853.50
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,488,042.21		$ 2,978,674.50		$ 509,367.71		
5c Day Ahead Non Asset Loss		$ 213,462.82		$ 182,290.30		$ 31,172.52		
3 Day Ahead Financial Bilateral Transaction Loss		$ 1,797.62		$ 1,797.62		$ -		
13c Real Time Loss		$ (81,323.02)		$ (81,323.03)		$ 0.01		
22c Real Time Non Asset Loss		$ 0.04		$ (797.07)		$ 797.11		
14 Real Time Distribution Losses		$ (1,146,336.64)		$ (1,146,336.64)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,475,643.03	-	$ 1,934,305.68	-	$ 541,337.35	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 428,143.14		$ 398,079.40		$ 30,063.74		$ 1,627.04
19 Real Time Market Administration (Schedule 17)		$ 29,413.76		$ 25,057.29		$ 4,356.47		
29 Financial Transmission Rights Administration (Schedule 16)		$ 29,176.72		$ 29,176.72		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 93,842.77		$ 87,324.70		$ 6,518.07		$ 357.04
34 Real -Time Schedule 24 Allocation Amount		$ (78,210.62)		$ 6,000.73		$ (84,211.35)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 502,365.77	-	$ 545,638.84	-	$ (43,273.07)	-	$ 1,984.08
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,996,616.80		$ 1,705,045.75		$ 291,571.05		
5b Day Ahead Non Asset Congestion		$ (35,883.01)		$ (30,642.92)		$ (5,240.09)		
13b Real Time Congestion		$ (168,205.37)		$ (168,205.38)		$ 0.01		
22b Real Time Non Asset Congestion		$ 0.05		$ (20,547.78)		$ 20,547.83		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 11,650.90		$ 11,650.90				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (381,905.51)		$ (381,905.51)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (90,157.52)		$ (90,157.52)				
32 Financial Transmission Rights Yearly Allocation		$ (426,287.70)		$ (426,287.70)				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 435,503.09		$ 435,503.09				
37 Financial Transmission Guarantee Uplift Amount		$ (473,346.96)		$ (473,346.96)				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 867,984.77	-	$ 561,105.97	-	$ 306,878.80	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 90,772.12		$ 77,516.44		$ 13,255.68		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (88,258.02)		$ (32,639.32)		$ (55,618.70)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 64,030.81		$ 54,680.23		$ 9,350.58		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (114,702.05)		$ (120,266.97)		$ 5,564.92		
43 Real Time Price Volatility Make Whole Payment		$ (55,970.79)		$ (44,762.49)		$ (11,208.30)		
SUBTOTAL	-	$ (104,127.93)	-	$ (65,472.12)	-	$ (38,655.81)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 48,986.87		$ 59,690.86		$ (10,703.99)		
21 Real Time Net Inadvertent Distribution		$ (50,899.18)		$ (50,899.18)				$ (68.86)
23 Real Time Revenue Neutrality Uplift Amount		$ 11,044.93		$ 9,432.01		$ 1,612.92		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 9,132.62	-	$ 18,223.69	-	$ (9,091.07)	-	$ (68.86)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,791,300.13		$ 1,791,300.13				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,791,548.83)		$ (1,675,105.03)		$ (116,443.80)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (153,246.61)		$ (153,246.61)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,389.67		$ 42,389.67				
SUBTOTAL	-	$ (111,105.64)	-	$5,338	-	($116,444)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (11,650.90)		$ (11,650.90)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,797.62)		$ (1,797.62)				
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	-	$ (13,448.52)	-	$ (13,448.52)	-	$ -	-	$ -
Total MISO Day 2 Charges	(427,650)	$ (3,929,290.24)	205,462	$ 12,394,497.61	(633,112)	$ (16,323,787.85)	30,184	$ 901,768.72

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

February 2019	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	(307,263)	$ (7,044,275.35)	177,205	$ 5,252,745.53	(484,468)	$ (12,297,020.88)		
5a Day Ahead Non Asset Energy	(94,219)	$ (2,963,666.07)	(94,219)	$ (2,963,666.07)			25,046	$ 708,353.30
13a Real Time Asset Energy	(2,940)	$ (147,856.74)	68,108	$ 1,282,858.16	(71,048)	$ (1,430,714.90)		
22a Real Time Non Asset Energy	-	$ 151.42	-	$ 151.42				
SUBTOTAL	(404,423)	$ (10,155,646.74)	151,094	$ 3,572,089.04	(555,516)	$ (13,727,735.78)	25,046	$ 708,353.30
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,693,104.17		$ 2,118,834.46		$ 574,269.71		
5c Day Ahead Non Asset Loss		$ 55,088.20		$ 43,341.35		$ 11,746.85		
3 Day Ahead Financial Bilateral Transaction Loss		$ 7,326.99		$ 7,326.99		$ -		
13c Real Time Loss		$ (6,318.04)		$ (6,318.04)		$ -		
22c Real Time Non Asset Loss		$ -		$ (11,560.02)		$ 11,560.02		
14 Real Time Distribution Losses		$ (1,319,387.99)		$ (1,319,387.99)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,429,813.33	-	$ 832,236.75	-	$ 597,576.58	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 551,980.86		$ 515,523.87		$ 36,456.99		$ 1,887.56
19 Real Time Market Administration (Schedule 17)		$ 41,461.12		$ 36,049.66		$ 5,411.46		
29 Financial Transmission Rights Administration (Schedule 16)		$ 7,976.88		$ 7,976.88		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 89,246.18		$ 83,339.22		$ 5,906.96		$ 305.48
34 Real -Time Schedule 24 Allocation Amount		$ (74,893.62)		$ 12,022.89		$ (86,916.51)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 615,771.42	-	$ 654,912.52	-	$ (39,141.10)	-	$ 2,193.04
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,482,893.85		$ 1,166,685.88		$ 316,207.97		
5b Day Ahead Non Asset Congestion		$ (483,219.56)		$ (380,179.23)		$ (103,040.33)		
13b Real Time Congestion		$ 16,808.99		$ 16,808.99		$ -		
22b Real Time Non Asset Congestion		$ -		$ (24,658.41)		$ 24,658.41		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 29,647.58		$ 29,647.58				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ 293,886.74		$ 293,886.74		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (94,015.01)		$ (94,015.01)				
32 Financial Transmission Rights Yearly Allocation		$ 1.07		$ 1.07				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (81,675.23)		$ (81,675.23)				
37 Financial Transmission Guarantee Uplift Amount		$ 102,923.50		$ 102,923.50				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 1,267,251.93	-	$ 1,029,425.88	-	$ 237,826.05	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 98,781.00		$ 77,717.23		$ 21,063.77		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (70,178.46)		$ (34,832.10)		$ (35,346.36)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 216,975.93		$ 170,708.61		$ 46,267.32		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (3,473,889.70)		$ (790,364.59)		$ (2,683,525.11)		
43 Real Time Price Volatility Make Whole Payment		$ (94,587.85)		$ (87,581.62)		$ (7,006.23)		
SUBTOTAL	-	$ (3,322,899.08)	-	$ (664,352.47)	-	$ (2,658,546.61)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 79,029.18		$ 88,697.30		$ (9,668.12)		
21 Real Time Net Inadvertent Distribution		$ (133,686.51)		$ (133,686.51)				$ (315.64)
23 Real Time Revenue Neutrality Uplift Amount		$ 1,712,181.83		$ 1,347,081.15		$ 365,100.68		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 1,657,524.50	-	$ 1,302,091.94	-	$ 355,432.56	-	$ (315.64)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,791,300.13		$ 1,791,300.13				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,791,548.83)		$ (1,732,810.51)		$ (58,738.32)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (156,670.33)		$ (156,670.33)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,379.47		$ 42,379.47				
SUBTOTAL	-	$ (114,539.56)	-	($55,801)	-	($58,738)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (29,647.58)		$ (29,647.58)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (7,326.99)		$ (7,326.99)				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$ -				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$ -				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$ -				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$ -				
SUBTOTAL	-	$ (36,974.57)	-	$ (36,974.57)	-	$ -	-	$ -
Total MISO Day 2 Charges	(404,423)	$ (8,659,698.77)	151,094	$ 6,633,627.85	(555,516)	$ (15,293,326.62)	25,046	$ 710,230.70

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

March 2019	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	(222,863)	$ (4,388,180.63)	262,419	$ 7,455,297.00	(485,282)	$ (11,843,477.63)		
5a Day Ahead Non Asset Energy	(114,308)	$ (3,650,021.92)	(114,308)	$ (3,650,021.92)			27,296	$ 774,630.81
13a Real Time Asset Energy	(31,892)	$ (705,137.65)	63,884	$ 1,166,612.75	(95,776)	$ (1,871,750.40)		
22a Real Time Non Asset Energy	-	$ 0.47	-	$ 0.47				
SUBTOTAL	(369,063)	$ (8,743,339.73)	211,995	$ 4,971,888.30	(581,058)	$ (13,715,228.03)	27,296	$ 774,630.81
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,045,595.98		$ 2,563,292.53		$ 482,303.45		
5c Day Ahead Non Asset Loss		$ 83,951.50		$ 70,656.86		$ 13,294.64		
3 Day Ahead Financial Bilateral Transaction Loss		$ 5,532.06		$ 5,532.06		$ -		
13c Real Time Loss		$ 47,058.99		$ 47,058.99		$ -		
22c Real Time Non Asset Loss		$ -		$ 9,043.42		$ (9,043.42)		
14 Real Time Distribution Losses		$ (793,578.25)		$ (793,578.25)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,388,560.28	-	$ 1,902,005.62	-	$ 486,554.66	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 686,113.77		$ 640,430.97		$ 45,682.80		$ 2,326.26
19 Real Time Market Administration (Schedule 17)		$ 56,279.14		$ 47,192.25		$ 9,086.89		
29 Financial Transmission Rights Administration (Schedule 16)		$ 28,312.64		$ 28,312.64		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 99,517.54		$ 92,905.12		$ 6,612.42		$ 354.28
34 Real -Time Schedule 24 Allocation Amount		$ (84,071.29)		$ (15,456.36)		$ (68,614.93)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 786,151.80	-	$ 793,384.62	-	$ (7,232.82)	-	$ 2,680.54
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,061,684.44		$ 1,735,194.15		$ 326,490.29		
5b Day Ahead Non Asset Congestion		$ 450,167.94		$ 378,878.92		$ 71,289.02		
13b Real Time Congestion		$ 96,488.85		$ 96,488.85		$ -		
22b Real Time Non Asset Congestion		$ -		$ (4,185.22)		$ 4,185.22		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 2,675.57		$ 2,675.57				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (2,156,939.27)		$ (2,156,939.27)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (112,020.04)		$ (112,020.04)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (58,051.82)		$ (58,051.82)				
37 Financial Transmission Guarantee Uplift Amount		$ 61,106.83		$ 61,106.83				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 345,112.50	-	$ (56,852.03)	-	$ 401,964.53	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 90,530.24		$ 76,193.79		$ 14,336.45		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (111,365.39)		$ (73,506.31)		$ (37,859.08)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 203,122.10		$ 170,955.49		$ 32,166.61		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (273,885.54)		$ (249,260.63)		$ (24,624.91)		
43 Real Time Price Volatility Make Whole Payment		$ (44,620.67)		$ (25,389.69)		$ (19,230.98)		
SUBTOTAL	-	$ (136,219.26)	-	$ (101,007.35)	-	$ (35,211.91)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 155,878.10		$ 166,582.09		$ (10,703.99)		
21 Real Time Net Inadvertent Distribution		$ 97,293.07		$ 97,293.07				$ 129.08
23 Real Time Revenue Neutrality Uplift Amount		$ 249,977.97		$ 210,391.22		$ 39,586.75		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 503,149.14	-	$ 474,266.38	-	$ 28,882.76	-	$ 129.08
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,547,181.68		$ 2,547,181.68				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,571,169.74)		$ (2,545,177.39)		$ (25,992.35)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (90,957.73)		$ (90,957.73)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 55,175.45		$ 55,175.45				
SUBTOTAL	-	$ (59,770.34)	-	($33,778)	-	($25,992)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (2,675.57)		$ (2,675.57)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (5,532.06)		$ (5,532.06)				
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	-	$ (8,207.63)	-	$ (8,207.63)	-	$ -	-	$ -
Total MISO Day 2 Charges	(369,063)	$ (4,924,563.24)	211,995	$ 7,941,699.92	(581,058)	$ (12,866,263.16)	27,296	$ 777,440.43

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

April 2019	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	(62,070)	$ (656,753.91)	251,909	$ 6,711,045.88	(313,979)	$ (7,367,799.79)		
5a Day Ahead Non Asset Energy	(80,613)	$ (2,391,705.22)	(80,613)	$ (2,391,705.22)			29,462	$ 722,158.72
13a Real Time Asset Energy	(8,376)	$ (49,991.23)	87,179	$ 1,971,131.03	(95,555)	$ (2,021,122.26)		
22a Real Time Non Asset Energy	268	$ 8,022.27	268	$ 8,022.27				
SUBTOTAL	(150,791)	$ (3,090,428.09)	258,743	$ 6,298,493.96	(409,534)	$ (9,388,922.05)	29,462	$ 722,158.72
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,032,461.42		$ 1,795,455.00		$ 237,006.42		
5c Day Ahead Non Asset Loss		$ 116,313.31		$ 102,749.95		$ 13,563.36		
3 Day Ahead Financial Bilateral Transaction Loss		$ 2,416.41		$ 2,416.41		$ -		
13c Real Time Loss		$ (5,167.08)		$ (5,138.10)		$ (28.98)		
22c Real Time Non Asset Loss		$ (248.56)		$ 4,043.26		$ (4,291.82)		
14 Real Time Distribution Losses		$ (675,750.58)		$ (675,750.58)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,470,024.92	-	$ 1,223,775.94	-	$ 246,248.98	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 606,290.04		$ 576,431.59		$ 29,858.45		$ 2,792.79
19 Real Time Market Administration (Schedule 17)		$ 58,805.28		$ 49,713.53		$ 9,091.75		
29 Financial Transmission Rights Administration (Schedule 16)		$ 40,536.92		$ 40,536.92		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 93,323.55		$ 88,647.03		$ 4,676.52		$ 429.96
34 Real -Time Schedule 24 Allocation Amount		$ (80,695.07)		$ 21,339.77		$ (102,034.84)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 718,260.72	-	$ 776,668.84	-	$ (58,408.12)	-	$ 3,222.75
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,003,404.09		$ 886,396.60		$ 117,007.49		
5b Day Ahead Non Asset Congestion		$ 210,874.36		$ 186,284.19		$ 24,590.17		
13b Real Time Congestion		$ 111,551.53		$ 110,768.22		$ 783.31		
22b Real Time Non Asset Congestion		$ 6,717.36		$ 67,064.16		$ (60,346.80)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (329.13)		$ (329.13)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (97,019.43)		$ (97,019.43)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (83,667.83)		$ (83,667.83)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 30,592.69		$ 30,592.69				
37 Financial Transmission Guarantee Uplift Amount		$ (16,787.49)		$ (16,787.49)				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 1,165,336.15	-	$ 1,083,301.97	-	$ 82,034.18	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 82,593.70		$ 72,962.40		$ 9,631.30		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (40,700.24)		$ (29,718.08)		$ (10,982.16)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 62,726.92		$ 55,412.30		$ 7,314.62		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (33,210.06)		$ (8,189.74)		$ (25,020.32)		
43 Real Time Price Volatility Make Whole Payment		$ (116,503.07)		$ (110,025.45)		$ (6,477.62)		
SUBTOTAL	-	$ (45,092.75)	-	$ (19,558.57)	-	$ (25,534.18)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 192,235.93		$ 202,594.63		$ (10,358.70)		
21 Real Time Net Inadvertent Distribution		$ (120,804.06)		$ (120,804.06)				$ (428.31)
23 Real Time Revenue Neutrality Uplift Amount		$ 330,681.35		$ 292,120.42		$ 38,560.93		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 402,113.22	-	$ 373,910.99	-	$ 28,202.23	-	$ (428.31)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,547,181.68		$ 2,547,181.68				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,571,169.74)		$ (2,547,177.39)		$ (23,992.35)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (90,957.87)		$ (90,957.87)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 55,175.45		$ 55,175.45				
SUBTOTAL	-	$ (59,770.48)	-	($35,778)	-	($23,992)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 329.13		$ 329.13				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (2,416.41)		$ (2,416.41)				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$ -				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$ -				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$ -				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$ -				
SUBTOTAL	-	$ (2,087.28)	-	$ (2,087.28)	-	$ -	-	$ -
Total MISO Day 2 Charges	(150,791)	$ 558,356.41	258,743	$ 9,698,727.73	(409,534)	$ (9,140,371.32)	29,462	$ 724,953.16

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

Docket No. E999/AA-20-171
Part J, Section 5
Schedule 7

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

May 2019	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	(716,689)	$ (13,086,587.61)	309,802	$ 6,471,383.66	(1,026,491)	$ (19,557,971.27)		
5a Day Ahead Non Asset Energy	(196,314)	$ (5,752,237.09)	(196,314)	$ (5,752,237.09)			30,184	$ 644,299.96
13a Real Time Asset Energy	(40,709)	$ (1,222,699.28)	74,950	$ 873,859.51	(115,658)	$ (2,096,558.79)		
22a Real Time Non Asset Energy	233	$ 5,416.78	233	$ 5,416.78				
SUBTOTAL	(953,479)	$ (20,056,107.20)	188,670	$ 1,598,422.86	(1,142,149)	$ (21,654,530.06)	30,184	$ 644,299.96
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,767,793.53		$ 1,287,068.06		$ 480,725.47		
5c Day Ahead Non Asset Loss		$ 466,646.76		$ 339,749.03		$ 126,897.73		
3 Day Ahead Financial Bilateral Transaction Loss		$ (315.23)		$ (315.23)		$ -		
13c Real Time Loss		$ 59,320.44		$ 59,433.25		$ (112.81)		
22c Real Time Non Asset Loss		$ (414.85)		$ 38,230.12		$ (38,644.97)		
14 Real Time Distribution Losses		$ (513,384.45)		$ (513,384.45)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,779,646.20	-	$ 1,210,780.78	-	$ 568,865.42	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 682,972.06		$ 586,437.02		$ 96,535.04		$ 2,851.35
19 Real Time Market Administration (Schedule 17)		$ 60,703.52		$ 47,704.49		$ 12,999.03		
29 Financial Transmission Rights Administration (Schedule 16)		$ 32,748.81		$ 32,748.81		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 98,029.65		$ 87,725.59		$ 10,304.06		$ 409.65
34 Real -Time Schedule 24 Allocation Amount		$ (79,433.57)		$ (7,531.64)		$ (71,901.93)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 795,020.47	-	$ 747,084.27	-	$ 47,936.20	-	$ 3,261.00
Congestion & FTRs								
1b Day Ahead Congestion		$ 526,019.77		$ 382,976.42		$ 143,043.35		
5b Day Ahead Non Asset Congestion		$ 937,003.39		$ 682,199.09		$ 254,804.30		
13b Real Time Congestion		$ 71,887.25		$ 71,920.25		$ (33.00)		
22b Real Time Non Asset Congestion		$ (121.36)		$ 33,713.42		$ (33,834.78)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (10,982.49)		$ (10,982.49)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (1,259,506.68)		$ (1,259,506.68)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (150,543.49)		$ (150,543.49)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (23,950.27)		$ (23,950.27)				
37 Financial Transmission Guarantee Uplift Amount		$ 6,700.83		$ 6,700.83				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 96,506.95	-	$ (267,472.92)	-	$ 363,979.87	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 79,507.00		$ 57,886.24		$ 21,620.76		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (92,547.73)		$ (35,584.03)		$ (56,963.70)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 143,230.20		$ 104,280.85		$ 38,949.35		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (15,698.46)		$ (44,981.22)		$ 29,282.76		
43 Real Time Price Volatility Make Whole Payment		$ (56,103.03)		$ (41,980.92)		$ (14,122.11)		
SUBTOTAL	-	$ 58,387.98	-	$ 39,620.92	-	$ 18,767.06	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ (116,506.77)		$ (105,802.78)		$ (10,703.99)		
21 Real Time Net Inadvertent Distribution		$ 147.75		$ 147.75				$ 6.54
23 Real Time Revenue Neutrality Uplift Amount		$ 463,508.81		$ 337,464.40		$ 126,044.41		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 347,149.79	-	$ 231,809.37	-	$ 115,340.42	-	$ 6.54
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,547,181.68		$ 2,547,181.68				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,571,169.74)		$ (2,546,000.58)		$ (25,169.16)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (90,957.87)		$ (90,957.87)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 55,175.45		$ 55,175.45				
SUBTOTAL	-	$ (59,770.48)	-	($34,601)	-	($25,169)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 10,982.49		$ 10,982.49				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 315.23		$ 315.23				
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	-	$ 11,297.72	-	$ 11,297.72	-	$ -	-	$ -
Total MISO Day 2 Charges	(953,479)	$ (17,027,868.57)	188,670	$ 3,536,941.68	(1,142,149)	$ (20,564,810.25)	30,184	$ 647,567.50

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

June 2019	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	(739,087)	$ (14,114,597.62)	13,237	$ 3,472,750.70	(752,323)	$ (17,587,348.32)		
5a Day Ahead Non Asset Energy	(177,915)	$ (4,979,711.15)	(177,915)	$ (4,979,711.15)			28,880	$ 586,618.69
13a Real Time Asset Energy	(48,872)	$ (1,232,387.51)	50,074	$ 552,489.89	(98,946)	$ (1,784,877.40)		
22a Real Time Non Asset Energy	747	$ 20,701.13	747	$ 20,701.13				
SUBTOTAL	(965,127)	$ (20,305,995.15)	(113,858)	$ (933,769.43)	(851,269)	$ (19,372,225.72)	28,880	$ 586,618.69
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,674,123.01		$ 1,314,972.38		$ 359,150.63		
5c Day Ahead Non Asset Loss		$ 638,256.19		$ 501,330.70		$ 136,925.49		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,320.69)		$ (2,320.69)		$ -		
13c Real Time Loss		$ 97,746.49		$ 98,356.47		$ (609.98)		
22c Real Time Non Asset Loss		$ (2,843.32)		$ (34,660.64)		$ 31,817.32		
14 Real Time Distribution Losses		$ (650,316.74)		$ (650,316.74)				
16 Real Time Financial Bilateral Loss		$ 7.25		$ 7.25				
SUBTOTAL	-	$ 1,754,652.19	-	$ 1,227,368.73	-	$ 527,283.46	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 876,227.03		$ 790,087.98		$ 86,139.05		$ 3,208.96
19 Real Time Market Administration (Schedule 17)		$ 65,146.30		$ 56,175.97		$ 8,970.33		
29 Financial Transmission Rights Administration (Schedule 16)		$ 43,186.77		$ 43,186.77		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 93,765.32		$ 81,640.08		$ 12,125.24		$ 341.60
34 Real -Time Schedule 24 Allocation Amount		$ (82,229.02)		$ 19,733.16		$ (101,962.18)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 996,096.40	-	$ 990,823.96	-	$ 5,272.44	-	$ 3,550.56
Congestion & FTRs								
1b Day Ahead Congestion		$ 435,190.70		$ 341,828.97		$ 93,361.73		
5b Day Ahead Non Asset Congestion		$ 684,043.94		$ 537,295.58		$ 146,748.36		
13b Real Time Congestion		$ 72,788.08		$ 73,849.55		$ (1,061.47)		
22b Real Time Non Asset Congestion		$ (4,947.87)		$ 16,459.87		$ (21,407.74)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (8,228.23)		$ (8,228.23)				
15 Real Time Financial Bilateral Congestion		$ 15.07		$ 15.07				
28 Financial Transmission Rights Hourly Allocation		$ (1,129,744.04)		$ (1,129,744.04)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (38,352.60)		$ (38,352.60)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (66,727.21)		$ (66,727.21)				
37 Financial Transmission Guarantee Uplift Amount		$ 51,872.13		$ 51,872.13				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ (4,090.03)	-	$ (221,730.91)	-	$ 217,640.88	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 63,219.85		$ 49,657.26		$ 13,562.59		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (62,870.47)		$ (30,092.82)		$ (32,777.65)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 146,536.63		$ 115,100.04		$ 31,436.59		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (37,234.01)		$ (4,312.11)		$ (32,921.90)		
43 Real Time Price Volatility Make Whole Payment		$ (40,310.38)		$ (27,855.46)		$ (12,454.92)		
SUBTOTAL	-	$ 69,341.62	-	$ 102,496.90	-	$ (33,155.28)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 212,493.08		$ 224,387.18		$ (11,894.10)		
21 Real Time Net Inadvertent Distribution		$ 43,454.12		$ 43,454.12				$ 151.16
23 Real Time Revenue Neutrality Uplift Amount		$ 158,851.88		$ 124,773.29		$ 34,078.59		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 414,799.08	-	$ 392,614.59	-	$ 22,184.49	-	$ 151.16
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,805,216.47		$ 1,805,216.47				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,805,445.07)		$ (1,796,652.27)		$ (8,792.80)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (202,033.21)		$ (202,033.21)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,882.21		$ 25,882.21				
SUBTOTAL	-	$ (176,379.60)	-	($167,587)	-	($8,793)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,228.23		$ 8,228.23				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,320.69		$ 2,320.69				
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		$ (15.07)		$ (15.07)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (7.25)		$ (7.25)				
SUBTOTAL	-	$ 10,526.60	-	$ 10,526.60	-	$ -	-	$ -
Total MISO Day 2 Charges	(965,127)	$ (17,241,048.89)	(113,858)	$ 1,400,743.65	(851,269)	$ (18,641,792.54)	28,880	$ 590,320.41

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

July 2019	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	(615,403)	$ (12,666,821.59)	194,857	$ 6,941,586.57	(810,260)	$ (19,608,408.16)		
5a Day Ahead Non Asset Energy	(196,406)	$ (6,636,433.37)	(196,406)	$ (6,636,433.37)			30,184	$ 740,128.10
13a Real Time Asset Energy	(34,826)	$ (1,221,316.15)	47,694	$ 675,013.61	(82,520)	$ (1,896,329.76)		
22a Real Time Non Asset Energy	338	$ 7,709.67	338	$ 7,709.67				
SUBTOTAL	(846,298)	$ (20,516,861.44)	46,482	$ 987,876.48	(892,780)	$ (21,504,737.92)	30,184	$ 740,128.10
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,664,374.28		$ 2,188,231.24		$ 476,143.04		
5c Day Ahead Non Asset Loss		$ 816,261.80		$ 670,389.89		$ 145,871.91		
3 Day Ahead Financial Bilateral Transaction Loss		$ (3,035.09)		$ (3,035.09)		$ -		
13c Real Time Loss		$ 119,784.67		$ 119,861.98		$ (77.31)		
22c Real Time Non Asset Loss		$ (432.62)		$ 25,868.08		$ (26,300.70)		
14 Real Time Distribution Losses		$ (1,175,922.23)		$ (1,175,922.23)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,421,030.81	-	$ 1,825,393.87	-	$ 595,636.94	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 695,556.87		$ 633,503.57		$ 62,053.30		$ 2,296.92
19 Real Time Market Administration (Schedule 17)		$ 53,676.55		$ 47,424.20		$ 6,252.35		
29 Financial Transmission Rights Administration (Schedule 16)		$ 27,042.60		$ 27,042.60		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 105,021.95		$ 95,698.36		$ 9,323.59		$ 346.08
34 Real -Time Schedule 24 Allocation Amount		$ (93,659.66)		$ (1,611.96)		$ (92,047.70)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 787,638.31	-	$ 802,056.77	-	$ (14,418.46)	-	$ 2,643.00
Congestion & FTRs								
1b Day Ahead Congestion		$ 3,569,518.59		$ 2,931,619.68		$ 637,898.91		
5b Day Ahead Non Asset Congestion		$ 1,378,480.18		$ 1,132,135.76		$ 246,344.42		
13b Real Time Congestion		$ 176,597.75		$ 176,672.67		$ (74.92)		
22b Real Time Non Asset Congestion		$ (419.25)		$ 80,098.04		$ (80,517.29)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 10,844.82		$ 10,844.82				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (4,460,660.10)		$ (4,460,660.10)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (137,857.43)		$ (137,857.43)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (264,018.18)		$ (264,018.18)				
37 Financial Transmission Guarantee Uplift Amount		$ 194,543.93		$ 194,543.93				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 467,030.31	-	$ (336,620.80)	-	$ 803,651.11	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 55,978.72		$ 45,974.92		$ 10,003.80		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (18,013.28)		$ (8,673.33)		$ (9,339.95)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 148,671.41		$ 122,102.75		$ 26,568.66		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (72,706.96)		$ (50,855.09)		$ (21,851.87)		
43 Real Time Price Volatility Make Whole Payment		$ (62,129.15)		$ (50,630.07)		$ (11,499.08)		
SUBTOTAL	-	$ 51,800.74	-	$ 57,919.17	-	$ (6,118.43)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 170,484.76		$ 182,775.33		$ (12,290.57)		
21 Real Time Net Inadvertent Distribution		$ (2,930.86)		$ (2,930.86)				$ (16.74)
23 Real Time Revenue Neutrality Uplift Amount		$ 467,688.86		$ 384,109.46		$ 83,579.40		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 635,242.76	-	$ 563,953.93	-	$ 71,288.83	-	$ (16.74)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,805,216.47		$ 1,805,216.47				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,805,445.07)		$ (1,796,375.36)		$ (9,069.71)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (204,112.67)		$ (204,112.67)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,882.21		$ 25,882.21				
SUBTOTAL	-	$ (178,459.06)	-	($169,389)	-	($9,070)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (10,844.82)		$ (10,844.82)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 3,035.09		$ 3,035.09				
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	-	$ (7,809.73)	-	$ (7,809.73)	-	$ -	-	$ -
Total MISO Day 2 Charges	(846,298)	$ (16,340,387.30)	46,482	$ 3,723,380.34	(892,780)	$ (20,063,767.64)	30,184	$ 742,754.36

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

August 2019	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	(561,079)	$ (10,882,366.12)	173,177	$ 5,522,222.44	(734,256)	$ (16,404,588.56)		
5a Day Ahead Non Asset Energy	(191,817)	$ (5,730,150.72)	(191,817)	$ (5,730,150.72)			30,184	$ 660,810.61
13a Real Time Asset Energy	(43,824)	$ (1,052,482.22)	26,934	$ 281,665.76	(70,758)	$ (1,334,147.98)		
22a Real Time Non Asset Energy	1,319	$ 8,686.61	1,319	$ 8,686.61				
SUBTOTAL	(795,401)	$ (17,656,312.45)	9,613	$ 82,424.09	(805,014)	$ (17,738,736.54)	30,184	$ 660,810.61
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,083,104.75		$ 1,690,309.07		$ 392,795.68		
5c Day Ahead Non Asset Loss		$ 706,449.61		$ 573,239.63		$ 133,209.98		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,674.69)		$ (2,674.69)		$ -		
13c Real Time Loss		$ 110,044.98		$ 110,117.44		$ (72.46)		
22c Real Time Non Asset Loss		$ (384.30)		$ 9,124.79		$ (9,509.09)		
14 Real Time Distribution Losses		$ (863,775.46)		$ (863,775.46)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,032,764.89	-	$ 1,516,340.79	-	$ 516,424.10	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 400,654.06		$ 365,442.77		$ 35,211.29		$ 1,439.17
19 Real Time Market Administration (Schedule 17)		$ 25,046.11		$ 21,828.23		$ 3,217.88		
29 Financial Transmission Rights Administration (Schedule 16)		$ 10,435.94		$ 10,435.94		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 93,136.38		$ 84,975.72		$ 8,160.66		$ 335.12
34 Real -Time Schedule 24 Allocation Amount		$ (84,546.43)		$ 21,449.69		$ (105,996.12)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 444,726.06	-	$ 504,132.35	-	$ (59,406.29)	-	$ 1,774.29
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,141,545.63		$ 1,737,730.19		$ 403,815.44		
5b Day Ahead Non Asset Congestion		$ 1,254,254.16		$ 1,017,748.72		$ 236,505.44		
13b Real Time Congestion		$ 22,656.96		$ 45,297.49		$ (22,640.53)		
22b Real Time Non Asset Congestion		$ (120,069.05)		$ (127,337.01)		$ 7,267.96		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 7,536.97		$ 7,536.97				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (3,699,105.15)		$ (3,699,105.15)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (200,076.68)		$ (200,076.68)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (174,203.01)		$ (174,203.01)				
37 Financial Transmission Guarantee Uplift Amount		$ 267,173.35		$ 267,173.35				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ (500,286.82)	-	$ (1,125,235.12)	-	$ 624,948.30	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 60,391.61		$ 49,004.01		$ 11,387.60		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (22,016.00)		$ (8,134.00)		$ (13,882.00)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 88,903.98		$ 72,140.01		$ 16,763.97		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (38,242.65)		$ (11,250.18)		$ (26,992.47)		
43 Real Time Price Volatility Make Whole Payment		$ (128,885.19)		$ (113,302.03)		$ (15,583.16)		
SUBTOTAL	-	$ (39,848.25)	-	$ (11,542.19)	-	$ (28,306.06)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 135,961.02		$ 148,596.88		$ (12,635.86)		
21 Real Time Net Inadvertent Distribution		$ 74,327.00		$ 74,327.00				$ 244.89
23 Real Time Revenue Neutrality Uplift Amount		$ 372,318.76		$ 302,113.36		$ 70,205.40		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 582,606.78	-	$ 525,037.24	-	$ 57,569.54	-	$ 244.89
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,805,216.47		$ 1,805,216.47				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,805,445.07)		$ (1,798,137.23)		$ (7,307.84)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (203,055.76)		$ (203,055.76)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,882.21		$ 25,882.21				
SUBTOTAL	-	$ (177,402.15)	-	($170,094)	-	($7,308)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (7,536.97)		$ (7,536.97)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,674.69		$ 2,674.69				
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	-	$ (4,862.28)	-	$ (4,862.28)	-	$ -	-	$ -
Total MISO Day 2 Charges	(795,401)	$ (15,318,614.22)	9,613	$ 1,316,200.57	(805,014)	$ (16,634,814.79)	30,184	$ 662,829.79

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

September 2019	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	(610,731)	$ (10,619,183.75)	170,420	$ 5,618,814.37	(781,150)	$ (16,237,998.12)		
5a Day Ahead Non Asset Energy	(179,618)	$ (5,526,254.85)	(179,618)	$ (5,526,254.85)			27,040	$ 544,899.10
13a Real Time Asset Energy	(41,547)	$ (841,420.20)	23,145	$ 337,596.47	(64,692)	$ (1,179,016.67)		
22a Real Time Non Asset Energy	12	$ 27.23	12	$ 27.23				
SUBTOTAL	(831,884)	$ (16,986,831.57)	13,958	$ 430,183.22	(845,842)	$ (17,417,014.79)	27,040	$ 544,899.10
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,770,942.42		$ 1,425,290.04		$ 345,652.38		
5c Day Ahead Non Asset Loss		$ 807,789.05		$ 650,124.86		$ 157,664.19		
3 Day Ahead Financial Bilateral Transaction Loss		$ (5,214.50)		$ (5,214.50)		$ -		
13c Real Time Loss		$ 122,175.29		$ 122,180.36		$ (5.07)		
22c Real Time Non Asset Loss		$ (25.99)		$ 37,612.78		$ (37,638.77)		
14 Real Time Distribution Losses		$ (805,409.36)		$ (805,409.36)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,890,256.91	-	$ 1,424,584.19	-	$ 465,672.72	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 592,456.64		$ 531,578.75		$ 60,877.89		$ 1,670.24
19 Real Time Market Administration (Schedule 17)		$ 47,334.67		$ 42,336.42		$ 4,998.25		
29 Financial Transmission Rights Administration (Schedule 16)		$ 28,566.79		$ 28,566.79		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 90,286.38		$ 80,986.32		$ 9,300.06		$ 309.44
34 Real -Time Schedule 24 Allocation Amount		$ (83,068.01)		$ (665.77)		$ (82,402.24)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 675,576.47	-	$ 682,802.51	-	$ (7,226.04)	-	$ 1,979.68
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,605,403.91		$ 1,292,061.32		$ 313,342.59		
5b Day Ahead Non Asset Congestion		$ 933,569.28		$ 751,355.32		$ 182,213.96		
13b Real Time Congestion		$ 218,626.21		$ 218,626.45		$ (0.24)		
22b Real Time Non Asset Congestion		$ (1.23)		$ 54,371.75		$ (54,372.98)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (6,828.80)		$ (6,828.80)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (1,525,831.06)		$ (1,525,831.06)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (63,914.41)		$ (63,914.41)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 30,121.26		$ 30,121.26				
37 Financial Transmission Guarantee Uplift Amount		$ (47,374.50)		$ (47,374.50)				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 1,143,770.66	-	$ 702,587.33	-	$ 441,183.33	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 54,807.01		$ 44,109.78		$ 10,697.23		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (142,948.39)		$ (70,861.95)		$ (72,086.44)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 56,155.10		$ 45,194.75		$ 10,960.35		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (83,337.48)		$ (68,714.77)		$ (14,622.71)		
43 Real Time Price Volatility Make Whole Payment		$ (87,380.70)		$ (65,161.69)		$ (22,219.01)		
SUBTOTAL	-	$ (202,704.46)	-	$ (115,433.87)	-	$ (87,270.59)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 254,600.63		$ 266,494.73		$ (11,894.10)		
21 Real Time Net Inadvertent Distribution		$ 15,768.18		$ 15,768.18				$ 146.53
23 Real Time Revenue Neutrality Uplift Amount		$ 71,452.24		$ 57,506.20		$ 13,946.04		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 341,821.05	-	$ 339,769.11	-	$ 2,051.94	-	$ 146.53
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,337,779.21		$ 1,337,779.21				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,340,179.39)		$ (1,338,355.35)		$ (1,824.04)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (198,269.67)		$ (198,269.67)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 59,727.45		$ 59,727.45				
SUBTOTAL	-	$ (140,942.40)	-	($139,118)	-	($1,824)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 6,828.80		$ 6,828.80				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 5,214.50		$ 5,214.50				
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	-	$ 12,043.30	-	$ 12,043.30	-	$ -	-	$ -
Total MISO Day 2 Charges	(831,884)	$ (13,267,010.04)	13,958	$ 3,337,417.42	(845,842)	$ (16,604,427.46)	27,040	$ 547,025.31

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 7

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

October 2019	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	(496,198)	$ (8,766,927.58)	137,114	$ 3,674,478.91	(633,312)	$ (12,441,406.49)		
5a Day Ahead Non Asset Energy	(123,906)	$ (3,249,260.05)	(123,906)	$ (3,249,260.05)			30,440	$ 585,180.35
13a Real Time Asset Energy	1,851	$ 39,443.49	80,719	$ 1,493,425.62	(78,868)	$ (1,453,982.13)		
22a Real Time Non Asset Energy	2,896	$ 64,519.87	2,896	$ 64,519.87				
SUBTOTAL	(615,357)	$ (11,912,224.27)	96,823	$ 1,983,164.35	(712,180)	$ (13,895,388.62)	30,440	$ 585,180.35
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,995,030.74		$ 1,632,300.43		$ 362,730.31		
5c Day Ahead Non Asset Loss		$ 332,517.90		$ 272,060.52		$ 60,457.38		
3 Day Ahead Financial Bilateral Transaction Loss		$ (958.82)		$ (958.82)		$ -		
13c Real Time Loss		$ 9,758.39		$ 9,565.06		$ 193.33		
22c Real Time Non Asset Loss		$ 1,063.34		$ (4,617.09)		$ 5,680.43		
14 Real Time Distribution Losses		$ (518,123.61)		$ (518,123.61)				
16 Real Time Financial Bilateral Loss		$ 12.56		$ 12.56				
SUBTOTAL	-	$ 1,819,300.50	-	$ 1,390,239.05	-	$ 429,061.45	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 687,978.31		$ 626,061.42		$ 61,916.89		$ 2,980.22
19 Real Time Market Administration (Schedule 17)		$ 63,928.30		$ 56,225.42		$ 7,702.88		
29 Financial Transmission Rights Administration (Schedule 16)		$ 23,921.89		$ 23,921.89		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 86,324.07		$ 78,535.93		$ 7,788.14		$ 374.96
34 Real -Time Schedule 24 Allocation Amount		$ (78,878.80)		$ 10,292.03		$ (89,170.83)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 783,273.77	-	$ 795,036.69	-	$ (11,762.92)	-	$ 3,355.18
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,262,762.43		$ 1,851,353.97		$ 411,408.46		
5b Day Ahead Non Asset Congestion		$ 552,425.65		$ 451,985.33		$ 100,440.32		
13b Real Time Congestion		$ 142,719.63		$ 141,920.82		$ 798.81		
22b Real Time Non Asset Congestion		$ 4,393.50		$ 38,832.79		$ (34,439.29)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (7,592.48)		$ (7,592.48)				
15 Real Time Financial Bilateral Congestion		$ 33.27		$ 33.27				
28 Financial Transmission Rights Hourly Allocation		$ (426,804.42)		$ (426,804.42)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (37,459.02)		$ (37,459.02)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (11,499.97)		$ (11,499.97)				
37 Financial Transmission Guarantee Uplift Amount		$ 29,504.90		$ 29,504.90				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 2,508,483.49	-	$ 2,030,275.19	-	$ 478,208.30	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 83,205.81		$ 68,077.59		$ 15,128.22		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (182,534.20)		$ (80,976.91)		$ (101,557.29)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 82,118.79		$ 67,188.21		$ 14,930.58		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (52,982.12)		$ (18,612.47)		$ (34,369.65)		
43 Real Time Price Volatility Make Whole Payment		$ (76,259.32)		$ (58,376.14)		$ (17,883.18)		
SUBTOTAL	-	$ (146,451.04)	-	$ (22,699.73)	-	$ (123,751.31)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 219,979.65		$ 232,270.22		$ (12,290.57)		
21 Real Time Net Inadvertent Distribution		$ 14,735.95		$ 14,735.95				$ 99.48
23 Real Time Revenue Neutrality Uplift Amount		$ 517,573.18		$ 423,469.63		$ 94,103.55		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 752,288.78	-	$ 670,475.80	-	$ 81,812.98	-	$ 99.48
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,337,779.21		$ 1,337,779.21				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,340,179.39)		$ (1,338,398.19)		$ (1,781.20)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (198,206.91)		$ (198,206.91)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 59,727.45		$ 59,727.45				
SUBTOTAL	-	$ (140,879.64)	-	($139,098)	-	($1,781)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 7,592.48		$ 7,592.48				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 958.82		$ 958.82				
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		$ (33.27)		$ (33.27)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (12.56)		$ (12.56)				
SUBTOTAL	-	$ 8,505.47	-	$ 8,505.47	-	$ -	-	$ -
Total MISO Day 2 Charges	(615,357)	$ (6,327,702.94)	96,823	$ 6,715,898.38	(712,180)	$ (13,043,601.32)	30,440	$ 588,635.01

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

Northern States Power Company

Electric Operations - State of Minnesota

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

November 2019	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	(623,797)	$ (14,003,311.03)	104,102	$ 2,540,064.18	(727,899)	$ (16,543,375.21)		
5a Day Ahead Non Asset Energy	(93,366)	$ (2,661,404.19)	(93,366)	$ (2,661,404.19)			26,642	$ 588,958.24
13a Real Time Asset Energy	(13,299)	$ (460,598.94)	133,090	$ 2,647,568.40	(146,389)	$ (3,108,167.34)		
22a Real Time Non Asset Energy	-	$ 215.56	-	$ 215.56				
SUBTOTAL	(730,462)	$ (17,125,098.60)	143,827	$ 2,526,443.95	(874,288)	$ (19,651,542.55)	26,642	$ 588,958.24
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,348,066.64		$ 2,839,732.36		$ (491,665.72)		
5c Day Ahead Non Asset Loss		$ 284,331.79		$ 343,868.51		$ (59,536.72)		
3 Day Ahead Financial Bilateral Transaction Loss		$ (63.64)		$ (63.64)		$ -		
13c Real Time Loss		$ 48,784.95		$ 48,776.61		$ 8.34		
22c Real Time Non Asset Loss		$ (39.83)		$ 122.34		$ (162.17)		
14 Real Time Distribution Losses		$ (657,043.93)		$ (657,043.93)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 2,024,035.98	-	$ 2,575,392.26	-	$ (551,356.28)	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 607,514.50		$ 543,246.51		$ 64,267.99		$ 2,348.85
19 Real Time Market Administration (Schedule 17)		$ 60,308.87		$ 47,484.92		$ 12,823.95		
29 Financial Transmission Rights Administration (Schedule 16)		$ 19,570.56		$ 19,570.56		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 84,740.12		$ 75,780.29		$ 8,959.83		$ 328.44
34 Real -Time Schedule 24 Allocation Amount		$ (74,091.80)		$ 7,768.95		$ (81,860.75)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 698,042.25	-	$ 693,851.23	-	$ 4,191.02	-	$ 2,677.29
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,905,613.83		$ 2,304,633.60		$ (399,019.77)		
5b Day Ahead Non Asset Congestion		$ 187,215.31		$ 226,416.65		$ (39,201.34)		
13b Real Time Congestion		$ 92,775.38		$ 92,754.89		$ 20.49		
22b Real Time Non Asset Congestion		$ (97.86)		$ (19,573.82)		$ 19,475.96		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 1,906.58		$ 1,906.58				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (1,169,823.12)		$ (1,169,823.12)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (42,276.61)		$ (42,276.61)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (68,725.91)		$ (68,725.91)				
37 Financial Transmission Guarantee Uplift Amount		$ 73,143.23		$ 73,143.23				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 979,730.83	-	$ 1,398,455.48	-	$ (418,724.65)	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 66,452.30		$ 80,366.86		$ (13,914.56)		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (107,080.46)		$ (48,939.37)		$ (58,141.09)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 82,598.89		$ 99,894.41		$ (17,295.52)		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (108,771.54)		$ (52,372.64)		$ (56,398.90)		
43 Real Time Price Volatility Make Whole Payment		$ (47,620.76)		$ (37,335.65)		$ (10,285.11)		
SUBTOTAL	-	$ (114,421.57)	-	$ 41,613.62	-	$ (156,035.19)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 606,534.59		$ 618,428.69		$ (11,894.10)		
21 Real Time Net Inadvertent Distribution		$ 22,346.64		$ 22,346.64				$ 70.64
23 Real Time Revenue Neutrality Uplift Amount		$ (70,454.99)		$ (85,207.68)		$ 14,752.69		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 558,426.24	-	$ 555,567.65	-	$ 2,858.59	-	$ 70.64
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,337,779.21		$ 1,337,779.21				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,340,179.39)		$ (1,338,284.22)		$ (1,895.17)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (198,218.84)		$ (198,218.84)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 59,727.45		$ 59,727.45				
SUBTOTAL	-	$ (140,891.57)	-	($138,996)	-	($1,895)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (1,906.58)		$ (1,906.58)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 63.64		$ 63.64				
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	-	$ (1,842.94)	-	$ (1,842.94)	-	$ -	-	$ -
Total MISO Day 2 Charges	(730,462)	$ (13,122,019.38)	143,827	$ 7,650,484.84	(874,288)	$ (20,772,504.22)	26,642	$ 591,706.17

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

December 2019	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	(605,320)	$ (11,711,719.33)	134,126	$ 3,655,114.41	(739,446)	$ (15,366,833.74)		
5a Day Ahead Non Asset Energy	(112,355)	$ (2,783,955.25)	(112,355)	$ (2,783,955.25)			32,176	$ 658,244.93
13a Real Time Asset Energy	6,473	$ 110,686.34	112,079	$ 1,747,987.90	(105,606)	$ (1,637,301.56)		
22a Real Time Non Asset Energy	-	$ (1,012.53)		$ (1,012.53)				
SUBTOTAL	(711,203)	$ (14,386,000.77)	133,850	$ 2,618,134.53	(845,052)	$ (17,004,135.30)	32,176	$ 658,244.93
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,301,715.99		$ 1,831,941.66		$ 469,774.33		
5c Day Ahead Non Asset Loss		$ 229,674.02		$ 182,798.14		$ 46,875.88		
3 Day Ahead Financial Bilateral Transaction Loss		$ 212.07		$ 212.07		$ -		
13c Real Time Loss		$ 16,816.94		$ 16,813.67		$ 3.27		
22c Real Time Non Asset Loss		$ 16.02		$ (2,340.90)		$ 2,356.92		
14 Real Time Distribution Losses		$ (912,334.22)		$ (912,334.22)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,636,100.82	-	$ 1,117,090.41	-	$ 519,010.41	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 780,267.99		$ 710,770.18		$ 69,497.81		$ 3,019.41
19 Real Time Market Administration (Schedule 17)		$ 65,004.23		$ 54,979.34		$ 10,024.89		
29 Financial Transmission Rights Administration (Schedule 16)		$ 24,626.30		$ 24,626.30		$ -		
33 Day-Ahead Schedule 24 Allocation Amount		$ 98,214.55		$ 89,489.30		$ 8,725.25		$ 381.68
34 Real -Time Schedule 24 Allocation Amount		$ (67,971.70)		$ 18,996.73		$ (86,968.43)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 900,141.37	-	$ 898,861.85	-	$ 1,279.52	-	$ 3,401.09
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,545,634.06		$ 1,230,174.11		$ 315,459.95		
5b Day Ahead Non Asset Congestion		$ (4,671.77)		$ (3,718.27)		$ (953.50)		
13b Real Time Congestion		$ (778.56)		$ (982.18)		$ 203.62		
22b Real Time Non Asset Congestion		$ 997.68		$ (11,917.21)		$ 12,914.89		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 10,460.62		$ 10,460.62				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (636,844.90)		$ (636,844.90)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (39,365.46)		$ (39,365.46)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (89,773.02)		$ (89,773.02)				
37 Financial Transmission Guarantee Uplift Amount		$ 82,954.80		$ 82,954.80				
38 Financial Transmission Rights Monthly Transaction Amount		$ -		$ -				
SUBTOTAL	-	$ 868,613.45	-	$ 540,988.49	-	$ 327,624.96	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 69,143.39		$ 55,031.40		$ 14,111.99		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (108,131.14)		$ (72,598.84)		$ (35,532.30)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 41,494.97		$ 33,025.95		$ 8,469.02		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (59,419.98)		$ (20,494.21)		$ (38,925.77)		
43 Real Time Price Volatility Make Whole Payment		$ (48,182.59)		$ (36,621.73)		$ (11,560.86)		
SUBTOTAL	-	$ (105,095.35)	-	$ (41,657.43)	-	$ (63,437.92)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ 117,351.45		$ 129,642.02		$ (12,290.57)		
21 Real Time Net Inadvertent Distribution		$ 14,831.50		$ 14,831.50				$ 12.30
23 Real Time Revenue Neutrality Uplift Amount		$ 352,729.16		$ 280,738.04		$ 71,991.12		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 484,912.11	-	$ 425,211.56	-	$ 59,700.55	-	$ 12.30
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 1,123,444.70		$ 1,123,444.70				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (1,123,867.22)		$ (1,068,902.97)		$ (54,964.25)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (207,296.32)		$ (207,296.32)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,660.70		$ 42,660.70				
SUBTOTAL	-	$ (165,058.14)	-	($110,094)	-	($54,964)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (10,460.62)		$ (10,460.62)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (212.07)		$ (212.07)				
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	-	$ (10,672.69)	-	$ (10,672.69)	-	$ -	-	$ -
Total MISO Day 2 Charges	(711,203)	$ (10,777,059.20)	133,850	$ 5,437,862.84	(845,052)	$ (16,214,922.04)	32,176	$ 661,658.32

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES **NOTE 1**

July 2018 - December 2019					Intersystem			
	NET INVOICE		RETAIL		ASSET BASED		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	(7,898,673)	$ (156,978,725.16)	3,075,572	$ 106,228,409.35	(10,974,245)	$ (263,207,134.51)	-	$ -
5a Day Ahead Non Asset Energy	(2,563,364)	$ (84,848,409.82)	(2,563,364)	$ (84,848,409.82)	-	$0	417,318	$ 10,123,004.56
13a Real Time Asset Energy	10,595	$ (2,261,498.64)	1,571,629	$ 31,683,372.80	(1,561,034)	$ (33,944,871.44)	-	$ -
22a Real Time Non Asset Energy	8,091	$ 183,672.25	8,091	$ 183,672.25	-	$ -	-	$ -
SUBTOTAL	(10,443,351)	$ (243,904,961.37)	2,091,927	$ 53,247,044.58	(12,535,279)	$ (297,152,005.95)	417,318	$ 10,123,004.56
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	$ 46,223,989.35	-	$ 39,558,171.56	-	$ 6,665,817.79	-	$ -
5c Day Ahead Non Asset Loss	-	$ 8,482,014.42	-	$ 7,194,993.14	-	$ 1,287,021.28	-	$ -
3 Day Ahead Financial Bilateral Transaction Loss	-	$ (4,960.77)	-	$ (4,960.77)	-	$ -	-	$ -
13c Real Time Loss	-	$ 948,269.12	-	$ 949,589.03	-	$ (1,319.91)	-	$ -
22c Real Time Non Asset Loss	-	$ (9,176.22)	-	$ 113,258.18	-	$ (122,434.40)	-	$ -
14 Real Time Distribution Losses	-	$ (17,055,776.23)	-	$ (17,055,776.23)	-	$ -	-	$ -
16 Real Time Financial Bilateral Loss	-	$ 126.95	-	$ 126.95	-	$ -	-	$ -
SUBTOTAL	-	$ 38,584,486.62	-	$ 30,755,401.87	-	$ 7,829,084.75	-	$ -
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$ -				
27 Real Time Virtual Energy		$ -		$ -				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	$ 11,781,050.48	-	$ 10,827,031.34	-	$ 954,019.14	-	$ 34,704.13
19 Real Time Market Administration (Schedule 17)	-	$ 936,468.71	-	$ 799,363.49	-	$ 137,105.22	-	$ -
29 Financial Transmission Rights Administration (Schedule 16)	-	$ 409,509.86	-	$ 409,509.86	-	$ -	-	$ -
33 Day-Ahead Schedule 24 Allocation Amount	-	$ 1,730,822.44	-	$ 1,594,028.81	-	$ 136,793.63	-	$ 5,172.21
34 Real -Time Schedule 24 Allocation Amount	-	$ (1,457,631.76)	-	$ 113,253.61	-	$ (1,570,885.37)	-	$ -
35 Schedule 24 Admin Allocation	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 13,400,219.73	-	$ 13,743,187.11	-	$ (342,967.38)	-	$ 39,876.34
Congestion & FTRs								
1b Day Ahead Congestion	-	$ 25,310,502.18	-	$ 21,695,322.58	-	$ 3,615,179.60	-	$ -
5b Day Ahead Non Asset Congestion	-	$ 9,202,620.12	-	$ 7,675,107.78	-	$ 1,527,512.34	-	$ -
13b Real Time Congestion	-	$ 1,766,468.97	-	$ 1,788,898.98	-	$ (22,430.01)	-	$ -
22b Real Time Non Asset Congestion	-	$ (116,841.80)	-	$ 187,066.11	-	$ (303,907.91)	-	$ -
2 Day Ahead Financial Bilateral Transaction Congestion	-	$ 6,834.11	-	$ 6,834.11	-	$ -	-	$ -
15 Real Time Financial Bilateral Congestion	-	$ 399.60	-	$ 399.60	-	$ -	-	$ -
28 Financial Transmission Rights Hourly Allocation	-	$ (21,797,806.23)	-	$ (21,797,806.23)	-	$ -	-	$ -
30 Financial Transmission Rights Monthly Allocation	-	$ (1,320,281.51)	-	$ (1,320,281.51)	-	$ -	-	$ -
32 Financial Transmission Rights Yearly Allocation	-	$ (426,286.63)	-	$ (426,286.63)	-	$ -	-	$ -
31 Financial Transmission Rights Transaction	-	$ -	-	$ -	-	$ -	-	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	-	$ (442,453.90)	-	$ (442,453.90)	-	$ -	-	$ -
37 Financial Transmission Guarantee Uplift Amount	-	$ 429,964.45	-	$ 429,964.45	-	$ -	-	$ -
38 Financial Transmission Rights Monthly Transaction Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 12,613,119.36	-	$ 7,796,765.33	-	$ 4,816,354.03	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	$ 1,389,086.14	-	$ 1,181,347.46	-	$ 207,738.68	-	$ -
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	$ (1,351,524.00)	-	$ (565,340.17)	-	$ (786,183.83)	-	$ -
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	$ 2,878,803.97	-	$ 2,448,986.72	-	$ 429,817.25	-	$ -
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	$ (5,725,397.54)	-	$ (1,978,522.70)	-	$ (3,746,874.84)	-	$ -
43 Real Time Price Volatility Make Whole Payment	-	$ (1,316,645.74)	-	$ (1,083,202.38)	-	$ (233,443.36)	-	$ -
SUBTOTAL	-	$ (4,125,677.17)	-	$ 3,268.93	-	$ (4,128,946.10)	-	$ -
Other Charges								
20 Real Time Miscellaneous	-	$ 3,336,381.21	-	$ 3,537,243.23	$ -	$ (200,862.02)	-	$ (8.83)
21 Real Time Net Inadvertent Distribution	-	$ 184,458.74	-	$ 184,458.74	$ -	$ -	-	$ 338.63
23 Real Time Revenue Neutrality Uplift Amount	-	$ 6,340,264.01	-	$ 5,167,935.73	-	$ 1,172,328.28	-	$ -
26 Real Time Uninstructed Deviation Amount	-	$ -	-	$ -	-	$ -	-	$ -
SUBTOTAL	-	$ 9,861,103.96	-	$ 8,889,637.70	-	$ 971,466.26	-	$ 329.80
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	$ 34,677,183.63	-	$ 34,677,183.63	$ -	$ -	-	$ -
40 Auction Revenue Rights - Monthly ARR Revenue	-	$ (34,807,924.71)	-	$ (34,447,914.81)	$ -	$ (360,009.90)	-	$ -
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	$ (3,518,264.39)	-	$ (3,518,264.39)	-	$ -	-	$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	$ 1,066,283.39	-	$ 1,066,283.39	-	$ -	-	$ -
SUBTOTAL	-	$ (2,582,722.08)	-	($2,222,712)	-	($360,010)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	$ (6,834.11)	-	$ (6,834.11)	-	$ -	-	$ -
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	$ 4,960.78	-	$ 4,960.78	-	$ -	-	$ -
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	-	$ (399.60)	-	$ (399.60)	-	$ -	-	$ -
18 Real Time Congestion Rebate on Carve Out Grandfathered	-	$ (126.95)	-	$ (126.95)	-	$ -	-	$ -
SUBTOTAL	-	$ (2,399.88)	-	$ (2,399.88)	-	$ -	-	$ -
Total MISO Day 2 Charges	(10,443,351)	$ (176,156,830.83)	2,091,927	$ 112,210,193.46	(12,535,279)	$ (288,367,024.29)	417,318	$ 10,163,210.70

NOTE 1: Due to the format of MISO settlement statements and current accounting set up, the Company is reporting net settlement figures here instead of breaking out revenues and costs as requested.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (302,134.95)		$ (302,134.95)	$ (223,684.78)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (317,720.30)		$ (317,720.30)	$ (235,223.35)
3	Day-Ahead Supplemental Reserve	$ (19,980.74)		$ (19,980.74)	$ (14,792.69)
4	Real-Time Regulation Amount (See Note 1)	$ (127,323.23)	$ 335,414.81	$ 208,091.58	$ 154,060.03
5	Real-Time Spinning Reserve Amount	$ 48,849.06	$ 190,891.97	$ 239,741.03	$ 177,491.61
6	Real-Time Supplemental Reserve Amount.	$ 14,549.40	$ 1,402.08	$ 15,951.48	$ 11,809.63
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 3,933.26		$ 3,933.26	$ 2,911.98
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,583,561.26		$ 3,583,561.26	$ 2,653,079.76
8b	Real Time Non Excessive Energy Congestion	$ (143,557.98)	$ (19,168.42)	$ (162,726.40)	$ (120,474.04)
8c	Real Time Non Excessive Energy Loss	$ (178,567.97)	$ (17,889.01)	$ (196,456.98)	$ (145,446.39)
9	Real Time Net Regulation Adjustment Amount	$ 68,610.58	$ (34,762.29)	$ 33,848.29	$ 25,059.49
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 119,499.19		$ 119,499.19	$ 88,470.90
11	Real Time Spinning Reserve Cost Distribution	$ 127,940.37		$ 127,940.37	$ 94,720.30
12	Real Time Supplemental Reserve Cost Distribution	$ 19,859.65		$ 19,859.65	$ 14,703.04
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 87,908.14	$ (48,845.86)	$ 39,062.28	$ 28,919.65
14	Real Time Contingency Reserve Deployment Failure	$ 1,487.96	$ -	$ 1,487.96	$ 1,101.61
	TOTAL MISO ASM CHARGES	**$ 2,986,913.70**	**$ 407,043.28**	**$ 3,393,956.98**	**$ 2,512,706.75**

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	$ (6,388.96)		$ (6,388.96)	$ (4,730.05)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,152.74)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,882.79)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,996,210.41**	**$ 407,043.28**	**$ 3,403,253.69**	**$ 2,519,589.54**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	August 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (196,992.06)		$ (196,992.06)	$ (144,331.68)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (337,160.12)		$ (337,160.12)	$ (247,029.68)
3	Day-Ahead Supplemental Reserve	$ (27,132.43)		$ (27,132.43)	$ (19,879.32)
4	Real-Time Regulation Amount (See Note 1)	$ (105,127.32)	$ 147,109.86	$ 41,982.54	$ 30,759.67
5	Real-Time Spinning Reserve Amount	$ 145,522.34	$ 75,241.87	$ 220,764.21	$ 161,749.00
6	Real-Time Supplemental Reserve Amount.	$ 5,534.10	$ (1,127.17)	$ 4,406.93	$ 3,228.86
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 1,228.65		$ 1,228.65	$ 900.20
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,802,233.75		$ 3,802,233.75	$ 2,785,811.64
8b	Real Time Non Excessive Energy Congestion	$ (580,203.27)	$ (42,317.08)	$ (622,520.35)	$ (456,106.74)
8c	Real Time Non Excessive Energy Loss	$ (298,932.70)	$ (20,886.42)	$ (319,819.12)	$ (234,324.32)
9	Real Time Net Regulation Adjustment Amount	$ 76,613.91	$ (33,669.38)	$ 42,944.53	$ 31,464.50
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 114,728.25		$ 114,728.25	$ 84,058.82
11	Real Time Spinning Reserve Cost Distribution	$ 116,938.26		$ 116,938.26	$ 85,678.05
12	Real Time Supplemental Reserve Cost Distribution	$ 23,987.62		$ 23,987.62	$ 17,575.19
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 90,847.37	$ (27,871.78)	$ 62,975.59	$ 46,140.81
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 2,832,086.35**	**$ 96,479.90**	**$ 2,928,566.25**	**$ 2,145,695.00**

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	$ (6,388.96)		$ (6,388.96)	$ (4,681.05)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,130.44)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,811.49)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,841,383.06**	**$ 96,479.90**	**$ 2,937,862.96**	**$ 2,152,506.49**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
September 2018 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (376,639.03)		$ (376,639.03)	$ (276,124.49)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (323,121.86)		$ (323,121.86)	$ (236,889.57)
3	Day-Ahead Supplemental Reserve	$ (35,805.11)		$ (35,805.11)	$ (26,249.72)
4	Real-Time Regulation Amount (See Note 1)	$ (137,684.42)	$ 328,009.35	$ 190,324.93	$ 139,532.47
5	Real-Time Spinning Reserve Amount	$ 57,825.92	$ 187,275.87	$ 245,101.79	$ 179,690.90
6	Real-Time Supplemental Reserve Amount.	$ 26,265.73	$ (1,265.81)	$ 24,999.92	$ 18,328.13
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 60,800.59		$ 60,800.59	$ 44,574.59
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,451,814.56		$ 3,451,814.56	$ 2,530,620.73
8b	Real Time Non Excessive Energy Congestion	$ (251,434.51)	$ (26,242.75)	$ (277,677.26)	$ (203,572.88)
8c	Real Time Non Excessive Energy Loss	$ (36,753.39)	$ (3,719.62)	$ (40,473.01)	$ (29,671.88)
9	Real Time Net Regulation Adjustment Amount	$ 47,173.89	$ (22,876.08)	$ 24,297.81	$ 17,813.40
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 122,911.04		$ 122,911.04	$ 90,109.48
11	Real Time Spinning Reserve Cost Distribution	$ 182,842.77		$ 182,842.77	$ 134,047.09
12	Real Time Supplemental Reserve Cost Distribution	$ 73,610.31		$ 73,610.31	$ 53,965.75
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 112,282.66	$ (43,418.84)	$ 68,863.82	$ 50,485.97
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 2,974,089.15**	**$ 417,762.12**	**$ 3,391,851.27**	**$ 2,486,659.99**

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	$ (6,388.96)		$ (6,388.96)	$ (4,683.92)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,131.75)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,815.68)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,983,385.86**	**$ 417,762.12**	**$ 3,401,147.98**	**$ 2,493,475.66**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
October 2018 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (246,593.38)		$ (246,593.38)	$ (176,931.92)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (220,082.32)		$ (220,082.32)	$ (157,910.11)
3	Day-Ahead Supplemental Reserve	$ (45,972.35)		$ (45,972.35)	$ (32,985.38)
4	Real-Time Regulation Amount (See Note 1)	$ (59,740.99)	$ 184,550.08	$ 124,809.09	$ 89,551.12
5	Real-Time Spinning Reserve Amount	$ (53,144.66)	$ 134,739.28	$ 81,594.62	$ 58,544.53
6	Real-Time Supplemental Reserve Amount.	$ 9,331.78	$ 14,069.52	$ 23,401.30	$ 16,790.54
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 369,413.12		$ 369,413.12	$ 265,055.67
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,214,112.71		$ 2,214,112.71	$ 1,588,636.41
8b	Real Time Non Excessive Energy Congestion	$ (19,316.20)	$ (4,075.31)	$ (23,391.51)	$ (16,783.52)
8c	Real Time Non Excessive Energy Loss	$ 30,463.21	$ (229.82)	$ 30,233.39	$ 21,692.60
9	Real Time Net Regulation Adjustment Amount	$ 1,378.67	$ (9,826.57)	$ (8,447.90)	$ (6,061.41)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 160,727.28		$ 160,727.28	$ 115,322.59
11	Real Time Spinning Reserve Cost Distribution	$ 215,012.98		$ 215,012.98	$ 154,272.84
12	Real Time Supplemental Reserve Cost Distribution	$ 34,453.68		$ 34,453.68	$ 24,720.68
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 88,696.82	$ (51,180.02)	$ 37,516.80	$ 26,918.48
14	Real Time Contingency Reserve Deployment Failure	$ -	$ (419.41)	$ (419.41)	$ (300.93)
	TOTAL MISO ASM CHARGES	**$ 2,478,740.35**	**$ 267,627.75**	**$ 2,746,368.10**	**$ 1,970,532.18**

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	$ (6,388.96)		$ (6,388.96)	$ (4,584.11)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,086.32)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,670.43)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,488,037.06**	**$ 267,627.75**	**$ 2,755,664.81**	**$ 1,977,202.62**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	November 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (250,955.55)		$ (250,955.55)	$ (179,384.01)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (164,144.21)		$ (164,144.21)	$ (117,330.92)
3	Day-Ahead Supplemental Reserve	$ (34,404.93)		$ (34,404.93)	$ (24,592.78)
4	Real-Time Regulation Amount (See Note 1)	$ (70,404.23)	$ 123,884.22	$ 53,479.99	$ 38,227.71
5	Real-Time Spinning Reserve Amount	$ (103,773.88)	$ 146,255.84	$ 42,481.96	$ 30,366.27
6	Real-Time Supplemental Reserve Amount.	$ 2,932.09	$ 13,810.27	$ 16,742.36	$ 11,967.50
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (287,274.77)		$ (287,274.77)	$ (205,345.13)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,175,015.03		$ 1,175,015.03	$ 839,905.33
8b	Real Time Non Excessive Energy Congestion	$ (11,023.61)	$ 4,300.09	$ (6,723.52)	$ (4,806.00)
8c	Real Time Non Excessive Energy Loss	$ 19,145.92	$ 3,061.55	$ 22,207.47	$ 15,873.99
9	Real Time Net Regulation Adjustment Amount	$ 9,459.53	$ (7,027.08)	$ 2,432.45	$ 1,738.72
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 172,672.43		$ 172,672.43	$ 123,426.93
11	Real Time Spinning Reserve Cost Distribution	$ 165,543.32		$ 165,543.32	$ 118,331.01
12	Real Time Supplemental Reserve Cost Distribution	$ 15,957.36		$ 15,957.36	$ 11,406.38
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 126,062.97	$ (52,227.50)	$ 73,835.47	$ 52,777.88
14	Real Time Contingency Reserve Deployment Failure	$ 2,655.11	$ -	$ 2,655.11	$ 1,897.88
	TOTAL MISO ASM CHARGES	**$ 767,462.58**	**$ 232,057.39**	**$ 999,519.97**	**$ 714,460.78**

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	$ (10,469.46)		$ (10,469.46)	$ (7,483.61)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (1,551.22)		$ (1,551.22)	$ (1,108.82)
	Total	$ (12,020.68)		$ (12,020.68)	$ (8,592.43)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 779,483.26**	**$ 232,057.39**	**$ 1,011,540.65**	**$ 723,053.20**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	December 2018 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (288,577.90)		$ (288,577.90)	$ (206,437.50)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (147,440.30)		$ (147,440.30)	$ (105,473.11)
3	Day-Ahead Supplemental Reserve	$ (24,905.43)		$ (24,905.43)	$ (17,816.38)
4	Real-Time Regulation Amount (See Note 1)	$ 7,347.67	$ 124,990.66	$ 132,338.33	$ 94,669.74
5	Real-Time Spinning Reserve Amount	$ (46,675.26)	$ 115,767.59	$ 69,092.33	$ 49,425.99
6	Real-Time Supplemental Reserve Amount.	$ 418.75	$ 2,372.40	$ 2,791.15	$ 1,996.68
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (92,894.22)		$ (92,894.22)	$ (66,452.94)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,340,646.55		$ 1,340,646.55	$ 959,046.85
8b	Real Time Non Excessive Energy Congestion	$ 10,204.25	$ (8,672.00)	$ 1,532.25	$ 1,096.11
8c	Real Time Non Excessive Energy Loss	$ 1,899.05	$ (2,323.32)	$ (424.27)	$ (303.50)
9	Real Time Net Regulation Adjustment Amount	$ 6,286.40	$ (1,732.06)	$ 4,554.34	$ 3,258.00
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 161,494.06		$ 161,494.06	$ 115,526.62
11	Real Time Spinning Reserve Cost Distribution	$ 146,531.41		$ 146,531.41	$ 104,822.92
12	Real Time Supplemental Reserve Cost Distribution	$ 23,646.16		$ 23,646.16	$ 16,915.55
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 117,162.44	$ (31,643.66)	$ 85,518.78	$ 61,176.84
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,215,143.63**	**$ 198,759.61**	**$ 1,413,903.24**	**$ 1,011,451.87**

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	$ (6,388.96)		$ (6,388.96)	$ (4,570.42)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,080.09)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,650.51)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 1,224,440.34**	**$ 198,759.61**	**$ 1,423,199.95**	**$ 1,018,102.37**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (65,489.47)		$ (65,489.47)	$ (46,606.64)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (147,034.33)		$ (147,034.33)	$ (104,639.37)
3	Day-Ahead Supplemental Reserve	$ (94,408.25)		$ (94,408.25)	$ (67,187.16)
4	Real-Time Regulation Amount (See Note 1)	$ (87,322.99)	$ 50,882.39	$ (36,440.60)	$ (25,933.54)
5	Real-Time Spinning Reserve Amount	$ (205,559.66)	$ 135,591.54	$ (69,968.12)	$ (49,793.95)
6	Real-Time Supplemental Reserve Amount.	$ 124,108.50	$ 18,018.62	$ 142,127.12	$ 101,147.07
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (4,807.63)		$ (4,807.63)	$ (3,421.43)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 830,010.01		$ 830,010.01	$ 590,690.10
8b	Real Time Non Excessive Energy Congestion	$ 140,707.18	$ 24,563.46	$ 165,270.64	$ 117,617.53
8c	Real Time Non Excessive Energy Loss	$ 5,458.46	$ 11,875.81	$ 17,334.27	$ 12,336.21
9	Real Time Net Regulation Adjustment Amount	$ 855.31	$ (2,376.83)	$ (1,521.52)	$ (1,082.81)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 116,558.55		$ 116,558.55	$ 82,950.78
11	Real Time Spinning Reserve Cost Distribution	$ 100,794.89		$ 100,794.89	$ 71,732.32
12	Real Time Supplemental Reserve Cost Distribution	$ 14,041.37		$ 14,041.37	$ 9,992.77
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 38,384.36	$ (12,442.16)	$ 25,942.20	$ 18,462.19
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 766,296.30**	**$ 226,112.83**	**$ 992,409.13**	**$ 706,264.07**

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	$ (6,388.96)		$ (6,388.96)	$ (4,546.81)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,069.35)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,616.15)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 775,593.01**	**$ 226,112.83**	**$ 1,001,705.84**	**$ 712,880.22**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	February 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (29,658.58)		$ (29,658.58)	$ (21,020.59)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (108,002.18)		$ (108,002.18)	$ (76,546.82)
3	Day-Ahead Supplemental Reserve	$ (53,989.65)		$ (53,989.65)	$ (38,265.30)
4	Real-Time Regulation Amount (See Note 1)	$ 46,175.72	$ 45,902.27	$ 92,077.99	$ 65,260.51
5	Real-Time Spinning Reserve Amount	$ 81,016.31	$ 215,421.39	$ 296,437.70	$ 210,100.96
6	Real-Time Supplemental Reserve Amount.	$ (118,382.13)	$ 120,698.71	$ 2,316.58	$ 1,641.88
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (29,899.07)		$ (29,899.07)	$ (21,191.04)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (950,890.59)		$ (950,890.59)	$ (673,946.08)
8b	Real Time Non Excessive Energy Congestion	$ 115,638.48	$ (3,584.30)	$ 112,054.18	$ 79,418.68
8c	Real Time Non Excessive Energy Loss	$ 54,212.06	$ 1,347.24	$ 55,559.30	$ 39,377.79
9	Real Time Net Regulation Adjustment Amount	$ (1,226.40)	$ (812.92)	$ (2,039.32)	$ (1,445.37)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 95,105.31		$ 95,105.31	$ 67,406.13
11	Real Time Spinning Reserve Cost Distribution	$ 110,674.83		$ 110,674.83	$ 78,441.06
12	Real Time Supplemental Reserve Cost Distribution	$ 37,530.72		$ 37,530.72	$ 26,599.99
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 29,945.18	$ (3,509.40)	$ 26,435.78	$ 18,736.43
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ (721,749.99)**	**$ 375,462.99**	**$ (346,287.00)**	**$ (245,431.78)**

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	$ (6,388.96)		$ (6,388.96)	$ (4,528.19)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,060.88)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,589.07)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ (712,453.28)**	**$ 375,462.99**	**$ (336,990.29)**	**$ (238,842.71)**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	March 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (68,520.07)		$ (68,520.07)	$ (49,134.20)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (160,313.60)		$ (160,313.60)	$ (114,957.27)
3	Day-Ahead Supplemental Reserve	$ (73,354.25)		$ (73,354.25)	$ (52,600.68)
4	Real-Time Regulation Amount (See Note 1)	$ (11,347.07)	$ 51,749.11	$ 40,402.04	$ 28,971.39
5	Real-Time Spinning Reserve Amount	$ (11,535.47)	$ 161,561.26	$ 150,025.79	$ 107,580.11
6	Real-Time Supplemental Reserve Amount.	$ 4,283.35	$ 67,594.81	$ 71,878.16	$ 51,542.21
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 1,113.91		$ 1,113.91	$ 798.76
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (903,809.71)		$ (903,809.71)	$ (648,101.56)
8b	Real Time Non Excessive Energy Congestion	$ 26,428.38	$ (15,280.07)	$ 11,148.31	$ 7,994.21
8c	Real Time Non Excessive Energy Loss	$ (57,106.41)	$ (7,452.31)	$ (64,558.72)	$ (46,293.60)
9	Real Time Net Regulation Adjustment Amount	$ 1,270.57	$ (541.97)	$ 728.60	$ 522.46
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 135,048.49		$ 135,048.49	$ 96,840.23
11	Real Time Spinning Reserve Cost Distribution	$ 133,340.13		$ 133,340.13	$ 95,615.20
12	Real Time Supplemental Reserve Cost Distribution	$ 42,798.77		$ 42,798.77	$ 30,690.03
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 22,292.50	$ (10,213.22)	$ 12,079.28	$ 8,661.78
14	Real Time Contingency Reserve Deployment Failure	$ 2,476.61	$ -	$ 2,476.61	$ 1,775.92
	TOTAL MISO ASM CHARGES	**$ (916,933.87)**	**$ 247,417.62**	**$ (669,516.25)**	**$ (480,095.00)**

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	$ (6,388.96)		$ (6,388.96)	$ (4,581.38)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,085.08)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,666.46)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ (907,637.16)**	**$ 247,417.62**	**$ (660,219.54)**	**$ (473,428.54)**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	April 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (191,674.00)		$ (191,674.00)	$ (137,314.62)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (242,423.81)		$ (242,423.81)	$ (173,671.61)
3	Day-Ahead Supplemental Reserve	$ (41,922.52)		$ (41,922.52)	$ (30,033.15)
4	Real-Time Regulation Amount (See Note 1)	$ (30,093.38)	$ 198,702.16	$ 168,608.78	$ 120,790.77
5	Real-Time Spinning Reserve Amount	$ 22,711.55	$ 231,313.06	$ 254,024.61	$ 181,982.39
6	Real-Time Supplemental Reserve Amount.	$ 2,202.48	$ 25,856.23	$ 28,058.71	$ 20,101.17
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 8,064.33		$ 8,064.33	$ 5,777.26
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (986,639.42)		$ (986,639.42)	$ (706,825.20)
8b	Real Time Non Excessive Energy Congestion	$ (517,507.25)	$ (13,008.08)	$ (530,515.33)	$ (380,059.42)
8c	Real Time Non Excessive Energy Loss	$ (36,804.75)	$ 602.54	$ (36,202.21)	$ (25,935.15)
9	Real Time Net Regulation Adjustment Amount	$ 10,412.42	$ (5,695.56)	$ 4,716.86	$ 3,379.14
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 94,207.90		$ 94,207.90	$ 67,490.23
11	Real Time Spinning Reserve Cost Distribution	$ 129,197.90		$ 129,197.90	$ 92,556.95
12	Real Time Supplemental Reserve Cost Distribution	$ 14,673.32		$ 14,673.32	$ 10,511.92
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 49,514.64	$ (18,524.14)	$ 30,990.50	$ 22,201.49
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ (1,716,080.59)**	**$ 419,246.20**	**$ (1,296,834.39)**	**$ (929,047.85)**

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	$ (6,388.96)		$ (6,388.96)	$ (4,577.03)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,083.10)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,660.13)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ (1,706,783.88)**	**$ 419,246.20**	**$ (1,287,537.68)**	**$ (922,387.71)**

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MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	May 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (252,687.15)		$ (252,687.15)	$ (181,726.89)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (188,154.45)		$ (188,154.45)	$ (135,316.43)
3	Day-Ahead Supplemental Reserve	$ (45,913.43)		$ (45,913.43)	$ (33,019.90)
4	Real-Time Regulation Amount (See Note 1)	$ 1,822.75	$ 272,904.26	$ 274,727.01	$ 197,577.46
5	Real-Time Spinning Reserve Amount	$ (51,638.82)	$ 239,678.99	$ 188,040.17	$ 135,234.24
6	Real-Time Supplemental Reserve Amount.	$ 823.95	$ 47,817.09	$ 48,641.04	$ 34,981.54
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (18,975.51)		$ (18,975.51)	$ (13,646.76)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,352,781.15		$ 3,352,781.15	$ 2,411,244.45
8b	Real Time Non Excessive Energy Congestion	$ (124,422.15)	$ (19,548.68)	$ (143,970.83)	$ (103,540.57)
8c	Real Time Non Excessive Energy Loss	$ (142,110.89)	$ (16,131.32)	$ (158,242.21)	$ (113,804.22)
9	Real Time Net Regulation Adjustment Amount	$ 5,516.31	$ (3,203.92)	$ 2,312.39	$ 1,663.02
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 124,327.44		$ 124,327.44	$ 89,413.49
11	Real Time Spinning Reserve Cost Distribution	$ 130,179.49		$ 130,179.49	$ 93,622.15
12	Real Time Supplemental Reserve Cost Distribution	$ 32,906.93		$ 32,906.93	$ 23,665.92
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 24,837.83	$ (10,963.84)	$ 13,873.99	$ 9,977.86
14	Real Time Contingency Reserve Deployment Failure	$ 60,844.20	$ (59,673.35)	$ 1,170.85	$ 842.05
	TOTAL MISO ASM CHARGES	**$ 2,910,137.65**	**$ 450,879.23**	**$ 3,361,016.88**	**$ 2,417,167.40**

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	$ (6,388.96)		$ (6,388.96)	$ (4,594.80)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,091.19)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,685.98)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,919,434.36**	**$ 450,879.23**	**$ 3,370,313.59**	**$ 2,423,853.38**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	June 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (259,930.00)		$ (259,930.00)	$ (188,861.77)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (257,956.82)		$ (257,956.82)	$ (187,428.09)
3	Day-Ahead Supplemental Reserve	$ (39,782.25)		$ (39,782.25)	$ (28,905.27)
4	Real-Time Regulation Amount (See Note 1)	$ 7,811.34	$ 212,874.91	$ 220,686.25	$ 160,347.77
5	Real-Time Spinning Reserve Amount	$ (33,570.91)	$ 261,053.65	$ 227,482.74	$ 165,286.02
6	Real-Time Supplemental Reserve Amount.	$ 2,619.90	$ 33,224.56	$ 35,844.46	$ 26,044.12
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (23,609.91)		$ (23,609.91)	$ (17,154.66)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (544,246.64)		$ (544,246.64)	$ (395,442.57)
8b	Real Time Non Excessive Energy Congestion	$ (99,788.74)	$ (15,615.27)	$ (115,404.01)	$ (83,851.06)
8c	Real Time Non Excessive Energy Loss	$ 148,311.34	$ (20,969.61)	$ 127,341.73	$ 92,524.85
9	Real Time Net Regulation Adjustment Amount	$ 7,965.29	$ (3,780.27)	$ 4,185.02	$ 3,040.78
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 100,244.56		$ 100,244.56	$ 72,836.40
11	Real Time Spinning Reserve Cost Distribution	$ 83,640.78		$ 83,640.78	$ 60,772.31
12	Real Time Supplemental Reserve Cost Distribution	$ 17,624.29		$ 17,624.29	$ 12,805.58
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 52,533.36	$ (25,676.50)	$ 26,856.86	$ 19,513.85
14	Real Time Contingency Reserve Deployment Failure	$ 483.03	$ (1,094.08)	$ (611.05)	$ (443.98)
	TOTAL MISO ASM CHARGES	**$ (837,651.38)**	**$ 440,017.39**	**$ (397,633.99)**	**$ (288,915.71)**

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	$ (6,388.96)		$ (6,388.96)	$ (4,642.14)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,112.73)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,754.87)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ (828,354.67)**	**$ 440,017.39**	**$ (388,337.28)**	**$ (282,160.85)**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (336,943.32)		$ (336,943.32)	$ (245,872.24)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (274,431.75)		$ (274,431.75)	$ (200,256.68)
3	Day-Ahead Supplemental Reserve	$ (43,582.38)		$ (43,582.38)	$ (31,802.67)
4	Real-Time Regulation Amount (See Note 1)	$ (36,633.71)	$ 248,521.61	$ 211,887.90	$ 154,617.56
5	Real-Time Spinning Reserve Amount	$ (33,141.62)	$ 216,613.11	$ 183,471.49	$ 133,881.71
6	Real-Time Supplemental Reserve Amount.	$ 8,942.96	$ 6,638.17	$ 15,581.13	$ 11,369.77
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (43,020.27)		$ (43,020.27)	$ (31,392.49)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,369,220.90		$ 3,369,220.90	$ 2,458,567.50
8b	Real Time Non Excessive Energy Congestion	$ (450,554.12)	$ (31,559.30)	$ (482,113.42)	$ (351,804.89)
8c	Real Time Non Excessive Energy Loss	$ (147,171.97)	$ (21,406.39)	$ (168,578.36)	$ (123,013.98)
9	Real Time Net Regulation Adjustment Amount	$ 51,778.23	$ (15,010.73)	$ 36,767.50	$ 26,829.76
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 120,697.86		$ 120,697.86	$ 88,074.91
11	Real Time Spinning Reserve Cost Distribution	$ 145,124.06		$ 145,124.06	$ 105,899.05
12	Real Time Supplemental Reserve Cost Distribution	$ 65,570.52		$ 65,570.52	$ 47,847.72
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 69,613.49	$ (30,168.62)	$ 39,444.87	$ 28,783.47
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 2,465,468.88**	**$ 373,627.85**	**$ 2,839,096.73**	**$ 2,071,728.49**

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	$ (6,388.96)		$ (6,388.96)	$ (4,662.11)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,121.83)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,783.94)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,474,765.59**	**$ 373,627.85**	**$ 2,848,393.44**	**$ 2,078,512.43**

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MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

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		System	Intersystem	Retail	Minnesota Retail
	August 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (347,636.17)		$ (347,636.17)	$ (252,481.88)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (222,718.72)		$ (222,718.72)	$ (161,756.59)
3	Day-Ahead Supplemental Reserve	$ (34,153.34)		$ (34,153.34)	$ (24,804.96)
4	Real-Time Regulation Amount (See Note 1)	$ (31,436.64)	$ 277,508.64	$ 246,072.00	$ 178,717.66
5	Real-Time Spinning Reserve Amount	$ (58,990.29)	$ 203,387.04	$ 144,396.75	$ 104,872.76
6	Real-Time Supplemental Reserve Amount.	$ 2,700.58	$ 14,480.75	$ 17,181.33	$ 12,478.49
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (31,402.77)		$ (31,402.77)	$ (22,807.27)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,609,958.30		$ 2,609,958.30	$ 1,895,565.65
8b	Real Time Non Excessive Energy Congestion	$ 38,543.99	$ (4,272.26)	$ 34,271.73	$ 24,890.94
8c	Real Time Non Excessive Energy Loss	$ (50,429.36)	$ (20,750.37)	$ (71,179.73)	$ (51,696.55)
9	Real Time Net Regulation Adjustment Amount	$ (15,396.86)	$ (1,458.82)	$ (16,855.68)	$ (12,241.98)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 117,309.15		$ 117,309.15	$ 85,199.52
11	Real Time Spinning Reserve Cost Distribution	$ 109,873.68		$ 109,873.68	$ 79,799.27
12	Real Time Supplemental Reserve Cost Distribution	$ 10,470.10		$ 10,470.10	$ 7,604.24
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 63,318.82	$ (30,915.12)	$ 32,403.70	$ 23,534.22
14	Real Time Contingency Reserve Deployment Failure	$ 5,660.62	$ (889.88)	$ 4,770.74	$ 3,464.90
	TOTAL MISO ASM CHARGES	**$ 2,165,671.09**	**$ 437,089.99**	**$ 2,602,761.08**	**$ 1,890,338.44**

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	$ (6,388.96)		$ (6,388.96)	$ (4,640.19)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,111.85)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,752.03)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 2,174,967.80**	**$ 437,089.99**	**$ 2,612,057.79**	**$ 1,897,090.47**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System		Intersystem		Retail		Minnesota Retail
September 2019 Actual								
Procurement Charges								
1	Day-Ahead Regulation Amount	$	(304,701.69)			$	(304,701.69) $	(223,043.17)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$	(254,591.74)			$	(254,591.74) $	(186,362.43)
3	Day-Ahead Supplemental Reserve	$	(36,637.61)			$	(36,637.61) $	(26,818.91)
4	Real-Time Regulation Amount (See Note 1)	$	2,358.11	$	166,794.76	$	169,152.87 $	123,820.75
5	Real-Time Spinning Reserve Amount	$	(37,208.07)	$	236,610.43	$	199,402.36 $	145,963.53
6	Real-Time Supplemental Reserve Amount.	$	4,193.21	$	18,270.21	$	22,463.42 $	16,443.34
Resource Energy Charges								
7a	Real Time Excessive Energy Amount	$	(14,729.69)			$	(14,729.69) $	(10,782.21)
7b	Real Time Excessive Energy Congestion					$	- $	-
7c	Real Time Excessive Energy Loss					$	- $	-
8a	Real Time Non Excessive Energy Amount	$	3,600,833.93			$	3,600,833.93 $	2,635,828.54
8b	Real Time Non Excessive Energy Congestion	$	(278,578.76)	$	(42,671.44)	$	(321,250.20) $	(235,156.76)
8c	Real Time Non Excessive Energy Loss	$	(192,841.42)	$	(23,846.16)	$	(216,687.58) $	(158,616.40)
9	Real Time Net Regulation Adjustment Amount	$	23,043.71	$	(8,460.32)	$	14,583.39 $	10,675.11
Cost Distribution Charges								
10	Real Time Regulation Reserve Cost Distribution Amount	$	114,096.37			$	114,096.37 $	83,519.12
11	Real Time Spinning Reserve Cost Distribution	$	89,867.81			$	89,867.81 $	65,783.69
12	Real Time Supplemental Reserve Cost Distribution	$	19,417.66			$	19,417.66 $	14,213.82
Penalty Charges								
13	Real Time Excessive/Deficient Energy Deployment	$	38,029.86	$	(21,505.40)	$	16,524.46 $	12,095.99
14	Real Time Contingency Reserve Deployment Failure	$	2,994.00	$	(2,647.05)	$	346.95 $	253.97
	TOTAL MISO ASM CHARGES	**$**	**2,775,545.68**	**$**	**322,545.03**	**$**	**3,098,090.71 $**	**2,267,817.97**

Note 1:

Ramp Capability Amounts (Included in Regulation Amounts)								
3	Day-Ahead Ramp Capability Amount Included in DA Regulation Amount	$	(6,388.96)			$	(6,388.96) $	(4,676.75)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$	(2,907.75)			$	(2,907.75) $	(2,128.49)
	Total	$	(9,296.71)			$	(9,296.71) $	(6,805.24)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$**	**2,784,842.39**	**$**	**322,545.03**	**$**	**3,107,387.42 $**	**2,274,623.21**

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MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	October 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (303,530.11)		$ (303,530.11)	$ (216,383.23)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (171,667.95)		$ (171,667.95)	$ (122,380.16)
3	Day-Ahead Supplemental Reserve	$ (41,607.96)		$ (41,607.96)	$ (29,661.85)
4	Real-Time Regulation Amount (See Note 1)	$ 16,789.22	$ 181,155.31	$ 197,944.53	$ 141,112.44
5	Real-Time Spinning Reserve Amount	$ (95,959.66)	$ 223,766.40	$ 127,806.74	$ 91,112.00
6	Real-Time Supplemental Reserve Amount.	$ (8,445.98)	$ 15,966.41	$ 7,520.43	$ 5,361.23
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (4,053.47)		$ (4,053.47)	$ (2,889.67)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 792,253.10		$ 792,253.10	$ 564,788.39
8b	Real Time Non Excessive Energy Congestion	$ (189,417.45)	$ (25,948.84)	$ (215,366.29)	$ (153,532.22)
8c	Real Time Non Excessive Energy Loss	$ 31,242.59	$ (1,774.24)	$ 29,468.35	$ 21,007.66
9	Real Time Net Regulation Adjustment Amount	$ 31,658.96	$ (21,164.90)	$ 10,494.06	$ 7,481.10
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 120,394.43		$ 120,394.43	$ 85,827.84
11	Real Time Spinning Reserve Cost Distribution	$ 88,266.99		$ 88,266.99	$ 62,924.55
12	Real Time Supplemental Reserve Cost Distribution	$ 26,654.64		$ 26,654.64	$ 19,001.80
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 29,037.30	$ (14,117.60)	$ 14,919.70	$ 10,636.09
14	Real Time Contingency Reserve Deployment Failure	$ -	$ 6.58	$ 6.58	$ 4.69
	TOTAL MISO ASM CHARGES	**$ 321,614.65**	**$ 357,889.12**	**$ 679,503.77**	**$ 484,410.65**

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	$ (6,388.96)		$ (6,388.96)	$ (4,554.62)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,072.90)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,627.52)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 330,911.36**	**$ 357,889.12**	**$ 688,800.48**	**$ 491,038.17**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	November 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (247,667.36)		$ (247,667.36)	$ (177,563.33)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (141,577.09)		$ (141,577.09)	$ (101,502.68)
3	Day-Ahead Supplemental Reserve	$ (41,658.18)		$ (41,658.18)	$ (29,866.53)
4	Real-Time Regulation Amount (See Note 1)	$ 18,725.82	$ 100,537.13	$ 119,262.95	$ 85,504.71
5	Real-Time Spinning Reserve Amount	$ 12,681.68	$ 92,539.57	$ 105,221.25	$ 75,437.62
6	Real-Time Supplemental Reserve Amount.	$ 27,110.57	$ 11,469.21	$ 38,579.78	$ 27,659.50
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (8,809.54)		$ (8,809.54)	$ (6,315.94)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,042,610.94		$ 1,042,610.94	$ 747,492.42
8b	Real Time Non Excessive Energy Congestion	$ (93,012.10)	$ 19,426.40	$ (73,585.70)	$ (52,756.74)
8c	Real Time Non Excessive Energy Loss	$ 774.48	$ 10,215.16	$ 10,989.64	$ 7,878.95
9	Real Time Net Regulation Adjustment Amount	$ (7,977.58)	$ (872.43)	$ (8,850.01)	$ (6,344.95)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 113,663.10		$ 113,663.10	$ 81,489.94
11	Real Time Spinning Reserve Cost Distribution	$ 63,589.54		$ 63,589.54	$ 45,590.06
12	Real Time Supplemental Reserve Cost Distribution	$ 1,014.52		$ 1,014.52	$ 727.35
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 30,814.53	$ (11,579.31)	$ 19,235.22	$ 13,790.55
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 770,283.33**	**$ 221,735.73**	**$ 992,019.06**	**$ 711,220.93**

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	$ (6,388.96)		$ (6,388.96)	$ (4,580.52)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,084.69)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,665.21)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 779,580.04**	**$ 221,735.73**	**$ 1,001,315.77**	**$ 717,886.14**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	December 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (219,482.67)		$ (219,482.67)	$ (156,653.07)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (108,567.80)		$ (108,567.80)	$ (77,488.94)
3	Day-Ahead Supplemental Reserve	$ (44,555.84)		$ (44,555.84)	$ (31,801.19)
4	Real-Time Regulation Amount (See Note 1)	$ 34,423.18	$ 53,706.58	$ 88,129.76	$ 62,901.54
5	Real-Time Spinning Reserve Amount	$ (40,111.56)	$ 66,722.60	$ 26,611.04	$ 18,993.30
6	Real-Time Supplemental Reserve Amount.	$ 7,386.41	$ 24,602.02	$ 31,988.43	$ 22,831.35
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (9,551.32)		$ (9,551.32)	$ (6,817.14)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,073,957.09		$ 1,073,957.09	$ 766,523.74
8b	Real Time Non Excessive Energy Congestion	$ 63,278.04	$ 158.90	$ 63,436.94	$ 45,277.34
8c	Real Time Non Excessive Energy Loss	$ 11,548.03	$ (3,432.29)	$ 8,115.74	$ 5,792.51
9	Real Time Net Regulation Adjustment Amount	$ (1,093.72)	$ 2,250.06	$ 1,156.34	$ 825.32
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 127,269.02		$ 127,269.02	$ 90,836.71
11	Real Time Spinning Reserve Cost Distribution	$ 38,178.33		$ 38,178.33	$ 27,249.32
12	Real Time Supplemental Reserve Cost Distribution	$ 14,462.77		$ 14,462.77	$ 10,322.63
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 31,313.48	$ (8,410.07)	$ 22,903.41	$ 16,347.03
14	Real Time Contingency Reserve Deployment Failure	$ -	$ 817.04	$ 817.04	$ 583.15
	TOTAL MISO ASM CHARGES	**$ 978,453.44**	**$ 136,414.84**	**$ 1,114,868.28**	**$ 795,723.60**

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	$ (6,388.96)		$ (6,388.96)	$ (4,560.04)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (2,907.75)		$ (2,907.75)	$ (2,075.37)
	Total	$ (9,296.71)		$ (9,296.71)	$ (6,635.41)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 987,750.15**	**$ 136,414.84**	**$ 1,124,164.99**	**$ 802,359.02**

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2018 - December 2019 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (4,289,813.46)	$ -	$ (4,289,813.46)	$ (3,103,556.02)
2	Day-Ahead Spinning Reserve Amount (See Note 1)	$ (3,787,109.35)	$ -	$ (3,787,109.35)	$ (2,742,163.81)
3	Day-Ahead Supplemental Reserve	$ (779,766.65)	$ -	$ (779,766.65)	$ (561,083.84)
4	Real-Time Regulation Amount (See Note 1)	$ (561,660.17)	$ 3,105,198.11	$ 2,543,537.94	$ 1,840,489.75
5	Real-Time Spinning Reserve Amount	$ (402,703.00)	$ 3,134,431.46	$ 2,731,728.46	$ 1,977,918.98
6	Real-Time Supplemental Reserve Amount.	$ 116,575.65	$ 433,898.08	$ 550,473.73	$ 395,723.01
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (124,474.31)	$ -	$ (124,474.31)	$ (88,198.19)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 28,853,422.92	$ -	$ 28,853,422.92	$ 21,003,486.09
8b	Real Time Non Excessive Energy Congestion	$ (2,364,015.82)	$ (223,514.96)	$ (2,587,530.78)	$ (1,886,150.04)
8c	Real Time Non Excessive Energy Loss	$ (837,663.72)	$ (133,708.59)	$ (971,372.31)	$ (712,621.44)
9	Real Time Net Regulation Adjustment Amount	$ 316,329.22	$ (171,022.07)	$ 145,307.15	$ 106,574.28
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 2,230,954.43	$ -	$ 2,230,954.43	$ 1,608,800.64
11	Real Time Spinning Reserve Cost Distribution	$ 2,177,537.54	$ -	$ 2,177,537.54	$ 1,571,858.14
12	Real Time Supplemental Reserve Cost Distribution	$ 488,680.39	$ -	$ 488,680.39	$ 353,270.38
Penalty Charges					
13	Real Time Excessive/Deficient Energy Deployment	$ 1,102,595.75	$ (453,213.04)	$ 649,382.71	$ 469,160.57
14	Real Time Contingency Reserve Deployment Failure	$ 76,601.53	$ (63,900.15)	$ 12,701.38	$ 9,179.27
		$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 22,215,490.95**	**$ 5,628,168.84**	**$ 27,843,659.79**	**$ 20,242,687.76**

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	$ (119,081.78)	$ -	$ (119,081.78)	$ (85,877.72)
4	Real Time-Ramp Capability Amount Included in RT Regulation Amount	$ (50,982.97)	$ -	$ (50,982.97)	$ (36,787.63)
	Total	$ (170,064.75)	0	$ (170,064.75)	$ (122,665.35)
	TOTAL MISO ASM CHARGES EXCLUDING RAMP CAP AMT	**$ 22,385,555.70**	**$ 5,628,168.84**	**$ 28,013,724.54**	**$ 20,365,353.12**

Northern States Power Company
Electric Operation - State of Minnesota

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

		July 18	August 18	September 18	3rd Qt	October 18	November 18	December 18	4th Qt	January 19	February 19	March 19	1st Qt	April 19	May 19	June 19	2nd Qt
Regulation																	
1	Day-Ahead Regulation Amount	$ (302,134.95)	$ (196,992.06)	$ (376,639.03)	$ (875,766.04)	$ (246,593.38)	$ (250,955.55)	$ (288,577.90)	$ (786,126.83)	$ (65,489.47)	$ (29,658.58)	$ (68,520.07)	$ (163,668.12)	$ (191,674.00)	$ (252,687.15)	$ (259,930.00)	$ (704,291.15)
4	Real-Time Regulation Amount	$ (127,323.23)	$ (105,127.32)	$ (137,684.42)	$ (370,134.97)	$ (59,740.99)	$ (70,404.23)	$ 7,347.67	$ (122,797.55)	$ (87,322.99)	$ 46,175.72	$ (11,347.07)	$ (52,494.34)	$ (30,093.38)	$ 1,822.75	$ 7,811.34	$ (20,459.29)
10	Real Time Regulation Reserve Cost Distribution Amount	$ 119,499.19	$ 114,728.25	$ 122,911.04	$ 357,138.48	$ 160,727.28	$ 172,672.43	$ 161,494.06	$ 494,893.77	$ 116,558.55	$ 95,105.31	$ 135,048.49	$ 346,712.35	$ 94,207.90	$ 124,327.44	$ 100,244.56	$ 318,779.90
	SUBTOTAL	$ (309,958.99)	$ (187,391.13)	$ (391,412.41)	$ (888,762.53)	$ (145,607.09)	$ (148,687.35)	$ (119,736.17)	$ (414,030.61)	$ (36,253.91)	$ 111,622.45	$ 55,181.35	$ 130,549.89	$ (127,559.48)	$ (126,536.96)	$ (151,874.10)	$ (405,970.54)
Spinning Reserve																	
2	Day-Ahead Spinning Reserve Amount	$ (317,720.30)	$ (337,160.12)	$ (323,121.86)	$ (978,002.28)	$ (220,082.32)	$ (164,144.21)	$ (147,440.30)	$ (531,666.83)	$ (147,034.33)	$ (108,002.18)	$ (160,313.60)	$ (415,350.11)	$ (242,423.81)	$ (188,154.45)	$ (257,956.82)	$ (688,535.08)
5	Real-Time Spinning Reserve Amount	$ 48,849.06	$ 145,522.34	$ 57,825.92	$ 252,197.32	$ (53,144.66)	$ (103,773.88)	$ (46,675.26)	$ (203,593.80)	$ (205,559.66)	$ 81,016.31	$ (11,535.47)	$ (136,078.82)	$ 22,711.55	$ (51,638.82)	$ (33,570.91)	$ (62,498.18)
11	Real Time Spinning Reserve Cost Distribution	$ 127,940.37	$ 116,938.26	$ 182,842.77	$ 427,721.40	$ 215,012.98	$ 165,543.32	$ 146,531.41	$ 527,087.71	$ 100,794.89	$ 110,674.83	$ 133,340.13	$ 344,809.85	$ 129,197.90	$ 130,179.49	$ 83,640.78	$ 343,018.17
	SUBTOTAL	$ (140,930.87)	$ (74,699.52)	$ (82,453.17)	$ (298,083.56)	$ (58,214.00)	$ (102,374.77)	$ (47,584.15)	$ (208,172.92)	$ (251,799.10)	$ 83,688.96	$ (38,508.94)	$ (206,619.08)	$ (90,514.36)	$ (109,613.78)	$ (207,886.95)	$ (408,015.09)
Supplemental Reserve																	
3	Day-Ahead Supplemental Reserve	$ (19,980.74)	$ (27,132.43)	$ (35,805.11)	$ (82,918.28)	$ (45,972.35)	$ (34,404.93)	$ (24,905.43)	$ (105,282.71)	$ (94,408.25)	$ (53,989.65)	$ (73,354.25)	$ (221,752.15)	$ (41,922.52)	$ (45,913.43)	$ (39,782.25)	$ (127,618.20)
6	Real-Time Supplemental Reserve Amount.	$ 14,549.40	$ 5,534.10	$ 26,265.73	$ 46,349.23	$ 9,331.78	$ 2,932.09	$ 418.75	$ 12,682.62	$ 124,108.50	$ (118,382.13)	$ 4,283.35	$ 10,009.72	$ 2,202.48	$ 823.95	$ 2,619.90	$ 5,646.33
12	Real Time Supplemental Reserve Cost Distribution	$ 19,859.65	$ 23,987.62	$ 73,610.31	$ 117,457.58	$ 34,453.68	$ 15,957.36	$ 23,646.16	$ 74,057.20	$ 14,041.37	$ 37,530.72	$ 42,798.77	$ 94,370.86	$ 14,673.32	$ 32,906.93	$ 17,624.29	$ 65,204.54
	SUBTOTAL	$ 14,428.31	$ 2,389.29	$ 64,070.93	$ 80,888.53	$ (2,186.89)	$ (15,515.48)	$ (840.52)	$ (18,542.89)	$ 43,741.62	$ (134,841.06)	$ (26,272.13)	$ (117,371.57)	$ (25,046.72)	$ (12,182.55)	$ (19,538.06)	$ (56,767.33)
Other Charges																	
14	Real Time Contingency Reserve Deployment Failure	$ 1,487.96	$ -	$ -	$ 1,487.96	$ -	$ 2,655.11	$ -	$ 2,655.11	$ -	$ -	$ 2,476.61	$ 2,476.61	$ -	$ 60,844.20	$ 483.03	$ 61,327.23
13	Real Time Excessive/Deficient Energy Deployment	$ 87,908.14	$ 90,847.37	$ 112,282.66	$ 291,038.17	$ 88,696.82	$ 126,062.97	$ 117,162.44	$ 331,922.23	$ 38,384.36	$ 29,945.18	$ 22,292.50	$ 90,622.04	$ 49,514.64	$ 24,837.83	$ 52,533.36	$ 126,885.83
9	Real Time Net Regulation Adjustment Amount	$ 68,610.58	$ 76,613.91	$ 47,173.89	$ 192,398.38	$ 1,378.67	$ 9,459.53	$ 6,286.40	$ 17,124.60	$ 855.31	$ (1,226.40)	$ 1,270.57	$ 899.48	$ 10,412.42	$ 5,516.31	$ 7,965.29	$ 23,894.02
	SUBTOTAL	$ 158,006.68	$ 167,461.28	$ 159,456.55	$ 484,924.51	$ 90,075.49	$ 138,177.61	$ 123,448.84	$ 351,701.94	$ 39,239.67	$ 28,718.78	$ 26,039.68	$ 93,998.13	$ 59,927.06	$ 91,198.34	$ 60,981.68	$ 212,107.08
	TOTAL MISO ASM CHARGES	$ (278,454.87)	$ (92,240.08)	$ (250,338.10)	$ (621,033.05)	$ (115,932.49)	$ (128,399.99)	$ (44,712.00)	$ (289,044.48)	$ (205,071.72)	$ 89,189.13	$ 16,439.96	$ (99,442.63)	$ (183,193.50)	$ (157,134.95)	$ (318,317.43)	$ (658,645.88)
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																	
7a	Real Time Excessive Energy Amount	$ 3,933.26	$ 1,228.65	$ 60,800.59	$ 65,962.50	$ 369,413.12	$ (287,274.77)	$ (92,894.22)	$ (10,755.87)	$ (4,807.63)	$ (29,899.07)	$ 1,113.91	$ (33,592.79)	$ 8,064.33	$ (18,975.51)	$ (23,609.91)	$ (34,521.09)
7b	Real Time Excessive Energy Congestion				$ -				$ -				$ -				$ -
7c	Real Time Excessive Energy Loss				$ -				$ -				$ -				$ -
8a	Real Time Non Excessive Energy Amount	$ 3,583,561.26	$ 3,802,233.75	$ 3,451,814.56	$ 10,837,609.57	$ 2,214,112.71	$ 1,175,015.03	$ 1,340,646.55	$ 4,729,774.29	$ 830,010.01	$ (950,890.59)	$ (903,809.71)	$ (1,024,690.29)	$ (986,639.42)	$ 3,352,781.15	$ (544,246.64)	$ 1,821,895.09
8b	Real Time Non Excessive Energy Congestion	$ (143,557.98)	$ (580,203.27)	$ (251,434.51)	$ (975,195.76)	$ (19,316.20)	$ (11,023.61)	$ 10,204.25	$ (20,135.56)	$ 140,707.18	$ 115,638.48	$ 26,428.38	$ 282,774.04	$ (517,507.25)	$ (124,422.15)	$ (99,788.74)	$ (741,718.14)
8c	Real Time Non Excessive Energy Loss	$ (178,567.97)	$ (298,932.70)	$ (36,753.39)	$ (514,254.06)	$ 30,463.21	$ 19,145.92	$ 1,899.05	$ 51,508.18	$ 5,458.46	$ 54,212.06	$ (57,106.41)	$ 2,564.11	$ (36,804.75)	$ (142,110.89)	$ 148,311.34	$ (30,604.30)
	SUBTOTAL	$ 3,265,368.57	$ 2,924,326.43	$ 3,224,427.25	$ 9,414,122.25	$ 2,594,672.84	$ 895,862.57	$ 1,259,855.63	$ 4,750,391.04	$ 971,368.02	$ (810,939.12)	$ (933,373.83)	$ (772,944.93)	$ (1,532,887.09)	$ 3,067,272.60	$ (519,333.95)	$ 1,015,051.56
	GRAND TOTAL MISO ASM CHARGES	$ 2,986,913.70	$ 2,832,086.35	$ 2,974,089.15	$ 8,793,089.20	$ 2,478,740.35	$ 767,462.58	$ 1,215,143.63	$ 4,461,346.56	$ 766,296.30	$ (721,749.99)	$ (916,933.87)	$ (872,387.56)	$ (1,716,080.59)	$ 2,910,137.65	$ (837,651.38)	$ 356,405.68

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

		July 19	August 19	September 19	3rd Qt	October 19	November 19	December 19	4th Qt	YTD
Regulation										
1	Day-Ahead Regulation Amount	$ (336,943.32)	$ (347,636.17)	$ (304,701.69)	$ (989,281.18)	$ (303,530.11)	$ (247,667.36)	$ (219,482.67)	$ (770,680.14)	$ (2,627,920.59)
4	Real-Time Regulation Amount	$ (36,633.71)	$ (31,436.64)	$ 2,358.11	$ (65,712.24)	$ 16,789.22	$ 18,725.82	$ 34,423.18	$ 69,938.22	$ (68,727.65)
10	Real Time Regulation Reserve Cost Distribution Amount	$ 120,697.86	$ 117,309.15	$ 114,096.37	$ 352,103.38	$ 120,394.43	$ 113,663.10	$ 127,269.02	$ 361,326.55	$ 1,378,922.18
	SUBTOTAL	$ (252,879.17)	$ (261,763.66)	$ (188,247.21)	$ (702,890.04)	$ (166,346.46)	$ (115,278.44)	$ (57,790.47)	$ (339,415.37)	$ (1,317,726.06)
Spinning Reserve										
2	Day-Ahead Spinning Reserve Amount	$ (274,431.75)	$ (222,718.72)	$ (254,591.74)	$ (751,742.21)	$ (171,667.95)	$ (141,577.09)	$ (108,567.80)	$ (421,812.84)	$ (2,277,440.24)
5	Real-Time Spinning Reserve Amount	$ (33,141.62)	$ (58,990.29)	$ (37,208.07)	$ (129,339.98)	$ (95,959.66)	$ 12,681.68	$ (40,111.56)	$ (123,389.54)	$ (451,306.52)
11	Real Time Spinning Reserve Cost Distribution	$ 145,124.06	$ 109,873.68	$ 89,867.81	$ 344,865.55	$ 88,266.99	$ 63,589.54	$ 38,178.33	$ 190,034.86	$ 1,222,728.43
	SUBTOTAL	$ (162,449.31)	$ (171,835.33)	$ (201,932.00)	$ (536,216.64)	$ (179,360.62)	$ (65,305.87)	$ (110,501.03)	$ (355,167.52)	$ (1,506,018.33)
Supplemental Reserve										
3	Day-Ahead Supplemental Reserve	$ (43,582.38)	$ (34,153.34)	$ (36,637.61)	$ (114,373.33)	$ (41,607.96)	$ (41,658.18)	$ (44,555.84)	$ (127,821.98)	$ (591,565.66)
6	Real-Time Supplemental Reserve Amount.	$ 8,942.96	$ 2,700.58	$ 4,193.21	$ 15,836.75	$ (8,445.98)	$ 27,110.57	$ 7,386.41	$ 26,051.00	$ 57,543.80
12	Real Time Supplemental Reserve Cost Distribution	$ 65,570.52	$ 10,470.10	$ 19,417.66	$ 95,458.28	$ 26,654.64	$ 1,014.52	$ 14,462.77	$ 42,131.93	$ 297,165.61
	SUBTOTAL	$ 30,931.10	$ (20,982.66)	$ (13,026.74)	$ (3,078.30)	$ (23,399.30)	$ (13,533.09)	$ (22,706.66)	$ (59,639.05)	$ (236,856.25)
Other Charges										
14	Real Time Contingency Reserve Deployment Failure	$ -	$ 5,660.62	$ 2,994.00	$ 8,654.62	$ -	$ -	$ -	$ -	$ 72,458.46
13	Real Time Excessive/Deficient Energy Deployment	$ 69,613.49	$ 63,318.82	$ 38,029.86	$ 170,962.17	$ 29,037.30	$ 30,814.53	$ 31,313.48	$ 91,165.31	$ 479,635.35
9	Real Time Net Regulation Adjustment Amount	$ 51,778.23	$ (15,396.86)	$ 23,043.71	$ 59,425.08	$ 31,658.96	$ (7,977.58)	$ (1,093.72)	$ 22,587.66	$ 106,806.24
	SUBTOTAL	$ 121,391.72	$ 53,582.58	$ 64,067.57	$ 239,041.87	$ 60,696.26	$ 22,836.95	$ 30,219.76	$ 113,752.97	$ 658,900.05
	TOTAL MISO ASM CHARGES	$ (263,005.66)	$ (400,999.07)	$ (339,138.38)	$ (1,003,143.11)	$ (308,410.12)	$ (171,280.45)	$ (160,778.40)	$ (640,468.97)	$ (2,401,700.59)
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT										
7a	Real Time Excessive Energy Amount	$ (43,020.27)	$ (31,402.77)	$ (14,729.69)	$ (89,152.73)	$ (4,053.47)	$ (8,809.54)	$ (9,551.32)	$ (22,414.33)	$ (179,680.94)
7b	Real Time Excessive Energy Congestion				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,369,220.90	$ 2,609,958.30	$ 3,600,833.93	$ 9,580,013.13	$ 792,253.10	$ 1,042,610.94	$ 1,073,957.09	$ 2,908,821.13	$ 13,286,039.06
8b	Real Time Non Excessive Energy Congestion	$ (450,554.12)	$ 38,543.99	$ (278,578.76)	$ (690,588.89)	$ (189,417.45)	$ (93,012.10)	$ 63,278.04	$ (219,151.51)	$ (1,368,684.50)
8c	Real Time Non Excessive Energy Loss	$ (147,171.97)	$ (50,429.36)	$ (192,841.42)	$ (390,442.75)	$ 31,242.59	$ 774.48	$ 11,548.03	$ 43,565.10	$ (374,917.84)
	SUBTOTAL	$ 2,728,474.54	$ 2,566,670.16	$ 3,114,684.06	$ 8,409,828.76	$ 630,024.77	$ 941,563.78	$ 1,139,231.84	$ 2,710,820.39	$ 11,362,755.78
	GRAND TOTAL MISO ASM CHARGES	$ 2,465,468.88	$ 2,165,671.09	$ 2,775,545.68	$ 7,406,685.65	$ 321,614.65	$ 770,283.33	$ 978,453.44	$ 2,070,351.42	$ 8,961,055.19

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

		July 18	August 18	September 18	3rd Qt	October 18	November 18	December 18	4th Qt	January 19	February 19	March 19	1st Qt	April 19	May 19	June 19	2nd Qt
Regulation																	
1	Day-Ahead Regulation Amount				$ -				$ -				$ -				$ -
4	Real-Time Regulation Amount	$ 335,414.81	$ 147,109.86	$ 328,009.35	$ 810,534.02	$ 184,550.08	$ 123,884.22	$ 124,990.66	$ 433,424.96	$ 50,882.39	$ 45,902.27	$ 51,749.11	$ 148,533.77	$ 198,702.16	$ 272,904.26	$ 212,874.91	$ 684,481.33
10	Real Time Regulation Reserve Cost Distribution Amount				$ -				$ -				$ -				$ -
	SUBTOTAL	$ 335,414.81	$ 147,109.86	$ 328,009.35	$ 810,534.02	$ 184,550.08	$ 123,884.22	$ 124,990.66	$ 433,424.96	$ 50,882.39	$ 45,902.27	$ 51,749.11	$ 148,533.77	$ 198,702.16	$ 272,904.26	$ 212,874.91	$ 684,481.33
Spinning Reserve																	
2	Day-Ahead Spinning Reserve Amount				$ -				$ -				$ -				$ -
5	Real-Time Spinning Reserve Amount	$ 190,891.97	$ 75,241.87	$ 187,275.87	$ 453,409.71	$ 134,739.28	$ 146,255.84	$ 115,767.59	$ 396,762.71	$ 135,591.54	$ 215,421.39	$ 161,561.26	$ 512,574.19	$ 231,313.06	$ 239,678.99	$ 261,053.65	$ 732,045.70
11	Real Time Spinning Reserve Cost Distribution				$ -				$ -				$ -				$ -
	SUBTOTAL	$ 190,891.97	$ 75,241.87	$ 187,275.87	$ 453,409.71	$ 134,739.28	$ 146,255.84	$ 115,767.59	$ 396,762.71	$ 135,591.54	$ 215,421.39	$ 161,561.26	$ 512,574.19	$ 231,313.06	$ 239,678.99	$ 261,053.65	$ 732,045.70
Supplemental Reserve																	
3	Day-Ahead Supplemental Reserve				$ -				$ -				$ -				$ -
6	Real-Time Supplemental Reserve Amount.	$ 1,402.08	$ (1,127.17)	$ (1,265.81)	$ (990.90)	$ 14,069.52	$ 13,810.27	$ 2,372.40	$ 30,252.19	$ 18,018.62	$ 120,698.71	$ 67,594.81	$ 206,312.14	$ 25,856.23	$ 47,817.09	$ 33,224.56	$ 106,897.88
12	Real Time Supplemental Reserve Cost Distribution				$ -				$ -				$ -				$ -
	SUBTOTAL	$ 1,402.08	$ (1,127.17)	$ (1,265.81)	$ (990.90)	$ 14,069.52	$ 13,810.27	$ 2,372.40	$ 30,252.19	$ 18,018.62	$ 120,698.71	$ 67,594.81	$ 206,312.14	$ 25,856.23	$ 47,817.09	$ 33,224.56	$ 106,897.88
Other Charges																	
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ -	$ -	$ (419.41)	$ -	$ -	$ (419.41)	$ -	$ -	$ -	$ -	$ -	$ (59,673.35)	$ (1,094.08)	$ (60,767.43)
13	Real Time Excessive/Deficient Energy Deployment	$ (48,845.86)	$ (27,871.78)	$ (43,418.84)	$ (120,136.48)	$ (51,180.02)	$ (52,227.50)	$ (31,643.66)	$ (135,051.18)	$ (12,442.16)	$ (3,509.40)	$ (10,213.22)	$ (26,164.78)	$ (18,524.14)	$ (10,963.84)	$ (25,676.50)	$ (55,164.48)
9	Real Time Net Regulation Adjustment Amount	$ (34,762.29)	$ (33,669.38)	$ (22,876.08)	$ (91,307.75)	$ (9,826.57)	$ (7,027.08)	$ (1,732.06)	$ (18,585.71)	$ (2,376.83)	$ (812.92)	$ (541.97)	$ (3,731.72)	$ (5,695.56)	$ (3,203.92)	$ (3,780.27)	$ (12,679.75)
	SUBTOTAL	$ (83,608.15)	$ (61,541.16)	$ (66,294.92)	$ (211,444.23)	$ (61,426.00)	$ (59,254.58)	$ (33,375.72)	$ (154,056.30)	$ (14,818.99)	$ (4,322.32)	$ (10,755.19)	$ (29,896.50)	$ (24,219.70)	$ (73,841.11)	$ (30,550.85)	$ (128,611.66)
	TOTAL MISO ASM CHARGES	$ 444,100.71	$ 159,683.40	$ 447,724.49	$ 1,051,508.60	$ 271,932.88	$ 224,695.75	$ 209,754.93	$ 706,383.56	$ 189,673.56	$ 377,700.05	$ 270,149.99	$ 837,523.60	$ 431,651.75	$ 486,559.23	$ 476,602.27	$ 1,394,813.25
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	$ (19,168.42)	$ (42,317.08)	$ (26,242.75)	$ (87,728.25)	$ (4,075.31)	$ 4,300.09	$ (8,672.00)	$ (8,447.22)	$ 24,563.46	$ (3,584.30)	$ (15,280.07)	$ 5,699.09	$ (13,008.08)	$ (19,548.68)	$ (15,615.27)	$ (48,172.04)
8c	Real Time Non Excessive Energy Loss	$ (17,889.01)	$ (20,886.42)	$ (3,719.62)	$ (42,495.05)	$ (229.82)	$ 3,061.55	$ (2,323.32)	$ 508.41	$ 11,875.81	$ 1,347.24	$ (7,452.31)	$ 5,770.74	$ 602.54	$ (16,131.32)	$ (20,969.61)	$ (36,498.40)
	SUBTOTAL	$ (37,057.43)	$ (63,203.50)	$ (29,962.37)	$ (130,223.31)	$ (4,305.13)	$ 7,361.64	$ (10,995.32)	$ (7,938.81)	$ 36,439.27	$ (2,237.06)	$ (22,732.37)	$ 11,469.84	$ (12,405.55)	$ (35,680.00)	$ (36,584.88)	$ (84,670.44)
	GRAND TOTAL MISO ASM CHARGES	$ 407,043.28	$ 96,479.90	$ 417,762.12	$ 921,285.29	$ 267,627.75	$ 232,057.39	$ 198,759.61	$ 698,444.75	$ 226,112.83	$ 375,462.99	$ 247,417.62	$ 848,993.44	$ 419,246.20	$ 450,879.23	$ 440,017.39	$ 1,310,142.81

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 10

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

		July 19	August 19	September 19	3rd Qt	October 19	November 19	December 19	4th Qt	YTD
Regulation										
1	Day-Ahead Regulation Amount				$ -				$ -	$ -
4	Real-Time Regulation Amount	$ 248,521.61	$ 277,508.64	$ 166,794.76	$ 692,825.01	$ 181,155.31	$ 100,537.13	$ 53,706.58	$ 335,399.02	$ 1,861,239.13
10	Real Time Regulation Reserve Cost Distribution Amount				$ -				$ -	$ -
	SUBTOTAL	$ 248,521.61	$ 277,508.64	$ 166,794.76	$ 692,825.01	$ 181,155.31	$ 100,537.13	$ 53,706.58	$ 335,399.02	$ 1,861,239.13
Spinning Reserve										
2	Day-Ahead Spinning Reserve Amount				$ -				$ -	$ -
5	Real-Time Spinning Reserve Amount	$ 216,613.11	$ 203,387.04	$ 236,610.43	$ 656,610.58	$ 223,766.40	$ 92,539.57	$ 66,722.60	$ 383,028.57	$ 2,284,259.04
11	Real Time Spinning Reserve Cost Distribution				$ -				$ -	$ -
	SUBTOTAL	$ 216,613.11	$ 203,387.04	$ 236,610.43	$ 656,610.58	$ 223,766.40	$ 92,539.57	$ 66,722.60	$ 383,028.57	$ 2,284,259.04
Supplemental Reserve										
3	Day-Ahead Supplemental Reserve				$ -				$ -	$ -
6	Real-Time Supplemental Reserve Amount.	$ 6,638.17	$ 14,480.75	$ 18,270.21	$ 39,389.13	$ 15,966.41	$ 11,469.21	$ 24,602.02	$ 52,037.64	$ 404,636.79
12	Real Time Supplemental Reserve Cost Distribution				$ -				$ -	$ -
	SUBTOTAL	$ 6,638.17	$ 14,480.75	$ 18,270.21	$ 39,389.13	$ 15,966.41	$ 11,469.21	$ 24,602.02	$ 52,037.64	$ 404,636.79
Other Charges										
14	Real Time Contingency Reserve Deployment Failure	$ -	$ (889.88)	$ (2,647.05)	$ (3,536.93)	$ 6.58	$ -	$ 817.04	$ 823.62	$ (63,480.74)
13	Real Time Excessive/Deficient Energy Deployment	$ (30,168.62)	$ (30,915.12)	$ (21,505.40)	$ (82,589.14)	$ (14,117.60)	$ (11,579.31)	$ (8,410.07)	$ (34,106.98)	$ (198,025.38)
9	Real Time Net Regulation Adjustment Amount	$ (15,010.73)	$ (1,458.82)	$ (8,460.32)	$ (24,929.87)	$ (21,164.90)	$ (872.43)	$ 2,250.06	$ (19,787.27)	$ (61,128.61)
	SUBTOTAL	$ (45,179.35)	$ (33,263.82)	$ (32,612.77)	$ (111,055.94)	$ (35,275.92)	$ (12,451.74)	$ (5,342.97)	$ (53,070.63)	$ (322,634.73)
	TOTAL MISO ASM CHARGES	$ 426,593.54	$ 462,112.61	$ 389,062.63	$ 1,277,768.78	$ 385,612.20	$ 192,094.17	$ 139,688.23	$ 717,394.60	$ 4,227,500.23
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	$ (31,559.30)	$ (4,272.26)	$ (42,671.44)	$ (78,503.00)	$ (25,948.84)	$ (19,426.40)	$ 158.90	$ (45,216.34)	$ (166,192.28)
8c	Real Time Non Excessive Energy Loss	$ (21,406.39)	$ (20,750.37)	$ (23,846.16)	$ (66,002.92)	$ (1,774.24)	$ (10,215.16)	$ (3,432.29)	$ (15,421.70)	$ (112,152.28)
	SUBTOTAL	$ (52,965.69)	$ (25,022.62)	$ (66,517.60)	$ (144,505.92)	$ (27,723.08)	$ (29,641.56)	$ (3,273.39)	$ (60,638.04)	$ (278,344.56)
	GRAND TOTAL MISO ASM CHARGES	$ 373,627.85	$ 437,089.99	$ 322,545.03	$ 1,133,262.86	$ 357,889.12	$ 162,452.61	$ 136,414.84	$ 656,756.56	$ 3,949,155.67

Northern States Power Company
Electric Operation - State of Minnesota

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 11

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

		July 18	August 18	September 18	3rd Qt	October 18	November 18	December 18	4th Qt	January 19	February 19	March 19	1st Qt	April 19	May 19	June 19	2nd Qt
Regulation																	
1	Day-Ahead Regulation Amount	$ (302,134.95)	$ (196,992.06)	$ (376,639.03)	$ (875,766.04)	$ (246,593.38)	$ (250,955.55)	$ (288,577.90)	$ (786,126.83)	$ (65,489.47)	$ (29,658.58)	$ (68,520.07)	$ (163,668.12)	$ (191,674.00)	$ (252,687.15)	$ (259,930.00)	$ (704,291.15)
4	Real-Time Regulation Amount	$ 208,091.58	$ 41,982.54	$ 190,324.93	$ 440,399.05	$ 124,809.09	$ 53,479.99	$ 132,338.33	$ 310,627.41	$ (36,440.60)	$ 92,077.99	$ 40,402.04	$ 96,039.43	$ 168,608.78	$ 274,727.01	$ 220,686.25	$ 664,022.04
10	Real Time Regulation Reserve Cost Distribution Amount	$ 119,499.19	$ 114,728.25	$ 122,911.04	$ 357,138.48	$ 160,727.28	$ 172,672.43	$ 161,494.06	$ 494,893.77	$ 116,558.55	$ 95,105.31	$ 135,048.49	$ 346,712.35	$ 94,207.90	$ 124,327.44	$ 100,244.56	$ 318,779.90
	SUBTOTAL	$ 25,455.82	$ (40,281.27)	$ (63,403.06)	$ (78,228.51)	$ 38,942.99	$ (24,803.13)	$ 5,254.49	$ 19,394.35	$ 14,628.48	$ 157,524.72	$ 106,930.46	$ 279,083.66	$ 71,142.68	$ 146,367.30	$ 61,000.81	$ 278,510.79
Spinning Reserve																	
2	Day-Ahead Spinning Reserve Amount	$ (317,720.30)	$ (337,160.12)	$ (323,121.86)	$ (978,002.28)	$ (220,082.32)	$ (164,144.21)	$ (147,440.30)	$ (531,666.83)	$ (147,034.33)	$ (108,002.18)	$ (160,313.60)	$ (415,350.11)	$ (242,423.81)	$ (188,154.45)	$ (257,956.82)	$ (688,535.08)
5	Real-Time Spinning Reserve Amount	$ 239,741.03	$ 220,764.21	$ 245,101.79	$ 705,607.03	$ 81,594.62	$ 42,481.96	$ 69,092.33	$ 193,168.91	$ (69,968.12)	$ 296,437.70	$ 150,025.79	$ 376,495.37	$ 254,024.61	$ 188,040.17	$ 227,482.74	$ 669,547.52
11	Real Time Spinning Reserve Cost Distribution	$ 127,940.37	$ 116,938.26	$ 182,842.77	$ 427,721.40	$ 215,012.98	$ 165,543.32	$ 146,531.41	$ 527,087.71	$ 100,794.89	$ 110,674.83	$ 133,340.13	$ 344,809.85	$ 129,197.90	$ 130,179.49	$ 83,640.78	$ 343,018.17
	SUBTOTAL	$ 49,961.10	$ 542.35	$ 104,822.70	$ 155,326.15	$ 76,525.28	$ 43,881.07	$ 68,183.44	$ 188,589.79	$ (116,207.56)	$ 299,110.35	$ 123,052.32	$ 305,955.11	$ 140,798.70	$ 130,065.21	$ 53,166.70	$ 324,030.61
Supplemental Reserve																	
3	Day-Ahead Supplemental Reserve	$ (19,980.74)	$ (27,132.43)	$ (35,805.11)	$ (82,918.28)	$ (45,972.35)	$ (34,404.93)	$ (24,905.43)	$ (105,282.71)	$ (94,408.25)	$ (53,989.65)	$ (73,354.25)	$ (221,752.15)	$ (41,922.52)	$ (45,913.43)	$ (39,782.25)	$ (127,618.20)
6	Real-Time Supplemental Reserve Amount.	$ 15,951.48	$ 4,406.93	$ 24,999.92	$ 45,358.33	$ 23,401.30	$ 16,742.36	$ 2,791.15	$ 42,934.81	$ 142,127.12	$ 2,316.58	$ 71,878.16	$ 216,321.86	$ 28,058.71	$ 48,641.04	$ 35,844.46	$ 112,544.21
12	Real Time Supplemental Reserve Cost Distribution	$ 19,859.65	$ 23,987.62	$ 73,610.31	$ 117,457.58	$ 34,453.68	$ 15,957.36	$ 23,646.16	$ 74,057.20	$ 14,041.37	$ 37,530.72	$ 42,798.77	$ 94,370.86	$ 14,673.32	$ 32,906.93	$ 17,624.29	$ 65,204.54
	SUBTOTAL	$ 15,830.39	$ 1,262.12	$ 62,805.12	$ 79,897.63	$ 11,882.63	$ (1,705.21)	$ 1,531.88	$ 11,709.30	$ 61,760.24	$ (14,142.35)	$ 41,322.68	$ 88,940.57	$ 809.51	$ 35,634.54	$ 13,686.50	$ 50,130.55
Other Charges																	
13	Real Time Excessive/Deficient Energy Deployment	$ 1,487.96	$ -	$ -	$ 1,487.96	$ (419.41)	$ 2,655.11	$ -	$ 2,235.70	$ -	$ -	$ 2,476.61	$ 2,476.61	$ -	$ 1,170.85	$ (611.05)	$ 559.80
14	Real Time Contingency Reserve Deployment Failure	$ 39,062.28	$ 62,975.59	$ 68,863.82	$ 170,901.69	$ 37,516.80	$ 73,835.47	$ 85,518.78	$ 196,871.05	$ 25,942.20	$ 26,435.78	$ 12,079.28	$ 64,457.26	$ 30,990.50	$ 13,873.99	$ 26,856.86	$ 71,721.35
9	Real Time Net Regulation Adjustment Amount	$ 33,848.29	$ 42,944.53	$ 24,297.81	$ 101,090.63	$ (8,447.90)	$ 2,432.45	$ 4,554.34	$ (1,461.11)	$ (1,521.52)	$ (2,039.32)	$ 728.60	$ (2,832.24)	$ 4,716.86	$ 2,312.39	$ 4,185.02	$ 11,214.27
	SUBTOTAL	$ 74,398.53	$ 105,920.12	$ 93,161.63	$ 273,480.28	$ 28,649.49	$ 78,923.03	$ 90,073.12	$ 197,645.64	$ 24,420.68	$ 24,396.46	$ 15,284.49	$ 64,101.63	$ 35,707.36	$ 17,357.23	$ 30,430.83	$ 83,495.42
	TOTAL MISO ASM CHARGES	$ 165,645.84	$ 67,443.32	$ 197,386.39	$ 430,475.55	$ 156,000.39	$ 96,295.76	$ 165,042.93	$ 417,339.08	$ (15,398.16)	$ 466,889.18	$ 286,589.95	$ 738,080.97	$ 248,458.25	$ 329,424.28	$ 158,284.84	$ 736,167.37
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																	
7a	Real Time Excessive Energy Amount	$ 3,933.26	$ 1,228.65	$ 60,800.59	$ 65,962.50	$ 369,413.12	$ (287,274.77)	$ (92,894.22)	$ (10,755.87)	$ (4,807.63)	$ (29,899.07)	$ 1,113.91	$ (33,592.79)	$ 8,064.33	$ (18,975.51)	$ (23,609.91)	$ (34,521.09)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,583,561.26	$ 3,802,233.75	$ 3,451,814.56	$ 10,837,609.57	$ 2,214,112.71	$ 1,175,015.03	$ 1,340,646.55	$ 4,729,774.29	$ 830,010.01	$ (950,890.59)	$ (903,809.71)	$ (1,024,690.29)	$ (986,639.42)	$ 3,352,781.15	$ (544,246.64)	$ 1,821,895.09
8b	Real Time Non Excessive Energy Congestion	$ (162,726.40)	$ (622,520.35)	$ (277,677.26)	$ (1,062,924.01)	$ (23,391.51)	$ (6,723.52)	$ 1,532.25	$ (28,582.78)	$ 165,270.64	$ 112,054.18	$ 11,148.31	$ 288,473.13	$ (530,515.33)	$ (143,970.83)	$ (115,404.01)	$ (789,890.18)
8c	Real Time Non Excessive Energy Loss	$ (196,456.98)	$ (319,819.12)	$ (40,473.01)	$ (556,749.11)	$ 30,233.39	$ 22,207.47	$ (424.27)	$ 52,016.59	$ 17,334.27	$ 55,559.30	$ (64,558.72)	$ 8,334.85	$ (36,202.21)	$ (158,242.21)	$ 127,341.73	$ (67,102.70)
	SUBTOTAL	$ 3,228,311.14	$ 2,861,122.93	$ 3,194,464.88	$ 9,283,898.94	$ 2,590,367.71	$ 903,224.21	$ 1,248,860.31	$ 4,742,452.23	$ 1,007,807.29	$ (813,176.18)	$ (956,106.20)	$ (761,475.09)	$ (1,545,292.64)	$ 3,031,592.60	$ (555,918.83)	$ 930,381.12
	GRAND TOTAL MISO ASM CHARGES	$ 3,393,956.98	$ 2,928,566.25	$ 3,391,851.27	$ 9,714,374.49	$ 2,746,368.10	$ 999,519.97	$ 1,413,903.24	$ 5,159,791.31	$ 992,409.13	$ (346,287.00)	$ (669,516.25)	$ (23,394.12)	$ (1,296,834.39)	$ 3,361,016.88	$ (397,633.99)	$ 1,666,548.49

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

		July 19	August 19	September 19	3rd Qt	October 19	November 19	December 19	4th Qt	YTD
Regulation										
1	Day-Ahead Regulation Amount	$ (336,943.32)	$ (347,636.17)	$ (304,701.69)	$ (989,281.18)	$ (303,530.11)	$ (247,667.36)	$ (219,482.67)	$ (770,680.14)	$ (4,289,813.46)
4	Real-Time Regulation Amount	$ 211,887.90	$ 246,072.00	$ 169,152.87	$ 627,112.77	$ 197,944.53	$ 119,262.95	$ 88,129.76	$ 405,337.24	$ 2,543,537.94
10	Real Time Regulation Reserve Cost Distribution Amount	$ 120,697.86	$ 117,309.15	$ 114,096.37	$ 352,103.38	$ 120,394.43	$ 113,663.10	$ 127,269.02	$ 361,326.55	$ 2,230,954.43
	SUBTOTAL	$ (4,357.56)	$ 15,744.98	$ (21,452.45)	$ (10,065.03)	$ 14,808.85	$ (14,741.31)	$ (4,083.89)	$ (4,016.35)	$ 484,678.91
Spinning Reserve										
2	Day-Ahead Spinning Reserve Amount	$ (274,431.75)	$ (222,718.72)	$ (254,591.74)	$ (751,742.21)	$ (171,667.95)	$ (141,577.09)	$ (108,567.80)	$ (421,812.84)	$ (3,787,109.35)
5	Real-Time Spinning Reserve Amount	$ 183,471.49	$ 144,396.75	$ 199,402.36	$ 527,270.60	$ 127,806.74	$ 105,221.25	$ 26,611.04	$ 259,639.03	$ 2,731,728.46
11	Real Time Spinning Reserve Cost Distribution	$ 145,124.06	$ 109,873.68	$ 89,867.81	$ 344,865.55	$ 88,266.99	$ 63,589.54	$ 38,178.33	$ 190,034.86	$ 2,177,537.54
	SUBTOTAL	$ 54,163.80	$ 31,551.71	$ 34,678.43	$ 120,393.94	$ 44,405.78	$ 27,233.70	$ (43,778.43)	$ 27,861.05	$ 1,122,156.65
Supplemental Reserve										
3	Day-Ahead Supplemental Reserve	$ (43,582.38)	$ (34,153.34)	$ (36,637.61)	$ (114,373.33)	$ (41,607.96)	$ (41,658.18)	$ (44,555.84)	$ (127,821.98)	$ (779,766.65)
6	Real-Time Supplemental Reserve Amount.	$ 15,581.13	$ 17,181.33	$ 22,463.42	$ 55,225.88	$ 7,520.43	$ 38,579.78	$ 31,988.43	$ 78,088.64	$ 550,473.73
12	Real Time Supplemental Reserve Cost Distribution	$ 65,570.52	$ 10,470.10	$ 19,417.66	$ 95,458.28	$ 26,654.64	$ 1,014.52	$ 14,462.77	$ 42,131.93	$ 488,680.39
	SUBTOTAL	$ 37,569.27	$ (6,501.91)	$ 5,243.47	$ 36,310.83	$ (7,432.89)	$ (2,063.88)	$ 1,895.36	$ (7,601.41)	$ 259,387.47
Other Charges										
13	Real Time Excessive/Deficient Energy Deployment	$ -	$ 4,770.74	$ 346.95	$ 5,117.69	$ 6.58	$ -	$ 817.04	$ 823.62	$ 12,701.38
14	Real Time Contingency Reserve Deployment Failure	$ 39,444.87	$ 32,403.70	$ 16,524.46	$ 88,373.03	$ 14,919.70	$ 19,235.22	$ 22,903.41	$ 57,058.33	$ 649,382.71
9	Real Time Net Regulation Adjustment Amount	$ 36,767.50	$ (16,855.68)	$ 14,583.39	$ 34,495.21	$ 10,494.06	$ (8,850.01)	$ 1,156.34	$ 2,800.39	$ 145,307.15
	SUBTOTAL	$ 76,212.37	$ 20,318.76	$ 31,454.80	$ 127,985.93	$ 25,420.34	$ 10,385.21	$ 24,876.79	$ 60,682.34	$ 807,391.24
	TOTAL MISO ASM CHARGES	$ 163,587.88	$ 61,113.54	$ 49,924.25	$ 274,625.67	$ 77,202.08	$ 20,813.72	$ (21,090.17)	$ 76,925.63	$ 2,673,614.27
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT										
7a	Real Time Excessive Energy Amount	$ (43,020.27)	$ (31,402.77)	$ (14,729.69)	$ (89,152.73)	$ (4,053.47)	$ (8,809.54)	$ (9,551.32)	$ (22,414.33)	$ (124,474.31)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,369,220.90	$ 2,609,958.30	$ 3,600,833.93	$ 9,580,013.13	$ 792,253.10	$ 1,042,610.94	$ 1,073,957.09	$ 2,908,821.13	$ 28,853,422.92
8b	Real Time Non Excessive Energy Congestion	$ (482,113.42)	$ 34,271.73	$ (321,250.20)	$ (769,091.89)	$ (215,366.29)	$ (112,438.50)	$ 63,436.94	$ (264,367.85)	$ (2,626,383.57)
8c	Real Time Non Excessive Energy Loss	$ (168,578.36)	$ (71,179.73)	$ (216,687.58)	$ (456,445.67)	$ 29,468.35	$ (9,440.68)	$ 8,115.74	$ 28,143.40	$ (991,802.64)
	SUBTOTAL	$ 2,675,508.85	$ 2,541,647.54	$ 3,048,166.46	$ 8,265,322.84	$ 602,301.69	$ 911,922.22	$ 1,135,958.45	$ 2,650,182.35	$ 25,110,762.40
	GRAND TOTAL MISO ASM CHARGES	$ 2,839,096.73	$ 2,602,761.08	$ 3,098,090.71	$ 8,539,948.51	$ 679,503.77	$ 932,735.94	$ 1,114,868.28	$ 2,727,107.98	$ 27,784,376.67

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

		July 18	August 18	September 18	3rd Qt	October 18	November 18	December 18	4th Qt
Regulation									
1	Day-Ahead Regulation Amount	$ (223,684.78)	$ (144,331.68)	$ (276,124.49)	$ (644,140.95)	$ (176,931.92)	$ (179,384.01)	$ (206,437.50)	$ (562,753.43)
4	Real-Time Regulation Amount	$ 154,060.03	$ 30,759.67	$ 139,532.47	$ 324,352.17	$ 89,551.12	$ 38,227.71	$ 94,669.74	$ 222,448.56
10	Real Time Regulation Reserve Cost Distribution Amount	$ 88,470.90	$ 84,058.82	$ 90,109.48	$ 262,639.20	$ 115,322.59	$ 123,426.93	$ 115,526.62	$ 354,276.14
	SUBTOTAL	$ 18,846.15	$ (29,513.19)	$ (46,482.54)	$ (57,149.58)	$ 27,941.78	$ (17,729.37)	$ 3,758.86	$ 13,971.27
Spinning Reserve									
2	Day-Ahead Spinning Reserve Amount	$ (235,223.35)	$ (247,029.68)	$ (236,889.57)	$ (719,142.61)	$ (157,910.11)	$ (117,330.92)	$ (105,473.11)	$ (380,714.14)
5	Real-Time Spinning Reserve Amount	$ 177,491.61	$ 161,749.00	$ 179,690.90	$ 518,931.52	$ 58,544.53	$ 30,366.27	$ 49,425.99	$ 138,336.79
11	Real Time Spinning Reserve Cost Distribution	$ 94,720.30	$ 85,678.05	$ 134,047.09	$ 314,445.44	$ 154,272.84	$ 118,331.01	$ 104,822.92	$ 377,426.77
	SUBTOTAL	$ 36,988.56	$ 397.37	$ 76,848.42	$ 114,234.35	$ 54,907.25	$ 31,366.36	$ 48,775.80	$ 135,049.42
Supplemental Reserve									
3	Day-Ahead Supplemental Reserve	$ (14,792.69)	$ (19,879.32)	$ (26,249.72)	$ (60,921.73)	$ (32,985.38)	$ (24,592.78)	$ (17,816.38)	$ (75,394.54)
6	Real-Time Supplemental Reserve Amount.	$ 11,809.63	$ 3,228.86	$ 18,328.13	$ 33,366.63	$ 16,790.54	$ 11,967.50	$ 1,996.68	$ 30,754.73
12	Real Time Supplemental Reserve Cost Distribution	$ 14,703.04	$ 17,575.19	$ 53,965.75	$ 86,243.98	$ 24,720.68	$ 11,406.38	$ 16,915.55	$ 53,042.61
	SUBTOTAL	$ 11,719.99	$ 924.73	$ 46,044.17	$ 58,688.88	$ 8,525.84	$ (1,218.89)	$ 1,095.85	$ 8,402.80
Other Charges									
14	Real Time Contingency Reserve Deployment Failure	$ 1,101.61	$ -	$ -	$ 1,101.61	$ (300.93)	$ 1,897.88	$ -	$ 1,596.95
13	Real Time Excessive/Deficient Energy Deployment	$ 28,919.65	$ 46,140.81	$ 50,485.97	$ 125,546.43	$ 26,918.48	$ 52,777.88	$ 61,176.84	$ 140,873.20
9	Real Time Net Regulation Adjustment Amount	$ 25,059.49	$ 31,464.50	$ 17,813.40	$ 74,337.38	$ (6,061.41)	$ 1,738.72	$ 3,258.00	$ (1,064.68)
	SUBTOTAL	$ 55,080.75	$ 77,605.30	$ 68,299.37	$ 200,985.42	$ 20,556.15	$ 56,414.49	$ 64,434.84	$ 141,405.47
	TOTAL MISO ASM CHARGES	$ 122,635.44	$ 49,414.21	$ 144,709.42	$ 316,759.08	$ 111,931.02	$ 68,832.58	$ 118,065.35	$ 298,828.96
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT									
7a	Real Time Excessive Energy Amount	$ 2,911.98	$ 900.20	$ 44,574.59	$ 48,386.78	$ 265,055.67	$ (205,345.13)	$ (66,452.94)	$ (6,742.40)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,653,079.76	$ 2,785,811.64	$ 2,530,620.73	$ 7,969,512.13	$ 1,588,636.41	$ 839,905.33	$ 959,046.85	$ 3,387,588.59
8b	Real Time Non Excessive Energy Congestion	$ (120,474.04)	$ (456,106.74)	$ (203,572.88)	$ (780,153.67)	$ (16,783.52)	$ (4,806.00)	$ 1,096.11	$ (20,493.41)
8c	Real Time Non Excessive Energy Loss	$ (145,446.39)	$ (234,324.32)	$ (29,671.88)	$ (409,442.59)	$ 21,692.60	$ 15,873.99	$ (303.50)	$ 37,263.08
	SUBTOTAL	$ 2,390,071.30	$ 2,096,280.78	$ 2,341,950.57	$ 6,828,302.65	$ 1,858,601.16	$ 645,628.19	$ 893,386.52	$ 3,397,615.87
	GRAND TOTAL MISO ASM CHARGES	$ 2,512,706.75	$ 2,145,695.00	$ 2,486,659.99	$ 7,145,061.73	$ 1,970,532.18	$ 714,460.78	$ 1,011,451.87	$ 3,696,444.82

		January 19	February 19	March 19	1st Qt	April 19	May 19	June 19	2nd Qt
Regulation									
1	Day-Ahead Regulation Amount	$ (46,606.64)	$ (21,020.59)	$ (49,134.20)	$ (116,761.43)	$ (137,314.62)	$ (181,726.89)	$ (188,861.77)	$ (507,903.28)
4	Real-Time Regulation Amount	$ (25,933.54)	$ 65,260.51	$ 28,971.39	$ 68,298.35	$ 120,790.77	$ 197,577.46	$ 160,347.77	$ 478,716.00
10	Real Time Regulation Reserve Cost Distribution Amount	$ 82,950.78	$ 67,406.13	$ 96,840.23	$ 247,197.14	$ 67,490.23	$ 89,413.49	$ 72,836.40	$ 229,740.11
	SUBTOTAL	$ 10,410.60	$ 111,646.04	$ 76,677.42	$ 198,734.06	$ 50,966.38	$ 105,264.06	$ 44,322.40	$ 200,552.83
Spinning Reserve									
2	Day-Ahead Spinning Reserve Amount	$ (104,639.37)	$ (76,546.82)	$ (114,957.27)	$ (296,143.45)	$ (173,671.61)	$ (135,316.43)	$ (187,428.09)	$ (496,416.13)
5	Real-Time Spinning Reserve Amount	$ (49,793.95)	$ 210,100.96	$ 107,580.11	$ 267,887.12	$ 181,982.39	$ 135,234.24	$ 165,286.02	$ 482,502.64
11	Real Time Spinning Reserve Cost Distribution	$ 71,732.32	$ 78,441.06	$ 95,615.20	$ 245,788.58	$ 92,556.95	$ 93,622.15	$ 60,772.31	$ 246,951.40
	SUBTOTAL	$ (82,701.00)	$ 211,995.21	$ 88,238.04	$ 217,532.26	$ 100,867.72	$ 93,539.96	$ 38,630.24	$ 233,037.92
Supplemental Reserve									
3	Day-Ahead Supplemental Reserve	$ (67,187.16)	$ (38,265.30)	$ (52,600.68)	$ (158,053.14)	$ (30,033.15)	$ (33,019.90)	$ (28,905.27)	$ (91,958.32)
6	Real-Time Supplemental Reserve Amount.	$ 101,147.07	$ 1,641.88	$ 51,542.21	$ 154,331.16	$ 20,101.17	$ 34,981.54	$ 26,044.12	$ 81,126.82
12	Real Time Supplemental Reserve Cost Distribution	$ 9,992.77	$ 26,599.99	$ 30,690.03	$ 67,282.79	$ 10,511.92	$ 23,665.92	$ 12,805.58	$ 46,983.42
	SUBTOTAL	$ 43,952.68	$ (10,023.43)	$ 29,631.56	$ 63,560.81	$ 579.93	$ 25,627.56	$ 9,944.43	$ 36,151.92
Other Charges									
14	Real Time Contingency Reserve Deployment Failure	$ -	$ -	$ 1,775.92	$ 1,775.92	$ -	$ 842.05	$ (443.98)	$ 398.07
13	Real Time Excessive/Deficient Energy Deployment	$ 18,462.19	$ 18,736.43	$ 8,661.78	$ 45,860.39	$ 22,201.49	$ 9,977.86	$ 19,513.85	$ 51,693.20
9	Real Time Net Regulation Adjustment Amount	$ (1,082.81)	$ (1,445.37)	$ 522.46	$ (2,005.72)	$ 3,379.14	$ 1,663.02	$ 3,040.78	$ 8,082.94
	SUBTOTAL	$ 17,379.37	$ 17,291.05	$ 10,960.16	$ 45,630.59	$ 25,580.63	$ 12,482.93	$ 22,110.65	$ 60,174.21
	TOTAL MISO ASM CHARGES	$ (10,958.35)	$ 330,908.87	$ 205,507.19	$ 525,457.71	$ 177,994.66	$ 236,914.50	$ 115,007.72	$ 529,916.88
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT									
7a	Real Time Excessive Energy Amount	$ (3,421.43)	$ (21,191.04)	$ 798.76	$ (23,813.71)	$ 5,777.26	$ (13,646.76)	$ (17,154.66)	$ (25,024.15)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 590,690.10	$ (673,946.08)	$ (648,101.56)	$ (731,357.55)	$ (706,825.20)	$ 2,411,244.45	$ (395,442.57)	$ 1,308,976.68
8b	Real Time Non Excessive Energy Congestion	$ 117,617.53	$ 79,418.68	$ 7,994.21	$ 205,030.42	$ (380,059.42)	$ (103,540.57)	$ (83,851.06)	$ (567,451.05)
8c	Real Time Non Excessive Energy Loss	$ 12,336.21	$ 39,377.79	$ (46,293.60)	$ 5,420.41	$ (25,935.15)	$ (113,804.22)	$ 92,524.85	$ (47,214.52)
	SUBTOTAL	$ 717,222.42	$ (576,340.65)	$ (685,602.19)	$ (544,720.43)	$ (1,107,042.51)	$ 2,180,252.90	$ (403,923.43)	$ 669,286.96
	GRAND TOTAL MISO ASM CHARGES	$ 706,264.07	$ (245,431.78)	$ (480,095.00)	$ (19,262.72)	$ (929,047.85)	$ 2,417,167.40	$ (288,915.71)	$ 1,199,203.84

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

		July 19	August 19	September 19	3rd Qt	October 19	November 19	December 19	4th Qt	YTD
Regulation										
1	Day-Ahead Regulation Amount	$ (245,872.24)	$ (252,481.88)	$ (223,043.17)	$ (721,397.29)	$ (216,383.23)	$ (177,563.33)	$ (156,653.07)	$ (550,599.63)	$ (3,103,556.02)
4	Real-Time Regulation Amount	$ 154,617.56	$ 178,717.66	$ 123,820.75	$ 457,155.96	$ 141,112.44	$ 85,504.71	$ 62,901.54	$ 289,518.70	$ 1,840,489.75
10	Real Time Regulation Reserve Cost Distribution Amount	$ 88,074.91	$ 85,199.52	$ 83,519.12	$ 256,793.55	$ 85,827.84	$ 81,489.94	$ 90,836.71	$ 258,154.49	$ 1,608,800.64
	SUBTOTAL	$ (3,179.77)	$ 11,435.30	$ (15,703.30)	$ (7,447.78)	$ 10,557.06	$ (10,568.68)	$ (2,914.83)	$ (2,926.44)	$ 345,734.36
Spinning Reserve										
2	Day-Ahead Spinning Reserve Amount	$ (200,256.68)	$ (161,756.59)	$ (186,362.43)	$ (548,375.70)	$ (122,380.16)	$ (101,502.68)	$ (77,488.94)	$ (301,371.78)	$ (2,742,163.81)
5	Real-Time Spinning Reserve Amount	$ 133,881.71	$ 104,872.76	$ 145,963.53	$ 384,717.99	$ 91,112.00	$ 75,437.62	$ 18,993.30	$ 185,542.92	$ 1,977,918.98
11	Real Time Spinning Reserve Cost Distribution	$ 105,899.05	$ 79,799.27	$ 65,783.69	$ 251,482.01	$ 62,924.55	$ 45,590.06	$ 27,249.32	$ 135,763.93	$ 1,571,858.14
	SUBTOTAL	$ 39,524.08	$ 22,915.44	$ 25,384.79	$ 87,824.30	$ 31,656.38	$ 19,525.01	$ (31,246.32)	$ 19,935.07	$ 807,613.32
Supplemental Reserve										
3	Day-Ahead Supplemental Reserve	$ (31,802.67)	$ (24,804.96)	$ (26,818.91)	$ (83,426.54)	$ (29,661.85)	$ (29,866.53)	$ (31,801.19)	$ (91,329.57)	$ (561,083.84)
6	Real-Time Supplemental Reserve Amount.	$ 11,369.77	$ 12,478.49	$ 16,443.34	$ 40,291.59	$ 5,361.23	$ 27,659.50	$ 22,831.35	$ 55,852.08	$ 395,723.01
12	Real Time Supplemental Reserve Cost Distribution	$ 47,847.72	$ 7,604.24	$ 14,213.82	$ 69,665.79	$ 19,001.80	$ 727.35	$ 10,322.63	$ 30,051.77	$ 353,270.38
	SUBTOTAL	$ 27,414.82	$ (4,722.22)	$ 3,838.25	$ 26,530.85	$ (5,298.82)	$ (1,479.68)	$ 1,352.79	$ (5,425.72)	$ 187,909.55
Other Charges										
14	Real Time Contingency Reserve Deployment Failure	$ -	$ 3,464.90	$ 253.97	$ 3,718.87	$ 4.69	$ -	$ 583.15	$ 587.84	$ 9,179.27
13	Real Time Excessive/Deficient Energy Deployment	$ 28,783.47	$ 23,534.22	$ 12,095.99	$ 64,413.68	$ 10,636.09	$ 13,790.55	$ 16,347.03	$ 40,773.67	$ 469,160.57
9	Real Time Net Regulation Adjustment Amount	$ 26,829.76	$ (12,241.98)	$ 10,675.11	$ 25,262.90	$ 7,481.10	$ (6,344.95)	$ 825.32	$ 1,961.47	$ 106,574.28
	SUBTOTAL	$ 55,613.23	$ 14,757.15	$ 23,025.07	$ 93,395.45	$ 18,121.88	$ 7,445.60	$ 17,755.50	$ 43,322.98	$ 584,914.12
	TOTAL MISO ASM CHARGES	$ 119,372.36	$ 44,385.66	$ 36,544.80	$ 200,302.82	$ 55,036.50	$ 14,922.25	$ (15,052.85)	$ 54,905.90	$ 1,926,171.35
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT										
7a	Real Time Excessive Energy Amount	$ (31,392.49)	$ (22,807.27)	$ (10,782.21)	$ (64,981.96)	$ (2,889.67)	$ (6,315.94)	$ (6,817.14)	$ (16,022.75)	$ (88,198.19)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,458,567.50	$ 1,895,565.65	$ 2,635,828.54	$ 6,989,961.69	$ 564,788.39	$ 747,492.42	$ 766,523.74	$ 2,078,804.54	$ 21,003,486.09
8b	Real Time Non Excessive Energy Congestion	$ (351,804.89)	$ 24,890.94	$ (235,156.76)	$ (562,070.71)	$ (153,532.22)	$ (80,611.97)	$ 45,277.34	$ (188,866.85)	$ (1,914,005.27)
8c	Real Time Non Excessive Energy Loss	$ (123,013.98)	$ (51,696.55)	$ (158,616.40)	$ (333,326.93)	$ 21,007.66	$ (6,768.43)	$ 5,792.51	$ 20,031.73	$ (727,268.82)
	SUBTOTAL	$ 1,952,356.13	$ 1,845,952.78	$ 2,231,273.17	$ 6,029,582.08	$ 429,374.15	$ 653,796.08	$ 810,776.45	$ 1,893,946.68	$ 18,274,013.81
	GRAND TOTAL MISO ASM CHARGES	$ 2,071,728.49	$ 1,890,338.44	$ 2,267,817.97	$ 6,229,884.90	$ 484,410.65	$ 668,718.32	$ 795,723.60	$ 1,948,852.57	$ 20,200,185.16

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

July 2018	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		$ (302,134.95)		$ (302,134.95)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (317,720.30)		$ (317,720.30)		$ -		
3 Day-Ahead Supplemental Reserve		$ (19,980.74)		$ (19,980.74)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (127,323.23)		$ 208,091.58		$ (335,414.81)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 48,849.06		$ 239,741.03		$ (190,891.97)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 14,549.40		$ 15,951.48		$ (1,402.08)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(4,176)	$ 3,933.26	(4,176)	$ 3,933.26		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	155,477	$ 3,583,561.26	155,477	$ 3,583,561.26		$ -		
8b Real Time Non Excessive Energy Congestion		$ (143,557.98)		$ (162,726.40)		$ 19,168.42		
8c Real Time Non Excessive Energy Loss		$ (178,567.97)		$ (196,456.98)		$ 17,889.01		
9 Real Time Net Regulation Adjustment Amount	-	$ 68,610.58	-	$ 33,848.29		$ 34,762.29		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 119,499.19		$ 119,499.19		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 127,940.37		$ 127,940.37		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 19,859.65		$ 19,859.65		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 87,908.14		$ 39,062.28		$ 48,845.86		
14 Real Time Contingency Reserve Deployment Failure		$ 1,487.96		$ 1,487.96		$ -		
TOTAL MISO ASM CHARGES	**151,301**	**$ 2,986,913.70**	**151,301**	**$ 3,393,956.98**		**$ (407,043.28)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

August 2018	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		$ (196,992.06)		$ (196,992.06)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (337,160.12)		$ (337,160.12)		$ -		
3 Day-Ahead Supplemental Reserve		$ (27,132.43)		$ (27,132.43)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (105,127.32)		$ 41,982.54		$ (147,109.86)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 145,522.34		$ 220,764.21		$ (75,241.87)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 5,534.10		$ 4,406.93		$ 1,127.17		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(5,171)	$ 1,228.65	(5,171)	$ 1,228.65		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	89,816	$ 3,802,233.75	89,816	$ 3,802,233.75		$ -		
8b Real Time Non Excessive Energy Congestion		$ (580,203.27)		$ (622,520.35)		$ 42,317.08		
8c Real Time Non Excessive Energy Loss		$ (298,932.70)		$ (319,819.12)		$ 20,886.42		
9 Real Time Net Regulation Adjustment Amount	-	$ 76,613.91	-	$ 42,944.53		$ 33,669.38		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 114,728.25		$ 114,728.25		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 116,938.26		$ 116,938.26		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 23,987.62		$ 23,987.62		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 90,847.37		$ 62,975.59		$ 27,871.78		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**84,645**	**$ 2,832,086.35**	**84,645**	**$ 2,928,566.25**		**$ (96,479.90)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

September 2018	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		$ (376,639.03)		$ (376,639.03)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (323,121.86)		$ (323,121.86)		$ -		
3 Day-Ahead Supplemental Reserve		$ (35,805.11)		$ (35,805.11)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (137,684.42)		$ 190,324.93		$ (328,009.35)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 57,825.92		$ 245,101.79		$ (187,275.87)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 26,265.73		$ 24,999.92		$ 1,265.81		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,311)	$ 60,800.59	(3,311)	$ 60,800.59		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	152,004	$ 3,451,814.56	152,004	$ 3,451,814.56		$ -		
8b Real Time Non Excessive Energy Congestion		$ (251,434.51)		$ (277,677.26)		$ 26,242.75		
8c Real Time Non Excessive Energy Loss		$ (36,753.39)		$ (40,473.01)		$ 3,719.62		
9 Real Time Net Regulation Adjustment Amount	-	$ 47,173.89	-	$ 24,297.81		$ 22,876.08		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 122,911.04		$ 122,911.04		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 182,842.77		$ 182,842.77		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 73,610.31		$ 73,610.31		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 112,282.66		$ 68,863.82		$ 43,418.84		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**148,694**	**$ 2,974,089.15**	**148,694**	**$ 3,391,851.27**		**$ (417,762.12)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

October 2018	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		$ (246,593.38)		$ (246,593.38)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (220,082.32)		$ (220,082.32)		$ -		
3 Day-Ahead Supplemental Reserve		$ (45,972.35)		$ (45,972.35)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (59,740.99)		$ 124,809.09		$ (184,550.08)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (53,144.66)		$ 81,594.62		$ (134,739.28)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 9,331.78		$ 23,401.30		$ (14,069.52)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(9,842)	$ 369,413.12	(9,842)	$ 369,413.12		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	114,810	$ 2,214,112.71	114,810	$ 2,214,112.71		$ -		
8b Real Time Non Excessive Energy Congestion		$ (19,316.20)		$ (23,391.51)		$ 4,075.31		
8c Real Time Non Excessive Energy Loss		$ 30,463.21		$ 30,233.39		$ 229.82		
9 Real Time Net Regulation Adjustment Amount	-	$ 1,378.67	-	$ (8,447.90)		$ 9,826.57		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 160,727.28		$ 160,727.28		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 215,012.98		$ 215,012.98		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 34,453.68		$ 34,453.68		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 88,696.82		$ 37,516.80		$ 51,180.02		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ (419.41)		$ 419.41		
TOTAL MISO ASM CHARGES	**104,968**	**$ 2,478,740.35**	**104,968**	**$ 2,746,368.10**		**$ (267,627.75)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

November 2018	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		$ (250,955.55)		$ (250,955.55)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (164,144.21)		$ (164,144.21)		$ -		
3 Day-Ahead Supplemental Reserve		$ (34,404.93)		$ (34,404.93)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (70,404.23)		$ 53,479.99		$ (123,884.22)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (103,773.88)		$ 42,481.96		$ (146,255.84)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,932.09		$ 16,742.36		$ (13,810.27)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	6,053	$ (287,274.77)	6,053	$ (287,274.77)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	78,479	$ 1,175,015.03	78,479	$ 1,175,015.03		$ -		
8b Real Time Non Excessive Energy Congestion		$ (11,023.61)		$ (6,723.52)		$ (4,300.09)		
8c Real Time Non Excessive Energy Loss		$ 19,145.92		$ 22,207.47		$ (3,061.55)		
9 Real Time Net Regulation Adjustment Amount	-	$ 9,459.53	-	$ 2,432.45		$ 7,027.08		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 172,672.43		$ 172,672.43		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 165,543.32		$ 165,543.32		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 15,957.36		$ 15,957.36		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 126,062.97		$ 73,835.47		$ 52,227.50		
14 Real Time Contingency Reserve Deployment Failure		$ 2,655.11		$ 2,655.11		$ -		
TOTAL MISO ASM CHARGES	**84,532**	**$ 767,462.58**	**84,532**	**$ 999,519.97**		**$ (232,057.39)**		**$ -**

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.

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MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

December 2018	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		$ (288,577.90)		$ (288,577.90)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (147,440.30)		$ (147,440.30)		$ -		
3 Day-Ahead Supplemental Reserve		$ (24,905.43)		$ (24,905.43)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 7,347.67		$ 132,338.33		$ (124,990.66)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (46,675.26)		$ 69,092.33		$ (115,767.59)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 418.75		$ 2,791.15		$ (2,372.40)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	629	$ (92,894.22)	629	$ (92,894.22)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	25,783	$ 1,340,646.55	25,783	$ 1,340,646.55		$ -		
8b Real Time Non Excessive Energy Congestion		$ 10,204.25		$ 1,532.25		$ 8,672.00		
8c Real Time Non Excessive Energy Loss		$ 1,899.05		$ (424.27)		$ 2,323.32		
9 Real Time Net Regulation Adjustment Amount	-	$ 6,286.40	-	$ 4,554.34		$ 1,732.06		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 161,494.06		$ 161,494.06		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 146,531.41		$ 146,531.41		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 23,646.16		$ 23,646.16		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 117,162.44		$ 85,518.78		$ 31,643.66		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**26,413**	**$ 1,215,143.63**	**26,413**	**$ 1,413,903.24**		**$ (198,759.61)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

January 2019	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		$ (65,489.47)		$ (65,489.47)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (147,034.33)		$ (147,034.33)		$ -		
3 Day-Ahead Supplemental Reserve		$ (94,408.25)		$ (94,408.25)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (87,322.99)		$ (36,440.60)		$ (50,882.39)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (205,559.66)		$ (69,968.12)		$ (135,591.54)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 124,108.50		$ 142,127.12		$ (18,018.62)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,241)	$ (4,807.63)	(1,241)	$ (4,807.63)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	24,831	$ 830,010.01	24,831	$ 830,010.01		$ -		
8b Real Time Non Excessive Energy Congestion		$ 140,707.18		$ 165,270.64		$ (24,563.46)		
8c Real Time Non Excessive Energy Loss		$ 5,458.46		$ 17,334.27		$ (11,875.81)		
9 Real Time Net Regulation Adjustment Amount	-	$ 855.31	-	$ (1,521.52)		$ 2,376.83		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 116,558.55		$ 116,558.55		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 100,794.89		$ 100,794.89		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 14,041.37		$ 14,041.37		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 38,384.36		$ 25,942.20		$ 12,442.16		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**23,591**	**$ 766,296.30**	**23,591**	**$ 992,409.13**		**$ (226,112.83)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

February 2019	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		$ (29,658.58)		$ (29,658.58)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (108,002.18)		$ (108,002.18)		$ -		
3 Day-Ahead Supplemental Reserve		$ (53,989.65)		$ (53,989.65)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 46,175.72		$ 92,077.99		$ (45,902.27)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 81,016.31		$ 296,437.70		$ (215,421.39)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (118,382.13)		$ 2,316.58		$ (120,698.71)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	131	$ (29,899.07)	131	$ (29,899.07)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	(148,099)	$ (950,890.59)	(148,099)	$ (950,890.59)		$ -		
8b Real Time Non Excessive Energy Congestion		$ 115,638.48		$ 112,054.18		$ 3,584.30		
8c Real Time Non Excessive Energy Loss		$ 54,212.06		$ 55,559.30		$ (1,347.24)		
9 Real Time Net Regulation Adjustment Amount	-	$ (1,226.40)	-	$ (2,039.32)		$ 812.92		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 95,105.31		$ 95,105.31		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 110,674.83		$ 110,674.83		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 37,530.72		$ 37,530.72		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 29,945.18		$ 26,435.78		$ 3,509.40		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**(147,968)**	**$ (721,749.99)**	**(147,968)**	**$ (346,287.00)**		**$ (375,462.99)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

March 2019	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		$ (68,520.07)		$ (68,520.07)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (160,313.60)		$ (160,313.60)		$ -		
3 Day-Ahead Supplemental Reserve		$ (73,354.25)		$ (73,354.25)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (11,347.07)		$ 40,402.04		$ (51,749.11)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (11,535.47)		$ 150,025.79		$ (161,561.26)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 4,283.35		$ 71,878.16		$ (67,594.81)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,965)	$ 1,113.91	(1,965)	$ 1,113.91		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	(103,746)	$ (903,809.71)	(103,746)	$ (903,809.71)		$ -		
8b Real Time Non Excessive Energy Congestion		$ 26,428.38		$ 11,148.31		$ 15,280.07		
8c Real Time Non Excessive Energy Loss		$ (57,106.41)		$ (64,558.72)		$ 7,452.31		
9 Real Time Net Regulation Adjustment Amount	-	$ 1,270.57	-	$ 728.60		$ 541.97		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 135,048.49		$ 135,048.49		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 133,340.13		$ 133,340.13		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 42,798.77		$ 42,798.77		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 22,292.50		$ 12,079.28		$ 10,213.22		
14 Real Time Contingency Reserve Deployment Failure		$ 2,476.61		$ 2,476.61		$ -		
TOTAL MISO ASM CHARGES	**(105,711)**	**$ (916,933.87)**	**(105,711)**	**$ (669,516.25)**		**$ (247,417.62)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

April 2019	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		$ (191,674.00)		$ (191,674.00)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (242,423.81)		$ (242,423.81)		$ -		
3 Day-Ahead Supplemental Reserve		$ (41,922.52)		$ (41,922.52)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (30,093.38)		$ 168,608.78		$ (198,702.16)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 22,711.55		$ 254,024.61		$ (231,313.06)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,202.48		$ 28,058.71		$ (25,856.23)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,936)	$ 8,064.33	(3,936)	$ 8,064.33		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	(135,883)	$ (986,639.42)	(135,883)	$ (986,639.42)		$ -		
8b Real Time Non Excessive Energy Congestion		$ (517,507.25)		$ (530,515.33)		$ 13,008.08		
8c Real Time Non Excessive Energy Loss		$ (36,804.75)		$ (36,202.21)		$ (602.54)		
9 Real Time Net Regulation Adjustment Amount	-	$ 10,412.42	-	$ 4,716.86		$ 5,695.56		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 94,207.90		$ 94,207.90		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 129,197.90		$ 129,197.90		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 14,673.32		$ 14,673.32		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 49,514.64		$ 30,990.50		$ 18,524.14		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**(139,819)**	**$ (1,716,080.59)**	**(139,819)**	**$ (1,296,834.39)**		**$ (419,246.20)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

May 2019	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		$ (252,687.15)		$ (252,687.15)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (188,154.45)		$ (188,154.45)		$ -		
3 Day-Ahead Supplemental Reserve		$ (45,913.43)		$ (45,913.43)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 1,822.75		$ 274,727.01		$ (272,904.26)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (51,638.82)		$ 188,040.17		$ (239,678.99)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 823.95		$ 48,641.04		$ (47,817.09)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,697)	$ (18,975.51)	(3,697)	$ (18,975.51)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	(95,664)	$ 3,352,781.15	(95,664)	$ 3,352,781.15		$ -		
8b Real Time Non Excessive Energy Congestion		$ (124,422.15)		$ (143,970.83)		$ 19,548.68		
8c Real Time Non Excessive Energy Loss		$ (142,110.89)		$ (158,242.21)		$ 16,131.32		
9 Real Time Net Regulation Adjustment Amount	-	$ 5,516.31	-	$ 2,312.39		$ 3,203.92		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 124,327.44		$ 124,327.44		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 130,179.49		$ 130,179.49		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 32,906.93		$ 32,906.93		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 24,837.83		$ 13,873.99		$ 10,963.84		
14 Real Time Contingency Reserve Deployment Failure		$ 60,844.20		$ 1,170.85		$ 59,673.35		
TOTAL MISO ASM CHARGES	**(99,362)**	**$ 2,910,137.65**	**(99,362)**	**$ 3,361,016.88**		**$ (450,879.23)**		**$ -**

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.

MISO ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

June 2019	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		$ (259,930.00)		$ (259,930.00)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (257,956.82)		$ (257,956.82)		$ -		
3 Day-Ahead Supplemental Reserve		$ (39,782.25)		$ (39,782.25)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 7,811.34		$ 220,686.25		$ (212,874.91)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (33,570.91)		$ 227,482.74		$ (261,053.65)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,619.90		$ 35,844.46		$ (33,224.56)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,338)	$ (23,609.91)	(2,338)	$ (23,609.91)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	107,473	$ (544,246.64)	107,473	$ (544,246.64)		$ -		
8b Real Time Non Excessive Energy Congestion		$ (99,788.74)		$ (115,404.01)		$ 15,615.27		
8c Real Time Non Excessive Energy Loss		$ 148,311.34		$ 127,341.73		$ 20,969.61		
9 Real Time Net Regulation Adjustment Amount	-	$ 7,965.29	-	$ 4,185.02		$ 3,780.27		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 100,244.56		$ 100,244.56		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 83,640.78		$ 83,640.78		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 17,624.29		$ 17,624.29		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 52,533.36		$ 26,856.86		$ 25,676.50		
14 Real Time Contingency Reserve Deployment Failure		$ 483.03		$ (611.05)		$ 1,094.08		
TOTAL MISO ASM CHARGES	**105,135**	**$ (837,651.38)**	**105,135**	**$ (397,633.99)**		**$ (440,017.39)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

July 2019	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		$ (336,943.32)		$ (336,943.32)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (274,431.75)		$ (274,431.75)		$ -		
3 Day-Ahead Supplemental Reserve		$ (43,582.38)		$ (43,582.38)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (36,633.71)		$ 211,887.90		$ (248,521.61)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (33,141.62)		$ 183,471.49		$ (216,613.11)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 8,942.96		$ 15,581.13		$ (6,638.17)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,465)	$ (43,020.27)	(2,465)	$ (43,020.27)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	152,066	$ 3,369,220.90	152,066	$ 3,369,220.90		$ -		
8b Real Time Non Excessive Energy Congestion		$ (450,554.12)		$ (482,113.42)		$ 31,559.30		
8c Real Time Non Excessive Energy Loss		$ (147,171.97)		$ (168,578.36)		$ 21,406.39		
9 Real Time Net Regulation Adjustment Amount	-	$ 51,778.23	-	$ 36,767.50		$ 15,010.73		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 120,697.86		$ 120,697.86		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 145,124.06		$ 145,124.06		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 65,570.52		$ 65,570.52		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 69,613.49		$ 39,444.87		$ 30,168.62		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**149,600**	**$ 2,465,468.88**	**149,600**	**$ 2,839,096.73**		**$ (373,627.85)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

August 2019	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		$ (347,636.17)		$ (347,636.17)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (222,718.72)		$ (222,718.72)		$ -		
3 Day-Ahead Supplemental Reserve		$ (34,153.34)		$ (34,153.34)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (31,436.64)		$ 246,072.00		$ (277,508.64)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (58,990.29)		$ 144,396.75		$ (203,387.04)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 2,700.58		$ 17,181.33		$ (14,480.75)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,736)	$ (31,402.77)	(1,736)	$ (31,402.77)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	147,615	$ 2,609,958.30	147,615	$ 2,609,958.30		$ -		
8b Real Time Non Excessive Energy Congestion		$ 38,543.99		$ 34,271.73		$ 4,272.26		
8c Real Time Non Excessive Energy Loss		$ (50,429.36)		$ (71,179.73)		$ 20,750.37		
9 Real Time Net Regulation Adjustment Amount	-	$ (15,396.86)	-	$ (16,855.68)		$ 1,458.82		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 117,309.15		$ 117,309.15		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 109,873.68		$ 109,873.68		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 10,470.10		$ 10,470.10		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 63,318.82		$ 32,403.70		$ 30,915.12		
14 Real Time Contingency Reserve Deployment Failure		$ 5,660.62		$ 4,770.74		$ 889.88		
TOTAL MISO ASM CHARGES	**145,878**	**$ 2,165,671.09**	**145,878**	**$ 2,602,761.08**		**$ (437,089.99)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

September 2019	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		$ (304,701.69)		$ (304,701.69)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (254,591.74)		$ (254,591.74)		$ -		
3 Day-Ahead Supplemental Reserve		$ (36,637.61)		$ (36,637.61)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 2,358.11		$ 169,152.87		$ (166,794.76)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (37,208.07)		$ 199,402.36		$ (236,610.43)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 4,193.21		$ 22,463.42		$ (18,270.21)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(956)	$ (14,729.69)	(956)	$ (14,729.69)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	181,519	$ 3,600,833.93	181,519	$ 3,600,833.93		$ -		
8b Real Time Non Excessive Energy Congestion		$ (278,578.76)		$ (321,250.20)		$ 42,671.44		
8c Real Time Non Excessive Energy Loss		$ (192,841.42)		$ (216,687.58)		$ 23,846.16		
9 Real Time Net Regulation Adjustment Amount	-	$ 23,043.71	-	$ 14,583.39		$ 8,460.32		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 114,096.37		$ 114,096.37		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 89,867.81		$ 89,867.81		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 19,417.66		$ 19,417.66		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 38,029.86		$ 16,524.46		$ 21,505.40		
14 Real Time Contingency Reserve Deployment Failure		$ 2,994.00		$ 346.95		$ 2,647.05		
TOTAL MISO ASM CHARGES	**180,563**	**$ 2,775,545.68**	**180,563**	**$ 3,098,090.71**		**$ (322,545.03)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

October 2019	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		$ (303,530.11)		$ (303,530.11)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (171,667.95)		$ (171,667.95)		$ -		
3 Day-Ahead Supplemental Reserve		$ (41,607.96)		$ (41,607.96)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 16,789.22		$ 197,944.53		$ (181,155.31)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (95,959.66)		$ 127,806.74		$ (223,766.40)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (8,445.98)		$ 7,520.43		$ (15,966.41)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,968)	$ (4,053.47)	(1,968)	$ (4,053.47)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	97,378	$ 792,253.10	97,378	$ 792,253.10		$ -		
8b Real Time Non Excessive Energy Congestion		$ (189,417.45)		$ (215,366.29)		$ 25,948.84		
8c Real Time Non Excessive Energy Loss		$ 31,242.59		$ 29,468.35		$ 1,774.24		
9 Real Time Net Regulation Adjustment Amount	-	$ 31,658.96	-	$ 10,494.06		$ 21,164.90		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 120,394.43		$ 120,394.43		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 88,266.99		$ 88,266.99		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 26,654.64		$ 26,654.64		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 29,037.30		$ 14,919.70		$ 14,117.60		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ 6.58		$ (6.58)		
TOTAL MISO ASM CHARGES	**95,410**	**$ 321,614.65**	**95,410**	**$ 679,503.77**		**$ (357,889.12)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

November 2019	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		$ (247,667.36)		$ (247,667.36)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (141,577.09)		$ (141,577.09)		$ -		
3 Day-Ahead Supplemental Reserve		$ (41,658.18)		$ (41,658.18)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 18,725.82		$ 119,262.95		$ (100,537.13)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 12,681.68		$ 105,221.25		$ (92,539.57)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 27,110.57		$ 38,579.78		$ (11,469.21)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(667)	$ (8,809.54)	(667)	$ (8,809.54)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	43,976	$ 1,042,610.94	43,976	$ 1,042,610.94		$ -		
8b Real Time Non Excessive Energy Congestion		$ (93,012.10)		$ (73,585.70)		$ (19,426.40)		
8c Real Time Non Excessive Energy Loss		$ 774.48		$ 10,989.64		$ (10,215.16)		
9 Real Time Net Regulation Adjustment Amount	-	$ (7,977.58)	-	$ (8,850.01)		$ 872.43		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 113,663.10		$ 113,663.10		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 63,589.54		$ 63,589.54		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 1,014.52		$ 1,014.52		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 30,814.53		$ 19,235.22		$ 11,579.31		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**43,310**	**$ 770,283.33**	**43,310**	**$ 992,019.06**		**$ (221,735.73)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

December 2019	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		$ (219,482.67)		$ (219,482.67)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (108,567.80)		$ (108,567.80)		$ -		
3 Day-Ahead Supplemental Reserve		$ (44,555.84)		$ (44,555.84)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 34,423.18		$ 88,129.76		$ (53,706.58)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (40,111.56)		$ 26,611.04		$ (66,722.60)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 7,386.41		$ 31,988.43		$ (24,602.02)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(744)	$ (9,551.32)	(744)	$ (9,551.32)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	49,284	$ 1,073,957.09	49,284	$ 1,073,957.09		$ -		
8b Real Time Non Excessive Energy Congestion		$ 63,278.04		$ 63,436.94		$ (158.90)		
8c Real Time Non Excessive Energy Loss		$ 11,548.03		$ 8,115.74		$ 3,432.29		
9 Real Time Net Regulation Adjustment Amount	-	$ (1,093.72)	-	$ 1,156.34		$ (2,250.06)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 127,269.02		$ 127,269.02		$ -		
11 Real Time Spinning Reserve Cost Distribution		$ 38,178.33		$ 38,178.33		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 14,462.77		$ 14,462.77		$ -		
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment		$ 31,313.48		$ 22,903.41		$ 8,410.07		
14 Real Time Contingency Reserve Deployment Failure		$ -		$ 817.04		$ (817.04)		
TOTAL MISO ASM CHARGES	**48,540**	**$ 978,453.44**	**48,540**	**$ 1,114,868.28**		**$ (136,414.84)**		**$ -**

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 ANCILLARY SERVICES MARKETS (ASM) CHARGE TYPES BY CATEGORIES

July 2018 - December 2019	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	-	$ (4,289,813.46)	$ -	$ (4,289,813.46)	$ -	$ -	$ -	$ -
2 Day-Ahead Spinning Reserve Amount	-	$ (3,787,109.35)	$ -	$ (3,787,109.35)	$ -	$ -	$ -	$ -
3 Day-Ahead Supplemental Reserve	-	$ (779,766.65)	$ -	$ (779,766.65)	$ -	$ -	$ -	$ -
4 Real-Time Regulation Amount (See Note 1)	-	$ (561,660.17)	$ -	$ 2,543,537.94	$ -	$ (3,105,198.11)	$ -	$ -
5 Real-Time Spinning Reserve Amount (See Note 1)	-	$ (402,703.00)	$ -	$ 2,731,728.46	$ -	$ (3,134,431.46)	$ -	$ -
6 Real-Time Supplemental Reserve Amount. (See Note 1)	-	$ 116,575.65	$ -	$ 550,473.73	$ -	$ (433,898.08)	$ -	$ -
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(37,400)	$ (124,474.31)	(37,400)	$ (124,474.31)	$ -	$ -	$ -	$ -
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	$ -	$ -	$ -	$ -
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	$ -	$ -	$ -	$ -
8a Real Time Non Excessive Energy Amount	937,119	$ 28,853,422.92	937,119	$ 28,853,422.92	$ -	$ -	$ -	$ -
8b Real Time Non Excessive Energy Congestion	-	$ (2,364,015.82)	-	$ (2,587,530.78)	$ -	$ 223,514.96	$ -	$ -
8c Real Time Non Excessive Energy Loss	-	$ (837,663.72)	-	$ (971,372.31)	$ -	$ 133,708.59	$ -	$ -
9 Real Time Net Regulation Adjustment Amount	-	$ 316,329.22	-	$ 145,307.15	$ -	$ 171,022.07	$ -	$ -
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 2,230,954.43	-	$ 2,230,954.43	$ -	$ -	$ -	$ -
11 Real Time Spinning Reserve Cost Distribution	-	$ 2,177,537.54	-	$ 2,177,537.54	$ -	$ -	$ -	$ -
12 Real Time Supplemental Reserve Cost Distribution	-	$ 488,680.39	-	$ 488,680.39	$ -	$ -	$ -	$ -
Penalty Charges								
13 Real Time Excessive/Deficient Energy Deployment	-	$ 1,102,595.75	-	$ 649,382.71	$ -	$ 453,213.04	$ -	$ -
14 Real Time Contingency Reserve Deployment Failure	-	$ 76,601.53	-	$ 12,701.38	$ -	$ 63,900.15	$ -	$ -
	-	0	-	0	0	0	0	0
TOTAL MISO ASM CHARGES	**899,719**	**$ 22,215,490.95**	**899,719**	**$ 27,843,659.79**	**$ -**	**$ (5,628,168.84)**	**$ -**	**$ -**

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.

Internal Order Description	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19
NSPM MISO NSPP DA_ASSET_EN Alloc	16,534,795.62	8,672,225.62	14,230,390.17	10,453,243.68	19,512,393.65	14,142,224.69	14,335,930.92	12,297,020.88	11,816,139.39
NSPM MISO NSPP RT_ASSET_EN Alloc	2,223,458.47	1,593,747.70	1,707,309.96	1,306,700.28	2,346,024.11	2,325,052.41	2,628,609.32	1,430,714.90	1,871,750.40
NSPM MISO NSPP DA_ADMIN Alloc	(45,158.58)	(20,001.83)	(48,001.57)	(39,523.79)	(79,283.01)	(43,489.12)	(30,063.74)	(36,456.99)	(45,682.80)
NSPM MISO NSPP RT_ADMIN Alloc	(6,262.88)	(3,745.54)	(5,266.24)	(6,406.62)	(10,955.16)	(9,532.65)	(4,356.47)	(5,411.46)	(9,086.89)
NSPM MISO NSPP RT_RSG_MWP Alloc	129,812.92	112,764.97	108,960.59	127,695.78	233,878.08	109,356.57	(5,564.92)	2,683,525.11	24,624.91
NSPM MISO NSPP RT_PV_MWP Alloc	18,768.89	9,149.72	12,531.14	15,386.86	7,590.31	10,485.88	11,208.30	7,006.23	19,230.98
NSPM MISO NSPP DA_RSG_MWP Alloc	27,159.57	62,347.80	32,926.20	33,357.48	72,089.54	38,216.52	55,618.70	35,346.36	37,859.08
NSPM MISO NSPP DA_SCHD_24_ALC Alloc	(6,492.24)	(3,559.35)	(7,424.82)	(4,967.40)	(9,527.73)	(6,421.29)	(6,518.07)	(5,906.96)	(6,612.42)
NSPM MISO NSPP RT_SCHD_24_ALC Alloc	(900.31)	(688.84)	(818.92)	(801.77)	(1,300.60)	(1,412.37)	(963.01)	(868.30)	(1,310.24)
NSPM MISO NSPP RT_RAA Alloc	10,703.99	10,703.99	10,358.70	10,703.99	10,358.70	10,703.99	10,703.99	9,668.12	10,703.99
NSPM MISO NSPP RT_MVP_DIST Alloc	2,407.08	10,397.76	10,541.26	(5,093.26)	2,677.80	3,108.27	116,443.80	58,738.32	25,992.35
NSPM MISO NSPP ASM_REG Alloc	335,414.81	147,109.86	328,009.35	184,550.08	123,884.22	124,990.66	50,882.39	45,902.27	51,749.11
NSPM MISO NSPP ASM_SPIN Alloc	190,891.97	75,241.87	187,275.87	134,739.28	146,255.84	115,767.59	135,591.54	215,421.39	161,561.26
NSPM MISO NSPP ASM_SUPP Alloc	1,402.08	(1,127.17)	(1,265.81)	14,069.52	13,810.27	2,372.40	18,018.62	120,698.71	67,594.81
NSPM MISO NSPP RT_ASM_CRDFC Alloc	-	-		(419.41)					
NSPM MISO NSPP RT_ASM_EXE_DFE_DEP Alloc	(48,845.86)	(27,871.78)	(43,418.84)	(51,180.02)	(52,227.50)	(31,643.66)	(12,442.16)	(3,509.40)	(10,213.22)
NSPM MISO NSPP RT_ASM_NRGA Alloc	(34,762.29)	(33,669.38)	(22,876.08)	(9,826.57)	(7,027.08)	(1,732.06)	(2,376.83)	(812.92)	(541.97)
NSPM MISO NSPP RT_SCHD_24_DIST Alloc	74,827.92	85,593.41	91,471.50	88,805.70	93,699.09	88,322.75	85,174.36	87,784.81	69,925.17
NSPM MISO NSPP DA_ASSET_EN	(6,427,342.24)	477,154.64	(7,186,012.70)	(6,997,648.67)	(15,227,576.71)	(10,555,045.51)	(3,121,529.45)	(7,044,275.35)	(4,388,180.63)
NSPM MISO NSPP DA_ASSET_EN_CG	1,614,903.69	667,548.79	448,282.98	348,422.11	187,285.79	1,507,770.72	1,996,616.80	1,482,893.85	2,061,684.44
NSPM MISO NSPP DA_ASSET_EN_LS	2,927,202.34	3,087,706.54	2,204,337.92	2,770,216.27	3,607,922.75	3,762,248.39	3,488,042.21	2,693,104.17	3,045,595.98
NSPM MISO NSPP DA_GFACO_RBT_CG	8,295.10	(848.86)	18,283.58	50.24	7,269.33	878.41	(11,650.90)	(29,647.58)	(2,675.57)
NSPM MISO NSPP DA_FIN_LS	(3,039.31)	(2,912.34)	(6,980.25)	(90.81)	2,345.74	3,013.71	1,797.62	7,326.99	5,532.06
NSPM MISO NSPP DA_FIN_CG	(8,295.10)	848.86	(18,283.58)	(50.24)	(7,269.33)	(878.41)	11,650.90	29,647.58	2,675.57
NSPM MISO NSPP DA_GFACO_RBT_LS	3,039.31	2,912.35	6,980.25	90.81	(2,345.74)	(3,013.71)	(1,797.62)	(7,326.99)	(5,532.06)
NSPM MISO NSPP DA_GFAOB_RBT_LS									
NSPM MISO NSPP DA_RSG_DIST	39,382.90	63,525.61	62,311.02	98,385.96	111,056.42	119,041.48	90,772.12	98,781.00	90,530.24
NSPM MISO NSPP DA_RSG_MWP	(28,978.79)	(30,490.54)	(39,059.66)	(15,835.89)	(76,788.74)	(113,726.60)	(88,258.02)	(70,178.46)	(111,365.39)
NSPM MISO NSPP DA_VIRT_EN									
NSPM MISO NSPP DA_NASSET_EN	(7,596,662.58)	(7,564,303.08)	(6,655,205.04)	(6,536,574.59)	(3,876,510.04)	(3,534,295.08)	(2,760,059.53)	(2,963,666.07)	(3,650,021.92)
NSPM MISO NSPP DA_NASSET_EN_CG	992591.94	647075.01	894184.74	260094.46	185495.14	158918.96	-35883.01	-483219.56	450167.94
NSPM MISO NSPP DA_NASSET_EN_LS	878,685.81	926,635.36	817,936.28	527,103.28	277,707.87	303,202.87	213,462.82	55,088.20	83,951.50
NSPM MISO NSPP DA_ASM_REG	(302,134.95)	(196,992.06)	(376,639.03)	(246,593.38)	(250,955.55)	(288,577.90)	(65,489.47)	(29,658.58)	(68,520.07)
NSPM MISO NSPP DA_ASM_SPIN	(317,720.30)	(337,160.12)	(323,121.86)	(220,082.32)	(164,144.21)	(147,440.30)	(147,034.33)	(108,002.18)	(160,313.60)
NSPM MISO NSPP DA_ASM_SUPP	(19,980.74)	(27,132.43)	(35,805.11)	(45,972.35)	(34,404.93)	(24,905.43)	(94,408.25)	(53,989.65)	(73,354.25)
NSPM MISO NSPP RT_GFACO_RBT_CG	(3.27)	(328.84)		(6.22)		(12.93)	-		
NSPM MISO NSPP RT_LOSS_DIST	(1,424,393.71)	(1,289,052.28)	(1,026,632.15)	(922,125.28)	(1,121,300.12)	(1,240,909.23)	(1,146,336.64)	(1,319,387.99)	(793,578.25)
NSPM MISO NSPP RT_FIN_LS	5.08	97.69		1.14		3.23	-		
NSPM MISO NSPP RT_FIN_CG	3.27	328.84		6.22		12.93	-		
NSPM MISO NSPP RT_GFACO_RBT_LS	(5.08)	(97.69)		(1.14)		(3.23)	-		
NSPM MISO NSPP RT_MISC	343,844.43	115,883.62	224,165.88	110,105.22	186,373.18	383,285.01	179,102.11	147,279.65	192,248.52
NSPM MISO NSPP RT_NI_DIST	220,572.75	11,705.02	(92,059.80)	77,626.14	(107,138.55)	99,169.58	(50,899.18)	(133,686.51)	97,293.07
NSPM MISO NSPP RT_RSG_DIST1	413,559.57	213,019.94	357,710.30	271,236.87	169,296.50	117,415.06	64,030.81	216,975.93	203,122.10
NSPM MISO NSPP RT_RSG_MWP	(209,141.97)	(99,818.34)	(178,197.87)	(300,760.84)	(378,364.21)	(195,033.76)	(114,702.05)	(3,473,889.70)	(273,885.54)
NSPM MISO NSPP RT_RNU	185,822.99	53,787.45	28,294.23	655,240.42	295,464.55	484,100.39	11,044.93	1,712,181.83	249,977.97
NSPM MISO NSPP RT_PV_MWP	(99,729.82)	(36,231.99)	(162,966.54)	(43,614.46)	(76,569.25)	(38,980.18)	(55,970.79)	(94,587.85)	(44,620.67)
NSPM MISO NSPP RT_NASSET_EN	12,529.25	53,987.66	7,664.82	78.96	(6.07)	108.63	(0.09)	-	(9.46)
NSPM MISO NSPP RT_NASSET_EN_CG	(2,267.85)	(803.75)	(210.35)	(19.68)	5.20	2.66	0.05	-	
NSPM MISO NSPP RT_NASSET_EN_LS	(1,450.74)	(3,661.95)	(704.45)	(15.55)	0.86	(34.32)	0.04	-	
NSPM MISO NSPP RT_ASM_CRDFC	1,487.96				2,655.11				2,476.61
NSPM MISO NSPP RT_ASM_EXE_DFE_DEP	87,908.14	90,847.37	112,282.66	88,696.82	126,062.97	117,162.44	38,384.36	29,945.18	22,292.50
NSPM MISO NSPP RT_ASM_NRGA	68,610.58	76,613.91	47,173.89	1,378.67	9,459.53	6,286.40	855.31	(1,226.40)	1,270.57
NSPM MISO NSPP RT_ASM_REG	(127,323.23)	(105,127.32)	(137,684.42)	(59,740.99)	(70,404.23)	7,347.67	(87,322.99)	46,175.72	(11,347.07)
NSPM MISO NSPP RT_ASM_REG_DIST	119,499.19	114,728.25	122,911.04	160,727.28	172,672.43	161,494.06	116,558.55	95,105.31	135,048.49
NSPM MISO NSPP RT_ASM_SPIN	48,849.06	145,522.34	57,825.92	(53,144.66)	(103,773.88)	(46,675.26)	(205,559.66)	81,016.31	(11,535.47)
NSPM MISO NSPP RT_ASM_SPIN_DIST	127,940.37	116,938.26	182,842.77	215,012.98	165,543.32	146,531.41	100,794.89	110,674.83	133,340.13
NSPM MISO NSPP RT_ASM_SUPP	14,549.40	5,534.10	26,265.73	9,331.78	2,932.09	418.75	124,108.50	(118,382.13)	4,283.35
NSPM MISO NSPP RT_ASM_SUPP_DIST	19,859.65	23,987.62	73,610.31	34,453.68	15,957.36	23,646.16	14,041.37	37,530.72	42,798.77

Internal Order Description	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
NSPM MISO NSPP DA_ASSET_EN Alloc	7,367,799.79	19,557,971.27	17,572,159.06	19,608,408.16	16,404,588.56	16,219,782.68	12,441,406.49	16,543,375.21	15,366,958.69	263,076,814.53
NSPM MISO NSPP RT_ASSET_EN Alloc	2,021,122.26	2,096,558.79	1,784,877.40	1,896,329.76	1,334,147.98	1,179,016.67	1,453,982.13	3,108,167.34	1,637,301.56	33,944,871.44
NSPM MISO NSPP DA_ADMIN Alloc	(29,858.45)	(96,535.04)	(86,139.05)	(62,053.30)	(35,211.29)	(60,877.89)	(61,916.89)	(64,267.99)	(69,497.81)	(954,019.14)
NSPM MISO NSPP RT_ADMIN Alloc	(9,091.75)	(12,999.03)	(8,970.33)	(6,252.35)	(3,217.88)	(4,998.25)	(7,702.88)	(12,823.95)	(10,024.89)	(137,105.22)
NSPM MISO NSPP RT_RSG_MWP Alloc	25,020.32	(29,282.76)	32,921.90	21,851.87	26,992.47	14,622.71	34,369.65	56,398.90	38,925.77	3,746,874.84
NSPM MISO NSPP RT_PV_MWP Alloc	6,477.62	14,122.11	12,454.92	11,499.08	15,583.16	22,219.01	17,883.18	10,285.11	11,560.86	233,443.36
NSPM MISO NSPP DA_RSG_MWP Alloc	10,982.16	56,963.70	32,777.65	9,339.95	13,882.00	72,086.44	101,557.29	58,141.09	35,532.30	786,183.83
NSPM MISO NSPP DA_SCHD_24_ALC Alloc	(4,676.52)	(10,304.06)	(12,125.24)	(9,323.59)	(8,160.66)	(9,300.06)	(7,788.14)	(8,959.83)	(8,725.25)	(136,793.63)
NSPM MISO NSPP RT_SCHD_24_ALC Alloc	(1,423.35)	(1,367.31)	(1,348.39)	(938.20)	(774.74)	(764.11)	(971.06)	(1,795.69)	(1,248.10)	(19,695.31)
NSPM MISO NSPP RT_RAA Alloc	10,358.70	10,703.99	11,894.10	12,290.57	12,635.86	11,894.10	12,290.57	11,894.10	12,290.57	200,862.02
NSPM MISO NSPP RT_MVP_DIST Alloc	23,992.35	25,169.16	8,792.80	9,069.71	7,307.84	1,824.04	1,781.20	1,895.17	54,964.25	360,009.90
NSPM MISO NSPP ASM_REG Alloc	198,702.16	272,904.26	212,874.91	248,521.61	277,508.64	166,794.76	181,155.31	100,537.13	53,706.58	3,105,198.11
NSPM MISO NSPP ASM_SPIN Alloc	231,313.06	239,678.99	261,053.65	216,613.11	203,387.04	236,610.43	223,766.40	92,539.57	66,722.60	3,134,431.46
NSPM MISO NSPP ASM_SUPP Alloc	25,856.23	47,817.09	33,224.56	6,638.17	14,480.75	18,270.21	15,966.41	11,469.21	24,602.02	433,898.08
NSPM MISO NSPP RT_ASM_CRDFC Alloc		(59,673.35)	(1,094.08)	-	(889.88)	(2,647.05)	6.58		817.04	(63,900.15)
NSPM MISO NSPP RT_ASM_EXE_DFE_DEP Alloc	(18,524.14)	(10,963.84)	(25,676.50)	(30,168.62)	(30,915.12)	(21,505.40)	(14,117.60)	(11,579.31)	(8,410.07)	(453,213.04)
NSPM MISO NSPP RT_ASM_NRGA Alloc	(5,695.56)	(3,203.92)	(3,780.27)	(15,010.73)	(1,458.82)	(8,460.32)	(21,164.90)	(872.43)	2,250.06	(171,022.07)
NSPM MISO NSPP RT_SCHD_24_DIST Alloc	103,458.19	73,269.24	103,310.57	92,985.90	106,770.86	83,166.35	90,141.89	83,656.44	88,216.53	1,590,580.68
NSPM MISO NSPP DA_ASSET_EN	(656,753.91)	(13,086,587.61)	(14,114,597.62)	(12,666,821.59)	(10,882,366.12)	(10,619,183.75)	(8,766,927.58)	(14,003,311.03)	(11,711,719.33)	(156,978,725.16)
NSPM MISO NSPP DA_ASSET_EN_CG	1,003,404.09	526,019.77	435,190.70	3,569,518.59	2,141,545.63	1,605,403.91	2,262,762.43	1,905,613.83	1,545,634.06	25,310,502.18
NSPM MISO NSPP DA_ASSET_EN_LS	2,032,461.42	1,767,793.53	1,674,123.01	2,664,374.28	2,083,104.75	1,770,942.42	1,995,030.74	2,348,066.64	2,301,715.99	46,223,989.35
NSPM MISO NSPP DA_GFACO_RBT_CG	329.13	10,982.49	8,228.23	(10,844.82)	(7,536.97)	6,828.80	7,592.48	(1,906.58)	(10,460.62)	(6,834.11)
NSPM MISO NSPP DA_FIN_LS	2,416.41	(315.23)	(2,320.69)	(3,035.09)	(2,674.69)	(5,214.50)	(958.82)	(63.64)	212.07	(4,960.77)
NSPM MISO NSPP DA_FIN_CG	(329.13)	(10,982.49)	(8,228.23)	10,844.82	7,536.97	(6,828.80)	(7,592.48)	1,906.58	10,460.62	6,834.11
NSPM MISO NSPP DA_GFACO_RBT_LS	(2,416.41)	315.23	2,320.69	3,035.09	2,674.69	5,214.50	958.82	63.64	(212.07)	4,960.78
NSPM MISO NSPP DA_GFAOB_RBT_LS										-
NSPM MISO NSPP DA_RSG_DIST	82,593.70	79,507.00	63,219.85	55,978.72	60,391.61	54,807.01	83,205.81	66,452.30	69,143.39	1,389,086.14
NSPM MISO NSPP DA_RSG_MWP	(40,700.24)	(92,547.73)	(62,870.47)	(18,013.28)	(22,016.00)	(142,948.39)	(182,534.20)	(107,080.46)	(108,131.14)	(1,351,524.00)
NSPM MISO NSPP DA_VIRT_EN										-
NSPM MISO NSPP DA_NASSET_EN	(2,391,705.22)	(5,752,237.09)	(4,979,711.15)	(6,636,433.37)	(5,730,150.72)	(5,526,254.85)	(3,249,260.05)	(2,661,404.19)	(2,783,955.25)	(84,848,409.82)
NSPM MISO NSPP DA_NASSET_EN_CG	210874.36	937003.39	684043.94	1378480.18	1254254.16	933569.28	552425.65	187215.31	-4671.77	9,202,620.12
NSPM MISO NSPP DA_NASSET_EN_LS	116,313.31	466,646.76	638,256.19	816,261.80	706,449.61	807,789.05	332,517.90	284,331.79	229,674.02	8,482,014.42
NSPM MISO NSPP DA_ASM_REG	(191,674.00)	(252,687.15)	(259,930.00)	(336,943.32)	(347,636.17)	(304,701.69)	(303,530.11)	(247,667.36)	(219,482.67)	(4,289,813.46)
NSPM MISO NSPP DA_ASM_SPIN	(242,423.81)	(188,154.45)	(257,956.82)	(274,431.75)	(222,718.72)	(254,591.74)	(171,667.95)	(141,577.09)	(108,567.80)	(3,787,109.35)
NSPM MISO NSPP DA_ASM_SUPP	(41,922.52)	(45,913.43)	(39,782.25)	(43,582.38)	(34,153.34)	(36,637.61)	(41,607.96)	(41,658.18)	(44,555.84)	(779,766.65)
NSPM MISO NSPP RT_GFACO_RBT_CG			(15.07)				(33.27)			(399.60)
NSPM MISO NSPP RT_LOSS_DIST	(675,750.58)	(513,384.45)	(650,316.74)	(1,175,922.23)	(863,775.46)	(805,409.36)	(518,123.61)	(657,043.93)	(912,334.22)	(17,055,776.23)
NSPM MISO NSPP RT_FIN_LS			7.25				12.56			126.95
NSPM MISO NSPP RT_FIN_CG			15.07				33.27			399.60
NSPM MISO NSPP RT_GFACO_RBT_LS			(7.25)				(12.56)			(126.95)
NSPM MISO NSPP RT_MISC	226,434.67	(80,378.47)	233,072.55	191,906.45	157,194.33	268,466.77	233,932.02	619,496.08	183,311.51	3,915,723.53
NSPM MISO NSPP RT_NI_DIST	(120,804.06)	147.75	43,454.12	(2,930.86)	74,327.00	15,768.18	14,735.95	22,346.64	14,831.50	184,458.74
NSPM MISO NSPP RT_RSG_DIST1	62,726.92	143,230.20	146,536.63	148,671.41	88,903.98	56,155.10	82,118.79	82,598.89	41,494.97	2,878,803.97
NSPM MISO NSPP RT_RSG_MWP	(33,210.06)	(15,698.46)	(37,234.01)	(72,706.96)	(38,242.65)	(83,337.48)	(52,982.12)	(108,771.54)	(59,419.98)	(5,725,397.54)
NSPM MISO NSPP RT_RNU	330,681.35	463,508.81	158,851.88	467,688.86	372,318.76	71,452.24	517,573.18	(70,454.99)	352,729.16	6,340,264.01
NSPM MISO NSPP RT_PV_MWP	(116,503.07)	(56,103.03)	(40,310.38)	(62,129.15)	(128,885.19)	(87,380.70)	(76,259.32)	(47,620.76)	(48,182.59)	(1,316,645.74)
NSPM MISO NSPP RT_NASSET_EN	8,022.27	5,416.78	20,701.13	7,709.67	8,686.61	27.21	64,519.77	215.56	(1,013.70)	188,639.00
NSPM MISO NSPP RT_NASSET_EN_CG	6,717.36	(121.36)	(4,947.87)	(419.25)	(120,069.05)	(1.23)	4,393.50	(97.86)	997.68	(116,841.80)
NSPM MISO NSPP RT_NASSET_EN_LS	(248.56)	(414.85)	(2,843.32)	(432.62)	(384.30)	(25.99)	1,063.34	(39.83)	16.02	(9,176.22)
NSPM MISO NSPP RT_ASM_CRDFC		60,844.20	483.03		5,660.62	2,994.00				76,601.53
NSPM MISO NSPP RT_ASM_EXE_DFE_DEP	49,514.64	24,837.83	52,533.36	69,613.49	63,318.82	38,029.86	29,037.30	30,814.53	31,313.48	1,102,595.75
NSPM MISO NSPP RT_ASM_NRGA	10,412.42	5,516.31	7,965.29	51,778.23	(15,396.86)	23,043.71	31,658.96	(7,977.58)	(1,093.72)	316,329.22
NSPM MISO NSPP RT_ASM_REG	(30,093.38)	1,822.75	7,811.34	(36,633.71)	(31,436.64)	2,358.11	16,789.22	18,725.82	34,423.18	(561,660.17)
NSPM MISO NSPP RT_ASM_REG_DIST	94,207.90	124,327.44	100,244.56	120,697.86	117,309.15	114,096.37	120,394.43	113,663.10	127,269.02	2,230,954.43
NSPM MISO NSPP RT_ASM_SPIN	22,711.55	(51,638.82)	(33,570.91)	(33,141.62)	(58,990.29)	(37,208.07)	(95,959.66)	12,681.68	(40,111.56)	(402,703.00)
NSPM MISO NSPP RT_ASM_SPIN_DIST	129,197.90	130,179.49	83,640.78	145,124.06	109,873.68	89,867.81	88,266.99	63,589.54	38,178.33	2,177,537.54
NSPM MISO NSPP RT_ASM_SUPP	2,202.48	823.95	2,619.90	8,942.96	2,700.58	4,193.21	(8,445.98)	27,110.57	7,386.41	116,575.65
NSPM MISO NSPP RT_ASM_SUPP_DIST	14,673.32	32,906.93	17,624.29	65,570.52	10,470.10	19,417.66	26,654.64	1,014.52	14,462.77	488,680.39

Internal Order Description	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Period Total
NSPM MISO NSPP RT_ASM_EXE	3,933.26	1,228.65	60,800.59	369,413.12	(287,274.77)	(92,894.22)	(4,807.63)	(29,899.07)	1,113.91	8,064.33	(18,975.51)	(23,609.91)	(43,020.27)	(31,402.77)	(14,729.69)	(4,053.47)	(8,809.54)	(9,551.32)	(124,474.31)
NSPM MISO NSPP RT_ASM_NXE	3,583,561.26	3,802,233.75	3,451,814.56	2,214,112.71	1,175,015.03	1,340,646.55	830,010.01	(950,890.59)	(903,809.71)	(986,639.42)	3,352,781.15	(544,246.64)	3,369,220.90	2,609,958.30	3,600,833.93	792,253.10	1,042,610.94	1,073,957.09	28,853,422.92
NSPM MISO NSPP RT_ASM_NXE_CG	(143,557.98)	(580,203.27)	(251,434.51)	(19,316.20)	(11,023.61)	10,204.25	140,707.18	115,638.48	26,428.38	(517,507.25)	(124,422.15)	(99,788.74)	(450,554.12)	38,543.99	(278,578.76)	(189,417.45)	(93,012.10)	63,278.04	(2,364,015.82)
NSPM MISO NSPP RT_ASM_NXE_LS	(178,567.97)	(298,932.70)	(36,753.39)	30,463.21	19,145.92	1,899.05	5,458.46	54,212.06	(57,106.41)	(36,804.75)	(142,110.89)	148,311.34	(147,171.97)	(50,429.36)	(192,841.42)	31,242.59	774.48	11,548.03	(837,663.72)
NSPM MISO NSPP RT_ASSET_EN	(1,304,549.72)	(1,123,121.63)	1,167,857.12	7,557,082.03	146,572.78	(245,591.13)	(1,675,988.00)	(147,856.74)	(705,137.65)	(49,991.23)	(1,222,699.28)	(1,232,387.51)	(1,221,316.15)	(1,052,482.22)	(841,420.20)	39,443.49	(460,598.94)	110,686.34	(2,261,498.64)
NSPM MISO NSPP RT_ASSET_EN_CG	132,109.20	527,854.56	171,379.30	46,300.57	(23,629.14)	58,537.78	(168,205.37)	16,808.99	96,488.85	111,551.53	71,887.25	72,788.08	176,597.75	22,656.96	218,626.21	142,719.63	92,775.38	(778.56)	1,766,468.97
NSPM MISO NSPP RT_ASSET_EN_LS	123,291.50	260,532.92	24,291.11	2,611.07	(16,823.34)	15,682.86	(81,323.02)	(6,318.04)	47,058.99	(5,167.08)	59,320.44	97,746.49	119,784.67	110,044.98	122,175.29	9,758.39	48,784.95	16,816.94	948,269.12
NSPM MISO NSPP RT_DRR_UPL	(699.33)	(884.42)	(3,434.22)	(6,261.57)	(715.18)	5,022.60	1,842.73	151.42	9.93	0.00	-				0.02	0.10		1.17	(4,966.75)
NSPM MISO NSPP RT_RAA	(10,703.99)	(9,380.38)	(11,682.31)	(10,703.99)	(10,358.70)	(10,703.99)	(10,703.99)	(9,668.12)	(10,703.99)	(10,358.70)	(10,703.99)	(11,894.10)	(12,290.57)	(12,290.57)	(11,894.10)	(12,290.57)	(11,101.16)	(10,799.84)	(198,233.06)
NSPM MISO NSPP RT_MVP_DIST	(11,179.80)	(10,463.44)	(10,402.61)	(3,125.85)	(2,762.56)	(2,837.00)	(119,411.25)	(58,582.35)	(25,666.43)	(23,840.04)	(25,424.31)	(8,685.37)	(9,131.12)	(8,942.74)	(1,972.04)	(1,661.80)	(1,860.33)	(55,160.22)	(381,109.26)
NSPM MISO NSPP FTR_HR_ALC	(2,712,847.13)	(834,866.42)	(503,905.53)	(80,434.15)	151,905.71	(1,167,361.77)	(381,905.51)	293,886.74	(2,156,939.27)	(97,019.43)	(1,259,506.68)	(1,129,744.04)	(4,460,660.10)	(3,699,105.15)	(1,525,831.06)	(426,804.42)	(1,169,823.12)	(636,844.90)	(21,797,806.23)
NSPM MISO NSPP FTR_MN_ALC	(3,582.30)	(37,459.65)	(44,253.83)	(48,652.72)	(16,516.41)	(80,110.50)	(90,157.52)	(94,015.01)	(112,020.04)	(83,667.83)	(150,543.49)	(38,352.60)	(137,857.43)	(200,076.68)	(63,914.41)	(37,459.02)	(42,276.61)	(39,365.46)	(1,320,281.51)
NSPM MISO NSPP FTR_YR_ALC							(426,287.70)	1.07	-	-	-	-	-	-	-				(426,286.63)
NSPM MISO NSPP FTR_FFG	(17,821.32)	(5,682.10)	5,818.31	(25,345.74)	40,298.85	(97,314.32)	435,503.09	(81,675.23)	(58,051.82)	30,592.69	(23,950.27)	(66,727.21)	(264,018.18)	(174,203.01)	30,121.26	(11,499.97)	(68,725.91)	(89,773.02)	(442,453.90)
NSPM MISO NSPP FTR_GUL	17,801.92	5,183.65	(5,065.14)	25,337.71	(40,641.55)	94,933.31	(473,346.96)	102,923.50	61,106.83	(16,787.49)	6,700.83	51,872.13	194,543.93	267,173.35	(47,374.50)	29,504.90	73,143.23	82,954.80	429,964.45
NSPM MISO NSPP FTR_ARR_FTR_TXN	2,270,304.83	2,270,304.83	2,189,565.60	2,189,565.60	2,189,565.60	1,791,300.13	1,791,300.13	1,791,300.13	2,547,181.68	2,547,181.68	2,547,181.68	1,805,216.47	1,805,216.47	1,805,216.47	1,337,779.21	1,337,779.21	1,337,779.21	1,123,444.70	34,677,183.63
NSPM MISO NSPP FTR_ARR_ARR_TXN	(2,293,458.77)	(2,293,458.77)	(2,190,703.62)	(2,190,703.62)	(2,190,703.62)	(1,791,548.83)	(1,791,548.83)	(1,791,548.83)	(2,571,169.74)	(2,571,169.74)	(2,571,169.74)	(1,805,445.07)	(1,805,445.07)	(1,805,445.07)	(1,340,179.39)	(1,340,179.39)	(1,340,179.39)	(1,123,867.22)	(34,807,924.71)
NSPM MISO NSPP FTR_ARR_INF_UPL	41,430.89	41,430.89	130,420.69	130,420.69	130,420.69	42,374.37	42,389.67	42,379.47	55,175.45	55,175.45	55,175.45	25,882.21	25,882.21	25,882.21	59,727.45	59,727.45	59,727.45	42,660.70	1,066,283.39
NSPM MISO NSPP FTR_ARR_STG2_DIST	(320,148.19)	(320,148.49)	(242,965.26)	(242,964.65)	(242,964.65)	(155,089.36)	(153,246.61)	(156,670.33)	(90,957.73)	(90,957.87)	(90,957.87)	(202,033.21)	(204,112.67)	(203,055.76)	(198,269.67)	(198,206.91)	(198,218.84)	(207,296.32)	(3,518,264.39)
NSPM MISO NSPP DA Native Sales (EXP)	(7,906,765.03)	(4,895,956.71)	(3,918,393.40)	(153,231.71)	(4,210,936.80)	(5,001,312.06)	(6,128,526.13)	(7,017,928.53)	(6,776,945.36)	(3,964,570.75)	(2,730,288.70)	(3,265,161.15)	(8,533,160.28)	(5,890,649.32)	(4,692,610.47)	(5,155,417.53)	(3,099,590.33)	(3,978,179.88)	(87,319,624.14)
NSPM MISO NSPP RT Native Sales (EXP)	(1,325,249.25)	2,745,864.00	(391,745.86)	(3,237,202.34)	(973,604.91)	38,570.94	676,183.38	1,328,063.98	1,819,580.78	1,123,740.69	170,127.34	(59,424.28)	223,687.21	2,533.28	(351,785.05)	234,299.00	(860,199.12)	159,184.96	1,322,624.75
NSPM MISO NSPP Battery Unit FERC Reclss			19,955.16			49,746.83			27,338.24			15,189.26			18,215.44			(124.95)	130,319.98
NSPM MISO NSPP RT Native Sales (EXP)	7,906,765.03	4,895,956.71	3,918,393.40	153,231.71	4,210,936.80	5,001,312.06	6,128,526.13	7,017,928.53	6,776,945.36	3,964,570.75	2,730,288.70	3,265,161.15	8,533,160.28	5,890,649.32	4,692,610.47	5,155,417.53	3,099,590.33	3,978,179.88	87,319,624.14
NSPM MISO NSPP RT Native Sales (REV)	1,325,249.25	(2,745,864.00)	391,745.86	3,237,202.34	973,604.91	(38,570.94)	(676,183.38)	(1,328,063.98)	(1,819,580.78)	(1,123,740.69)	(170,127.34)	59,424.28	(223,687.21)	(2,533.28)	351,785.05	(234,299.00)	860,199.12	(159,184.96)	(1,322,624.75)
NSPM MISO NSPP DA_ADMIN	656,616.55	537,904.16	647,893.53	783,368.61	894,534.22	664,578.14	428,143.14	551,980.86	686,113.77	606,290.04	682,972.06	876,227.03	695,556.87	400,654.06	592,456.64	687,978.31	607,514.50	780,267.99	11,781,050.48
NSPM MISO NSPP DA_SCHD_24_ALC	96,499.39	96,356.87	107,122.00	103,289.24	103,860.95	98,245.53	93,842.77	89,246.18	99,517.54	93,323.55	98,029.65	93,765.32	105,021.95	93,136.38	90,286.38	86,324.07	84,740.12	98,214.55	1,730,822.44
NSPM MISO NSPP RT_ADMIN	50,704.08	38,818.57	56,094.68	52,710.27	62,294.73	48,738.53	29,413.76	41,461.12	56,279.14	58,805.28	60,703.52	65,146.30	53,676.55	25,046.11	47,334.67	63,928.30	60,308.87	65,004.23	936,468.71
NSPM MISO NSPP RT_SCHD_24_ALC	6,876.23	6,635.93	9,184.91	6,360.42	6,937.03	7,186.41	6,453.12	6,692.05	8,178.87	9,032.08	8,759.36	6,903.27	8,120.61	5,920.58	7,214.11	8,038.20	8,397.85	8,187.85	135,078.88
NSPM MISO NSPP RT_SCHD_24_DIST	(91,836.68)	(76,501.90)	(102,916.04)	(90,874.24)	(87,710.59)	(89,223.65)	(84,663.74)	(81,585.67)	(92,250.16)	(89,727.15)	(88,192.93)	(89,132.29)	(101,780.27)	(90,467.01)	(90,282.12)	(86,917.00)	(82,489.65)	(76,159.55)	(1,592,710.64)
NSPM MISO NSPP FTR_ADMIN	20,096.24	18,087.28	16,066.00	14,516.00	8,686.24	15,955.28	29,176.72	7,976.88	28,312.64	40,536.92	32,748.81	43,186.77	27,042.60	10,435.94	28,566.79	23,921.89	19,570.56	24,626.30	409,509.86
TOTAL	10,882,166.43	9,905,515.34	10,698,951.07	13,244,184.57	8,428,408.74	8,601,274.50	14,222,902.80	7,557,412.31	8,269,525.04	8,798,088.89	8,053,098.37	1,863,696.65	8,134,882.68	5,183,713.64	7,444,485.40	8,454,557.34	7,626,324.02	7,497,212.00	154,866,399.79
Purchased Power Gen Trading																			
RSG/RNU Wholesale Allocation																			
Manual Adjustment - DA RSG	(5,714.27)	(5,092.73)	(9,541.48)	(8,659.79)	(20,210.33)	(17,635.24)	(13,255.68)	(21,063.77)	(14,336.45)	(9,631.30)	(21,620.76)	(13,562.59)	(10,003.80)	(11,387.60)	(10,697.23)	(15,128.22)	(13,914.56)	(14,111.99)	(235,567.81)
Manual Adjustment - RT RSG	(60,005.54)	(17,077.40)	(54,775.01)	(23,873.89)	(30,809.00)	(17,394.30)	(9,350.58)	(46,267.32)	(32,166.61)	(7,314.62)	(38,949.35)	(31,436.59)	(26,568.66)	(16,763.97)	(10,960.35)	(14,930.58)	(17,295.52)	(8,469.02)	(464,408.30)
Manual Adjustment - RNU	(26,962.04)	(4,312.04)	(4,332.60)	(57,673.34)	(53,769.38)	(71,716.41)	(1,612.92)	(365,100.68)	(39,586.75)	(38,560.93)	(126,044.41)	(34,078.59)	(83,579.40)	(70,205.40)	(13,946.04)	(94,103.55)	14,752.69	(71,991.12)	(1,142,822.89)
Total RSG/RNU	(92,681.85)	(26,482.16)	(68,649.09)	(90,207.02)	(104,788.70)	(106,745.95)	(24,219.19)	(432,431.77)	(86,089.81)	(55,506.85)	(186,614.52)	(79,077.78)	(120,151.86)	(98,356.97)	(35,603.62)	(124,162.36)	(16,457.39)	(94,572.12)	(1,842,798.99)
Congestion and Loss Wholesale Allocation																			
Manual Adjustment - DA Congestion	(234,314.89)	(53,516.10)	(68,644.11)	(30,667.62)	(34,082.74)	(223,366.70)	(291,571.05)	(316,207.97)	(326,490.29)	(117,007.49)	(143,043.35)	(93,361.73)	(637,898.91)	(403,815.44)	(313,342.59)	(411,408.46)	(399,019.77)	(315,459.95)	(4,413,219.14)
Manual Adjustment - DA Loss	(424,723.22)	(247,535.48)	(337,543.05)	(243,830.52)	(656,578.81)	(557,353.31)	(509,367.71)	(574,269.71)	(482,303.45)	(237,006.42)	(480,725.47)	(359,150.63)	(476,143.04)	(392,795.68)	(345,652.38)	(362,730.31)	(491,665.72)	(469,774.33)	(7,649,149.24)
Manual Adjustment - DA Non-Asset Congestion	(144,020.40)	(51,874.76)	(136,923.58)	(22,893.15)	(33,756.87)	(23,542.84)	5,240.09	103,040.33	(71,289.02)	(24,590.17)	(254,804.30)	(146,748.36)	(246,344.42)	(236,505.44)	(182,213.96)	(100,440.32)	(39,201.34)	953.50	(1,605,915.02)
Manual Adjustment - DA Non-Asset Loss	(127,493.16)	(74,286.57)	(125,247.90)	(46,394.89)	(50,537.97)	(44,917.59)	(31,172.52)	(11,746.85)	(13,294.64)	(13,563.36)	(126,897.73)	(136,925.49)	(145,871.91)	(133,209.98)	(157,664.19)	(60,457.38)	(59,536.72)	(46,875.88)	(1,406,094.73)
Manual Adjustment - RT Non-Asset Congestion	20,829.58	46,513.78	38,501.34	1,700.18	2,006.10	(1,511.70)	(20,547.83)	(24,658.41)	(4,185.22)	60,346.80	33,834.78	21,407.74	80,517.29	(7,267.96)	54,372.98	34,439.29	19,475.96	(12,914.89)	342,859.84
Manual Adjustment - RT Non-Asset Loss	25,909.37	23,964.86	5,627.93	(2,681.33)	(3,484.22)	(281.33)	(797.11)	(11,560.02)	9,043.42	4,291.82	38,644.97	(31,817.32)	26,300.70	9,509.09	37,638.77	(5,680.43)	(162.17)	(2,356.92)	122,110.07
Manual Adjustment - ASM RT Asset EN GEN CONG	(19,168.42)	(42,317.08)	(26,242.75)	(4,075.31)	4,300.09	(8,672.00)	24,563.46	(3,584.30)	(15,280.07)	(13,008.08)	(19,548.68)	(15,615.27)	(31,559.30)	(4,272.26)	(42,671.44)	(25,948.84)	(19,426.40)	158.90	(262,367.75)
Manual Adjustment - ASM RT Asset EN GEN LOSS	(17,889.01)	(20,886.42)	(3,719.62)	(229.82)	3,061.55	(2,323.32)	11,875.81	1,347.24	(7,452.31)	602.54	(16,131.32)	(20,969.61)	(21,406.39)	(20,750.37)	(23,846.16)	(1,774.24)	(10,215.16)	(3,432.29)	(154,138.92)
Manual Adjustment - RT Asset EN Load CONG	329.05	64.44	32.21	1.73	(0.95)	(0.39)	(0.01)	-	-	(783.31)	33.00	1,061.47	74.92	22,640.53	0.24	(798.81)	20.49	(203.62)	22,470.99
Manual Adjustment - RT Asset EN Load LOSS	210.50	293.57	107.87	1.37	(0.16)	5.08	(0.01)	-	-	28.98	112.81	609.98	77.31	72.46	5.07	(193.33)	8.34	(3.27)	1,336.59
Total Congestion and Loss	(920,330.60)	(419,579.76)	(654,051.66)	(349,069.35)	(769,073.97)	(861,964.09)	(811,776.88)	(837,639.69)	(911,251.56)	(340,688.71)	(968,525.29)	(781,509.22)	(1,452,253.75)	(1,166,395.03)	(973,373.66)	(934,992.83)	(999,722.49)	(849,908.76)	(15,002,107.31)
Ramp Capability Amount																			
Embedded in ASM - DA Regulation	(13,571.61)	(8,395.12)	(17,398.42)	(14,219.34)	(10,469.46)	(4,131.62)	(1,943.27)	(1,505.65)	(2,459.76)	(8,133.80)	(2,605.68)	(365.97)	(1,756.81)	(3,073.85)	(6,092.84)	(4,312.67)	(10,758.71)	(2,747.64)	(113,942.22)
Embedded in ASM - RT Regulation	(3,501.73)	(1,625.25)	445.20	252.90	(1,551.22)	(1,803.55)	(732.08)	(832.71)	(613.94)	(1,239.49)	(1,125.41)	(285.74)	(28.82)	(150.39)	(367.77)	(261.83)	(459.95)	(101.12)	(13,982.90)

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	July 2018	**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	(282,428)	$ (1,885,236.15)	4,189,534	$ 122,634,384.38	(3,891,245)	$ (107,984,824.91)			(580,717)	$ (16,534,795.62)				
5a	Day Ahead Non Asset Energy	(191,594)	$ (5,725,384.83)	-	$ -	(191,594)	$ (5,725,384.83)					11,688	$ 338,962.67	-	$ -
13a	Real Time Asset Energy	(39,228)	$ (1,049,149.05)	69,059	$ 1,964,519.14	(27,773)	$ (790,209.72)			(80,514)	$ (2,223,458.47)				
22a	Real Time Non Asset Energy	336	$ 8,810.66	336	$ 8,810.66	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(512,914)	$ (8,650,959.37)	4,258,929	$ 124,607,714.18	(4,110,612)	$ (114,500,419.46)	-	$ -	(661,231)	$ (18,758,254.09)	11,688	$ 338,962.67	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (3,039.31)		$ 715.28		$ (3,754.59)								
14	Real Time Distribution Losses		$ (1,424,393.71)		$ -		$ (1,424,393.71)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,427,433.02)		$ 715.28		$ (1,428,148.30)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 656,616.55		$ 611,457.97		$ -		$ 45,158.58				$ 865.44		
19	Real Time Market Administration (Schedule 17)		$ 50,704.08		$ 44,441.20		$ -		$ 6,262.88				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 20,096.24		$ 20,096.24		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 96,499.39		$ 90,007.15		$ -		$ 6,492.24				$ 127.68		
34	Real -Time Schedule 24 Allocation Amount		$ (84,960.45)				$ (11,032.84)				$ (73,927.61)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 738,955.81		$ 766,002.56		$ (11,032.84)		$ 57,913.70		$ (73,927.61)		$ 993.12		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (8,295.10)		$ 3,380.31		$ (11,675.41)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (2,712,847.13)		$ 380,348.36		$ (3,093,195.49)								$ -
30	Financial Transmission Rights Monthly Allocation		$ (3,582.30)		$ -		$ (3,582.30)						$ -		
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (17,821.32)		$ -		$ (17,821.32)						$ -		
37	Financial Transmission Guarantee Uplift Amount		$ 17,801.92		$ 17,801.92		$ -								$ -
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (2,724,743.93)		$ 401,530.59		$ (3,126,274.52)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 39,382.90		$ 33,668.63				$ 5,714.27						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (28,978.79)		$ -		$ (1,819.22)				$ (27,159.57)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 413,559.57		$ 353,554.03				$ 60,005.54						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (209,141.97)		$ -		$ (79,329.05)				$ (129,812.92)				
43	Real Time Price Volatility Make Whole Payment		$ (99,729.82)		$ -		($80,960.93)				$ (18,768.89)				
	SUBTOTAL		$ 115,091.89		$ 387,222.66		$ (162,109.20)		$ 65,719.81		$ (175,741.38)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 321,261.31		$ 355,236.79		$ (23,271.49)				$ (10,703.99)		$ -		
21	Real Time Net Inadvertent Distribution		$ 220,572.75		$ 223,297.18		$ (2,724.43)						$ 275.45		$ (2.00)
23	Real Time Revenue Neutrality Uplift Amount		$ 185,822.99		$ 431,522.49		$ (272,661.54)		$ 26,962.04						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 727,657.05		$ 1,010,056.46		$ (298,657.46)		$ 26,962.04		$ (10,703.99)		$ 275.45		$ (2.00)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,270,304.83		$ 2,279,263.02		$ (8,958.19)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,293,458.77)		$ 8,366.75		$ (2,299,418.44)				$ (2,407.08)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (320,148.19)		$ -		$ (320,148.19)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 41,430.89		$ 41,430.89		$ -								
	SUBTOTAL		$ (301,871.24)		$ 2,329,060.66		$ (2,628,524.82)		$ -		$ (2,407.08)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,295.10		$ 11,675.41		$ (3,380.31)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 3,039.31		$ 3,754.59		$ (715.28)								
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	-	$ 11,334.41	-	$ 15,430.00	-	$ (4,095.59)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(512,914)	$ (11,511,968.40)	4,258,929	$ 129,517,732.39	(4,110,612)	$ (122,159,262.19)	-	$ 150,595.55	(661,231)	$ (19,021,034.15)	11,688	$ 340,231.24	-	$ (2.00)
x	Net Congestion Amount		$ 2,737,336.98		$ 2,380,160.33				$ 357,176.65						
y	Net Loss Amount		$ 3,927,728.91		$ 3,401,632.39				$ 526,096.52						
z	Net Congestion and Loss Energy Offset		$ (6,665,065.89)		$ (5,781,792.72)				$ (883,273.17)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(512,914)**	$ (11,511,968.40)	4,258,929	$ 129,517,732.39	(4,110,612)	$ (122,159,262.19)	-	$ 150,595.55	(661,231)	$ (19,021,034.15)	11,688	$ 340,231.24	-	$ (2.00)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

August 2018		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	(71,375)	$ 4,232,409.92	4,124,882	$ 118,433,363.84	(3,878,096)	$ (105,528,728.30)			(318,161)	$ (8,672,225.62)				
5a	Day Ahead Non Asset Energy	(195,291)	$ (5,990,592.70)	58	$ 1,506.27	(195,349)	$ (5,992,098.97)					11,880	$ 328,644.20	-	$ -
13a	Real Time Asset Energy	(14,803)	$ (334,734.16)	85,670	$ 2,526,610.90	(37,900)	$ (1,267,597.36)			(62,573)	$ (1,593,747.70)				
22a	Real Time Non Asset Energy	1,649	$ 49,521.96	1,649	$ 49,521.98	-	$ (0.02)					-	$ -	-	$ -
	SUBTOTAL	(279,820)	$ (2,043,394.98)	4,212,259	$ 121,011,002.99	(4,111,345)	$ (112,788,424.65)	-	$ -	(380,734)	$ (10,265,973.32)	11,880	$ 328,644.20	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,912.34)		$ 339.86		$ (3,252.20)								
14	Real Time Distribution Losses		$ (1,289,052.28)		$ -		$ (1,289,052.28)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,291,964.62)		$ 339.86		$ (1,292,304.48)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 537,904.16		$ 517,902.33		$ -		$ 20,001.83				$ 749.92		
19	Real Time Market Administration (Schedule 17)		$ 38,818.57		$ 35,073.03		$ -		$ 3,745.54				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 18,087.28		$ 18,087.28		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 96,356.87		$ 92,797.52		$ -		$ 3,559.35				$ 134.40		
34	Real -Time Schedule 24 Allocation Amount		$ (69,865.97)		$ 15,038.60		$ -				$ (84,904.57)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 621,300.91		$ 678,898.76		$ -		$ 27,306.72		$ (84,904.57)		$ 884.32		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 848.86		$ 3,225.36		$ (2,376.50)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (834,866.42)		$ 336,632.45		$ (1,171,498.87)								$ -
30	Financial Transmission Rights Monthly Allocation		$ (37,459.65)		$ -		$ (37,459.65)						$ -		
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (5,682.10)		$ -		$ (5,682.10)						$ -		
37	Financial Transmission Guarantee Uplift Amount		$ 5,183.65		$ 5,183.65		$ -								$ -
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (871,975.66)		$ 345,041.46		$ (1,217,017.12)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 63,525.61		$ 58,432.88				$ 5,092.73						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (30,490.54)		$ 31,857.26						$ (62,347.80)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 213,019.94		$ 195,942.54				$ 17,077.40						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (99,818.34)		$ 12,946.63						$ (112,764.97)				
43	Real Time Price Volatility Make Whole Payment		$ (36,231.99)		$ -		($27,082.27)				$ (9,149.72)				
	SUBTOTAL		$ 110,004.68		$ 299,179.32		$ (27,082.27)		$ 22,170.12		$ (184,262.49)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 95,155.38		$ 133,284.69		$ (27,425.32)				$ (10,703.99)		$ (8.83)		
21	Real Time Net Inadvertent Distribution		$ 11,705.02		$ 84,461.11		$ (72,756.09)						$ 111.05		$ (89.48)
23	Real Time Revenue Neutrality Uplift Amount		$ 53,787.45		$ 387,373.90		$ (337,898.49)		$ 4,312.04						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 160,647.85		$ 605,119.70		$ (438,079.90)		$ 4,312.04		$ (10,703.99)		$ 102.22		$ (89.48)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,270,304.83		$ 2,279,263.02		$ (8,958.19)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,293,458.77)		$ 8,366.75		$ (2,291,427.76)				$ (10,397.76)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (320,148.49)		$ -		$ (320,148.49)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 41,430.89		$ 41,430.89		$ -								
	SUBTOTAL		$ (301,871.54)		$ 2,329,060.66		$ (2,620,534.44)		$ -		$ (10,397.76)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (848.86)		$ 2,376.50		$ (3,225.36)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,912.35		$ 3,252.21		$ (339.86)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ 2,063.49	-	$ 5,628.71	-	$ (3,565.22)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(279,820)	$ (3,615,189.87)	4,212,259	$ 125,274,271.46	(4,111,345)	$ (118,387,008.08)	-	$ 53,788.88	(380,734)	$ (10,556,242.13)	11,880	$ 329,630.74	-	$ (89.48)
x	Net Congestion Amount		$ 1,841,674.61		$ 1,782,861.97				$ 58,812.64						
y	Net Loss Amount		$ 4,271,212.87		$ 3,973,649.25				$ 297,563.62						
z	Net Congestion and Loss Energy Offset		$ (6,112,887.48)		$ (5,756,511.22)				$ (356,376.26)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(279,820)**	$ (3,615,189.87)	4,212,259	$ 125,274,271.46	(4,111,345)	$ (118,387,008.08)	-	$ 53,788.88	(380,734)	$ (10,556,242.13)	11,880	$ 329,630.74	-	$ (89.48)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	September 2018	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	(377,422)	$ (4,533,391.76)	3,472,374	$ 92,694,265.74	(3,293,700)	$ (82,977,312.17)			(556,096)	$ (14,250,345.33)				
5a	Day Ahead Non Asset Energy	(167,316)	$ (4,943,084.02)	33	$ 794.01	(167,349)	$ (4,943,878.03)					11,184	$ 290,251.53	-	$ -
13a	Real Time Asset Energy	24,361	$ 1,363,527.51	93,853	$ 3,084,605.54	(9,217)	$ (13,768.07)			(60,275)	$ (1,707,309.96)				
22a	Real Time Non Asset Energy	290	$ 6,750.01	290	$ 6,750.01	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(520,087)	$ (8,106,198.26)	3,566,550	$ 95,786,415.30	(3,470,266)	$ (87,934,958.27)	-	$ -	(616,371)	$ (15,957,655.29)	11,184	$ 290,251.53	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (6,980.25)		$ 108.95		$ (7,089.20)								
14	Real Time Distribution Losses		$ (1,026,632.15)		$ -		$ (1,026,632.15)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,033,612.40)		$ 108.95		$ (1,033,721.35)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 647,893.53		$ 599,891.96		$ -		$ 48,001.57				$ 964.48		
19	Real Time Market Administration (Schedule 17)		$ 56,094.68		$ 50,828.44		$ -		$ 5,266.24				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 16,066.00		$ 16,066.00		$ -						$ 45.60		
33	Day-Ahead Schedule 24 Allocation Amount		$ 107,122.00		$ 99,697.18		$ -		$ 7,424.82				$ 160.24		
34	Real -Time Schedule 24 Allocation Amount		$ (93,731.13)		$ (3,078.55)		$ -				$ (90,652.58)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 733,445.08		$ 763,405.03		$ -		$ 60,692.63		$ (90,652.58)		$ 1,170.32		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (18,283.58)		$ 3,670.97		$ (21,954.55)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (503,905.53)		$ 1,075,075.27		$ (1,578,980.80)						$ 5,459.85		$ (5,087.73)
30	Financial Transmission Rights Monthly Allocation		$ (44,253.83)		$ -		$ (44,253.83)						$ -		
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 5,818.31		$ 5,818.31		$ -						$ (84.08)		
37	Financial Transmission Guarantee Uplift Amount		$ (5,065.14)		$ -		$ (5,065.14)								$ 84.08
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (565,689.77)		$ 1,084,564.55		$ (1,650,254.32)		$ -		$ -		$ 5,375.77		$ (5,003.65)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 62,311.02		$ 52,769.54				$ 9,541.48						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (39,059.66)		$ (6,133.46)						$ (32,926.20)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 357,710.30		$ 302,935.29				$ 54,775.01						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (178,197.87)		$ (69,237.28)						$ (108,960.59)				
43	Real Time Price Volatility Make Whole Payment		$ (162,966.54)		$ -		($150,435.40)				$ (12,531.14)				
	SUBTOTAL		$ 39,797.25		$ 280,334.09		$ (150,435.40)		$ 64,316.49		$ (154,417.93)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 198,646.74		$ 234,731.83		$ (25,726.39)				$ (10,358.70)		$ -		
21	Real Time Net Inadvertent Distribution		$ (92,059.80)		$ 113,988.04		$ (206,047.84)						$ 151.69		$ (262.94)
23	Real Time Revenue Neutrality Uplift Amount		$ 28,294.23		$ 774,731.03		$ (750,769.40)		$ 4,332.60						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 134,881.17		$ 1,123,450.90		$ (982,543.63)		$ 4,332.60		$ (10,358.70)		$ 151.69		$ (262.94)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,189,565.60		$ 2,194,936.35		$ (5,370.75)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,190,703.62)		$ 4,715.85		$ (2,184,878.21)				$ (10,541.26)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (242,965.26)		$ -		$ (242,965.26)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 130,420.69		$ 130,420.69		$ -								
	SUBTOTAL		$ (113,682.59)		$ 2,330,072.89		$ (2,433,214.22)		$ -		$ (10,541.26)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 18,283.58		$ 21,954.55		$ (3,670.97)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 6,980.25		$ 7,089.20		$ (108.95)								
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	-	$ 25,263.83	-	$ 29,043.75	-	$ (3,779.92)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(520,087)	$ (8,885,795.69)	3,566,550	$ 101,397,395.46	(3,470,266)	$ (94,188,907.11)	-	$ 129,341.72	(616,371)	$ (16,223,625.76)	11,184	$ 296,949.31	-	$ (5,266.59)
x	Net Congestion Amount		$ 1,513,636.67		$ 1,346,602.54				$ 167,034.13						
y	Net Loss Amount		$ 3,045,860.86		$ 2,588,805.70				$ 457,055.16						
z	Net Congestion and Loss Energy Offset		$ (4,559,497.53)		$ (3,935,408.24)				$ (624,089.29)						
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(520,087)**	$ (8,885,795.69)	3,566,550	$ 101,397,395.46	(3,470,266)	$ (94,188,907.11)	-	$ 129,341.72	(616,371)	$ (16,223,625.76)	11,184	$ 296,949.31	-	$ (5,266.59)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	October 2018	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	(322,844)	$ (3,879,010.31)	3,284,639	$ 100,163,389.48	(3,293,927)	$ (93,589,156.11)			(313,556)	$ (10,453,243.68)				
5a	Day Ahead Non Asset Energy	(165,588)	$ (5,749,376.85)	-	$ -	(165,588)	$ (5,749,376.85)					11,880	$ 359,007.62	-	$ -
13a	Real Time Asset Energy	333,223	$ 7,605,993.68	383,067	$ 9,002,950.61	(94)	$ (90,256.65)			(49,750)	$ (1,306,700.28)				
22a	Real Time Non Asset Energy	2	$ 43.74	2	$ 43.74	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(155,207)	$ (2,022,349.74)	3,667,708	$ 109,166,383.83	(3,459,609)	$ (99,428,789.61)	-	$ -	(363,306)	$ (11,759,943.96)	11,880	$ 359,007.62	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (90.81)		$ 1,795.71		$ (1,886.52)								
14	Real Time Distribution Losses		$ (922,125.28)		$ -		$ (922,125.28)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (922,216.09)		$ 1,795.71		$ (924,011.80)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 783,368.61		$ 743,844.82		$ -		$ 39,523.79				$ 1,317.92		
19	Real Time Market Administration (Schedule 17)		$ 52,710.27		$ 46,303.65		$ -		$ 6,406.62				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 14,516.00		$ 14,516.00		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 103,289.24		$ 98,321.84		$ -		$ 4,967.40				$ 170.80		
34	Real -Time Schedule 24 Allocation Amount		$ (84,513.82)		$ 3,490.11		$ -				$ (88,003.93)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 869,370.30		$ 906,476.42		$ -		$ 50,897.81		$ (88,003.93)		$ 1,488.72		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (50.24)		$ 6,611.42		$ (6,661.66)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (80,434.15)		$ 865,210.56		$ (945,644.71)						$ 0.01		$ 24.46
30	Financial Transmission Rights Monthly Allocation		$ (48,652.72)		$ -		$ (48,652.72)						$ (108.53)		
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (25,345.74)		$ -		$ (25,345.74)						$ 84.08		
37	Financial Transmission Rights Guarantee Uplift Amount		$ 25,337.71		$ 25,337.71		$ -								$ (84.08)
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (129,145.14)		$ 897,159.69		$ (1,026,304.83)		$ -		$ -		$ (24.44)		$ (59.62)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 98,385.96		$ 89,726.17				$ 8,659.79						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (15,835.89)		$ 17,521.59						$ (33,357.48)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 271,236.87		$ 247,362.98				$ 23,873.89						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (300,760.84)		$ (173,065.06)						$ (127,695.78)				
43	Real Time Price Volatility Make Whole Payment		$ (43,614.46)		$ -		($28,227.60)				$ (15,386.86)				
	SUBTOTAL		$ 9,411.64		$ 181,545.68		$ (28,227.60)		$ 32,533.68		$ (176,440.12)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 90,013.81		$ 124,451.96		$ (23,734.16)				$ (10,703.99)		$ -		
21	Real Time Net Inadvertent Distribution		$ 77,626.14		$ 210,771.99		$ (133,145.85)						$ 322.81		$ (182.08)
23	Real Time Revenue Neutrality Uplift Amount		$ 655,240.42		$ 1,064,563.39		$ (466,996.31)		$ 57,673.34						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 822,880.37		$ 1,399,787.34		$ (623,876.32)		$ 57,673.34		$ (10,703.99)		$ 322.81		$ (182.08)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,189,565.60		$ 2,194,936.35		$ (5,370.75)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,190,703.62)		$ 4,715.85		$ (2,200,512.73)				$ 5,093.26				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (242,964.65)		$ -		$ (242,964.65)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 130,420.69		$ 130,420.69		$ -								
	SUBTOTAL		$ (113,681.98)		$ 2,330,072.89		$ (2,448,848.13)		$ -		$ 5,093.26		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 50.24		$ 6,661.66		$ (6,611.42)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 90.81		$ 1,886.52		$ (1,795.71)								
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	-	$ 141.05	-	$ 8,548.18	-	$ (8,407.13)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(155,207)	$ (1,485,589.59)	3,667,708	$ 114,891,769.74	(3,459,609)	$ (104,488,465.42)	-	$ 141,104.83	(363,306)	$ (12,029,998.74)	11,880	$ 360,794.71	-	$ (241.70)
x	Net Congestion Amount		$ 654,797.46		$ 602,938.61				$ 51,858.85						
y	Net Loss Amount		$ 3,299,915.06		$ 3,007,009.69				$ 292,905.37						
z	Net Congestion and Loss Energy Offset		$ (3,954,712.52)		$ (3,954,712.52)										
	SUBTOTAL	-	$ -	-	$ (344,764.22)	-	$ -	-	$ 344,764.22	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(155,207)**	$ (1,485,589.59)	3,667,708	$ 114,547,005.52	(3,459,609)	$ (104,488,465.42)	-	$ 485,869.05	(363,306)	$ (12,029,998.74)	11,880	$ 360,794.71	-	$ (241.70)

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

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 15

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

November 2018		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														
1	Day-Ahead Regulation Amount		$ (250,955.55)		$ -		$ (127,071.33)				$ (123,884.22)				
2	Day-Ahead Spinning Reserve Amount		$ (164,144.21)		$ -		$ (17,888.37)				$ (146,255.84)				
3	Day-Ahead Supplemental Reserve		$ (34,404.93)		$ -		$ (20,594.66)				$ (13,810.27)				
4	Real-Time Regulation Amount (See Note 1)		$ (70,404.23)		$ 94,508.49		$ (164,912.72)								
5	Real-Time Spinning Reserve Amount (See Note 1)		$ (103,773.88)		$ 44,465.46		$ (148,239.34)								
6	**Real-Time Supplemental Reserve Amount. (See Note 1)**														
7b	Real Time Excessive Energy Congestion														
8b	Real Time Non Excessive Energy Congestion														
8c	Real Time Non Excessive Energy Loss														
9	Real Time Net Regulation Adjustment Amount		$ 9,459.53		$ 8,076.40		$ (5,643.95)		$ 7,027.08						
Cost Distribution Charges															
10	Real Time Regulation Reserve Cost Distribution Amount		$ 172,672.43		$ 172,672.43		$ -								
11	Real Time Spinning Reserve Cost Distribution		$ 165,543.32		$ 165,543.32		$ -								
12	Real Time Supplemental Reserve Cost Distribution		$ 15,957.36		$ 15,957.36		$ -								
Penalty Charges															
13	Real Time Excessive/Deficient Energy Deployment		$ 126,062.97		$ 73,835.47		$ -		$ 52,227.50						
14	Real Time Contingency Reserve Deployment Failure		$ 2,655.11		$ 2,655.11		$ -		$ -						
	MISO ASM CHARGES	84,531	$ 767,462.57	346,846	$ 8,740,230.54	(262,315)	$ (7,748,072.22)	-	$ 59,254.58	-	$ (283,950.33)	-	$ -	-	$ -
x	Net Congestion Amount		$ (11,023.61)		$ (15,323.70)				$ 4,300.09						
y	Net Loss Amount		$ 19,145.92		$ 16,084.37				$ 3,061.55						
z	Net Congestion and Loss Energy Offset		$ (8,122.31)		$ (8,122.31)										
	SUBTOTAL	-	$ -	-	$ (7,361.64)	-	$ -	-	$ 7,361.64	-	$ -	-	$ -	-	$ -
	Total MISO ASM CHARGES														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (50.24)		$ 6,611.42		$ (6,661.66)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (80,434.15)		$ 865,210.56		$ (945,644.71)						$ 0.01		$ 24.46
30	Financial Transmission Rights Monthly Allocation		$ (48,652.72)		$ -		$ (48,652.72)						$ (108.53)		
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (25,345.74)		$ -		$ (25,345.74)						$ 84.08		
37	Financial Transmission Guarantee Uplift Amount		$ 25,337.71		$ 25,337.71		$ -								$ (84.08)
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (129,145.14)		$ 897,159.69		$ (1,026,304.83)		$ -		$ -		$ (24.44)		$ (59.62)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 98,385.96		$ 89,726.17				$ 8,659.79						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (15,835.89)		$ 17,521.59						$ (33,357.48)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 271,236.87		$ 247,362.98				$ 23,873.89						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (300,760.84)		$ (173,065.06)						$ (127,695.78)				
43	Real Time Price Volatility Make Whole Payment		$ (43,614.46)		$ -		($28,227.60)				$ (15,386.86)				
	SUBTOTAL		$ 9,411.64		$ 181,545.68		$ (28,227.60)		$ 32,533.68		$ (176,440.12)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 90,013.81		$ 124,451.96		$ (23,734.16)				$ (10,703.99)		$ -		
21	Real Time Net Inadvertent Distribution		$ 77,626.14		$ 210,771.99		$ (133,145.85)						$ 322.81		$ (182.08)
23	Real Time Revenue Neutrality Uplift Amount		$ 655,240.42		$ 1,064,563.39		$ (466,996.31)		$ 57,673.34						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 822,880.37		$ 1,399,787.34		$ (623,876.32)		$ 57,673.34		$ (10,703.99)		$ 322.81		$ (182.08)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,189,565.60		$ 2,194,936.35		$ (5,370.75)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,190,703.62)		$ 4,715.85		$ (2,200,512.73)				$ 5,093.26				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (242,964.65)		$ -		$ (242,964.65)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 130,420.69		$ 130,420.69		$ -								
	SUBTOTAL		$ (113,681.98)		$ 2,330,072.89		$ (2,448,848.13)		$ -		$ 5,093.26		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 50.24		$ 6,661.66		$ (6,611.42)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 90.81		$ 1,886.52		$ (1,795.71)								
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	-	$ 141.05	-	$ 8,548.18	-	$ (8,407.13)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(155,207)	$ (1,485,589.59)	3,667,708	$ 114,891,769.74	(3,459,609)	$ (104,488,465.42)	-	$ 141,104.83	(363,306)	$ (12,029,998.74)	11,880	$ 360,794.71	-	$ (241.70)
x	Net Congestion Amount		$ 654,797.46		$ 602,938.61				$ 51,858.85						
y	Net Loss Amount		$ 3,299,915.06		$ 3,007,009.69				$ 292,905.37						
z	Net Congestion and Loss Energy Offset		$ (3,954,712.52)		$ (3,954,712.52)										
	SUBTOTAL	-	$ -	-	$ (344,764.22)	-	$ -	-	$ 344,764.22	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(155,207)**	$ (1,485,589.59)	3,667,708	$ 114,547,005.52	(3,459,609)	$ (104,488,465.42)	-	$ 485,869.05	(363,306)	$ (12,029,998.74)	11,880	$ 360,794.71	-	$ (241.70)

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 2018		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	(409,926)	$ (5,285,026.37)	3,584,252	$ 105,065,216.14	(3,492,876)	$ (96,158,270.99)			(501,302)	$ (14,191,971.52)				
5a	Day Ahead Non Asset Energy	(96,419)	$ (3,072,173.26)	-	$ -	(96,419)	$ (3,072,173.26)					11,592	$ 332,847.45	-	$ -
13a	Real Time Asset Energy	(9,916)	$ (171,370.50)	56,276	$ 1,546,763.13	44,162	$ 606,918.78			(110,354)	$ (2,325,052.41)				
22a	Real Time Non Asset Energy	3	$ 76.96	3	$ 76.97	-	$ (0.01)					-	$ -	-	$ -
	SUBTOTAL	(516,258)	$ (8,528,493.17)	3,640,531	$ 106,612,056.24	(3,545,133)	$ (98,623,525.48)	-	$ -	(611,656)	$ (16,517,023.93)	11,592	$ 332,847.45	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 3,013.71		$ 3,903.48		$ (889.77)								
14	Real Time Distribution Losses		$ (1,240,909.23)		$ -		$ (1,240,909.23)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,237,895.52)		$ 3,903.48		$ (1,241,799.00)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 664,578.14		$ 621,089.02		$ -		$ 43,489.12				$ 999.68		
19	Real Time Market Administration (Schedule 17)		$ 48,738.53		$ 39,205.88		$ -		$ 9,532.65				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 15,955.28		$ 15,955.28		$ -						$ 48.00		
33	Day-Ahead Schedule 24 Allocation Amount		$ 98,245.53		$ 91,824.24		$ -		$ 6,421.29				$ 148.88		
34	Real -Time Schedule 24 Allocation Amount		$ (82,037.24)		$ 4,873.14		$ -				$ (86,910.38)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 745,480.24		$ 772,947.56		$ -		$ 59,443.06		$ (86,910.38)		$ 1,196.56		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (878.41)		$ 2,792.81		$ (3,671.22)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,167,361.77)		$ 777,506.99		$ (1,944,868.76)						$ 5,108.32		$ (9,598.73)
30	Financial Transmission Rights Monthly Allocation		$ (80,110.50)		$ -		$ (80,110.50)						$ -		
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (97,314.32)		$ -		$ (97,314.32)						$ (500.59)		
37	Financial Transmission Guarantee Uplift Amount		$ 94,933.31		$ 94,933.31		$ -								$ 496.75
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ 1,500.66		$ (170.77)
	SUBTOTAL		$ (1,250,731.69)		$ 875,233.11		$ (2,125,964.80)		$ -		$ -		$ 6,108.39		$ (9,272.75)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 119,041.48		$ 101,406.24				$ 17,635.24						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (113,726.60)				$ (75,510.08)				$ (38,216.52)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 117,415.06		$ 100,020.76				$ 17,394.30						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (195,033.76)				$ (85,677.19)				$ (109,356.57)				
43	Real Time Price Volatility Make Whole Payment		$ (38,980.18)		$ -		($28,494.30)				$ (10,485.88)				
	SUBTOTAL		$ (111,284.00)		$ 201,427.00		$ (189,681.57)		$ 35,029.54		$ (158,058.97)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 374,766.62		$ 400,831.58		$ (15,360.97)				$ (10,703.99)		$ -		
21	Real Time Net Inadvertent Distribution		$ 99,169.58		$ 186,317.55		$ (87,147.97)						$ 268.55		$ (125.33)
23	Real Time Revenue Neutrality Uplift Amount		$ 484,100.39		$ 757,403.26		$ (345,019.28)		$ 71,716.41						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 958,036.59		$ 1,344,552.39		$ (447,528.22)		$ 71,716.41		$ (10,703.99)		$ 268.55		$ (125.33)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,791,300.13		$ 1,832,066.26		$ (40,766.13)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,791,548.83)		$ 39,624.54		$ (1,828,065.10)				$ (3,108.27)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (155,089.36)		$ -		$ (155,089.36)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,374.37		$ 42,374.37		$ -								
	SUBTOTAL		$ (112,963.69)		$ 1,914,065.17		$ (2,023,920.59)		$ -		$ (3,108.27)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 878.41		$ 3,671.22		$ (2,792.81)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,013.71)		$ 889.77		$ (3,903.48)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ (2,135.30)	-	$ 4,560.99	-	$ (6,696.29)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(516,258)	$ (9,539,986.54)	3,640,531	$ 111,728,745.94	(3,545,133)	$ (104,659,115.95)	-	$ 166,189.01	(611,656)	$ (16,775,805.54)	11,592	$ 340,420.95	-	$ (9,398.08)
x	Net Congestion Amount		$ 1,725,230.12		$ 1,476,808.49				$ 248,421.63						
y	Net Loss Amount		$ 4,081,099.80		$ 3,478,552.65				$ 602,547.15						
z	Net Congestion and Loss Energy Offset		$ (5,806,329.92)		$ (5,806,329.92)										
	SUBTOTAL	-	$ -	-	$ (850,968.77)	-	$ -	-	$ 850,968.77	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	(516,258)	$ (9,539,986.54)	3,640,531	$ 110,877,777.16	(3,545,133)	$ (104,659,115.95)	-	$ 1,017,157.79	(611,656)	$ (16,775,805.54)	11,592	$ 340,420.95	-	$ (9,398.08)

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

January 2019		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	(309,136)	$ 2,363,129.58	3,777,000	$ 115,253,260.38	(3,534,736)	$ (98,554,199.88)			(551,400)	$ (14,335,930.92)				
5a	Day Ahead Non Asset Energy	(88,555)	$ (2,582,479.73)	104	$ 2,654.75	(88,659)	$ (2,585,134.48)					30,184	$ 899,853.50	-	$ -
13a	Real Time Asset Energy	(29,961)	$ (1,925,516.40)	48,353	$ 1,328,652.89	3,398	$ (625,559.97)			(81,712)	$ (2,628,609.32)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(427,652)	$ (2,144,866.55)	3,825,457	$ 116,584,568.02	(3,619,997)	$ (101,764,894.33)	-	$ -	(633,112)	$ (16,964,540.24)	30,184	$ 899,853.50	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 1,797.62		$ 2,415.04		$ (617.42)								
14	Real Time Distribution Losses		$ (1,146,336.64)		$ -		$ (1,146,336.64)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,144,539.02)		$ 2,415.04		$ (1,146,954.06)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 428,143.14		$ 398,079.40		$ -		$ 30,063.74				$ 1,627.04		
19	Real Time Market Administration (Schedule 17)		$ 29,413.76		$ 25,057.29		$ -		$ 4,356.47				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 29,176.72		$ 29,176.72		$ -						$ 95.04		
33	Day-Ahead Schedule 24 Allocation Amount		$ 93,842.77		$ 87,324.70		$ -		$ 6,518.07				$ 357.04		
34	Real -Time Schedule 24 Allocation Amount		$ (78,210.62)		$ 6,000.73		$ -				$ (84,211.35)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 502,365.77		$ 545,638.84		$ -		$ 40,938.28		$ (84,211.35)		$ 2,079.12		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 11,650.90		$ 12,251.45		$ (600.55)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (381,905.51)		$ 1,995,821.87		$ (2,377,727.38)						$ 11,918.12		$ (25,472.93)
30	Financial Transmission Rights Monthly Allocation		$ (90,157.52)		$ -		$ (90,157.52)						$ (498.01)		
32	Financial Transmission Rights Yearly Allocation		$ (426,287.70)		$ -		$ (426,287.70)								$ (255.71)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 435,503.09		$ 435,503.09		$ -						$ (122.97)		
37	Financial Transmission Guarantee Uplift Amount		$ (473,346.96)		$ -		$ (473,346.96)								$ (60.35)
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ 1,234.46		$ (284.21)
	SUBTOTAL		$ (924,543.70)		$ 2,443,576.41		$ (3,368,120.11)		$ -		$ -		$ 12,531.60		$ (26,073.20)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 90,772.12		$ 77,516.44				$ 13,255.68						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (88,258.02)				$ (32,639.32)				$ (55,618.70)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 64,030.81		$ 54,680.23				$ 9,350.58						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (114,702.05)				$ (120,266.97)				$ 5,564.92				
43	Real Time Price Volatility Make Whole Payment		$ (55,970.79)		$ -		($44,762.49)				$ (11,208.30)				
	SUBTOTAL		$ (104,127.93)		$ 132,196.66		$ (197,668.78)		$ 22,606.27		$ (61,262.08)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 50,829.60		$ 198,824.97		$ (137,291.38)				$ (10,703.99)		$ (8.65)		
21	Real Time Net Inadvertent Distribution		$ (50,899.18)		$ 79,530.59		$ (130,429.77)						$ 166.52		$ (235.38)
23	Real Time Revenue Neutrality Uplift Amount		$ 11,044.93		$ 399,437.62		$ (390,005.61)		$ 1,612.92						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 10,975.35		$ 677,793.18		$ (657,726.76)		$ 1,612.92		$ (10,703.99)		$ 157.87		$ (235.38)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,791,300.13		$ 1,832,066.26		$ (40,766.13)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,791,548.83)		$ 39,624.54		$ (1,714,729.57)				$ (116,443.80)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (153,246.61)		$ -		$ (153,246.61)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,389.67		$ 42,389.67		$ -								
	SUBTOTAL		$ (111,105.64)		$ 1,914,080.47		$ (1,908,742.31)		$ -		$ (116,443.80)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (11,650.90)		$ 600.55		$ (12,251.45)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,797.62)		$ 617.42		$ (2,415.04)								
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	-	$ (13,448.52)	-	$ 1,217.97	-	$ (14,666.49)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(427,652)	$ (3,929,290.24)	3,825,457	$ 122,301,486.59	(3,619,997)	$ (109,058,772.84)	-	$ 65,157.47	(633,112)	$ (17,237,161.46)	30,184	$ 914,622.09	-	$ (26,308.58)
x	Net Congestion Amount		$ 1,792,528.47		$ 1,485,649.67				$ 306,878.80						
y	Net Loss Amount		$ 3,620,182.05		$ 3,078,844.70				$ 541,337.35						
z	Net Congestion and Loss Energy Offset		$ (5,412,710.52)		$ (5,412,710.52)										
	SUBTOTAL	-	$ -	-	$ (848,216.14)	-	$ -	-	$ 848,216.14	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(427,652)**	$ (3,929,290.24)	3,825,457	$ 121,453,270.45	(3,619,997)	$ (109,058,772.84)	-	$ 913,373.61	(633,112)	$ (17,237,161.46)	30,184	$ 914,622.09	-	$ (26,308.58)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	February 2019	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	(307,263)	$ (2,868,277.34)	3,456,935	$ 97,830,536.03	(3,279,730)	$ (88,401,792.49)			(484,468)	$ (12,297,020.88)				
5a	Day Ahead Non Asset Energy	(94,219)	$ (3,391,797.41)	-	$ -	(94,219)	$ (3,391,797.41)					25,046	$ 708,353.30	-	$ -
13a	Real Time Asset Energy	(2,940)	$ (137,365.80)	49,260	$ 1,318,007.39	18,848	$ (24,658.29)			(71,048)	$ (1,430,714.90)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(404,422)	$ (6,397,440.55)	3,506,195	$ 99,148,543.42	(3,355,101)	$ (91,818,248.19)	-	$ -	(555,516)	$ (13,727,735.78)	25,046	$ 708,353.30	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 7,326.99		$ 7,506.37		$ (179.38)								
14	Real Time Distribution Losses		$ (1,319,387.99)		$ -		$ (1,319,387.99)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,312,061.00)		$ 7,506.37		$ (1,319,567.37)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 551,980.86		$ 515,523.87		$ -		$ 36,456.99				$ 1,887.56		
19	Real Time Market Administration (Schedule 17)		$ 41,461.12		$ 36,049.66		$ -		$ 5,411.46				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 7,976.88		$ 7,976.88		$ -						$ 25.60		
33	Day-Ahead Schedule 24 Allocation Amount		$ 89,246.18		$ 83,339.22		$ -		$ 5,906.96				$ 305.48		
34	Real -Time Schedule 24 Allocation Amount		$ (74,893.62)		$ 12,022.89		$ -				$ (86,916.51)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 615,771.42		$ 654,912.52		$ -		$ 47,775.41		$ (86,916.51)		$ 2,218.64		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 29,647.58		$ 29,479.63		$ 167.95								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ 293,886.74		$ 2,170,797.79		$ (1,876,911.05)						$ 3,053.57		$ (39,995.65)
30	Financial Transmission Rights Monthly Allocation		$ (94,015.01)		$ -		$ (94,015.01)								$ (900.21)
32	Financial Transmission Rights Yearly Allocation		$ 1.07		$ 1.07		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (81,675.23)		$ -		$ (81,675.23)								$ (2,135.21)
37	Financial Transmission Rights Guarantee Uplift Amount		$ 102,923.50		$ 102,923.50		$ -						$ 2,146.40		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ (2,421.00)
	SUBTOTAL		$ 250,768.65		$ 2,303,201.99		$ (2,052,433.34)		$ -		$ -		$ 5,199.97		$ (45,452.07)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 98,781.00		$ 77,717.23				$ 21,063.77						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (70,178.46)				$ (34,832.10)				$ (35,346.36)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 216,975.93		$ 170,708.61				$ 46,267.32						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (3,473,889.70)				$ (790,364.59)				$ (2,683,525.11)				
43	Real Time Price Volatility Make Whole Payment		$ (94,587.85)		$ -		$(87,581.62)				$ (7,006.23)				
	SUBTOTAL		$ (3,322,899.08)		$ 248,425.84		$ (912,778.31)		$ 67,331.09		$ (2,725,877.70)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 79,180.60		$ 157,440.72		$ (68,592.00)				$ (9,668.12)		$ -		
21	Real Time Net Inadvertent Distribution		$ (133,686.51)		$ 17,867.62		$ (151,554.13)						$ 53.95		$ (369.59)
23	Real Time Revenue Neutrality Uplift Amount		$ 1,712,181.83		$ 1,484,122.70		$ (137,041.55)		$ 365,100.68						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 1,657,675.92		$ 1,659,431.04		$ (357,187.68)		$ 365,100.68		$ (9,668.12)		$ 53.95		$ (369.59)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,791,300.13		$ 1,832,066.26		$ (40,766.13)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,791,548.83)		$ 39,624.54		$ (1,772,435.05)				$ (58,738.32)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (156,670.33)		$ -		$ (156,670.33)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,379.47		$ 42,379.47		$ -								
	SUBTOTAL		$ (114,539.56)		$ 1,914,070.27		$ (1,969,871.51)		$ -		$ (58,738.32)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (29,647.58)		$ (167.95)		$ (29,479.63)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (7,326.99)		$ 179.38		$ (7,506.37)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ (36,974.57)	-	$ 11.43	-	$ (36,986.00)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(404,422)	$ (8,659,698.77)	3,506,195	$ 105,936,102.88	(3,355,101)	$ (98,467,072.40)	-	$ 480,207.18	(555,516)	$ (16,608,936.43)	25,046	$ 715,825.86	-	$ (45,821.66)
x	Net Congestion Amount		$ 1,016,483.28		$ 778,657.23				$ 237,826.05						
y	Net Loss Amount		$ 2,741,874.33		$ 2,144,297.75				$ 597,576.58						
z	Net Congestion and Loss Energy Offset		$ (3,758,357.61)		$ (3,758,357.61)										
	SUBTOTAL	-	$ -	-	$ (835,402.63)	-	$ -	-	$ 835,402.63	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(404,422)**	$ (8,659,698.77)	3,506,195	$ 105,100,700.25	(3,355,101)	$ (98,467,072.40)	-	$ 1,315,609.81	(555,516)	$ (16,608,936.43)	25,046	$ 715,825.86	-	$ (45,821.66)

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 2019	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	(222,863)	$ 719,099.76	3,489,816	$ 93,088,570.72	(3,227,201)	$ (80,525,993.33)			(485,478)	$ (11,843,477.63)				
5a	Day Ahead Non Asset Energy	(114,308)	$ (3,115,902.47)	59	$ 1,531.03	(114,367)	$ (3,117,433.50)					29,938	$ 774,398.77	-	$ -
13a	Real Time Asset Energy	(31,894)	$ (561,589.80)	49,285	$ 1,395,731.54	14,597	$ (85,570.94)			(95,776)	$ (1,871,750.40)				
22a	Real Time Non Asset Energy	-	$ (9.46)	-	$ 10.46	-	$ (19.92)					-	$ -	-	$ -
	SUBTOTAL	(369,065)	$ (2,958,401.97)	3,539,160	$ 94,485,843.75	(3,326,971)	$ (83,729,017.69)	-	$ -	(581,254)	$ (13,715,228.03)	29,938	$ 774,398.77	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 5,532.06		$ 5,778.93		$ (246.87)								
14	Real Time Distribution Losses		$ (793,578.25)		$ -		$ (793,578.25)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (788,046.19)		$ 5,778.93		$ (793,825.12)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 686,113.77		$ 640,430.97		$ -		$ 45,682.80				$ 2,803.90		
19	Real Time Market Administration (Schedule 17)		$ 56,279.14		$ 47,192.25		$ -		$ 9,086.89				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 28,312.64		$ 28,312.64		$ -						$ (0.00)		
33	Day-Ahead Schedule 24 Allocation Amount		$ 99,517.54		$ 92,905.12		$ -		$ 6,612.42				$ 408.70		
34	Real -Time Schedule 24 Allocation Amount		$ (84,071.29)		$ (15,456.36)		$ -				$ (68,614.93)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 786,151.80		$ 793,384.62		$ -		$ 61,382.11		$ (68,614.93)		$ 3,212.60		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 2,675.57		$ 5,266.87		$ (2,591.30)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (2,156,939.27)		$ 950,957.40		$ (3,107,896.67)						$ 0.18		$ (165.96)
30	Financial Transmission Rights Monthly Allocation		$ (112,020.04)		$ -		$ (112,020.04)								$ (2,096.42)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -								$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (58,051.82)		$ -		$ (58,051.82)								$ 2,262.20
37	Financial Transmission Guarantee Uplift Amount		$ 61,106.83		$ 61,106.83		$ -						$ (2,130.29)		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (2,263,228.73)		$ 1,017,331.10		$ (3,280,559.83)		$ -		$ -		$ (2,130.11)		$ (0.18)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 90,530.24		$ 76,193.79				$ 14,336.45						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (111,365.39)				$ (73,506.31)				$ (37,859.08)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 203,122.10		$ 170,955.49				$ 32,166.61						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (273,885.54)				$ (249,260.63)				$ (24,624.91)				
43	Real Time Price Volatility Make Whole Payment		$ (44,620.67)		$ -		($25,389.69)				$ (19,230.98)				
	SUBTOTAL		$ (136,219.26)		$ 247,149.28		$ (348,156.63)		$ 46,503.06		$ (81,714.97)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 155,888.03		$ 204,908.59		$ (38,316.57)				$ (10,703.99)		$ -		
21	Real Time Net Inadvertent Distribution		$ 97,293.07		$ 194,491.96		$ (97,198.89)						$ 714.20		$ (358.09)
23	Real Time Revenue Neutrality Uplift Amount		$ 249,977.97		$ 502,282.24		$ (291,891.02)		$ 39,586.75						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 503,159.07		$ 901,682.79		$ (427,406.48)		$ 39,586.75		$ (10,703.99)		$ 714.20		$ (358.09)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,547,181.68		$ 2,565,722.12		$ (18,540.44)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,571,169.74)		$ 17,946.42		$ (2,563,123.81)				$ (25,992.35)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (90,957.73)		$ -		$ (90,957.73)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 55,175.45		$ 55,175.45		$ -								
	SUBTOTAL		$ (59,770.34)		$ 2,638,843.99		$ (2,672,621.98)		$ -		$ (25,992.35)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (2,675.57)		$ 2,591.30		$ (5,266.87)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (5,532.06)		$ 246.87		$ (5,778.93)								
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	-	$ (8,207.63)	-	$ 2,838.17	-	$ (11,045.80)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(369,065)	$ (4,924,563.25)	3,539,160	$ 100,092,852.63	(3,326,971)	$ (91,262,633.53)	-	$ 147,471.92	(581,254)	$ (13,902,254.27)	29,938	$ 776,195.46	-	$ (358.27)
x	Net Congestion Amount		$ 2,608,341.23		$ 2,206,376.70				$ 401,964.53						
y	Net Loss Amount		$ 3,176,606.47		$ 2,690,051.81				$ 486,554.66						
z	Net Congestion and Loss Energy Offset		$ (5,784,947.70)		$ (5,784,947.70)										
	SUBTOTAL	-	$ -	-	$ (888,519.19)	-	$ -	-	$ 888,519.19	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(369,065)**	$ (4,924,563.25)	3,539,160	$ 99,204,333.44	(3,326,971)	$ (91,262,633.53)	-	$ 1,035,991.11	(581,254)	$ (13,902,254.27)	29,938	$ 776,195.46	-	$ (358.27)

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

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MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	April 2019	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	(62,070)	$ 2,379,111.64	3,124,208	$ 75,856,362.34	(2,872,299)	$ (66,109,450.91)			(313,979)	$ (7,367,799.79)				
5a	Day Ahead Non Asset Energy	(80,613)	$ (2,064,517.55)	59	$ 1,190.18	(80,672)	$ (2,065,707.73)					29,462	$ 722,158.72	-	$ -
13a	Real Time Asset Energy	(8,375)	$ 56,393.18	59,909	$ 1,588,427.94	27,271	$ 489,087.50			(95,555)	$ (2,021,122.26)				
22a	Real Time Non Asset Energy	268	$ 14,491.07	268	$ 14,491.09	-	$ (0.02)					-	$ -	-	$ -
	SUBTOTAL	(150,790)	$ 385,478.34	3,184,444	$ 77,460,471.55	(2,925,700)	$ (67,686,071.16)	-	$ -	(409,534)	$ (9,388,922.05)	29,462	$ 722,158.72	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 2,416.41		$ 3,038.39		$ (621.98)								
14	Real Time Distribution Losses		$ (675,750.58)		$ -		$ (675,750.58)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (673,334.17)		$ 3,038.39		$ (676,372.56)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 606,290.04		$ 576,431.59		$ -		$ 29,858.45				$ 2,792.79		
19	Real Time Market Administration (Schedule 17)		$ 58,805.28		$ 49,713.53		$ -		$ 9,091.75				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 40,536.92		$ 40,536.92		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 93,323.55		$ 88,647.03		$ -		$ 4,676.52				$ 429.96		
34	Real -Time Schedule 24 Allocation Amount		$ (80,695.07)		$ 21,339.77		$ -				$ (102,034.84)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 718,260.72		$ 776,668.84		$ -		$ 43,626.72		$ (102,034.84)		$ 3,222.75		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (329.13)		$ 3,227.72		$ (3,556.85)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (97,019.43)		$ 1,975,160.73		$ (2,072,180.16)						$ 0.11		$ (0.15)
30	Financial Transmission Rights Monthly Allocation		$ (83,667.83)		$ -		$ (83,667.83)								$ 0.04
32	Financial Transmission Rights Yearly Allocation		$ -		$ 86,475.54		$ (86,475.54)						$ 803.98		$ (803.98)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 30,592.69		$ 30,592.69		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (16,787.49)		$ -		$ (16,787.49)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (167,211.19)		$ 2,095,456.68		$ (2,262,667.87)		$ -		$ -		$ 804.09		$ (804.09)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 82,593.70		$ 72,962.40				$ 9,631.30						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (40,700.24)				$ (29,718.08)				$ (10,982.16)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 62,726.92		$ 55,412.30				$ 7,314.62						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (33,210.06)				$ (8,189.74)				$ (25,020.32)				
43	Real Time Price Volatility Make Whole Payment		$ (116,503.07)		$ -		($110,025.45)				$ (6,477.62)				
	SUBTOTAL		$ (45,092.75)		$ 128,374.70		$ (147,933.27)		$ 16,945.92		$ (42,480.10)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 192,235.93		$ 236,793.37		$ (34,198.74)				$ (10,358.70)		$ -		
21	Real Time Net Inadvertent Distribution		$ (120,804.06)		$ 37,575.96		$ (158,380.02)						$ 181.59		$ (609.90)
23	Real Time Revenue Neutrality Uplift Amount		$ 330,681.35		$ 598,767.57		$ (306,647.15)		$ 38,560.93						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 402,113.22		$ 873,136.90		$ (499,225.91)		$ 38,560.93		$ (10,358.70)		$ 181.59		$ (609.90)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,547,181.68		$ 2,565,722.12		$ (18,540.44)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,571,169.74)		$ 17,946.42		$ (2,565,123.81)				$ (23,992.35)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (90,957.87)		$ -		$ (90,957.87)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 55,175.45		$ 55,175.45		$ -								
	SUBTOTAL		$ (59,770.48)		$ 2,638,843.99		$ (2,674,622.12)		$ -		$ (23,992.35)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 329.13		$ 3,556.85		$ (3,227.72)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (2,416.41)		$ 621.98		$ (3,038.39)								
8	Day Ahead Congestion Rebate on Option B-Grandfathered														
9	Day Ahead Loss Rebate on Option B-Grandfathered														
17	Real Time Loss Rebate on Carve Out Grandfathered														
18	Real Time Congestion Rebate on Carve Out Grandfathered														
	SUBTOTAL	-	$ (2,087.28)	-	$ 4,178.83	-	$ (6,266.11)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(150,790)	$ 558,356.41	3,184,444	$ 83,980,169.88	(2,925,700)	$ (73,953,159.00)	-	$ 99,133.57	(409,534)	$ (9,567,788.04)	29,462	$ 726,367.15	-	$ (1,413.99)
x	Net Congestion Amount		$ 1,332,547.34		$ 1,250,513.16				$ 82,034.18						
y	Net Loss Amount		$ 2,143,359.09		$ 1,897,110.11				$ 246,248.98						
z	Net Congestion and Loss Energy Offset		$ (3,475,906.43)		$ (3,475,906.43)										
	SUBTOTAL	-	$ -	-	$ (328,283.16)	-	$ -	-	$ 328,283.16	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	(150,790)	$ 558,356.41	3,184,444	$ 83,651,886.73	(2,925,700)	$ (73,953,159.00)	-	$ 427,416.72	(409,534)	$ (9,567,788.04)	29,462	$ 726,367.15	-	$ (1,413.99)

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 2019	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	(716,690)	$ (10,792,774.27)	3,157,919	$ 68,273,964.33	(2,848,118)	$ (59,508,767.33)			#####	$ (19,557,971.27)				
5a	Day Ahead Non Asset Energy	(196,314)	$ (4,348,586.95)	85	$ 2,045.72	(196,399)	$ (4,350,632.67)					30,184	$ 644,299.96	-	$ -
13a	Real Time Asset Energy	(40,706)	$ (1,091,491.62)	49,029	$ 976,116.14	25,923	$ 28,951.03			(115,658)	$ (2,096,558.79)				
22a	Real Time Non Asset Energy	233	$ 4,880.57	233	$ 4,880.57	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(953,477)	$ (16,227,972.27)	3,207,266	$ 69,257,006.76	(3,018,594)	$ (63,830,448.97)	-	$ -	#####	$ (21,654,530.06)	30,184	$ 644,299.96	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (315.23)		$ 1,628.95		$ (1,944.18)								
14	Real Time Distribution Losses		$ (513,384.45)		$ -		$ (513,384.45)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (513,699.68)		$ 1,628.95		$ (515,328.63)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 682,972.06		$ 586,437.02		$ -		$ 96,535.04				$ 2,851.35		
19	Real Time Market Administration (Schedule 17)		$ 60,703.52		$ 47,704.49		$ -		$ 12,999.03				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 32,748.81		$ 32,748.81		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 98,029.65		$ 87,725.59		$ -		$ 10,304.06				$ 409.65		
34	Real -Time Schedule 24 Allocation Amount		$ (79,433.57)		$ (7,531.64)		$ -				$ (71,901.93)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 795,020.47		$ 747,084.27		$ -		$ 119,838.13		$ (71,901.93)		$ 3,261.00		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (10,982.49)		$ 3,105.97		$ (14,088.46)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,259,506.68)		$ 655,027.41		$ (1,914,534.09)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (150,543.49)		$ -		$ (150,543.49)								$ (0.08)
32	Financial Transmission Rights Yearly Allocation		$ -		$ 183,852.80		$ (183,852.80)						$ 1,573.20		$ (1,573.20)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (23,950.27)		$ -		$ (23,950.27)								$ 0.08
37	Financial Transmission Guarantee Uplift Amount		$ 6,700.83		$ 6,700.83		$ -						$ (0.13)		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,438,282.10)		$ 848,687.01		$ (2,286,969.11)		$ -		$ -		$ 1,573.07		$ (1,573.20)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 79,507.00		$ 57,886.24				$ 21,620.76						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (92,547.73)				$ (35,584.03)				$ (56,963.70)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 143,230.20		$ 104,280.85				$ 38,949.35						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (15,698.46)				$ (44,981.22)				$ 29,282.76				
43	Real Time Price Volatility Make Whole Payment		$ (56,103.03)		$ -		($41,980.92)				$ (14,122.11)				
	SUBTOTAL		$ 58,387.98		$ 162,167.09		$ (122,546.17)		$ 60,570.11		$ (41,803.05)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ (116,506.77)		$ 283,992.50		$ (389,795.28)				$ (10,703.99)		$ -		
21	Real Time Net Inadvertent Distribution		$ 147.75		$ 46,398.94		$ (46,251.19)						$ 184.64		$ (178.10)
23	Real Time Revenue Neutrality Uplift Amount		$ 463,508.81		$ 498,051.56		$ (160,587.16)		$ 126,044.41						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 347,149.79		$ 828,443.00		$ (596,633.63)		$ 126,044.41		$ (10,703.99)		$ 184.64		$ (178.10)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,547,181.68		$ 2,565,722.12		$ (18,540.44)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,571,169.74)		$ 17,946.42		$ (2,563,947.00)				$ (25,169.16)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (90,957.87)		$ -		$ (90,957.87)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 55,175.45		$ 55,175.45		$ -								
	SUBTOTAL		$ (59,770.48)		$ 2,638,843.99		$ (2,673,445.31)		$ -		$ (25,169.16)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 10,982.49		$ 14,088.46		$ (3,105.97)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 315.23		$ 1,944.18		$ (1,628.95)								
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	-	$ 11,297.72	-	$ 16,032.64	-	$ (4,734.92)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(953,477)	$ (17,027,868.57)	3,207,266	$ 74,499,893.71	(3,018,594)	$ (70,030,106.74)	-	$ 306,452.65	#####	$ (21,804,108.19)	30,184	$ 649,318.67	-	$ (1,751.30)
x	Net Congestion Amount		$ 1,534,789.05		$ 1,170,809.18				$ 363,979.87						
y	Net Loss Amount		$ 2,293,345.88		$ 1,724,480.46				$ 568,865.42						
z	Net Congestion and Loss Energy Offset		$ (3,828,134.93)		$ (3,828,134.93)										
	SUBTOTAL	-	$ -	-	$ (932,845.29)	-	$ -	-	$ 932,845.29	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(953,477)**	$ (17,027,868.57)	3,207,266	$ 73,567,048.42	(3,018,594)	$ (70,030,106.74)	-	$ 1,239,297.94	#####	$ (21,804,108.19)	30,184	$ 649,318.67	-	$ (1,751.30)

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

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Schedule 15

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

June 2019		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	(739,084)	$ (12,005,283.89)	3,481,277	$ 72,973,217.45	(3,467,856)	$ (67,391,153.02)			(752,505)	$ (17,587,348.32)				
5a	Day Ahead Non Asset Energy	(177,915)	$ (3,657,411.01)	53	$ 1,163.59	(177,968)	$ (3,658,574.60)					28,880	$ 586,618.69	-	$ -
13a	Real Time Asset Energy	(48,874)	$ (1,061,852.95)	54,682	$ 1,129,537.43	(4,610)	$ (406,512.98)			(98,946)	$ (1,784,877.40)				
22a	Real Time Non Asset Energy	747	$ 12,909.93	747	$ 12,909.93	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(965,126)	$ (16,711,637.92)	3,536,759	$ 74,116,828.40	(3,650,434)	$ (71,456,240.60)	-	$ -	(851,451)	$ (19,372,225.72)	28,880	$ 586,618.69	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,320.69)		$ 138.00		$ (2,458.69)								
14	Real Time Distribution Losses		$ (650,316.74)		$ -		$ (650,316.74)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (652,637.43)		$ 138.00		$ (652,775.43)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 876,227.03		$ 790,087.98		$ -		$ 86,139.05				$ 3,208.96		
19	Real Time Market Administration (Schedule 17)		$ 65,146.30		$ 56,175.97		$ -		$ 8,970.33				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 43,186.77		$ 43,186.77		$ -						$ 275.20		
33	Day-Ahead Schedule 24 Allocation Amount		$ 93,765.32		$ 81,640.08		$ -		$ 12,125.24				$ 341.60		
34	Real -Time Schedule 24 Allocation Amount		$ (82,229.02)		$ 19,733.16		$ -				$ (101,962.18)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 996,096.40		$ 990,823.96		$ -		$ 107,234.62		$ (101,962.18)		$ 3,825.76		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (8,228.23)		$ 459.74		$ (8,687.97)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,129,744.04)		$ 414,197.39		$ (1,543,941.43)						$ 22,772.23		$ (11,117.48)
30	Financial Transmission Rights Monthly Allocation		$ (38,352.60)		$ -		$ (38,352.60)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ 177,599.95		$ (177,599.95)						$ 1,559.49		$ (1,559.49)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (66,727.21)		$ -		$ (66,727.21)								$ (1,418.75)
37	Financial Transmission Guarantee Uplift Amount		$ 51,872.13		$ 51,872.13		$ -						$ 1,155.31		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ (2,480.00)
	SUBTOTAL		$ (1,191,179.95)		$ 644,129.21		$ (1,835,309.16)		$ -		$ -		$ 25,487.03		$ (16,575.72)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 63,219.85		$ 49,657.26				$ 13,562.59						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (62,870.47)				$ (30,092.82)				$ (32,777.65)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 146,536.63		$ 115,100.04				$ 31,436.59						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (37,234.01)				$ (4,312.11)				$ (32,921.90)				
43	Real Time Price Volatility Make Whole Payment		$ (40,310.38)		$ -		($27,855.46)				$ (12,454.92)				
	SUBTOTAL		$ 69,341.62		$ 164,757.29		$ (62,260.39)		$ 44,999.19		$ (78,154.47)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 212,493.08		$ 246,382.38		$ (21,995.20)				$ (11,894.10)		$ -		
21	Real Time Net Inadvertent Distribution		$ 43,454.12		$ 59,699.37		$ (16,245.25)						$ 213.72		$ (62.56)
23	Real Time Revenue Neutrality Uplift Amount		$ 158,851.88		$ 506,124.70		$ (381,351.41)		$ 34,078.59						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 414,799.08		$ 812,206.45		$ (419,591.86)		$ 34,078.59		$ (11,894.10)		$ 213.72		$ (62.56)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,805,216.47		$ 1,836,859.23		$ (31,642.76)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,805,445.07)		$ 27,446.07		$ (1,824,098.34)				$ (8,792.80)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (202,033.21)		$ -		$ (202,033.21)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,882.21		$ 25,882.21		$ -								
	SUBTOTAL		$ (176,379.60)		$ 1,890,187.51		$ (2,057,774.31)		$ -		$ (8,792.80)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,228.23		$ 8,687.97		$ (459.74)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,320.69		$ 2,458.69		$ (138.00)								
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	-	$ 10,548.92	-	$ 11,146.66	-	$ (597.74)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(965,126)	$ (17,241,048.88)	3,536,759	$ 78,630,217.48	(3,650,434)	$ (76,484,549.49)	-	$ 186,312.40	(851,451)	$ (19,573,029.27)	28,880	$ 616,145.20	-	$ (16,638.28)
x	Net Congestion Amount		$ 1,187,074.85		$ 969,433.97				$ 217,640.88						
y	Net Loss Amount		$ 2,407,282.37		$ 1,879,998.91				$ 527,283.46						
z	Net Congestion and Loss Energy Offset		$ (3,594,357.22)		$ (3,594,357.22)										
	SUBTOTAL	-	$ -	-	$ (744,924.34)	-	$ -	-	$ 744,924.34	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(965,126)**	$ (17,241,048.88)	3,536,759	$ 77,885,293.15	(3,650,434)	$ (76,484,549.49)	-	$ 931,236.73	(851,451)	$ (19,573,029.27)	28,880	$ 616,145.20	-	$ (16,638.28)

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

Docker No. E999/AA-20-171
Part J, Section 5
Schedule 15

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	July 2019	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	(615,403)	$ (6,432,928.72)	4,160,264	$ 106,949,375.03	(3,965,407)	$ (93,773,895.59)			(810,260)	$ (19,608,408.16)				
5a	Day Ahead Non Asset Energy	(196,406)	$ (4,441,691.38)	-	$ -	(196,406)	$ (4,441,691.38)					30,184	$ 740,128.10	-	$ -
13a	Real Time Asset Energy	(34,827)	$ (924,933.73)	83,806	$ 1,996,404.40	(36,113)	$ (1,025,008.37)			(82,520)	$ (1,896,329.76)				
22a	Real Time Non Asset Energy	338	$ 6,857.80	338	$ 6,857.83	-	$ (0.03)					-	$ -	-	$ -
	SUBTOTAL	(846,298)	$ (11,792,696.03)	4,244,408	$ 108,952,637.26	(4,197,926)	$ (99,240,595.37)	-	$ -	(892,780)	$ (21,504,737.92)	30,184	$ 740,128.10	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (3,035.09)		$ 417.10		$ (3,452.19)								
14	Real Time Distribution Losses		$ (1,175,922.23)		$ -		$ (1,175,922.23)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (1,178,957.32)		$ 417.10		$ (1,179,374.42)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 695,556.87		$ 633,503.57		$ -		$ 62,053.30				$ 2,296.92		
19	Real Time Market Administration (Schedule 17)		$ 53,676.55		$ 47,424.20		$ -		$ 6,252.35				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 27,042.60		$ 27,042.60		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 105,021.95		$ 95,698.36		$ -		$ 9,323.59				$ 346.08		
34	Real -Time Schedule 24 Allocation Amount		$ (93,659.66)		$ (1,611.96)		$ -				$ (92,047.70)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 787,638.31		$ 802,056.77		$ -		$ 77,629.24		$ (92,047.70)		$ 2,643.00		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 10,844.82		$ 21,755.53		$ (10,910.71)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (4,460,660.10)		$ 1,219,612.99		$ (5,680,273.09)						$ 0.09		$ (135.54)
30	Financial Transmission Rights Monthly Allocation		$ (137,857.43)		$ -		$ (137,857.43)								$ (429.85)
32	Financial Transmission Rights Yearly Allocation		$ -		$ 181,439.35		$ (181,439.35)						$ 1,523.15		$ (1,523.15)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (264,018.18)		$ -		$ (264,018.18)								$ 565.30
37	Financial Transmission Guarantee Uplift Amount		$ 194,543.93		$ 194,543.93		$ -						$ (481.26)		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (4,657,146.96)		$ 1,617,351.80		$ (6,274,498.76)		$ -		$ -		$ 1,041.98		$ (1,523.24)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 55,978.72		$ 45,974.92				$ 10,003.80						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (18,013.28)				$ (8,673.33)				$ (9,339.95)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 148,671.41		$ 122,102.75				$ 26,568.66						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (72,706.96)				$ (50,855.09)				$ (21,851.87)				
43	Real Time Price Volatility Make Whole Payment		$ (62,129.15)		$ -		($50,630.07)				$ (11,499.08)				
	SUBTOTAL		$ 51,800.74		$ 168,077.66		$ (110,158.49)		$ 36,572.47		$ (42,690.90)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 170,484.76		$ 207,936.94		$ (25,161.61)				$ (12,290.57)		$ -		
21	Real Time Net Inadvertent Distribution		$ (2,930.86)		$ 36,571.41		$ (39,502.27)						$ 115.20		$ (131.94)
23	Real Time Revenue Neutrality Uplift Amount		$ 467,688.86		$ 578,363.26		$ (194,253.80)		$ 83,579.40						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 635,242.76		$ 822,871.61		$ (258,917.68)		$ 83,579.40		$ (12,290.57)		$ 115.20		$ (131.94)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,805,216.47		$ 1,836,859.23		$ (31,642.76)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,805,445.07)		$ 27,446.07		$ (1,823,821.43)				$ (9,069.71)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (204,112.67)		$ -		$ (204,112.67)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,882.21		$ 25,882.21		$ -								
	SUBTOTAL		$ (178,459.06)		$ 1,890,187.51		$ (2,059,576.86)		$ -		$ (9,069.71)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (10,844.82)		$ 10,910.71		$ (21,755.53)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 3,035.09		$ 3,452.19		$ (417.10)								
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	-	$ (7,809.73)	-	$ 14,362.90	-	$ (22,172.63)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(846,298)	$ (16,340,387.29)	4,244,408	$ 114,267,962.62	(4,197,926)	$ (109,145,294.21)	-	$ 197,781.10	(892,780)	$ (21,660,836.80)	30,184	$ 743,928.28	-	$ (1,655.18)
x	Net Congestion Amount		$ 5,124,177.27		$ 4,320,526.16				$ 803,651.11						
y	Net Loss Amount		$ 3,599,988.13		$ 3,004,351.19				$ 595,636.94						
z	Net Congestion and Loss Energy Offset		$ (8,724,165.40)		$ (8,724,165.40)										
	SUBTOTAL	-	$ -	-	$ (1,399,288.06)	-	$ -	-	$ 1,399,288.06	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(846,298)**	$ (16,340,387.29)	4,244,408	$ 112,868,674.56	(4,197,926)	$ (109,145,294.21)	-	$ 1,597,069.16	(892,780)	$ (21,660,836.80)	30,184	$ 743,928.28	-	$ (1,655.18)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	August 2019	NET INVOICE		RETAIL				INTERSYSTEM - ASSET BASED				INTERSYSTEM - NON-ASSET BASED			
	Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Day Ahead & Real Time Energy														
1a	Day Ahead Asset Energy	(561,078)	$ (6,657,715.72)	3,819,030	$ 86,746,176.22	(3,645,852)	$ (76,999,303.38)			(734,256)	$ (16,404,588.56)				
5a	Day Ahead Non Asset Energy	(191,817)	$ (3,769,446.95)	70	$ 1,356.15	(191,887)	$ (3,770,803.10)					30,184	$ 660,810.61	-	$ -
13a	Real Time Asset Energy	(43,823)	$ (919,780.29)	53,470	$ 1,140,353.89	(26,535)	$ (725,986.20)			(70,758)	$ (1,334,147.98)				
22a	Real Time Non Asset Energy	1,319	$ (111,766.74)	1,319	$ (111,766.73)	-	$ (0.01)					-	$ -	-	$ -
	SUBTOTAL	(795,399)	$ (11,458,709.70)	3,873,889	$ 87,776,119.53	(3,864,274)	$ (81,496,092.69)	-	$ -	(805,014)	$ (17,738,736.54)	30,184	$ 660,810.61	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (2,674.69)		$ 267.69		$ (2,942.38)								
14	Real Time Distribution Losses		$ (863,775.46)		$ -		$ (863,775.46)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (866,450.15)		$ 267.69		$ (866,717.84)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 400,654.06		$ 365,442.77		$ -		$ 35,211.29				$ 1,439.17		
19	Real Time Market Administration (Schedule 17)		$ 25,046.11		$ 21,828.23		$ -		$ 3,217.88				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 10,435.94		$ 10,435.94		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 93,136.38		$ 84,975.72		$ -		$ 8,160.66				$ 335.12		
34	Real -Time Schedule 24 Allocation Amount		$ (84,546.43)		$ 21,449.69		$ -				$ (105,996.12)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 444,726.06		$ 504,132.35		$ -		$ 46,589.83		$ (105,996.12)		$ 1,774.29		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 7,536.97		$ 8,673.39		$ (1,136.42)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (3,699,105.15)		$ 482,104.06		$ (4,181,209.21)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (200,076.68)		$ -		$ (200,076.68)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ 289,949.73		$ (289,949.73)						$ 1,286.80		$ (1,286.80)
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (174,203.01)		$ -		$ (174,203.01)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 267,173.35		$ 267,173.35		$ -						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (3,798,674.52)		$ 1,047,900.53		$ (4,846,575.05)		$ -		$ -		$ 1,286.80		$ (1,286.80)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 60,391.61		$ 49,004.01				$ 11,387.60						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (22,016.00)				$ (8,134.00)				$ (13,882.00)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 88,903.98		$ 72,140.01				$ 16,763.97						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (38,242.65)				$ (11,250.18)				$ (26,992.47)				
43	Real Time Price Volatility Make Whole Payment		$ (128,885.19)		$ -		($113,302.03)				$ (15,583.16)				
	SUBTOTAL		$ (39,848.25)		$ 121,144.02		$ (132,686.21)		$ 28,151.57		$ (56,457.63)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 135,961.02		$ 172,360.15		$ (23,763.27)				$ (12,635.86)		$ -		
21	Real Time Net Inadvertent Distribution		$ 74,327.00		$ 112,596.86		$ (38,269.86)						$ 372.19		$ (127.30)
23	Real Time Revenue Neutrality Uplift Amount		$ 372,318.76		$ 480,876.83		$ (178,763.47)		$ 70,205.40						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 582,606.78		$ 765,833.84		$ (240,796.60)		$ 70,205.40		$ (12,635.86)		$ 372.19		$ (127.30)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,805,216.47		$ 1,836,859.23		$ (31,642.76)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,805,445.07)		$ 27,446.07		$ (1,825,583.30)				$ (7,307.84)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (203,055.76)		$ -		$ (203,055.76)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 25,882.21		$ 25,882.21		$ -								
	SUBTOTAL		$ (177,402.15)		$ 1,890,187.51		$ (2,060,281.82)		$ -		$ (7,307.84)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (7,536.97)		$ 1,136.42		$ (8,673.39)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,674.69		$ 2,942.38		$ (267.69)								
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	-	$ (4,862.28)	-	$ 4,078.80	-	$ (8,941.08)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(795,399)	$ (15,318,614.21)	3,873,889	$ 92,109,664.27	(3,864,274)	$ (89,652,091.29)	-	$ 144,946.80	(805,014)	$ (17,921,133.99)	30,184	$ 664,243.89	-	$ (1,414.10)
x	Net Congestion Amount		$ 3,298,387.70		$ 2,673,439.40				$ 624,948.30						
y	Net Loss Amount		$ 2,899,215.04		$ 2,382,790.94				$ 516,424.10						
z	Net Congestion and Loss Energy Offset		$ (6,197,602.74)		$ (6,197,602.74)										
	SUBTOTAL	-	$ -	-	$ (1,141,372.41)	-	$ -	-	$ 1,141,372.41	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(795,399)**	$ (15,318,614.21)	3,873,889	$ 90,968,291.87	(3,864,274)	$ (89,652,091.29)	-	$ 1,286,319.20	(805,014)	$ (17,921,133.99)	30,184	$ 664,243.89	-	$ (1,414.10)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	September 2019	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	(610,732)	$ (7,242,837.44)	3,398,069	$ 69,517,822.16	(3,227,504)	$ (60,522,661.48)			(781,297)	$ (16,237,998.12)				
5a	Day Ahead Non Asset Energy	(179,618)	$ (3,784,896.51)	66	$ 1,607.49	(179,684)	$ (3,786,504.00)					28,880	$ 574,721.40	-	$ -
13a	Real Time Asset Energy	(41,547)	$ (500,618.71)	47,393	$ 1,112,437.32	(24,248)	$ (434,039.36)			(64,692)	$ (1,179,016.67)				
22a	Real Time Non Asset Energy	12	$ -	12	$ 106.99	-	$ (106.99)					-	$ -	-	$ -
	SUBTOTAL	(831,885)	$ (11,528,352.66)	3,445,540	$ 70,631,973.96	(3,431,436)	$ (64,743,311.83)	-	$ -	(845,989)	$ (17,417,014.79)	28,880	$ 574,721.40	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (5,214.50)		$ (9.62)		$ (5,204.88)								
14	Real Time Distribution Losses		$ (805,409.36)		$ -		$ (805,409.36)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (810,623.86)		$ (9.62)		$ (810,614.24)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 592,456.64		$ 531,578.75		$ -		$ 60,877.89				$ 2,250.84		
19	Real Time Market Administration (Schedule 17)		$ 47,334.67		$ 42,336.42		$ -		$ 4,998.25				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 28,566.79		$ 28,566.79		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 90,286.38		$ 80,986.32		$ -		$ 9,300.06				$ 341.60		
34	Real -Time Schedule 24 Allocation Amount		$ (83,068.01)		$ (665.77)		$ -				$ (82,402.24)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 675,576.47		$ 682,802.51		$ -		$ 75,176.20		$ (82,402.24)		$ 2,592.44		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (6,828.80)		$ 1,781.95		$ (8,610.75)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,525,831.06)		$ 599,366.42		$ (2,125,197.48)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (63,914.41)		$ -		$ (63,914.41)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 30,121.26		$ 30,121.26		$ -								$ -
37	Financial Transmission Guarantee Uplift Amount		$ (47,374.50)		$ -		$ (47,374.50)						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,613,827.51)		$ 631,269.63		$ (2,245,097.14)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 54,807.01		$ 44,109.78				$ 10,697.23						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (142,948.39)				$ (70,861.95)				$ (72,086.44)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 56,155.10		$ 45,194.75				$ 10,960.35						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (83,337.48)				$ (68,714.77)				$ (14,622.71)				
43	Real Time Price Volatility Make Whole Payment		$ (87,380.70)		$ -		($65,161.69)				$ (22,219.01)				
	SUBTOTAL		$ (202,704.46)		$ 89,304.54		$ (204,738.41)		$ 21,657.57		$ (108,928.16)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 254,600.65		$ 282,805.38		$ (16,310.63)				$ (11,894.10)		$ 30.37		
21	Real Time Net Inadvertent Distribution		$ 15,768.18		$ 89,368.00		$ (73,599.82)						$ 326.28		$ (265.10)
23	Real Time Revenue Neutrality Uplift Amount		$ 71,452.24		$ 362,495.67		$ (304,989.47)		$ 13,946.04						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 341,821.07		$ 734,669.05		$ (394,899.92)		$ 13,946.04		$ (11,894.10)		$ 356.65		$ (265.10)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,337,779.21		$ 1,385,437.61		$ (47,658.40)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,340,179.39)		$ 44,530.04		$ (1,382,885.39)				$ (1,824.04)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (198,269.67)		$ -		$ (198,269.67)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 59,727.45		$ 59,727.45		$ -								
	SUBTOTAL		$ (140,942.40)		$ 1,489,695.10		$ (1,628,813.46)		$ -		$ (1,824.04)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 6,828.80		$ 8,610.75		$ (1,781.95)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 5,214.50		$ 5,204.88		$ 9.62								
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	-	$ 12,043.30	-	$ 13,815.63	-	$ (1,772.33)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(831,885)	$ (13,267,010.05)	3,445,540	$ 74,273,520.79	(3,431,436)	$ (70,029,247.33)	-	$ 110,779.82	(845,989)	$ (17,622,063.33)	28,880	$ 577,670.49	-	$ (265.10)
x	Net Congestion Amount		$ 2,757,598.17		$ 2,316,414.84				$ 441,183.33						
y	Net Loss Amount		$ 2,700,880.77		$ 2,235,208.05				$ 465,672.72						
z	Net Congestion and Loss Energy Offset		$ (5,458,478.94)		$ (5,458,478.94)										
	SUBTOTAL	-	$ -	-	$ (906,856.06)	-	$ -	-	$ 906,856.06	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(831,885)**	$ (13,267,010.05)	3,445,540	$ 73,366,664.74	(3,431,436)	$ (70,029,247.33)	-	$ 1,017,635.87	(845,989)	$ (17,622,063.33)	28,880	$ 577,670.49	-	$ (265.10)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

	October 2019	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	(496,198)	$ (4,509,134.38)	3,199,440	$ 61,946,143.64	(3,062,326)	$ (54,013,871.53)			(633,312)	$ (12,441,406.49)				
5a	Day Ahead Non Asset Energy	(123,906)	$ (2,364,316.52)	-	$ -	(123,906)	$ (2,364,316.52)					30,440	$ 585,180.35	-	$ -
13a	Real Time Asset Energy	1,852	$ 191,921.51	57,333	$ 1,137,838.16	23,387	$ 508,065.48			(78,868)	$ (1,453,982.13)				
22a	Real Time Non Asset Energy	2,896	$ 69,976.60	4,085	$ 93,939.51	(1,189)	$ (23,962.91)					-	$ -	-	$ -
	SUBTOTAL	(615,356)	$ (6,611,552.79)	3,260,858	$ 63,177,921.31	(3,164,034)	$ (55,894,085.48)	-	$ -	(712,180)	$ (13,895,388.62)	30,440	$ 585,180.35	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (958.82)		$ 727.40		$ (1,686.22)								
14	Real Time Distribution Losses		$ (518,123.61)		$ -		$ (518,123.61)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (519,082.43)		$ 727.40		$ (519,809.83)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 687,978.31		$ 626,061.42		$ -		$ 61,916.89				$ 2,980.22		
19	Real Time Market Administration (Schedule 17)		$ 63,928.30		$ 56,225.42		$ -		$ 7,702.88				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 23,921.89		$ 23,921.89		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 86,324.07		$ 78,535.93		$ -		$ 7,788.14				$ 374.96		
34	Real -Time Schedule 24 Allocation Amount		$ (78,878.80)		$ 10,292.03		$ -				$ (89,170.83)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 783,273.77		$ 795,036.69		$ -		$ 77,407.91		$ (89,170.83)		$ 3,355.18		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ (7,592.48)		$ 4,328.51		$ (11,920.99)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (426,804.42)		$ 911,361.73		$ (1,338,166.15)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (37,459.02)		$ -		$ (37,459.02)								$ (0.06)
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (11,499.97)		$ -		$ (11,499.97)								$ 0.06
37	Financial Transmission Guarantee Uplift Amount		$ 29,504.90		$ 29,504.90		$ -						$ (0.15)		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (453,850.99)		$ 945,195.14		$ (1,399,046.13)		$ -		$ -		$ (0.15)		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 83,205.81		$ 68,077.59				$ 15,128.22						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (182,534.20)				$ (80,976.91)				$ (101,557.29)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 82,118.79		$ 67,188.21				$ 14,930.58						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (52,982.12)				$ (18,612.47)				$ (34,369.65)				
43	Real Time Price Volatility Make Whole Payment		$ (76,259.32)		$ -		($58,376.14)				$ (17,883.18)				
	SUBTOTAL		$ (146,451.04)		$ 135,265.79		$ (157,965.52)		$ 30,058.81		$ (153,810.12)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 219,979.75		$ 253,209.64		$ (20,939.32)				$ (12,290.57)		$ -		
21	Real Time Net Inadvertent Distribution		$ 14,735.95		$ 94,019.62		$ (79,283.67)						$ 369.17		$ (269.69)
23	Real Time Revenue Neutrality Uplift Amount		$ 517,573.18		$ 880,255.12		$ (456,785.49)		$ 94,103.55						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 752,288.88		$ 1,227,484.38		$ (557,008.48)		$ 94,103.55		$ (12,290.57)		$ 369.17		$ (269.69)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,337,779.21		$ 1,385,437.61		$ (47,658.40)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,340,179.39)		$ 44,530.04		$ (1,382,928.23)				$ (1,781.20)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (198,206.91)		$ -		$ (198,206.91)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 59,727.45		$ 59,727.45		$ -								
	SUBTOTAL		$ (140,879.64)		$ 1,489,695.10		$ (1,628,793.54)		$ -		$ (1,781.20)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 7,592.48		$ 11,920.99		$ (4,328.51)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 958.82		$ 1,686.22		$ (727.40)								
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	-	$ 8,551.30	-	$ 13,607.21	-	$ (5,055.91)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(615,356)	$ (6,327,702.94)	3,260,858	$ 67,784,933.02	(3,164,034)	$ (60,161,764.89)	-	$ 201,570.27	(712,180)	$ (14,152,441.34)	30,440	$ 588,904.55	-	$ (269.69)
x	Net Congestion Amount		$ 2,962,301.21		$ 2,551,323.52				$ 410,977.69						
y	Net Loss Amount		$ 2,338,370.37		$ 1,904,579.95				$ 433,790.42						
z	Net Congestion and Loss Energy Offset		$ (5,300,671.58)		$ (5,300,671.58)										
	SUBTOTAL	-	$ -	-	$ (844,768.11)	-	$ -	-	$ 844,768.11	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(615,356)**	$ (6,327,702.94)	3,260,858	$ 66,940,164.91	(3,164,034)	$ (60,161,764.89)	-	$ 1,046,338.38	(712,180)	$ (14,152,441.34)	30,440	$ 588,904.55	-	$ (269.69)

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

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - DETAIL

November 2019		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	(623,796)	$ (9,749,630.52)	3,085,893	$ 69,455,869.17	(2,981,790)	$ (62,662,124.48)			(727,899)	$ (16,543,375.21)				
5a	Day Ahead Non Asset Energy	(93,366)	$ (2,189,857.10)	31	$ 494.45	(93,397)	$ (2,190,351.55)					26,642	$ 588,958.24	-	$ -
13a	Real Time Asset Energy	(13,300)	$ (319,038.63)	54,808	$ 1,183,221.47	78,281	$ 1,605,907.24			(146,389)	$ (3,108,167.34)				
22a	Real Time Non Asset Energy	-	$ 77.87	-	$ 77.89	-	$ (0.02)					-	$ -	-	$ -
	SUBTOTAL	(730,462)	$ (12,258,448.38)	3,140,732	$ 70,639,662.98	(2,996,906)	$ (63,246,568.81)	-	$ -	(874,288)	$ (19,651,542.55)	26,642	$ 588,958.24	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ (63.64)		$ 1,047.26		$ (1,110.90)								
14	Real Time Distribution Losses		$ (657,043.93)		$ -		$ (657,043.93)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (657,107.57)		$ 1,047.26		$ (658,154.83)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 607,514.50		$ 543,246.51		$ -		$ 64,267.99				$ 2,348.85		
19	Real Time Market Administration (Schedule 17)		$ 60,308.87		$ 47,484.92		$ -		$ 12,823.95				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 19,570.56		$ 19,570.56		$ -						$ -		
33	Day-Ahead Schedule 24 Allocation Amount		$ 84,740.12		$ 75,780.29		$ -		$ 8,959.83				$ 328.44		
34	Real -Time Schedule 24 Allocation Amount		$ (74,091.80)		$ 7,768.95		$ -				$ (81,860.75)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 698,042.25		$ 693,851.23		$ -		$ 86,051.77		$ (81,860.75)		$ 2,677.29		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 1,906.58		$ 5,510.42		$ (3,603.84)								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (1,169,823.12)		$ 540,829.40		$ (1,710,652.52)						$ -		$ -
30	Financial Transmission Rights Monthly Allocation		$ (42,276.61)		$ -		$ (42,276.61)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (68,725.91)		$ -		$ (68,725.91)								$ -
37	Financial Transmission Guarantee Uplift Amount		$ 73,143.23		$ 73,143.23		$ -						$ -		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ -		$ -
	SUBTOTAL		$ (1,205,775.83)		$ 619,483.05		$ (1,825,258.88)		$ -		$ -		$ -		$ -
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 66,452.30		$ 80,366.86				$ (13,914.56)						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (107,080.46)				$ (48,939.37)				$ (58,141.09)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 82,598.89		$ 99,894.41				$ (17,295.52)						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (108,771.54)				$ (52,372.64)				$ (56,398.90)				
43	Real Time Price Volatility Make Whole Payment		$ (47,620.76)		$ -		($37,335.65)				$ (10,285.11)				
	SUBTOTAL		$ (114,421.57)		$ 180,261.28		$ (138,647.66)		$ (31,210.09)		$ (124,825.10)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 606,534.59		$ 631,390.22		$ (12,961.53)				$ (11,894.10)		$ -		
21	Real Time Net Inadvertent Distribution		$ 22,346.64		$ 63,648.67		$ (41,302.03)						$ 214.46		$ (143.82)
23	Real Time Revenue Neutrality Uplift Amount		$ (70,454.99)		$ 376,812.41		$ (462,020.09)		$ 14,752.69						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 558,426.24		$ 1,071,851.30		$ (516,283.65)		$ 14,752.69		$ (11,894.10)		$ 214.46		$ (143.82)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,337,779.21		$ 1,385,437.61		$ (47,658.40)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,340,179.39)		$ 44,530.04		$ (1,382,814.26)				$ (1,895.17)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (198,218.84)		$ -		$ (198,218.84)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 59,727.45		$ 59,727.45		$ -								
	SUBTOTAL		$ (140,891.57)		$ 1,489,695.10		$ (1,628,691.50)		$ -		$ (1,895.17)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (1,906.58)		$ 3,603.84		$ (5,510.42)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 63.64		$ 1,110.90		$ (1,047.26)								
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	-	$ (1,842.94)	-	$ 4,714.74	-	$ (6,557.68)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(730,462)	$ (13,122,019.37)	3,140,732	$ 74,700,566.93	(2,996,906)	$ (68,020,163.01)	-	$ 69,594.38	(874,288)	$ (19,872,017.67)	26,642	$ 591,849.99	-	$ (143.82)
x	Net Congestion Amount		$ 2,185,506.66		$ 2,604,231.31				$ (418,724.65)						
y	Net Loss Amount		$ 2,681,143.55		$ 3,232,499.83				$ (551,356.28)						
z	Net Congestion and Loss Energy Offset		$ (4,866,650.21)		$ (4,866,650.21)										
	SUBTOTAL	-	$ -	-	$ 970,080.93	-	$ -	-	$ (970,080.93)	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(730,462)**	$ (13,122,019.37)	3,140,732	$ 75,670,647.86	(2,996,906)	$ (68,020,163.01)	-	$ (900,486.55)	(874,288)	$ (19,872,017.67)	26,642	$ 591,849.99	-	$ (143.82)

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

	December 2019	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	(605,321)	$ (7,864,369.28)	3,793,208	$ 78,721,610.97	(3,659,076)	$ (71,219,146.51)			(739,453)	$ (15,366,833.74)				
5a	Day Ahead Non Asset Energy	(112,355)	$ (2,558,953.00)	57	$ 1,219.85	(112,412)	$ (2,560,172.85)					32,176	$ 658,244.93	-	$ -
13a	Real Time Asset Energy	6,471	$ 126,724.71	74,873	$ 1,455,247.79	37,204	$ 308,778.48			(105,606)	$ (1,637,301.56)				
22a	Real Time Non Asset Energy	-	$ -	-	$ -	-	$ -					-	$ -	-	$ -
	SUBTOTAL	(711,205)	$ (10,296,597.57)	3,868,138	$ 80,178,078.61	(3,734,284)	$ (73,470,540.88)	-	$ -	(845,059)	$ (17,004,135.30)	32,176	$ 658,244.93	-	$ -
	Day Ahead & Real Time Energy Loss														
3	Day Ahead Financial Bilateral Transaction Loss		$ 212.07		$ 1,335.88		$ (1,123.81)								
14	Real Time Distribution Losses		$ (912,334.22)		$ -		$ (912,334.22)								
16	Real Time Financial Bilateral Loss														
	SUBTOTAL		$ (912,122.15)		$ 1,335.88		$ (913,458.03)		$ -		$ -		$ -		$ -
	Virtual Energy														
12	Day Ahead Virtual Energy														
27	Real Time Virtual Energy														
	SUBTOTAL	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
	Schedules 16, 17 & 24														
4	Day Ahead Market Administration (Schedule 17)		$ 780,267.99		$ 710,770.18		$ -		$ 69,497.81				$ 3,019.41		
19	Real Time Market Administration (Schedule 17)		$ 65,004.23		$ 54,979.34		$ -		$ 10,024.89				$ -		
29	Financial Transmission Rights Administration (Schedule 16)		$ 24,626.30		$ 24,626.30		$ -						$ 83.68		
33	Day-Ahead Schedule 24 Allocation Amount		$ 98,214.55		$ 89,489.30		$ -		$ 8,725.25				$ 381.68		
34	Real -Time Schedule 24 Allocation Amount		$ (67,971.70)		$ 18,996.73		$ -				$ (86,968.43)		$ -		
35	Schedule 24 Admin Allocation														
	SUBTOTAL		$ 900,141.37		$ 898,861.85		$ -		$ 88,247.95		$ (86,968.43)		$ 3,484.77		$ -
	Congestion & FTRs														
2	Day Ahead Financial Bilateral Transaction Congestion		$ 10,460.62		$ 10,379.10		$ 81.52								
15	Real Time Financial Bilateral Congestion														
28	Financial Transmission Rights Hourly Allocation		$ (636,844.90)		$ 1,064,911.13		$ (1,701,756.03)						$ 4,391.01		$ (12,347.92)
30	Financial Transmission Rights Monthly Allocation		$ (39,365.46)		$ -		$ (39,365.46)								$ -
32	Financial Transmission Rights Yearly Allocation		$ -		$ -		$ -						$ -		$ -
31	Financial Transmission Rights Transaction														
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (89,773.02)		$ -		$ (89,773.02)								$ (1,167.59)
37	Financial Transmission Guarantee Uplift Amount		$ 82,954.80		$ 82,954.80		$ -						$ 1,155.30		
38	Financial Transmission Rights Monthly Transaction Amount		$ -		$ -		$ -						$ 8,948.50		$ -
	SUBTOTAL		$ (672,567.96)		$ 1,158,245.03		$ (1,830,812.99)		$ -		$ -		$ 14,494.81		$ (13,515.51)
	RSG & Make Whole Payments														
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 69,143.39		$ 55,031.40				$ 14,111.99						
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (108,131.14)				$ (72,598.84)				$ (35,532.30)				
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 41,494.97		$ 33,025.95				$ 8,469.02						
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (59,419.98)				$ (20,494.21)				$ (38,925.77)				
43	Real Time Price Volatility Make Whole Payment		$ (48,182.59)		$ -		($36,621.73)				$ (11,560.86)				
	SUBTOTAL		$ (105,095.35)		$ 88,057.35		$ (129,714.78)		$ 22,581.01		$ (86,018.93)		$ -		$ -
	Other Charges														
20	Real Time Miscellaneous		$ 117,352.62		$ 196,937.55		$ (67,294.36)				$ (12,290.57)		$ -		
21	Real Time Net Inadvertent Distribution		$ 14,831.50		$ 92,577.66		$ (77,746.16)						$ 311.36		$ (299.06)
23	Real Time Revenue Neutrality Uplift Amount		$ 352,729.16		$ 442,319.99		$ (161,581.95)		$ 71,991.12						
26	Real Time Uninstructed Deviation Amount														
	SUBTOTAL		$ 484,913.28		$ 731,835.20		$ (306,622.47)		$ 71,991.12		$ (12,290.57)		$ 311.36		$ (299.06)
	Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions		$ 1,123,444.70		$ 1,302,629.36		$ (179,184.66)								
40	Auction Revenue Rights - Monthly ARR Revenue		$ (1,123,867.22)		$ 177,460.39		$ (1,246,363.36)				$ (54,964.25)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (207,296.32)		$ -		$ (207,296.32)								
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 42,660.70		$ 42,660.70		$ -								
	SUBTOTAL		$ (165,058.14)		$ 1,522,750.45		$ (1,632,844.34)		$ -		$ (54,964.25)		$ -		$ -
	Grandfathered Charge Types														
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (10,460.62)		$ (81.52)		$ (10,379.10)								
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (212.07)		$ 1,123.81		$ (1,335.88)								
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	-	$ (10,672.69)	-	$ 1,042.29	-	$ (11,714.98)	-	$ -	-	$ -	-	$ -	-	$ -
	MISO Day 2 Charges	(711,205)	$ (10,777,059.21)	3,868,138	$ 84,580,206.67	(3,734,284)	$ (78,295,708.47)	-	$ 182,820.07	(845,059)	$ (17,244,377.48)	32,176	$ 676,535.87	-	$ (13,814.57)
x	Net Congestion Amount		$ 1,541,181.41		$ 1,213,556.45				$ 327,624.96						
y	Net Loss Amount		$ 2,548,222.97		$ 2,029,212.56				$ 519,010.41						
z	Net Congestion and Loss Energy Offset		$ (4,089,404.38)		$ (4,089,404.38)										
	SUBTOTAL	-	$ -	-	$ (846,635.37)	-	$ -	-	$ 846,635.37	-	$ -	-	$ -	-	$ -
	Total MISO Day 2 Charges	**(711,205)**	$ (10,777,059.21)	3,868,138	$ 83,733,571.30	(3,734,284)	$ (78,295,708.47)	-	$ 1,029,455.44	(845,059)	$ (17,244,377.48)	32,176	$ 676,535.87	-	$ (13,814.57)

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 ASM

A. Overall Market Performance to Date

During the 2018-2019 AAA reporting 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.

Below are observations made by the MISO Market Monitor in annual (2018) and quarterly (Summer 2018 and 2019) reports. Please see the following MISO Market Monitor websites for these reports and for further information pertaining to the compliant and economic market operations for the 2018 and 2019 periods:

https://cdn.misoenergy.org/2018%20State%20of%20the%20Market%20Report364567.pdf
https://cdn.misoenergy.org/2018%20IMM%20Quarterly%20Report%20Summer279325.pdf
https://cdn.misoenergy.org/2019%20Summer%20Assessment%20Report409083.pdf

2018 Weather/Load:
MISO's annual peak load of 121.6 GW occurred on June 29, almost a month earlier than the peak load in prior years. Actual peak load was well below the forecasted peak of 124.7 GW from MISO's 2018 Summer Resource Assessment.

2019 Weather/Load:
MISO's annual peak load of 120.9 GW occurred on July 19, 600 MW lower than last year's peak and well below the forecast peak of 125.5 GW.

2018 Energy Prices:
Energy prices increased by eight percent compared to 2017, primarily because of higher fuel prices and load.

2019 Energy Prices:
A significant drop in natural gas prices had multiple impacts on the markets. For the summer of 2019, Real time energy prices fell by 19 percent compared to 2018.

2018 Fuel Prices:
Fuel input price changes were mixed – as natural gas prices declined one percent and western coal prices increased 8 percent from the prior summer.

2019 Fuel Prices:
Natural gas prices at the Chicago and Henry Hubs both fell by more than 20 percent over last summer due to record levels of natural gas production. Western coal prices decreased 1 percent from the prior summer.

From the beginning of this reporting period, wind capacity in MISO is up over 26% and accounted for 5.9% of MISO's total energy in the summer of 2019. Also, the general trend of decreasing coal contributions offset by increasing natural gas contributions persisted through the report period. The summer 2019 showed 39.9% of the total real-time energy production being sourced from coal assets and 30.6% of the total coming from natural gas resources. Finally, despite some challenging weather conditions, such as the Polar Vortex of late January 2019 and Hurricane Barry in July 2019, throughout the report period, MISO performed market functions fairly well.

B. Estimated Market Benefits

1. Benefits Calculation

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 2018-2019 AAA reporting period, and are provided in the table below.

ASM Benefit Analysis - NSP System

	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Other Market Charge Types	ASM Admin Fees	Net Savings
Jul '18	(38,842,395)	(39,093,763)	251,368	146,854	29,698	74,816
Aug '18	(38,021,042)	(38,388,406)	367,364	171,851	23,739	171,774
Sep '18	(30,003,125)	(30,327,737)	324,612	169,858	27,932	126,823
Oct '18	(27,925,176)	(28,374,226)	299,050	75,036	32,694	191,321
Nov '18	(36,159,471)	(36,423,919)	264,448	148,587	40,745	75,115
Dec '18	(37,547,829)	(37,836,463)	288,634	113,045	29,831	145,757
Jan '19	(34,179,191)	(34,453,842)	274,651	22,131	18,509	234,011
Feb '19	(36,356,401)	(36,599,757)	243,356	17,672	25,766	199,918
Mar '19	(32,352,477)	(32,626,269)	273,792	29,598	29,559	214,635
Apr '19	(26,558,276)	(26,770,153)	211,877	35,400	25,194	151,283
May '19	(22,200,725)	(22,567,515)	366,790	120,638	33,262	212,890
Jun '19	(29,217,311)	(29,589,802)	372,491	55,551	42,002	274,938
Subtotal	-389,363,419	-393,051,852	3,538,433	1,106,221	358,931	2,073,281
Jul '19	(32,640,096)	(32,939,086)	298,990	110,793	33,730	154,467
Aug '19	(36,078,986)	(36,335,750)	256,764	57,014	19,041	180,709
Sep '19	(29,478,845)	(29,705,471)	226,626	55,747	26,777	144,103
Oct '19	(24,237,157)	(24,585,762)	348,605	60,933	29,265	258,407
Nov '19	(32,248,806)	(32,483,504)	234,698	29,226	30,342	175,131
Dec '19	(30,282,596)	(30,510,076)	227,480	28,264	34,265	164,951
Subtotal	(184,966,486)	(186,559,649)	1,593,163	341,977	173,420	1,077,768
TOTAL	(574,329,905)	(579,611,501)	5,131,596	1,448,198	532,351	3,151,049

The Company estimates the ASM resulted in total NSP System savings of approximately $2.0 million for the 2018-19 reporting period. The Minnesota jurisdictional allocation of the savings is approximately 75 percent, or $1.555 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.

2. 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 J, Section 6, Schedule 2 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 2018-2019 AAA reporting period, the net benefit for the Company was approximately $2.0 million[1] while the amount incurred in EDEDCs was $1.1 million. The $3.5 million in gross benefits would not have been achievable if the

[1] The $2.0 million in ASM benefits calculated by the Company for 2018-2019 does not include all of the savings made possible by offering high flexibility to MISO. In addition to the ASM related benefits, increased ramp rates and flexibility minimizes overall price volatility in the market, increases the ability to integrate intermittent resources such as wind, and limits uneconomic market purchases or sales.

Company had been offering ramp rates for its units that would have all but eliminated the chance of incurring an Excessive Deficient Energy charge.

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 on a daily basis 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.

3. 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 J, Section 6, Schedule 3 shows NSP incurred a total of $70,994 in CRDFC during the 2018-2019 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 of whether MISO has 15 minutes to meet the standard or less than 10 minutes.

The charges were not the result of any oversight or error 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.

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.

4. *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.

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
7/1/2018	(1,209,746)	(1,241,827)	32,081	2.58%	0	5,644	829	8,613	1,510	1,012	24,595
7/2/2018	(1,720,830)	(1,733,806)	12,976	0.75%	0	5,365	-679	10,628	1,402	1,203	7,088
7/3/2018	(1,228,482)	(1,245,027)	16,545	1.33%	0	4,328	1,154	9,509	1,052	1,056	10,006
7/4/2018	(1,099,825)	(1,152,945)	53,120	4.61%	0	9,214	2,570	8,763	654	942	40,394
7/5/2018	(1,653,560)	(1,688,788)	35,228	2.09%	0	2,241	-1,808	10,302	604	1,091	33,704
7/6/2018	(1,132,595)	(1,163,800)	31,205	2.68%	0	4,836	-4	8,677	442	912	25,461
7/7/2018	(859,225)	(874,095)	14,870	1.70%	0	1,201	-36	6,577	118	669	13,036
7/8/2018	(933,963)	(946,168)	12,205	1.29%	0	1,580	776	7,580	162	774	9,075
7/9/2018	(1,537,564)	(1,548,977)	11,413	0.74%	0	4,971	1,651	9,949	421	1,037	3,753
7/10/2018	(1,369,261)	(1,386,033)	16,772	1.21%	0	6,053	9,714	9,702	828	1,053	(48)
7/11/2018	(1,497,409)	(1,504,916)	7,507	0.50%	0	2,705	2,672	9,840	461	1,030	1,100
7/12/2018	(1,481,732)	(1,480,453)	-1,279	-0.09%	0	2,306	942	9,756	695	1,045	(5,572)
7/13/2018	(1,659,481)	(1,662,562)	3,081	0.19%	0	503	3,109	10,254	319	1,057	(1,588)
7/14/2018	(1,360,461)	(1,366,178)	5,717	0.42%	0	4,598	619	9,613	512	1,012	(513)
7/15/2018	(1,202,631)	(1,204,694)	2,063	0.17%	0	3,933	2,094	9,185	305	949	(4,913)
7/16/2018	(1,362,436)	(1,367,388)	4,952	0.36%	0	3,628	3,848	9,640	528	1,017	(3,541)
7/17/2018	(1,399,695)	(1,404,406)	4,711	0.34%	0	880	3,832	9,624	661	1,028	(1,030)
7/18/2018	(1,250,631)	(1,259,546)	8,915	0.71%	0	3,693	3,258	9,123	492	961	1,003
7/19/2018	(1,053,023)	(1,058,868)	5,845	0.55%	0	1,281	631	8,285	350	864	3,069
7/20/2018	(1,110,065)	(1,111,091)	1,026	0.09%	0	2,600	3,931	8,490	385	888	(6,392)
7/21/2018	(1,029,478)	(1,033,597)	4,119	0.40%	0	1,913	564	8,324	427	875	767
7/22/2018	(1,097,921)	(1,091,116)	-6,805	-0.62%	0	2,879	699	8,620	421	904	(11,287)
7/23/2018	(1,270,346)	(1,268,135)	-2,211	-0.17%	0	2,563	3,748	9,460	195	966	(9,487)
7/24/2018	(1,312,189)	(1,308,366)	-3,823	-0.29%	0	1,900	6,603	9,584	220	980	(13,307)
7/25/2018	(1,251,811)	(1,250,153)	-1,658	-0.13%	0	2,719	-562	9,342	561	990	(4,806)
7/26/2018	(1,210,595)	(1,211,537)	942	0.08%	0	3,112	171	9,100	710	981	(3,322)
7/27/2018	(1,187,132)	(1,182,850)	-4,282	-0.36%	0	1,265	1,651	8,984	349	933	(8,131)
7/28/2018	(1,006,903)	(1,007,207)	304	0.03%	0	2,704	363	7,634	2,199	983	(3,746)
7/29/2018	(1,062,957)	(1,058,023)	-4,934	-0.47%	0	636	54	7,934	134	807	(6,431)
7/30/2018	(1,164,110)	(1,156,075)	-8,035	-0.70%	0	185	2,120	8,340	87	843	(11,183)
7/31/2018	(1,126,338)	(1,125,136)	-1,202	-0.11%	0	572	330	8,187	160	835	(2,939)
8/1/2018	(1,151,451)	(1,156,798)	5,347	0.46%	0	226	434	6,979	192	717	3,970
8/2/2018	(1,165,520)	(1,180,194)	14,674	1.24%	0	2,079	16,962	7,282	329	761	(5,128)
8/3/2018	(1,147,869)	(1,160,945)	13,076	1.13%	0	9,728	4,271	7,531	664	819	(1,742)
8/4/2018	(973,115)	(999,888)	26,773	2.68%	0	2,676	1,410	6,435	506	694	21,993
8/5/2018	(1,044,980)	(1,059,834)	14,854	1.40%	0	2,292	3,215	6,956	210	717	8,631
8/6/2018	(1,467,807)	(1,505,155)	37,348	2.48%	0	5,768	3,042	8,371	201	857	27,681

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
8/7/2018	(1,354,432)	(1,361,825)	7,393	0.54%	0	214	3,457	7,842	437	828	2,894
8/8/2018	(1,430,735)	(1,441,134)	10,399	0.72%	0	5,779	7,954	7,960	359	832	(4,166)
8/9/2018	(1,490,743)	(1,502,496)	11,753	0.78%	0	152	1,117	8,193	205	840	9,644
8/10/2018	(1,457,392)	(1,464,149)	6,757	0.46%	0	392	174	7,989	370	836	5,355
8/11/2018	(1,243,863)	(1,257,826)	13,963	1.11%	0	3,474	1,886	7,386	511	790	7,814
8/12/2018	(1,239,373)	(1,253,971)	14,598	1.16%	0	2,494	3,322	7,480	439	792	7,990
8/13/2018	(1,427,707)	(1,444,146)	16,439	1.14%	0	2,256	1,756	8,045	797	884	11,543
8/14/2018	(1,392,114)	(1,401,136)	9,022	0.64%	0	2,844	3,856	8,100	313	841	1,480
8/15/2018	(1,437,419)	(1,446,210)	8,791	0.61%	0	1,421	4,558	8,221	168	839	1,973
8/16/2018	(1,477,797)	(1,484,406)	6,609	0.45%	0	2,484	3,830	8,250	237	849	(554)
8/17/2018	(1,725,285)	(1,732,801)	7,516	0.43%	0	741	2,621	8,456	424	888	3,266
8/18/2018	(1,226,104)	(1,236,163)	10,059	0.81%	0	149	2,001	6,997	221	722	7,188
8/19/2018	(1,113,342)	(1,122,869)	9,527	0.85%	0	1,786	97	6,711	131	684	6,960
8/20/2018	(1,093,508)	(1,102,804)	9,296	0.84%	0	3,723	329	6,779	355	713	4,531
8/21/2018	(1,193,088)	(1,199,865)	6,777	0.56%	0	3,276	249	7,492	752	824	2,428
8/22/2018	(1,153,665)	(1,163,031)	9,366	0.81%	0	1,758	5	6,827	875	770	6,832
8/23/2018	(1,001,520)	(1,004,524)	3,004	0.30%	0	3,686	219	6,155	478	663	(1,565)
8/24/2018	(1,063,288)	(1,068,005)	4,717	0.44%	0	3,215	26	6,514	193	671	805
8/25/2018	(1,073,179)	(1,081,802)	8,623	0.80%	0	1,183	248	6,529	99	663	6,529
8/26/2018	(1,032,700)	(1,051,627)	18,927	1.80%	0	10,242	2,932	6,542	264	681	5,073
8/27/2018	(1,358,974)	(1,375,525)	16,551	1.20%	0	6,410	17,279	7,536	429	796	(7,935)
8/28/2018	(1,206,552)	(1,225,750)	19,198	1.57%	0	743	-407	7,233	459	769	18,092
8/29/2018	(1,158,725)	(1,170,353)	11,628	0.99%	0	1,127	155	6,940	382	732	9,614
8/30/2018	(852,886)	(861,221)	8,335	0.97%	0	1,024	41	5,356	1,003	636	6,634
8/31/2018	(865,909)	(871,953)	6,044	0.69%	0	1,493	-22	5,438	859	630	3,944
9/1/2018	(799,638)	(798,141)	-1,497	-0.19%	0	2,107	429	7,084	1,791	887	(4,920)
9/2/2018	(1,000,621)	(1,006,697)	6,076	0.60%	0	3,711	320	9,004	242	925	1,120
9/3/2018	(1,031,343)	(1,038,618)	7,275	0.70%	0	5,526	173	9,249	495	974	602
9/4/2018	(1,409,059)	(1,430,312)	21,253	1.49%	0	4,361	1,548	10,528	734	1,126	14,218
9/5/2018	(1,096,369)	(1,114,075)	17,706	1.59%	0	3,656	85	9,277	709	999	12,965
9/6/2018	(976,108)	(979,407)	3,299	0.34%	0	2,732	57	8,347	500	885	(374)
9/7/2018	(864,216)	(867,787)	3,571	0.41%	0	546	190	7,315	510	783	2,052
9/8/2018	(751,909)	(751,960)	51	0.01%	0	776	-22	6,684	271	695	(1,399)
9/9/2018	(771,264)	(768,536)	-2,728	-0.35%	0	1,781	32	7,392	515	791	(5,332)
9/10/2018	(882,826)	(887,881)	5,055	0.57%	0	2,614	76	8,542	333	887	1,478
9/11/2018	(869,096)	(867,352)	-1,744	-0.20%	0	2,963	204	8,567	338	890	(5,801)
9/12/2018	(932,271)	(928,755)	-3,516	-0.38%	0	3,974	622	9,016	348	936	(9,049)

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
9/13/2018	(970,587)	(969,861)	-726	-0.07%	0	4,801	7,355	9,405	440	985	(13,867)
9/14/2018	(1,383,864)	(1,383,185)	-679	-0.05%	0	8,703	19,988	10,469	574	1,104	(30,474)
9/15/2018	(1,152,342)	(1,157,272)	4,930	0.43%	0	11,293	-4,852	9,546	475	1,002	(2,513)
9/16/2018	(1,124,033)	(1,139,120)	15,087	1.32%	0	9,414	4,189	9,712	402	1,011	473
9/17/2018	(1,619,569)	(1,703,907)	84,338	4.95%	0	4,219	5,091	10,898	808	1,171	73,858
9/18/2018	(1,653,618)	(1,668,911)	15,293	0.92%	0	5,737	-889	10,751	1,177	1,193	9,253
9/19/2018	(1,116,498)	(1,135,003)	18,505	1.63%	0	5,144	1,374	10,047	862	1,091	10,896
9/20/2018	(1,070,346)	(1,078,741)	8,395	0.78%	0	3,845	515	9,894	636	1,053	2,982
9/21/2018	(825,980)	(839,058)	13,078	1.56%	0	1,482	181	7,879	812	869	10,546
9/22/2018	(845,322)	(855,194)	9,872	1.15%	0	3,773	76	7,982	979	896	5,127
9/23/2018	(654,556)	(666,328)	11,772	1.77%	0	4,707	-202	6,434	644	708	6,560
9/24/2018	(815,455)	(820,279)	4,824	0.59%	0	3,880	2,356	7,637	675	831	(2,243)
9/25/2018	(965,944)	(980,475)	14,531	1.48%	0	5,766	-218	8,300	858	916	8,068
9/26/2018	(765,407)	(772,290)	6,883	0.89%	0	4,854	-212	7,592	577	817	1,424
9/27/2018	(891,011)	(917,910)	26,899	2.93%	0	8,113	-37	7,765	889	865	17,957
9/28/2018	(932,433)	(947,280)	14,847	1.57%	0	4,324	-230	8,384	828	921	9,832
9/29/2018	(972,175)	(987,383)	15,208	1.54%	0	3,635	98	8,506	1,182	969	10,506
9/30/2018	(859,265)	(866,019)	6,754	0.78%	0	2,591	537	7,157	350	751	2,876
10/1/2018	(1,032,629)	(1,048,818)	16,189	1.54%	0	2,468	-50	10,067	344	1,041	12,730
10/2/2018	(1,010,521)	(1,026,239)	15,718	1.53%	0	1,545	-1,073	9,966	495	1,046	14,200
10/3/2018	(742,685)	(761,541)	18,856	2.48%	0	2,289	-54	8,450	829	928	15,693
10/4/2018	(978,124)	(988,209)	10,085	1.02%	0	1,429	3,610	9,270	819	1,009	4,037
10/5/2018	(1,088,575)	(1,111,217)	22,642	2.04%	0	1,237	3,802	9,929	2,307	1,224	16,379
10/6/2018	(848,022)	(875,483)	27,461	3.14%	0	12,489	-1,961	8,970	284	925	16,008
10/7/2018	(644,563)	(653,998)	9,435	1.44%	0	490	795	8,974	824	980	7,170
10/8/2018	(866,562)	(878,598)	12,036	1.37%	0	1,649	2,413	10,043	945	1,099	6,875
10/9/2018	(942,025)	(974,235)	32,210	3.31%	0	1,467	432	10,633	835	1,147	29,165
10/10/2018	(659,819)	(693,653)	33,834	4.88%	0	2,000	59	9,472	769	1,024	30,750
10/11/2018	(662,275)	(708,942)	46,667	6.58%	0	608	-3	9,359	392	975	45,087
10/12/2018	(746,236)	(774,971)	28,735	3.71%	0	1,893	-100	9,566	452	1,002	25,940
10/13/2018	(565,444)	(572,716)	7,272	1.27%	0	3,096	116	7,401	991	839	3,220
10/14/2018	(634,661)	(651,230)	16,569	2.54%	0	3,670	-12	8,664	906	957	11,954
10/15/2018	(893,157)	(918,615)	25,458	2.77%	0	1,422	-49	10,417	1,482	1,190	22,895
10/16/2018	(953,583)	(964,583)	11,000	1.14%	0	119	-16	10,481	1,838	1,232	9,665
10/17/2018	(956,818)	(966,636)	9,818	1.02%	0	91	321	10,330	326	1,066	8,341
10/18/2018	(662,722)	(678,042)	15,320	2.26%	0	689	-18	9,035	856	989	13,660
10/19/2018	(543,107)	(545,628)	2,521	0.46%	0	839	13	7,239	378	762	907

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10/20/2018	(543,083)	(561,976)	18,893	3.36%	0	1,904	-19	7,645	346	799	16,209
10/21/2018	(611,932)	(623,882)	11,950	1.92%	0	478	-1	8,314	439	875	10,597
10/22/2018	(1,040,300)	(1,045,343)	5,043	0.48%	0	1,313	599	10,318	821	1,114	2,017
10/23/2018	(1,306,650)	(1,319,979)	13,329	1.01%	0	8,520	-181	11,331	773	1,210	3,779
10/24/2018	(1,083,255)	(1,087,563)	4,308	0.40%	0	1,117	57	10,412	985	1,140	1,995
10/25/2018	(1,115,644)	(1,117,512)	1,868	0.17%	0	405	-504	10,585	922	1,151	816
10/26/2018	(1,300,172)	(1,307,763)	7,591	0.58%	0	1,698	-440	11,227	580	1,181	5,152
10/27/2018	(1,111,222)	(1,114,336)	3,114	0.28%	0	1,193	104	10,380	561	1,094	723
10/28/2018	(802,341)	(808,597)	6,256	0.77%	0	3,727	53	8,671	249	892	1,584
10/29/2018	(1,164,297)	(1,173,270)	8,973	0.76%	0	2,082	400	11,403	803	1,221	5,271
10/30/2018	(1,145,309)	(1,148,590)	3,281	0.29%	0	616	520	11,463	951	1,241	903
10/31/2018	(1,269,443)	(1,272,061)	2,618	0.21%	0	3,175	503	12,546	869	1,342	(2,401)
11/1/2018	(1,193,830)	(1,204,637)	10,807	0.90%	0	1,099	730	13,548	1,024	1,457	7,521
11/2/2018	(1,184,498)	(1,186,236)	1,738	0.15%	0	884	1,334	13,072	338	1,341	(1,821)
11/3/2018	(922,523)	(943,095)	20,572	2.18%	0	2,331	141	12,239	1,052	1,329	16,770
11/4/2018	(1,086,770)	(1,083,121)	-3,649	-0.34%	0	3,312	382	12,993	1,462	1,446	(8,789)
11/5/2018	(1,153,019)	(1,145,812)	-7,207	-0.63%	0	4,097	71	13,587	1,071	1,466	(12,841)
11/6/2018	(913,462)	(916,418)	2,956	0.32%	0	1,719	37	11,214	1,291	1,250	(51)
11/7/2018	(1,098,887)	(1,104,423)	5,536	0.50%	0	5,568	80	12,538	638	1,318	(1,430)
11/8/2018	(1,631,643)	(1,650,955)	19,312	1.17%	0	3,116	2,184	15,097	163	1,526	12,486
11/9/2018	(1,270,173)	(1,263,222)	-6,951	-0.55%	0	2,683	-23	13,421	2,039	1,546	(11,158)
11/10/2018	(1,013,570)	(1,018,708)	5,138	0.50%	0	2,225	891	10,522	915	1,144	878
11/11/2018	(865,659)	(873,724)	8,065	0.92%	0	275	-6	9,804	875	1,068	6,728
11/12/2018	(1,314,294)	(1,310,213)	-4,081	-0.31%	0	2,426	1,155	13,096	1,487	1,458	(9,120)
11/13/2018	(1,673,819)	(1,674,768)	949	0.06%	0	3,465	-12	15,209	547	1,576	(4,079)
11/14/2018	(1,293,634)	(1,299,513)	5,879	0.45%	0	4,600	-44	13,358	1,051	1,441	(118)
11/15/2018	(1,073,445)	(1,079,312)	5,867	0.54%	0	9,832	656	11,739	1,323	1,306	(5,927)
11/16/2018	(1,186,102)	(1,188,079)	1,977	0.17%	0	4,990	60	12,379	1,580	1,396	(4,470)
11/17/2018	(883,964)	(888,929)	4,965	0.56%	0	2,940	82	9,893	414	1,031	912
11/18/2018	(952,690)	(962,926)	10,236	1.06%	0	6,053	-77	10,862	535	1,140	3,120
11/19/2018	(1,296,229)	(1,299,299)	3,070	0.24%	0	2,748	929	12,596	735	1,333	(1,941)
11/20/2018	(1,369,009)	(1,391,129)	22,120	1.59%	0	8,115	566	13,669	1,437	1,511	11,928
11/21/2018	(1,199,703)	(1,221,375)	21,672	1.77%	0	3,476	-8	12,778	442	1,322	16,882
11/22/2018	(1,025,016)	(1,037,680)	12,664	1.22%	0	10,902	-307	10,370	1,221	1,159	910
11/23/2018	(993,000)	(1,009,377)	16,377	1.62%	0	12,034	104	10,304	438	1,074	3,165
11/24/2018	(1,018,984)	(1,043,720)	24,736	2.37%	0	11,114	-267	11,097	290	1,139	12,750
11/25/2018	(999,502)	(1,018,239)	18,737	1.84%	0	8,012	12	10,721	308	1,103	9,610

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11/26/2018	(1,269,156)	(1,302,523)	33,367	2.56%	0	4,180	1,964	13,335	684	1,402	25,821
11/27/2018	(1,580,769)	(1,582,479)	1,710	0.11%	0	711	45	15,284	262	1,555	(601)
11/28/2018	(1,596,977)	(1,601,400)	4,423	0.28%	0	1,519	212	15,467	582	1,605	1,088
11/29/2018	(1,607,134)	(1,611,681)	4,547	0.28%	0	4,154	362	15,524	1,137	1,666	(1,635)
11/30/2018	(1,492,010)	(1,510,926)	18,916	1.25%	0	7,232	1,520	15,006	1,388	1,639	8,525
12/1/2018	(984,626)	(1,002,068)	17,442	1.74%	0	10,417	-203	7,703	749	845	6,384
12/2/2018	(951,133)	(965,121)	13,988	1.45%	0	8,392	531	7,480	873	835	4,230
12/3/2018	(1,288,614)	(1,298,443)	9,829	0.76%	0	3,796	54	9,841	252	1,009	4,970
12/4/2018	(1,587,954)	(1,592,549)	4,595	0.29%	0	405	4	11,098	284	1,138	3,048
12/5/2018	(1,518,419)	(1,524,650)	6,231	0.41%	0	643	-67	10,899	345	1,124	4,531
12/6/2018	(1,579,894)	(1,572,038)	-7,856	-0.50%	0	1,503	-19	10,648	538	1,119	(10,458)
12/7/2018	(1,666,507)	(1,665,159)	-1,348	-0.08%	0	463	-26	11,206	580	1,179	(2,964)
12/8/2018	(1,483,283)	(1,494,034)	10,751	0.72%	0	3,481	-200	10,609	171	1,078	6,392
12/9/2018	(1,365,599)	(1,375,957)	10,358	0.75%	0	1,301	-365	10,032	367	1,040	8,382
12/10/2018	(1,503,711)	(1,508,421)	4,710	0.31%	0	2,742	-62	10,981	377	1,136	895
12/11/2018	(1,597,175)	(1,594,071)	-3,104	-0.19%	0	1,533	-106	11,019	676	1,169	(5,700)
12/12/2018	(1,490,247)	(1,496,775)	6,528	0.44%	0	5,036	1,717	10,451	483	1,093	(1,318)
12/13/2018	(1,104,257)	(1,130,093)	25,836	2.29%	0	1,675	400	8,546	89	864	22,898
12/14/2018	(1,097,576)	(1,119,743)	22,167	1.98%	0	1,366	562	8,368	322	869	19,370
12/15/2018	(994,112)	(1,009,187)	15,075	1.49%	0	5,318	267	7,831	519	835	8,655
12/16/2018	(988,724)	(993,541)	4,817	0.48%	0	6,095	64	8,140	694	883	(2,225)
12/17/2018	(1,413,552)	(1,427,229)	13,677	0.96%	0	5,395	253	10,823	871	1,169	6,859
12/18/2018	(1,064,324)	(1,074,536)	10,212	0.95%	0	3,872	39	8,449	574	902	5,399
12/19/2018	(1,180,675)	(1,185,329)	4,654	0.39%	0	1,543	-54	8,502	1,043	955	2,210
12/20/2018	(992,847)	(997,033)	4,186	0.42%	0	3,029	30	7,793	749	854	273
12/21/2018	(1,122,322)	(1,141,347)	19,025	1.67%	0	2,353	296	8,552	214	877	15,500
12/22/2018	(1,083,207)	(1,090,470)	7,263	0.67%	0	6,718	50	7,902	621	852	(357)
12/23/2018	(1,033,556)	(1,046,936)	13,380	1.28%	0	6,833	-77	8,263	771	903	5,721
12/24/2018	(1,258,387)	(1,266,335)	7,948	0.63%	0	2,603	3	9,301	762	1,006	4,336
12/25/2018	(1,187,152)	(1,196,462)	9,310	0.78%	0	7,022	39	8,907	250	916	1,334
12/26/2018	(1,082,684)	(1,093,078)	10,394	0.95%	0	3,825	14	8,547	451	900	5,656
12/27/2018	(947,265)	(954,238)	6,973	0.73%	0	2,222	-30	7,638	802	844	3,936
12/28/2018	(1,005,003)	(1,018,365)	13,362	1.31%	0	4,206	824	8,355	270	863	7,470
12/29/2018	(1,062,126)	(1,075,099)	12,973	1.21%	0	3,551	591	8,546	268	881	7,949
12/30/2018	(915,127)	(920,334)	5,207	0.57%	0	726	-259	7,626	749	838	3,902
12/31/2018	(997,771)	(1,007,822)	10,051	1.00%	0	802	-86	8,250	292	854	8,482
1/1/2019	(969,288)	(970,164)	876	0.09%	0	728	-249	5,213	182	539	(142)

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1/2/2019	(993,042)	(1,003,718)	10,676	1.06%	0	1,332	35	5,493	437	593	8,716
1/3/2019	(959,310)	(961,859)	2,549	0.27%	0	34	0	5,250	804	605	1,909
1/4/2019	(913,406)	(914,423)	1,017	0.11%	0	564	-3	4,885	40	493	(36)
1/5/2019	(860,134)	(864,137)	4,003	0.46%	0	1,252	22	4,827	287	511	2,218
1/6/2019	(796,221)	(798,875)	2,654	0.33%	0	774	15	4,217	497	471	1,393
1/7/2019	(840,426)	(842,719)	2,293	0.27%	0	1,183	72	4,666	403	507	531
1/8/2019	(871,805)	(870,186)	-1,619	-0.19%	0	165	0	5,359	529	589	(2,373)
1/9/2019	(1,085,183)	(1,084,301)	-882	-0.08%	0	780	14	5,835	323	616	(2,292)
1/10/2019	(1,469,431)	(1,467,063)	-2,368	-0.16%	0	989	88	7,219	223	744	(4,189)
1/11/2019	(1,356,985)	(1,357,631)	646	0.05%	0	319	95	6,941	309	725	(493)
1/12/2019	(1,082,755)	(1,082,343)	-412	-0.04%	0	1,443	8	6,424	56	648	(2,511)
1/13/2019	(1,051,509)	(1,050,001)	-1,508	-0.14%	0	2,852	129	6,387	82	647	(5,135)
1/14/2019	(1,041,469)	(1,051,678)	10,209	0.97%	0	190	5	6,418	89	651	9,364
1/15/2019	(1,109,436)	(1,114,967)	5,531	0.50%	0	1,812	7	6,573	205	678	3,034
1/16/2019	(1,119,044)	(1,138,033)	18,989	1.67%	0	615	8	6,230	131	636	17,730
1/17/2019	(1,212,532)	(1,220,886)	8,354	0.68%	0	31	322	6,216	433	665	7,336
1/18/2019	(1,008,944)	(1,019,404)	10,460	1.03%	0	397	70	5,175	115	529	9,464
1/19/2019	(1,021,536)	(1,028,331)	6,795	0.66%	0	1,372	-49	5,457	79	554	4,918
1/20/2019	(1,210,429)	(1,213,704)	3,275	0.27%	0	29	12	6,018	185	620	2,614
1/21/2019	(1,251,578)	(1,252,949)	1,371	0.11%	0	668	-308	6,235	548	678	332
1/22/2019	(1,286,095)	(1,283,487)	-2,608	-0.20%	0	28	46	5,892	141	603	(3,285)
1/23/2019	(1,229,237)	(1,228,297)	-940	-0.08%	0	8	6	5,668	116	578	(1,532)
1/24/2019	(1,175,914)	(1,176,234)	320	0.03%	0	1,028	-2	5,644	370	601	(1,307)
1/25/2019	(1,321,069)	(1,322,249)	1,180	0.09%	0	785	88	5,752	106	586	(279)
1/26/2019	(1,057,378)	(1,064,068)	6,690	0.63%	0	944	67	5,409	46	546	5,133
1/27/2019	(881,903)	(908,071)	26,168	2.88%	0	201	-13	4,318	23	434	25,546
1/28/2019	(1,050,723)	(1,048,621)	-2,102	-0.20%	0	452	-21	5,096	143	524	(3,057)
1/29/2019	(1,298,766)	(1,305,546)	6,780	0.52%	0	167	-3	5,906	242	615	6,001
1/30/2019	(1,257,613)	(1,328,455)	70,842	5.33%	0	577	-574	5,796	863	666	70,173
1/31/2019	(1,396,030)	(1,481,442)	85,412	5.77%	0	151	375	5,823	745	657	84,229
2/1/2019	(1,179,398)	(1,236,036)	56,638	4.58%	0	93	38	7,891	491	838	55,669
2/2/2019	(1,199,806)	(1,201,650)	1,844	0.15%	0	162	-1	8,115	145	826	857
2/3/2019	(1,096,341)	(1,099,449)	3,108	0.28%	0	306	201	7,866	259	812	1,788
2/4/2019	(1,134,087)	(1,137,038)	2,951	0.26%	0	132	4	8,043	1,152	919	1,896
2/5/2019	(1,300,547)	(1,306,195)	5,648	0.43%	0	40	-7	9,279	201	948	4,667
2/6/2019	(1,393,232)	(1,391,857)	-1,375	-0.10%	0	2,264	-42	9,728	447	1,017	(4,614)
2/7/2019	(1,224,284)	(1,226,758)	2,474	0.20%	0	2,731	-28	9,651	335	999	(1,228)

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
2/8/2019	(1,500,858)	(1,504,864)	4,006	0.27%	0	51	0	10,036	352	1,039	2,916
2/9/2019	(1,349,556)	(1,359,490)	9,934	0.73%	0	187	-15	8,688	533	922	8,840
2/10/2019	(1,227,427)	(1,238,911)	11,484	0.93%	0	4	0	8,455	118	857	10,623
2/11/2019	(1,252,723)	(1,253,840)	1,117	0.09%	0	14	0	8,567	87	865	238
2/12/2019	(1,244,623)	(1,264,765)	20,142	1.59%	0	2,713	-429	8,452	1,105	956	16,903
2/13/2019	(1,250,541)	(1,268,496)	17,955	1.42%	0	169	50	8,467	770	924	16,812
2/14/2019	(1,153,379)	(1,159,935)	6,556	0.57%	0	1,803	-519	8,067	599	867	4,406
2/15/2019	(1,181,640)	(1,217,784)	36,144	2.97%	0	324	15	8,556	469	902	34,902
2/16/2019	(1,205,802)	(1,207,943)	2,141	0.18%	0	388	10	8,546	123	867	877
2/17/2019	(1,122,567)	(1,122,676)	109	0.01%	0	850	-2	8,246	226	847	(1,585)
2/18/2019	(1,325,426)	(1,322,766)	-2,660	-0.20%	0	110	2	9,593	458	1,005	(3,777)
2/19/2019	(1,462,242)	(1,465,057)	2,815	0.19%	0	661	-56	10,255	581	1,084	1,126
2/20/2019	(1,341,253)	(1,343,554)	2,301	0.17%	0	604	-12	9,514	1,205	1,072	637
2/21/2019	(1,325,930)	(1,329,561)	3,631	0.27%	0	177	-4	9,093	285	938	2,520
2/22/2019	(1,375,938)	(1,376,596)	658	0.05%	0	222	-1	9,022	348	937	(500)
2/23/2019	(1,274,534)	(1,275,779)	1,245	0.10%	2,326	114	2	7,916	412	833	(2,030)
2/24/2019	(1,065,309)	(1,066,046)	737	0.07%	0	682	26	7,118	886	800	(771)
2/25/2019	(1,409,678)	(1,423,549)	13,871	0.97%	0	598	-148	8,376	712	909	12,512
2/26/2019	(1,509,072)	(1,511,526)	2,454	0.16%	0	78	70	8,913	611	952	1,353
2/27/2019	(1,490,540)	(1,499,576)	9,036	0.60%	0	47	11	8,512	322	883	8,095
2/28/2019	(1,759,668)	(1,788,060)	28,392	1.59%	0	453	206	9,013	456	947	26,787
3/1/2019	(1,326,624)	(1,340,672)	14,048	1.05%	0	365	-72	10,641	694	1,133	12,622
3/2/2019	(977,677)	(1,007,434)	29,757	2.95%	0	1,178	12	9,007	129	914	27,653
3/3/2019	(1,133,766)	(1,139,769)	6,003	0.53%	0	662	2	9,464	869	1,033	4,305
3/4/2019	(1,276,312)	(1,317,681)	41,369	3.14%	0	1,321	-27	9,790	168	996	39,079
3/5/2019	(1,077,884)	(1,113,027)	35,143	3.16%	0	3,400	-44	9,699	619	1,032	30,755
3/6/2019	(1,179,224)	(1,191,194)	11,970	1.00%	0	1,196	-29	10,147	154	1,030	9,773
3/7/2019	(1,319,242)	(1,335,564)	16,322	1.22%	0	31	0	10,893	190	1,108	15,183
3/8/2019	(1,237,767)	(1,243,948)	6,181	0.50%	0	42	-1	10,796	226	1,102	5,037
3/9/2019	(875,612)	(898,236)	22,624	2.52%	0	4,895	173	8,330	472	880	16,676
3/10/2019	(810,748)	(834,370)	23,622	2.83%	0	1,051	133	6,727	630	736	21,703
3/11/2019	(1,223,225)	(1,230,976)	7,751	0.63%	0	66	578	10,749	1,427	1,218	5,889
3/12/2019	(774,590)	(796,029)	21,439	2.69%	0	649	-72	6,366	645	701	20,160
3/13/2019	(821,584)	(827,901)	6,317	0.76%	0	1,065	-24	7,676	390	807	4,469
3/14/2019	(862,928)	(871,598)	8,670	0.99%	0	183	-4	7,697	910	861	7,631
3/15/2019	(865,800)	(870,826)	5,026	0.58%	0	282	-4	7,709	604	831	3,917
3/16/2019	(1,137,492)	(1,140,113)	2,621	0.23%	0	1	0	9,764	171	994	1,627

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3/17/2019	(1,168,195)	(1,167,804)	-391	-0.03%	0	135	240	9,905	73	998	(1,763)
3/18/2019	(1,258,021)	(1,257,823)	-198	-0.02%	0	100	17	10,712	1,062	1,177	(1,493)
3/19/2019	(1,190,861)	(1,187,694)	-3,167	-0.27%	0	664	-116	10,002	372	1,037	(4,753)
3/20/2019	(1,130,449)	(1,129,118)	-1,331	-0.12%	0	1,015	-69	9,768	634	1,040	(3,318)
3/21/2019	(1,000,223)	(1,000,128)	-95	-0.01%	0	5	1	9,251	540	979	(1,080)
3/22/2019	(1,129,011)	(1,126,035)	-2,976	-0.26%	0	727	-44	9,781	596	1,038	(4,697)
3/23/2019	(933,957)	(938,419)	4,462	0.48%	0	1,477	-24	8,995	1,281	1,028	1,982
3/24/2019	(853,928)	(852,491)	-1,437	-0.17%	0	29	7	6,859	13	687	(2,160)
3/25/2019	(1,164,450)	(1,171,939)	7,489	0.64%	0	3,989	994	9,487	998	1,048	1,458
3/26/2019	(1,030,578)	(1,037,796)	7,218	0.70%	0	1,025	-68	8,698	450	915	5,346
3/27/2019	(758,010)	(756,463)	-1,547	-0.20%	0	637	-123	5,655	631	629	(2,689)
3/28/2019	(922,028)	(923,682)	1,654	0.18%	0	120	46	8,225	935	916	572
3/29/2019	(1,011,318)	(1,013,181)	1,863	0.18%	0	71	74	8,642	440	908	810
3/30/2019	(905,784)	(905,966)	182	0.02%	0	373	8	8,563	187	875	(1,074)
3/31/2019	(995,189)	(998,392)	3,203	0.32%	0	1,208	70	8,580	503	908	1,016
4/1/2019	(1,135,581)	(1,146,982)	11,401	0.99%	0	535	1,468	9,615	546	1,016	8,381
4/2/2019	(998,437)	(1,002,264)	3,827	0.38%	0	931	562	8,701	691	939	1,394
4/3/2019	(1,073,724)	(1,077,987)	4,263	0.40%	0	1,043	910	8,841	398	924	1,387
4/4/2019	(937,337)	(938,295)	958	0.10%	0	64	296	8,200	190	839	(241)
4/5/2019	(1,126,910)	(1,143,560)	16,650	1.46%	0	2,736	1,044	9,233	324	956	11,914
4/6/2019	(890,494)	(890,498)	4	0.00%	0	109	42	8,087	385	847	(994)
4/7/2019	(836,822)	(840,714)	3,892	0.46%	0	223	46	8,088	450	854	2,769
4/8/2019	(825,663)	(827,540)	1,877	0.23%	0	1,445	-294	8,241	726	897	(170)
4/9/2019	(1,053,533)	(1,062,017)	8,484	0.80%	0	1,277	2,702	9,203	859	1,006	3,500
4/10/2019	(777,991)	(778,517)	526	0.07%	0	186	-14	7,693	344	804	(449)
4/11/2019	(828,775)	(836,129)	7,354	0.88%	0	877	-44	7,832	493	832	5,688
4/12/2019	(892,553)	(898,763)	6,210	0.69%	0	267	18	8,175	687	886	5,038
4/13/2019	(940,555)	(950,122)	9,567	1.01%	0	543	-73	7,874	436	831	8,266
4/14/2019	(820,874)	(825,857)	4,983	0.60%	0	674	9	7,182	92	727	3,573
4/15/2019	(893,797)	(900,561)	6,764	0.75%	0	138	-8	7,594	450	804	5,830
4/16/2019	(1,045,967)	(1,060,179)	14,212	1.34%	0	2,610	-324	8,322	859	918	11,008
4/17/2019	(840,389)	(843,175)	2,786	0.33%	0	522	102	7,677	918	859	1,303
4/18/2019	(802,932)	(807,324)	4,392	0.54%	0	117	28	7,150	1,565	871	3,375
4/19/2019	(793,843)	(796,759)	2,916	0.37%	0	205	24	7,342	724	807	1,880
4/20/2019	(705,852)	(706,643)	791	0.11%	0	47	0	5,599	-62	554	190
4/21/2019	(699,837)	(699,406)	-431	-0.06%	0	68	0	5,375	103	548	(1,047)
4/22/2019	(825,719)	(833,019)	7,300	0.88%	0	1,601	-177	6,821	944	776	5,099

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4/23/2019	(900,903)	(908,026)	7,123	0.78%	0	3,302	1,192	6,920	804	772	1,856
4/24/2019	(961,255)	(972,964)	11,709	1.20%	0	1,224	465	7,253	1,066	832	9,188
4/25/2019	(877,178)	(890,445)	13,267	1.49%	0	100	-691	6,586	1,275	786	13,072
4/26/2019	(860,377)	(873,399)	13,022	1.49%	0	207	531	6,596	1,036	763	11,521
4/27/2019	(680,730)	(685,907)	5,177	0.75%	0	982	-112	6,771	476	725	3,582
4/28/2019	(626,038)	(636,716)	10,678	1.68%	0	2,553	148	6,291	1,291	758	7,218
4/29/2019	(948,329)	(958,832)	10,503	1.10%	0	2,315	1,293	8,697	770	947	5,948
4/30/2019	(955,881)	(977,553)	21,672	2.22%	0	293	-938	9,924	1,223	1,115	21,203
5/1/2019	(1,255,898)	(1,259,006)	3,108	0.25%	0	427	-1,097	10,203	1,026	1,123	2,655
5/2/2019	(1,399,205)	(1,404,651)	5,446	0.39%	0	1,346	-1,278	10,969	1,303	1,227	4,151
5/3/2019	(840,461)	(871,185)	30,724	3.53%	0	3,690	-26	9,536	1,592	1,113	25,947
5/4/2019	(618,348)	(648,886)	30,538	4.71%	0	778	-52	8,847	1,503	1,035	28,777
5/5/2019	(548,100)	(595,335)	47,235	7.93%	0	790	-41	8,583	995	958	45,528
5/6/2019	(781,460)	(799,308)	17,848	2.23%	0	2,370	890	10,217	904	1,112	13,475
5/7/2019	(720,903)	(758,769)	37,866	4.99%	0	2,925	316	10,309	1,404	1,171	33,454
5/8/2019	(527,615)	(566,001)	38,386	6.78%	0	251	9	7,033	902	793	37,333
5/9/2019	(572,004)	(619,074)	47,070	7.60%	0	487	576	9,013	1,092	1,010	44,997
5/10/2019	(672,871)	(709,685)	36,814	5.19%	0	851	77	10,243	177	1,042	34,844
5/11/2019	(537,222)	(569,542)	32,320	5.67%	0	2,508	170	6,057	606	666	28,976
5/12/2019	(693,202)	(697,599)	4,397	0.63%	1,984	2,993	315	10,053	349	1,040	(1,935)
5/13/2019	(810,846)	(807,318)	-3,528	-0.44%	0	3,843	1,699	10,196	527	1,072	(10,142)
5/14/2019	(764,603)	(755,213)	-9,390	-1.24%	0	1,316	89	10,379	265	1,064	(11,860)
5/15/2019	(870,827)	(869,035)	-1,792	-0.21%	0	1,074	485	10,826	1,025	1,185	(4,535)
5/16/2019	(854,523)	(856,956)	2,433	0.28%	57,535	680	2,125	10,624	1,011	1,163	(59,070)
5/17/2019	(664,908)	(669,216)	4,308	0.64%	0	628	107	8,050	917	897	2,676
5/18/2019	(513,177)	(522,097)	8,920	1.71%	0	1,247	-11	7,354	588	794	6,889
5/19/2019	(493,753)	(500,086)	6,333	1.27%	0	955	-46	6,283	140	642	4,782
5/20/2019	(708,661)	(717,300)	8,639	1.20%	0	3,717	522	9,404	814	1,022	3,378
5/21/2019	(604,731)	(609,611)	4,880	0.80%	0	24	-17	7,136	73	721	4,152
5/22/2019	(566,405)	(567,584)	1,179	0.21%	0	7	7	7,344	203	755	410
5/23/2019	(759,846)	(760,564)	718	0.09%	0	1,766	1,060	9,713	515	1,023	(3,131)
5/24/2019	(513,747)	(516,590)	2,843	0.55%	0	379	-35	5,894	314	621	1,878
5/25/2019	(644,051)	(644,919)	868	0.13%	0	375	136	9,706	1,043	1,075	(718)
5/26/2019	(714,159)	(719,308)	5,149	0.72%	1,325	2,646	-5	9,783	242	1,003	181
5/27/2019	(696,367)	(698,229)	1,862	0.27%	0	383	172	7,144	454	760	547
5/28/2019	(588,986)	(589,142)	156	0.03%	0	4,356	855	9,353	686	1,004	(6,059)
5/29/2019	(679,585)	(681,432)	1,847	0.27%	0	2,983	-46	9,967	1,163	1,113	(2,203)

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5/30/2019	(806,992)	(806,955)	-37	0.00%	0	1,877	-46	22,157	893	2,305	(4,173)
5/31/2019	(777,269)	(776,919)	-350	-0.05%	0	4,696	516	26,056	1,471	2,753	(8,314)
6/1/2019	(609,547)	(649,899)	40,352	6.21%	483	424	560	10,524	611	1,114	37,771
6/2/2019	(684,679)	(722,377)	37,698	5.22%	0	1,016	-33	11,198	288	1,149	35,566
6/3/2019	(673,575)	(707,049)	33,474	4.73%	0	829	9	11,271	355	1,163	31,473
6/4/2019	(1,032,715)	(1,060,159)	27,444	2.59%	0	1,362	340	14,293	1,209	1,550	24,192
6/5/2019	(1,275,430)	(1,297,058)	21,628	1.67%	0	2,486	5,220	15,614	746	1,636	12,286
6/6/2019	(1,235,314)	(1,260,313)	24,999	1.98%	0	1,691	244	15,405	776	1,618	21,446
6/7/2019	(1,153,490)	(1,190,737)	37,247	3.13%	0	1,259	267	14,897	366	1,526	34,195
6/8/2019	(947,258)	(990,124)	42,866	4.33%	0	2,317	47	12,728	558	1,329	39,174
6/9/2019	(689,370)	(739,014)	49,644	6.72%	0	17	0	9,549	474	1,002	48,624
6/10/2019	(843,481)	(892,641)	49,160	5.51%	0	818	76	12,778	1,149	1,393	46,874
6/11/2019	(990,788)	(1,000,550)	9,762	0.98%	0	3,958	306	12,378	1,007	1,338	4,160
6/12/2019	(772,272)	(779,824)	7,552	0.97%	0	445	-42	8,774	215	899	6,250
6/13/2019	(747,820)	(755,096)	7,276	0.96%	0	794	-338	10,872	563	1,143	5,677
6/14/2019	(689,502)	(697,220)	7,718	1.11%	0	2,123	11	9,369	1,166	1,054	4,530
6/15/2019	(711,952)	(722,266)	10,314	1.43%	0	1,671	38	10,937	1,151	1,209	7,396
6/16/2019	(709,621)	(716,822)	7,201	1.00%	0	1,045	0	12,099	546	1,265	4,891
6/17/2019	(1,184,286)	(1,182,661)	-1,625	-0.14%	0	2,487	-327	15,690	1,245	1,693	(5,479)
6/18/2019	(1,306,695)	(1,307,242)	547	0.04%	0	3,109	-448	15,957	1,150	1,711	(3,824)
6/19/2019	(1,005,941)	(1,014,645)	8,704	0.86%	0	2,227	-482	14,317	886	1,520	5,439
6/20/2019	(914,970)	(917,602)	2,632	0.29%	0	2,542	757	13,746	419	1,417	(2,084)
6/21/2019	(799,329)	(801,582)	2,253	0.28%	0	1,723	0	10,016	256	1,027	(497)
6/22/2019	(783,127)	(777,604)	-5,523	-0.71%	0	646	8	12,502	585	1,309	(7,485)
6/23/2019	(1,048,637)	(1,040,380)	-8,257	-0.79%	0	2,550	-504	14,820	1,311	1,613	(11,915)
6/24/2019	(1,009,570)	(995,584)	-13,986	-1.40%	0	1,544	-54	14,759	1,312	1,607	(17,082)
6/25/2019	(1,104,919)	(1,099,856)	-5,063	-0.46%	0	1,931	-259	14,760	1,551	1,631	(8,367)
6/26/2019	(1,425,498)	(1,423,572)	-1,926	-0.14%	0	2,262	1	16,260	453	1,671	(5,860)
6/27/2019	(1,219,754)	(1,215,168)	-4,586	-0.38%	0	2,326	-286	15,369	1,140	1,651	(8,277)
6/28/2019	(1,413,617)	(1,409,974)	-3,643	-0.26%	0	1,759	94	16,140	837	1,698	(7,194)
6/29/2019	(1,088,162)	(1,082,369)	-5,793	-0.54%	0	1,562	-86	14,494	388	1,488	(8,756)
6/30/2019	(1,145,992)	(1,140,414)	-5,578	-0.49%	0	1,362	-334	14,791	1,008	1,580	(8,185)
7/1/2019	(1,327,091)	(1,329,219)	2,128	0.16%	0	1,599	1,031	11,332	549	1,188	(1,689)
7/2/2019	(1,348,662)	(1,352,229)	3,567	0.26%	0	856	-761	11,477	248	1,172	2,300
7/3/2019	(1,184,387)	(1,181,385)	-3,002	-0.25%	0	1,044	-219	11,029	330	1,136	(4,963)
7/4/2019	(1,048,807)	(1,056,006)	7,199	0.68%	0	1,415	508	10,298	394	1,069	4,207
7/5/2019	(1,206,235)	(1,224,729)	18,494	1.51%	0	4,029	-148	11,125	1,102	1,223	13,390

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
7/6/2019	(813,780)	(822,345)	8,565	1.04%	0	840	1	9,570	261	983	6,741
7/7/2019	(945,707)	(951,675)	5,968	0.63%	0	4,069	158	9,914	206	1,012	729
7/8/2019	(896,498)	(909,977)	13,479	1.48%	0	3,183	4,390	9,128	1,196	1,032	4,874
7/9/2019	(892,572)	(908,685)	16,113	1.77%	0	5,515	40,020	9,109	1,364	1,047	(30,470)
7/10/2019	(797,076)	(809,482)	12,406	1.53%	0	1,769	236	8,715	794	951	9,450
7/11/2019	(1,211,529)	(1,212,052)	523	0.04%	0	821	-437	10,376	279	1,066	(927)
7/12/2019	(1,119,805)	(1,119,052)	-753	-0.07%	0	2,594	185	9,948	581	1,053	(4,584)
7/13/2019	(985,837)	(989,874)	4,037	0.41%	0	1,595	353	9,333	994	1,033	1,056
7/14/2019	(1,092,045)	(1,092,541)	496	0.05%	0	1,294	-319	10,280	882	1,116	(1,595)
7/15/2019	(1,132,123)	(1,137,035)	4,912	0.43%	0	2,955	-66	10,491	697	1,119	905
7/16/2019	(1,362,561)	(1,369,923)	7,362	0.54%	0	1,258	-668	11,280	1,170	1,245	5,527
7/17/2019	(1,082,234)	(1,087,288)	5,054	0.46%	0	2,523	675	10,710	657	1,137	719
7/18/2019	(1,499,317)	(1,535,211)	35,894	2.34%	0	2,472	-1,692	11,447	1,374	1,282	33,831
7/19/2019	(1,479,291)	(1,546,056)	66,765	4.32%	0	1,988	-1,372	11,410	1,469	1,288	64,861
7/20/2019	(943,323)	(961,971)	18,648	1.94%	0	612	-491	9,800	1,356	1,116	17,411
7/21/2019	(926,593)	(927,725)	1,132	0.12%	0	2,647	-63	10,104	487	1,059	(2,511)
7/22/2019	(1,012,119)	(1,016,724)	4,605	0.45%	0	2,223	2	10,572	693	1,126	1,253
7/23/2019	(811,775)	(809,781)	-1,994	-0.25%	0	2,187	142	9,754	161	991	(5,314)
7/24/2019	(997,603)	(994,309)	-3,294	-0.33%	0	5,686	561	10,341	481	1,082	(10,623)
7/25/2019	(899,764)	(914,404)	14,640	1.60%	0	2,036	1,517	9,644	456	1,010	10,077
7/26/2019	(936,298)	(944,828)	8,530	0.90%	0	2,361	-223	10,076	498	1,057	5,335
7/27/2019	(1,061,531)	(1,069,248)	7,717	0.72%	0	1,774	287	10,449	307	1,076	4,580
7/28/2019	(844,128)	(861,195)	17,067	1.98%	0	1,118	1,821	9,069	1,089	1,016	13,112
7/29/2019	(926,637)	(937,175)	10,538	1.12%	0	672	-884	9,524	1,057	1,058	9,692
7/30/2019	(969,089)	(978,362)	9,273	0.95%	0	1,817	-590	9,843	209	1,005	7,040
7/31/2019	(885,679)	(888,600)	2,921	0.33%	0	1,053	833	9,313	498	981	54
8/1/2019	(1,599,657)	(1,619,871)	20,214	1.25%	0	1,272	2,134	6,509	160	667	16,142
8/2/2019	(1,407,027)	(1,431,170)	24,143	1.69%	0	2,352	-5,465	6,262	165	643	26,613
8/3/2019	(1,159,326)	(1,166,403)	7,077	0.61%	0	1,740	-372	5,907	248	616	5,094
8/4/2019	(1,197,901)	(1,212,791)	14,890	1.23%	0	1,553	-71	6,092	141	623	12,785
8/5/2019	(1,556,500)	(1,585,825)	29,325	1.85%	0	3,397	-569	6,850	1,001	785	25,712
8/6/2019	(1,575,578)	(1,599,042)	23,464	1.47%	0	2,895	-889	7,194	691	788	20,669
8/7/2019	(1,338,655)	(1,357,263)	18,608	1.37%	0	1,551	253	6,315	255	657	16,147
8/8/2019	(1,108,199)	(1,115,971)	7,772	0.70%	0	1,574	-756	5,723	132	585	6,369
8/9/2019	(1,158,180)	(1,172,121)	13,941	1.19%	0	4,077	878	5,961	180	614	8,371
8/10/2019	(1,011,656)	(1,009,005)	-2,651	-0.26%	0	1,149	250	5,329	239	557	(4,607)
8/11/2019	(1,081,986)	(1,085,062)	3,076	0.28%	0	4,615	-293	5,786	133	592	(1,838)

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8/12/2019	(1,467,714)	(1,485,540)	17,826	1.20%	0	1,989	5,471	6,714	383	710	9,656
8/13/2019	(1,237,345)	(1,243,236)	5,891	0.47%	0	4,630	-561	6,577	500	708	1,114
8/14/2019	(1,237,387)	(1,247,800)	10,413	0.83%	0	1,525	-1,164	6,470	180	665	9,387
8/15/2019	(1,095,825)	(1,106,865)	11,040	1.00%	0	1,492	-438	5,703	164	587	9,399
8/16/2019	(1,110,834)	(1,117,921)	7,087	0.63%	0	3,036	363	5,814	164	598	3,090
8/17/2019	(1,093,257)	(1,099,670)	6,413	0.58%	0	469	-304	5,719	345	606	5,642
8/18/2019	(1,090,899)	(1,097,200)	6,301	0.57%	0	1,976	-658	5,658	558	622	4,362
8/19/2019	(1,356,639)	(1,367,148)	10,509	0.77%	0	1,377	417	6,370	523	689	8,025
8/20/2019	(1,579,637)	(1,592,431)	12,794	0.80%	0	1,567	-522	6,957	726	768	10,981
8/21/2019	(1,230,255)	(1,236,933)	6,678	0.54%	0	2,516	275	6,049	232	628	3,259
8/22/2019	(1,201,296)	(1,206,237)	4,941	0.41%	0	1,309	-2,625	6,008	284	629	5,627
8/23/2019	(988,145)	(985,338)	-2,807	-0.28%	0	683	1	5,380	238	562	(4,053)
8/24/2019	(735,872)	(739,275)	3,403	0.46%	0	197	7	4,489	259	475	2,724
8/25/2019	(610,784)	(610,680)	-104	-0.02%	0	280	60	3,980	146	413	(857)
8/26/2019	(968,095)	(964,766)	-3,329	-0.35%	4,346	2,071	-274	5,460	229	569	(10,042)
8/27/2019	(784,024)	(782,646)	-1,378	-0.18%	0	90	244	4,510	307	482	(2,194)
8/28/2019	(992,025)	(994,285)	2,260	0.23%	0	1,145	157	5,556	390	595	364
8/29/2019	(973,991)	(975,232)	1,241	0.13%	0	1,444	2,617	4,939	259	520	(3,339)
8/30/2019	(1,166,077)	(1,172,369)	6,292	0.54%	0	1,691	-1,310	5,503	164	567	5,344
8/31/2019	(964,220)	(955,654)	-8,566	-0.90%	0	194	-46	5,057	177	523	(9,237)
9/1/2019	(1,077,303)	(1,080,759)	3,456	0.32%	0	576	-161	8,386	405	879	2,161
9/2/2019	(967,502)	(970,488)	2,986	0.31%	0	1,719	798	8,466	792	926	(457)
9/3/2019	(654,804)	(659,678)	4,874	0.74%	0	492	479	6,884	537	742	3,161
9/4/2019	(1,230,363)	(1,241,154)	10,791	0.87%	0	4,434	4,462	9,154	326	948	947
9/5/2019	(1,019,405)	(1,025,493)	6,088	0.59%	0	1,995	216	8,363	354	872	3,005
9/6/2019	(1,091,901)	(1,097,887)	5,986	0.55%	0	1,764	103	8,505	149	865	3,254
9/7/2019	(1,000,362)	(1,004,626)	4,264	0.42%	0	34	290	8,385	181	857	3,084
9/8/2019	(944,480)	(946,755)	2,275	0.24%	0	231	-32	8,231	369	860	1,216
9/9/2019	(571,223)	(574,817)	3,594	0.63%	0	728	1,612	6,186	725	691	563
9/10/2019	(1,381,129)	(1,385,603)	4,474	0.32%	0	1,590	-440	10,197	982	1,118	2,206
9/11/2019	(1,134,696)	(1,142,581)	7,885	0.69%	0	3,524	130	9,886	750	1,064	3,168
9/12/2019	(829,241)	(848,036)	18,795	2.22%	0	915	-16	8,380	1,572	995	16,901
9/13/2019	(700,167)	(703,671)	3,504	0.50%	2,994	110	-192	6,899	776	768	(175)
9/14/2019	(707,210)	(709,759)	2,549	0.36%	0	474	263	6,618	707	733	1,079
9/15/2019	(1,075,438)	(1,087,328)	11,890	1.09%	0	1,888	5,642	8,500	303	880	3,480
9/16/2019	(1,340,173)	(1,357,379)	17,206	1.27%	0	1,748	-898	9,998	776	1,077	15,279
9/17/2019	(939,788)	(949,927)	10,139	1.07%	0	649	193	8,044	909	895	8,402

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9/18/2019	(1,203,593)	(1,215,208)	11,615	0.96%	0	1,424	-929	9,118	823	994	10,126
9/19/2019	(1,335,790)	(1,344,285)	8,495	0.63%	0	834	5	10,508	348	1,086	6,571
9/20/2019	(1,070,169)	(1,084,967)	14,798	1.36%	0	4,241	-130	8,917	508	943	9,745
9/21/2019	(608,880)	(609,004)	124	0.02%	0	514	-50	6,057	447	650	(990)
9/22/2019	(1,119,235)	(1,131,985)	12,750	1.13%	0	1,442	4,202	9,315	557	987	6,119
9/23/2019	(1,281,494)	(1,298,665)	17,171	1.32%	0	1,528	186	10,867	409	1,128	14,329
9/24/2019	(993,398)	(999,393)	5,995	0.60%	0	372	-113	9,410	1,474	1,088	4,648
9/25/2019	(975,606)	(971,295)	-4,311	-0.44%	0	744	-27	9,070	1,050	1,012	(6,040)
9/26/2019	(963,017)	(966,518)	3,501	0.36%	0	365	-39	8,554	562	912	2,264
9/27/2019	(954,754)	(959,685)	4,931	0.51%	0	756	391	7,955	536	849	2,935
9/28/2019	(699,979)	(701,154)	1,175	0.17%	0	78	47	6,233	156	639	411
9/29/2019	(560,086)	(559,380)	-706	-0.13%	0	2	-54	4,601	-29	457	(1,111)
9/30/2019	(1,047,659)	(1,077,991)	30,332	2.81%	0	1,437	209	8,016	610	863	27,823
10/1/2019	(1,156,860)	(1,179,819)	22,959	1.95%	0	1,077	34,691	11,362	1,677	1,304	(14,113)
10/2/2019	(1,220,100)	(1,233,820)	13,720	1.11%	0	3,048	465	11,522	337	1,186	9,022
10/3/2019	(1,013,594)	(1,016,435)	2,841	0.28%	0	257	-105	11,084	537	1,162	1,527
10/4/2019	(859,150)	(855,436)	-3,714	-0.43%	0	666	293	9,667	545	1,021	(5,694)
10/5/2019	(381,148)	(385,401)	4,253	1.10%	0	605	215	6,224	301	652	2,781
10/6/2019	(573,682)	(573,807)	125	0.02%	0	614	-25	8,168	858	903	(1,367)
10/7/2019	(921,393)	(941,346)	19,953	2.12%	0	1,586	-669	10,166	432	1,060	17,976
10/8/2019	(375,065)	(416,477)	41,412	9.94%	0	586	-67	6,222	676	690	40,204
10/9/2019	(459,411)	(494,953)	35,542	7.18%	0	676	-49	6,220	587	681	34,233
10/10/2019	(924,999)	(929,288)	4,289	0.46%	0	1,770	-196	8,192	1,162	935	1,780
10/11/2019	(491,823)	(485,348)	-6,475	-1.33%	0	86	421	8,246	1,479	972	(7,954)
10/12/2019	(301,862)	(299,744)	-2,118	-0.71%	0	21	57	6,932	695	763	(2,960)
10/13/2019	(358,483)	(356,385)	-2,098	-0.59%	0	928	-1,356	7,211	313	752	(2,422)
10/14/2019	(940,928)	(958,169)	17,241	1.80%	0	2,020	-835	9,097	726	982	15,074
10/15/2019	(488,059)	(499,135)	11,076	2.22%	0	1,542	-830	7,840	555	840	9,525
10/16/2019	(584,393)	(610,727)	26,334	4.31%	0	1,904	-1,203	8,398	339	874	24,759
10/17/2019	(576,061)	(591,780)	15,719	2.66%	0	1,598	-2,345	8,111	932	904	15,562
10/18/2019	(453,678)	(471,417)	17,739	3.76%	0	37	-20	5,811	952	676	17,045
10/19/2019	(1,050,171)	(1,076,931)	26,760	2.48%	0	1,225	-349	8,592	935	953	24,931
10/20/2019	(814,471)	(821,862)	7,391	0.90%	0	1,779	-103	8,546	885	943	4,771
10/21/2019	(619,281)	(625,034)	5,753	0.92%	0	97	15	7,273	583	786	4,855
10/22/2019	(772,927)	(778,927)	6,000	0.77%	0	354	43	6,709	768	748	4,856
10/23/2019	(1,160,201)	(1,180,208)	20,007	1.70%	0	1,585	308	11,619	1,848	1,347	16,767
10/24/2019	(1,201,787)	(1,220,555)	18,768	1.54%	0	1,025	-500	11,951	1,788	1,374	16,869

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10/25/2019	(919,789)	(923,128)	3,339	0.36%	0	1,997	-60	8,706	1,337	1,004	398
10/26/2019	(465,947)	(470,743)	4,796	1.02%	0	46	22	5,369	358	573	4,155
10/27/2019	(709,756)	(715,779)	6,023	0.84%	0	162	62	6,428	712	714	5,085
10/28/2019	(1,076,649)	(1,084,824)	8,175	0.75%	0	1,612	30	10,255	907	1,116	5,416
10/29/2019	(1,079,885)	(1,093,003)	13,118	1.20%	0	1,636	-631	10,368	496	1,086	11,026
10/30/2019	(1,102,055)	(1,105,235)	3,180	0.29%	0	1,282	-384	10,482	714	1,120	1,163
10/31/2019	(1,183,549)	(1,190,046)	6,497	0.55%	0	2,117	99	11,115	332	1,145	3,136
11/1/2019	(1,139,066)	(1,142,996)	3,930	0.34%	0	730	-814	8,950	332	928	3,085
11/2/2019	(924,551)	(927,777)	3,226	0.35%	0	2,125	236	8,775	428	920	(56)
11/3/2019	(1,137,209)	(1,145,592)	8,383	0.73%	0	188	-152	10,128	691	1,082	7,265
11/4/2019	(1,100,187)	(1,097,927)	-2,260	-0.21%	0	823	2	9,893	1,549	1,144	(4,230)
11/5/2019	(1,422,148)	(1,435,744)	13,596	0.95%	0	1,080	31	11,254	1,448	1,270	11,216
11/6/2019	(1,620,918)	(1,621,385)	467	0.03%	0	847	-480	11,358	1,906	1,326	(1,226)
11/7/2019	(1,686,381)	(1,682,071)	-4,310	-0.26%	0	702	138	12,293	1,061	1,335	(6,485)
11/8/2019	(1,132,117)	(1,144,038)	11,921	1.04%	0	479	75	10,030	1,236	1,127	10,240
11/9/2019	(993,329)	(997,062)	3,733	0.37%	0	1,357	-95	10,157	1,409	1,157	1,314
11/10/2019	(817,607)	(833,159)	15,552	1.87%	0	562	7	8,341	1,629	997	13,986
11/11/2019	(1,251,634)	(1,249,153)	-2,481	-0.20%	0	66	52	10,770	2,027	1,280	(3,878)
11/12/2019	(1,606,559)	(1,626,704)	20,145	1.24%	0	1,828	-645	12,720	1,821	1,454	17,508
11/13/2019	(1,340,084)	(1,347,658)	7,574	0.56%	0	2,327	2,713	11,544	1,467	1,301	1,233
11/14/2019	(1,305,878)	(1,315,259)	9,381	0.71%	0	1,164	-76	12,540	1,227	1,377	6,916
11/15/2019	(1,260,224)	(1,280,839)	20,615	1.61%	0	597	-54	12,236	1,356	1,359	18,713
11/16/2019	(692,014)	(697,516)	5,502	0.79%	0	330	14	6,120	297	642	4,516
11/17/2019	(1,059,929)	(1,078,674)	18,745	1.74%	0	400	36	9,779	608	1,039	17,271
11/18/2019	(1,160,752)	(1,165,786)	5,034	0.43%	0	2,315	-299	10,842	608	1,145	1,873
11/19/2019	(1,102,741)	(1,112,344)	9,603	0.86%	0	1,347	-26	10,493	783	1,128	7,154
11/20/2019	(994,928)	(998,650)	3,722	0.37%	0	2,821	86	7,618	764	838	(23)
11/21/2019	(773,499)	(797,910)	24,411	3.06%	0	503	9	6,142	811	695	23,204
11/22/2019	(1,146,258)	(1,143,410)	-2,848	-0.25%	0	1,370	-22	9,126	705	983	(5,179)
11/23/2019	(682,147)	(702,318)	20,171	2.87%	0	212	0	5,737	216	595	19,364
11/24/2019	(656,403)	(675,873)	19,470	2.88%	0	66	-2	5,638	83	572	18,834
11/25/2019	(692,169)	(705,176)	13,007	1.84%	0	286	9	6,161	180	634	12,078
11/26/2019	(921,097)	(921,580)	483	0.05%	0	616	-10	7,353	391	774	(897)
11/27/2019	(1,025,714)	(1,027,115)	1,401	0.14%	0	329	-9	7,917	519	844	238
11/28/2019	(1,032,254)	(1,034,988)	2,734	0.26%	0	1,283	13	8,270	574	884	553
11/29/2019	(921,696)	(924,793)	3,097	0.33%	0	1,648	-237	8,249	894	914	772
11/30/2019	(649,313)	(650,007)	694	0.11%	0	327	-4	5,608	356	596	(225)

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
12/1/2019	(767,840)	(779,603)	11,763	1.51%	0	287	-208	6,994	291	728	10,956
12/2/2019	(1,388,305)	(1,398,878)	10,573	0.76%	0	2,275	-8	10,742	1,114	1,186	7,121
12/3/2019	(793,764)	(800,964)	7,200	0.90%	0	458	159	8,704	627	933	5,651
12/4/2019	(1,047,109)	(1,056,585)	9,476	0.90%	0	396	74	9,798	595	1,039	7,967
12/5/2019	(1,126,649)	(1,133,084)	6,435	0.57%	0	508	-64	10,476	1,170	1,165	4,827
12/6/2019	(1,100,869)	(1,106,331)	5,462	0.49%	0	488	-45	10,295	635	1,093	3,926
12/7/2019	(715,053)	(717,855)	2,802	0.39%	0	411	154	7,438	280	772	1,466
12/8/2019	(890,655)	(894,969)	4,314	0.48%	0	544	-8	8,867	265	913	2,865
12/9/2019	(1,065,393)	(1,068,140)	2,747	0.26%	0	599	42	10,540	906	1,145	961
12/10/2019	(1,188,371)	(1,201,901)	13,530	1.13%	0	361	86	12,742	693	1,343	11,740
12/11/2019	(1,182,190)	(1,183,472)	1,282	0.11%	0	3,153	-146	13,355	1,012	1,437	(3,162)
12/12/2019	(964,798)	(983,325)	18,527	1.88%	0	2,138	300	12,190	1,319	1,351	14,738
12/13/2019	(1,001,966)	(1,009,572)	7,606	0.75%	0	629	60	12,585	547	1,313	5,604
12/14/2019	(917,418)	(927,122)	9,704	1.05%	0	588	13	11,089	1,007	1,210	7,894
12/15/2019	(1,402,292)	(1,416,642)	14,350	1.01%	0	1,379	361	12,908	1,079	1,399	11,211
12/16/2019	(1,025,396)	(1,038,224)	12,828	1.24%	0	801	-329	12,769	754	1,352	11,004
12/17/2019	(1,418,975)	(1,416,900)	-2,075	-0.15%	0	2,690	483	13,231	1,222	1,445	(6,694)
12/18/2019	(1,105,939)	(1,116,404)	10,465	0.94%	0	3,420	99	13,135	1,576	1,471	5,475
12/19/2019	(1,015,641)	(1,023,083)	7,442	0.73%	0	1,460	-1,020	12,788	1,309	1,410	5,592
12/20/2019	(828,532)	(837,192)	8,660	1.03%	0	557	-367	11,364	796	1,216	7,254
12/21/2019	(654,368)	(659,041)	4,673	0.71%	0	28	17	7,687	305	799	3,829
12/22/2019	(631,555)	(642,194)	10,639	1.66%	0	0	8	5,853	3	586	10,046
12/23/2019	(1,117,528)	(1,128,727)	11,199	0.99%	0	979	-251	10,136	925	1,106	9,365
12/24/2019	(1,025,440)	(1,028,009)	2,569	0.25%	0	448	-126	10,354	905	1,126	1,121
12/25/2019	(902,404)	(907,333)	4,929	0.54%	0	376	-23	9,065	269	933	3,643
12/26/2019	(923,603)	(928,122)	4,519	0.49%	0	696	42	9,184	581	976	2,804
12/27/2019	(1,054,078)	(1,057,840)	3,762	0.36%	0	487	-187	10,597	824	1,142	2,319
12/28/2019	(894,304)	(898,250)	3,946	0.44%	0	1,734	-78	9,683	343	1,003	1,287
12/29/2019	(631,905)	(634,699)	2,794	0.44%	0	813	22	7,445	319	776	1,183
12/30/2019	(626,078)	(633,686)	7,608	1.20%	0	418	-56	8,160	609	877	6,369
12/31/2019	(874,178)	(881,929)	7,751	0.88%	0	277	-135	9,835	358	1,019	6,589
Total	**(574,329,905)**	**(579,611,501)**	**5,281,596**	**0.01**	**70,994**	**1,064,446**	**312,756**	**4,974,546**	**348,973**	**532,352**	**3,301,048**

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

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ 340	$ 13	$ 256	$ 7	$ -	$ -	$ 31	$ -	$ -	$ -	$ -	$ -
Anson_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9
Anson_G4	$ 1,822	$ 3	$ 701	$ 9	$ 2	$ -	$ -	$ -	$ -	$ 50	$ 1,487	$ 458
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_ A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G6	$ 2,308	$ 15,160	$ 23,344	$ 13,314	$ 20	$ 1,743	$ 5	$ 3	$ -	$ 4,007	$ 6,066	$ 10,985
Blk_Dog_G52	$ 29,074	$ 7,623	$ 14,421	$ 9,179	$ 5,982	$ 2,081	$ 729	$ 516	$ 459	$ 453	$ 2,088	$ 578
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ 1,439	$ 5	$ 189	$ 29	$ -	$ -	$ -	$ -	$ -	$ 722	$ -	$ 333
Blue_Lk_G8	$ 1,951	$ 16	$ 340	$ 2	$ -	$ -	$ -	$ 4	$ 2	$ -	$ -	$ 340
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ 5,241	$ 3,363	$ 3,011	$ 3,274	$ 6	$ -	$ 24	$ -	$ -	$ -	$ 284	$ -
Canon_Falls2	$ 4,197	$ -	$ 2,779	$ 3,164	$ 928	$ -	$ 1	$ -	$ -	$ -	$ 464	$ 104
CC Highbridge1	$ 3,720	$ 1,786	$ 3,673	$ -	$ 768	$ 89	$ 102	$ 38	$ 334	$ 186	$ 29	$ 2,278
CC Highbridge2	$ -	$ 113	$ 127	$ -	$ 407	$ 53	$ 366	$ 29	$ 180	$ 49	$ 15	$ 431
CC Mankato	$ 12,553	$ 1,638	$ 867	$ -	$ 2,326	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6	$ 42	$ 107	$ -	$ 870
CC Mankato2	$ -	$ -	$ -	$ -	$ -	$ 331	$ 43	$ 320	$ 63	$ 69	$ 382	$ 824
CCRiverside1	$ 5,417	$ 10,766	$ 16,501	$ 2,535	$ 6,360	$ 3,589	$ 122	$ 485	$ 1,890	$ 345	$ 500	$ 219
CCRiverside2	$ 9,729	$ 23,177	$ 27,740	$ 8,298	$ 15,397	$ 3,098	$ 34	$ 485	$ 782	$ 1,168	$ 1,129	$ 132
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ 2	$ 123	$ 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_2	$ 0	$ 9	$ -	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_3	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_4	$ 0	$ 6	$ -	$ -	$ 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_5	$ 4	$ 11	$ 44	$ 0	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_6	$ -	$ 7	$ 77	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ 49	$ 330	$ 1,909	$ 2,080	$ 12,902	$ 12,575	$ 421	$ 2,135	$ 1,982	$ -	$ 2,013	$ 2,787
LSPower_1	$ 1,981	$ 5,876	$ 1,030	$ 2,069	$ 694	$ 3	$ 409	$ 4	$ 257	$ 3,542	$ 1,755	$ 946
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MHEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ -	$ 43	$ -	$ -	$ 9	$ -	$ -
MP.LASKIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.NSP1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP ROCK_CO BAT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ADAMSWD1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.GEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.SER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50	$ -
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	$ 91	$ 83	$ 117	$ 129	$ 108	$ 96	$ 101	$ 74	$ 82	$ 65	$ -	$ -
NSP.NOBLES_TR2	$ 66	$ 89	$ 128	$ 105	$ 70	$ 80	$ 71	$ 52	$ 69	$ 41	$ -	$ -
NSP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
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	$ -	$ -	$ -	$ 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ -	$ -	$ 58	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rapidan_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIV9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD71	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock_County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ 9,861	$ 12,257	$ 21,552	$ 5,639	$ 8,447	$ 9,347	$ 182	$ 210	$ 3,053	$ 2,280	$ 1,916	$ 1,080
SHERCO_G1	$ 710	$ 1,245	$ 5,995	$ 11,838	$ 56,286	$ 41,667	$ 4,471	$ 6,355	$ 18,641	$ 13,271	$ 21,293	$ 8,633
SHERCO_G2	$ 1,278	$ 990	$ 4,571	$ 2,349	$ 24,920	$ 33,949	$ 14,618	$ 5,018	$ -	$ 729	$ 12,897	$ 19,277
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ 10	$ -	$ 727	$ -	$ -	$ -	$ 3	$ -	$ -	$ -	$ -	$ -
Wheaton_2	$ 26	$ 4	$ 1	$ 617	$ -	$ -	$ 3	$ -	$ -	$ -	$ -	$ -
Wheaton_3	$ 8	$ -	$ 724	$ 440	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_4	$ 10	$ -	$ 23	$ 502	$ -	$ -	$ -	$ -	$ 5	$ -	$ -	$ -
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ 1	$ -	$ -	$ 2	$ -	$ 6	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

LOCATION	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ 121	$ 135	$ 160	$ 118	$ 126	$ 162	$ 84	$ 239	$ 121	$ 102	$ -	$ -
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	**$ 92,009**	**$ 84,836**	**$ 131,023**	**$ 65,718**	**$ 135,816**	**$ 108,862**	**$ 21,868**	**$ 15,975**	**$ 27,962**	**$ 27,196**	**$ 52,368**	**$ 50,284**

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ 302	$ -	$ 295	$ -	$ -	$ -
Anson_G3	$ 214	$ -	$ 14	$ -	$ -	$ -
Anson_G4	$ 243	$ 1,164	$ 343	$ 2,370	$ 438	$ 1
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_ A	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G6	$ 28,964	$ 27,414	$ 4,295	$ 3,576	$ 901	$ 88
Blk_Dog_G52	$ 1,027	$ 929	$ 571	$ 1,143	$ 363	$ 589
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ 2,087	$ 425	$ -	$ 6	$ -	$ -
Blue_Lk_G8	$ 1,389	$ 34	$ -	$ 0	$ 580	$ -
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ -	$ 14	$ -	$ -	$ 42	$ -
Canon_Falls2	$ 8	$ 9	$ 15	$ -	$ 49	$ -
CC Highbridge1	$ 646	$ 10	$ 88	$ 72	$ 57	$ 18
CC Highbridge2	$ -	$ -	$ 21	$ 19	$ 17	$ -
CC Mankato	$ -	$ -	$ -	$ -	$ -	$ -
CC Mankato1	$ 519	$ 468	$ 690	$ 417	$ 1,931	$ 1,705
CC Mankato2	$ 380	$ 573	$ 931	$ 1,543	$ 934	$ 629
CCRiverside1	$ 470	$ 1,141	$ 2,214	$ 438	$ 2,268	$ 2,938
CCRiverside2	$ 703	$ 496	$ 715	$ 306	$ 155	$ 467
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	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_2	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_3	$ 1	$ -	$ -	$ -	$ -	$ -
InvrHils_4	$ 1	$ -	$ -	$ -	$ -	$ -
InvrHils_5	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_6	$ 1	$ -	$ -	$ -	$ -	$ -
JIMFL	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ 1,529	$ 1,366	$ 3,148	$ 598	$ 446	$ 104
LSPower_1	$ 4,014	$ 2,668	$ 2,610	$ 3,754	$ 3,927	$ 7,906
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	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NOBLES_TR2	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSP	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -

LOCATION	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
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	$ 386	$ 226	$ 382	$ 683	$ 1,216	$ 943
SHERCO_G1	$ 10,947	$ 9,333	$ 5,578	$ 1,724	$ 8,964	$ 6,527
SHERCO_G2	$ 12,046	$ 9,587	$ 14,222	$ 17,268	$ 6,419	$ 7,481
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ 5	$ -	$ 5	$ 8	$ -	$ -
Wheaton_2	$ 9	$ -	$ 449	$ 1	$ 17	$ -
Wheaton_3	$ 4	$ -	$ 12	$ 8	$ 3	$ -
Wheaton_4	$ 110	$ -	$ 9	$ -	$ 1	$ -
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -

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

LOCATION	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ 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	**$ 66,005**	**$ 55,857**	**$ 36,606**	**$ 33,938**	**$ 28,728**	**$ 29,396**

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,576	$ -	$ -	$ 1,984	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 57,535	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 483
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,325	$ -
SHERCO_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 187	$ -	$ -	$ -	$ -
Wheaton_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 187	$ -	$ -	$ -	$ -
Wheaton_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 187	$ -	$ -	$ -	$ -
Wheaton_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 187	$ -	$ -	$ -	$ -
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19
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	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2,326**	**$ -**	**$ -**	**$ 60,844**	**$ 483**

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
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	$ -	$ -	$ 2,994	$ -	$ -	$ -
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	$ -	$ 1,681	$ -	$ -	$ -	$ -
CC Mankato2	$ -	$ 2,665	$ -	$ -	$ -	$ -
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	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
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	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL2.WND	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
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	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G2	$ -	$ -	$ -	$ -	$ -	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
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	**$ -**	**$ 4,346**	**$ 2,994**	**$ -**	**$ -**	**$ -**

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

Xcel Energy®

PART K

REPORTING REQUIREMENTS FROM PRIOR AAA ORDERS

2006 AAA and MISO Day 2 Ordered Reporting Requirements

On February 6, 2008, the Commission issued its 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*. In compliance with this Order, the Company is required to report the following information as part of its AAA report:

<u>Order Item 11</u>

Xcel Energy shall provide in future electric annual automatic adjustment filings a Wind Curtailment Summary Report Table similar to the table that Xcel is already providing in its AAA filings, but expanded to include the amount of any curtailment payments made under the following four curtailment categories:

1= Lack of firm transmission as described in Attachment C of the MISO Open Access Transmission Tariff, or any successor provision

2= Low Load

3= Transmission loading relief or MISO directive for reasons other than (1) above

4= Other, which must be explained in detail if compensation is requested

The Wind Curtailment Summary Report Table for January 2017 to December 2019 is included in Part H, Section 5, Schedule 1.

<u>Order Item 12</u>

The Commission finds that Xcel Energy has satisfied the Commission's directive in docket E002/CI-00-415 to include in its annual automatic adjustment filing a monthly comparison of generation costs allocated to retail and wholesale customers for the months of June, July and August. The Company shall continue to report this information in future annual automatic adjustment filings.

This information is reported in Part H, Section 2, Schedule 1.

Order Item 16

The Commission discontinues the requirement that all electric utilities subject to automatic adjustment filing requirements report in these annual filings "each instance where MISO directed Companies to redispatch Companies' own generation for reliability reasons, including an explanation of financial impact on rates, in any, and the reason for the redispatch, if known."

The Company discontinued reporting this item (formerly included as Part I, Section 8).

Order Item 18

All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.

The Company's compliance Maintenance Expenses of Generation Plants report is included in Part K, Section 1, Schedule 1.

Order Item 21

All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall provide information requested by the Department in docket E,G999/AA-07-1130 according to the spreadsheet attached to the 2007 Report pertaining to MISO Day 2 charges, one for every month in the AAA period and as a summary of MISO Day 2 charges for the entire AAA period, for a total of 13 pages in each utility's AAA filings.

The Company has included this additional MISO Day 2 Report in Part J, Section 5, Schedule 7. Amounts and MWh for the intersystem charge types are allocated based on the MISO invoice for asset based amounts, and come directly from MISO NSP Trading settlement statements for the non-asset based amounts.

Northern States Power Company Docket No. E999/AA-20-171

Expenses Pertaining to Maintenance of Generation Plants Part K Section 1

Schedule 1

Page 1 of 1

	2016	2018	2019
Energy Allocation Ratios	**87.3278%**	**87.1688%**	**86.8573%**
Demand Allocation Ratios	**87.3461%**	**87.6880%**	**87.0633%**

			NSP Minnesota Company Totals			**Minnesota Jurisdictional Totals ***		
FERC Account	**Description**	**Allocation Method**	**2016 Test Year**	**2018 Actuals**	**2019 Actuals**	**2016 Test Year**	**2018 Actuals**	**2019 Actuals**
510	Stm Maint Super&Eng	Energy	$ 2,008,848	$ 3,701,428	$ 3,765,365	$ 1,754,283	$ 3,226,490	$ 3,270,494
511	Stm Maint of Structures	Demand	$ 2,784,311	$ 5,715,120	$ 6,419,921	$ 2,431,987	$ 5,011,474	$ 5,589,395
512	Stm Maint of Boiler Plt	Energy	$ 39,704,208	$ 25,986,582	$ 22,850,699	$ 34,672,811	$ 22,652,192	$ 19,847,500
513	Stm Maint of Elec Plant	Energy	$ 4,931,682	$ 13,323,980	$ 6,807,557	$ 4,306,730	$ 11,614,353	$ 5,912,861
514	Stm Maint of Misc Stm Plt	Demand	$ 18,325,365	$ 11,506,279	$ 11,713,257	$ 16,006,492	$ 10,089,626	$ 10,197,948
528	Nuc Maint Super & Eng	Energy	$ 6,183,520	$ 5,044,952	$ 7,262,125	$ 5,399,932	$ 4,397,624	$ 6,307,686
529	Nuc Maint of Structures	Demand	$ 9,368	$ 142,945	$ 24,683	$ 8,183	$ 125,346	$ 21,489
530	Nuc Mtc of React Plt Equip	Energy	$ 48,934,011	$ 40,743,589	$ 38,926,797	$ 42,732,995	$ 35,515,698	$ 33,810,765
531	Nuc Maint of Elect Plant	Energy	$ 13,522,861	$ 9,787,389	$ 12,389,211	$ 11,809,217	$ 8,531,550	$ 10,760,934
532	Nuc Mtc of Misc Nuc Plant	Demand	$ 25,463,010	$ 32,043,555	$ 31,045,208	$ 22,240,946	$ 28,098,353	$ 27,028,983
541	Hydro Mtc Super& Eng	Energy	$ 5,509	$ 8,644	$ 2,653	$ 4,811	$ 7,535	$ 2,305
542	Hyd Maint of Structures	Demand	$ 22,000	$ 37,215	$ 39,246	$ 19,216	$ 32,633	$ 34,169
543	Hydro Mtc Resv, Dams	Demand	$ 22,000	$ 207,434	$ 62,498	$ 19,216	$ 181,895	$ 54,413
544	Hyd Maint of Elec Plant	Energy	$ 88,144	$ 107,266	$ 120,543	$ 76,974	$ 93,502	$ 104,700
545	Hyd Mt Misc Hyd Plnt Mjr	Demand	$ 59,713	$ 1,397	$ 4,755	$ 52,157	$ 1,225	$ 4,139
551	Oth Maint Super & Eng	Demand	$ 310,346	$ 1,783,205	$ 1,698,454	$ 271,075	$ 1,563,657	$ 1,478,730
552	Oth Maint of Structures	Demand	$ 3,242,151	$ 9,901,944	$ 6,650,945	$ 2,831,892	$ 8,682,817	$ 5,790,532
553	Oth Mtc of Gen & Ele Plant	Demand	$ 17,225,836	$ 9,706,726	$ 6,306,898	$ 15,046,096	$ 8,511,634	$ 5,490,994
554	Oth Mtc Misc Gen Plt Mjr	Demand	$ 1,866,543	$ 3,667,049	$ 5,025,921	$ 1,630,353	$ 3,215,562	$ 4,375,733
Production Maintenance Expense Totals			**$ 184,709,427**	**$ 173,416,699**	**$ 161,116,736**	**$ 161,315,366**	**$ 151,553,165**	**$ 140,083,770**

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

2007 AAA Ordered Reporting Requirements

On August 31, 2009, the Commission issued its ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS in Docket Nos. E,G999/AA-07-1130, E999/M-07-1028, E999/M-09-602 and E001/PA-05-1272. In compliance with this Order, the Company has included the following information as part of this report:

1. Annual Transmission Transformers Report

This compliance report is included in Part H, Section 4 of this report. Part H, Section 4, Schedule 1 provides status categories for each transformer (in-service standalone or in-service duplicate) as required in the Commission's Order dated August 16, 2013 in Docket No. E999/AA-11-792, Order Point No. 23a.

2. Auction Revenue Rights

Within 30 days of the 2007 AAA Order, utilities subject to automatic adjustment filing requirements were required to provide Auction Revenue Rights (ARR) data for fiscal years 2008 and 2009. On March 17, 2009, the Commission issued an interim order in Docket No. E001, E015, E002, E017/M-08-528, which authorized the Company to flow through the following 4 ARR charge types:

- ARR - FTR Auction Transactions
- Monthly ARR Revenue
- Infeasible ARR Uplift
- ARR Stage 2 Distribution

The monthly ARR by charge type data is listed in Part J, Section 5 of this report.

3. Emergency Demand Response

Currently the Company puts all of its demand response in MISO's resource adequacy construct, making the demand response available in a NERC-declared Emergency Event Alert Level Two. The Company does not offer any of its demand response economically to the market, or under Schedule 30 (Emergency demand Response) of the MISO tariff.

2008 AAA Ordered Reporting Requirements

On March 15, 2010, the Commission issued its ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND SETTING FURTHER REQUIREMENTS in Docket No. E999/AA-08-995. Order Point No. 12 requires the Company to report the following information as part of its AAA report:

> *All electric utilities required to file annual automatic adjustment reports shall work with their contractors to identify and develop reasonable contingency plans to mitigate against the risk of delays or lack of performance when contractors perform poorly and increase costs during plant outages. The Commission asks the OES to continue monitoring this issue and to include a report on the electric utilities' plans in its next review.*

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 alliance-like agreements with companies that consistently exceed others in technology, quality and contract management (including following the Scope of Work). As Xcel Energy increases the percentage of spend with these select companies, the possibility of contractor service or supplier product failure decreases.

Third, Xcel Energy has invested time and resources in developing a better Scope of Work. Successful adherence to the Scope of Work by a contractor or vendor is measured by completion of the total work scope defined in the bid Technical Specification that is part of the Purchase Order and/or contract. By writing Scopes of Work with greater level of detail and expectations, Xcel Energy gets better project scheduling, reducing 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.

For more information about how we have worked to manage contractor performance, see Part K, Section 4 (*2009 and 2010 AAA Ordered Reporting Requirements*) where we outline our approach to forced outages and specifically discuss our quality management program as it relates to contractors.

2009 and 2010 AAA Order Reporting Requirements

On April 6, 2012, the Commission issued its 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. In compliance with this Order, the Company has included the following information as part of this report:

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

Order Point 8 of the Commission Order states:

> *Interstate, Minnesota Power, Otter Tail, and Xcel shall report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by their ratepayers. If any offsetting revenues and/or compensation are not credited back to a utility's ratepayers through the fuel clause, the IOUs shall clearly identify such revenues or compensation by source and amount and fully justify their action in the relevant AAA filings.*

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. See Part K, Section 4, Schedule 1 for a summary of power purchase agreement off-setting revenues.

2. Forced Outages

Order Point 22 of the Commission Order states:

> *The Commission requests Interstate, Minnesota Power, Otter Tail and Xcel to comment on sharing lessons learned regarding the handling of forced outages. The Commission also requests the companies to discuss amongst themselves whether and what kind of information sharing would be beneficial. The companies shall provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.*

Part K, Section 4, Schedule 2 provides for each forced outage, 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.

As we have stated in prior AAA reports, we have several operational improvement initiatives at work under the Generation Operating Model, including Human Performance Improvements, Quality Assurance / Quality Control and Work Management Process Improvements. We provide greater detail on each of these initiatives below.

Generation Operating Model

Energy Supply's updated Generation Operating Model and organizational structure is designed for success in a rapidly-evolving environment that resulted in Xcel Energy's carbon vision and change to its generation mix.

The updated Operating Model drives the consistent planning and management of capital, O&M and plant overhaul projects; the successful delivery of new assets; and project development for emerging and innovative generation technologies, such as wind, solar and storage per our carbon vision. The model drives consistency and alignment to optimize environmental compliance, and relies on a central business operations coordination role to lead the business unit's engagement with corporate processes. The model reflects a future orientation emphasizing employee collaboration, which provides significant benefits to our fleet transformation work. It will enable us to create more value for our customers and the company by increasing utilization of physical and personnel assets and directing investment to where they drive the best returns.

The Operating Model includes an accountability framework assigning leadership and decision-making roles for cross-functional teams across the organization, adopting behaviors that promote greater collaboration and streamlining the decision-making processes. The long-standing practices of managing our assets a certain way is yielding to a significantly different portfolio and future-focused, fleet-based approach.

[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.

The structure and accountabilities of the organizations describe where key work is done and who does it, as well as the organization services and coordinating mechanisms that encourage collaboration and expertise sharing. Core business function accountabilities specify roles and responsibilities, and clarify decision rights for issues that cross the business. The organization's goal is to make decisions through informed consensus and to streamline the decision-making process through adoption of behaviors that promote greater communication and partnerships.

Enablers that support the Operating Model include talent development, resource sharing, new technology, data-driven analysis, expertise in critical areas, fleet maintenance strategies by fuel type, and thriving partnerships with other organizations. Employee engagement is enhanced through knowledge that everyone's contributions matter and the expectation that we work together as a strong team.

Human Performance

An example of a human performance improvement can be found at the Sherco plant. The Sherco team sought to engender behaviors that support safe, reliable, and predictable operation by reducing the frequency and severity of events caused by human errors in the operations department. As a result, a team created operator help guides that were incorporated into the plant's control system. Sherco Unit 1 and 2 operators and other plant personnel have access to help guides for every system and almost every piece of operating equipment. These guides cover an array of operational parameters, such as temperatures, pressures, vibrations, and environmental permit limits.

Contractor Control - Quality Assurance / Quality Control

Improvements in contractor and vendor/supplier performance continue through the implementation of the Energy Supply Quality Management Program. During this AAA reporting period, there were only minor events that contributed to fleet plant unplanned loss of capacity in the areas of external service and material quality, and equipment design issues directly related to poor performance by contractors and suppliers.

The 2018/2019 Quality Management program oversight efforts continue to focus on contractor/supplier performance during plant overhauls and major capital projects. A significantly higher number of in-house plant personnel are using the quality program tools and practices to conduct oversight and monitoring of contractors and suppliers engaged in their specific projects. Plant personnel continue to identify cases where equipment or services provided by contractors did not meet specifications and requirements and document these conditions under the Non-Conformance Report (NCR) process. The NCR process has been an effective tool to correct deficiencies, prevent them from reoccurring, and also capture rework costs, recovering costs from Suppliers/Contractors.

Work Management Process Improvements
As part of the Generation Operating Model playbook, the Energy Supply work and asset management (WAM) planning and scheduling process is a standard approach to ensure all work is properly identified, prioritized, planned, scheduled, executed, and documented. The objective of the process is to optimize the use of personnel, financial, materials and services resources to improve safety, availability, reliability and equipment/facility performance. Every plant and department are required to conform to the standardized work management planning and scheduling process to ensure consistency. Staffing levels and position titles may differ from plant to plant; but this difference does not preclude use of the process at all generating facilities and service departments., work management process improvements are being implemented to reduce repeat failures of critical equipment by implementing standard Predictive Maintenance (PdM) and Preventive Maintenance (PM) actions prior to failure.

In 2018/2019 we continued the best practice of thermography scans and vibration monitoring during operator rounds. Prior to a planned outage, we scan critical equipment such as large motors, pumps and fans to identify any emergent repairs that may be needed to reduce the risk of unplanned derates or outages.

Improvements in reliability have also been made with the establishment of the Monitoring and Diagnostic Center in 2014. The center monitors the performance and health of our generating fleet and provides the data enabling us to make cost-effective condition-based, rather than time-based, maintenance decisions.

3. MISO Module E

Order Point 22 of the Commission Order states:

> *Interstate, Minnesota Power, Otter Tail and Xcel shall continue to provide a comparison and reconciliation of the MISO accredited value of their generators using MISO accredited UCAP values and integrated resource plan capacity ratings in future AAA filings. This comparison and reconciliation should be prepared in sufficient detail to allow the Department to understand: (a) the impacts of generation*

resources that are not network deliverable (i.e., not interconnected), and (b) the possible constraints of utilities' systems and the impact of those constraints.

Part K, Section 4, Schedule 3 compares NSP's resource plan capacity assumptions with the capacity accredited by MISO through their Module E process. Schedule 3 uses the 2016-2030 Resource Plan model and the Module E accreditation for the 2018/2019 planning year. These most closely match the AAA reporting period of July 2018 to December 2019. Schedule 3 contains both the installed capacity (ICAP) and the unforced capacity (UCAP) for all capacity resources. Note that MISO uses the same ICAP value as UCAP value for intermittent resources such as run of river hydro. MISO used slightly different assumptions in accrediting wind.

All Company resources are accredited by MISO to be deliverable to NSP System load. The Company does not expect constraints on its system to impact the deliverability of these capacity resources to its loads.

4. Summary of Unusual Adjustments Over $500,000

Order Point 30 of the Commission's Order states:

Xcel shall provide footnotes in future monthly FCA filings and future AAA filings to explain unusual adjustments of $500,000 and higher on a going forward basis.

The Company began including this information in our monthly FCA reports in the report filed on April 30, 2012 for March 2012. Part K, Section 4, Schedule 4 provides a monthly breakdown of the unusual adjustments of $500,000 which were reported in the FCA filings during the current AAA reporting period.

This report of unusual items is also in compliance with Order Point 5 of the Commission's November 13, 2019 Order in Docket No. E999/AA-18-373, which states:

Xcel shall identify and include error reports in future AAA filings and annual FCA true-up filings under the new FCA reform process.

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Summary of Power Purchase Agreement Off-Setting Revenues (July 1, 2018 - December 31, 2019)

Project	Docket No.	Amount Received	Date Booked	Credited to FCA (Yes/No)	Month/Year Credited to FCA	FCA Docket No.	Reason for Payment
		[PROTECTED DATA BEGINS					
Viking Group	E002/M-10-820		July 2018	Yes	September 2018	September 2018	Energy Production Credit
			October 2018	Yes	December 2018	December 2018	Energy Production Credit
			January 2019	Yes	March 2019	March 2019	Energy Production Credit
		PROTECTED DATA ENDS]					

Note:

These offsetting revenues represent primarily non-recurring events for a limited number of contracts in a given month. These revenue credits are embedded in the FERC Account 555 line item in the monthly FCA calculation (Attachment 1 page 2 line 3a).

Unit Outage Information
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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Duration (Days)	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
JULY 2018										
BayFrnt_G6	Forced	Exciter\Boiler Tube Leaks	07/28/2018	07/31/2018	**3**	1) Reserve Exciter 2) Boiler #2 Superheat Tubes	1) The brushes on the reserve exciter failed causing a loss of the unit 2) There were 2 leaks found in the secondary superheat tubes		1) No similar failures were reported during this reporting period. 2) No similar failures were reported during this reporting period.	1) Increased inspections of reserve exciter brushes 2) Boiler #2 Superheat tubes (primary and secondary) were replaced in September - October 2018 as a planned capital project.
SHERCO_G1	Forced	Circulating Water Systems	07/01/2018	07/31/2018	**30**	11 Boiler Circulating Pump	The thrust disc assembly un-bonded during the initial startup of the pump indicating a manufacturing defect of the thrust disc assembly. This in turn caused high vibrations on the pump.		Associated events on 8/18/18 and 9/5/18.	Thrust disc assembly and other resultant damage to the pump was refurbished by Hayward Tyler. A blanking plate was purchased to facilitate removal of a pump and returning to on line status during any future required repairs to all the boiler circ pumps.
Anson_G3	Forced	Miscellaneous (Gas Turbine)	07/01/2018	07/31/2018	**30**	Turbine	High vibration on turbine bearings		No similar failures were reported during this reporting period	A major, rotor out overhaul was conducted and the unit was put back into service in May of 2019
Blk_Dog_G6	Forced	Auxiliary	07/01/2018	07/02/2018	**1**	Turbine Hydraulic Oil	Hydraulic manifold developed a leak and required the unit to be held out of service and the turbine compartment to be cleaned.		No similar failures were reported during this reporting period.	Hydraulic manifold was inspected and loose plug was found. Plug was reinstallated and torqued properly and verified.
French_1	Forced	Generator	07/05/2018	07/09/2018	**4**	Generator	Hign Vibrations		No similar failures were reported during this reporting period	A balance shot was performed on the generator rotor.
French_1	Forced	Boiler Overhaul and Inspections	07/26/2018	07/30/2018	**4**	Boiler	This was a maintenance outage for periodic cleaning and inspection.		No similar failures were reported during this reporting period	RDF fuel causes boiler fouling. We believe we are cleaning at appropriate intervals.
French_2	Forced	Boiler Tube Leaks	07/18/2018	07/23/2018	**5**	Boiler	Boiler tube leaks.		No similar failures were reported during this reporting period	Worn tubes that contributed to this failure have been replaced.
Redwing_1	Forced	Miscellaneous Boiler Tube Problems	07/10/2018	07/13/2018	**2**	Boiler	Routine boiler cleaning due to tube fouling. This is a planned evolution which occurs multiple times per year.		Similar event U2 events on 07/08/2018 and 11/22/2019	Routine Boiler Cleaning
Redwing_2	Forced	Miscellaneous Boiler Tube Problems	07/08/2018	07/12/2018	**4**	Boiler	Routine boiler cleaning due to tube fouling. This is a planned evolution which occurs multiple times per year.		Similar event on 11/22/2019, and U1 event on 7/10/2018	Routine Boiler Cleaning
SHERCO_G2	Forced	Boiler Tube Leaks	07/28/2018	07/31/2018	**3**	Sootblower Supply Piping	Unit taken off line to repair a previously identified leak in the penthouse. Leak was on the sootblower supply piping coming off of the west inlet SH pendant platen header on the fillet weld of the stub tube to the header.		No similar failures were reported during this reporting period.	Through wall weld repair completed on the leak. MT survey was completed on the rest of the welds on the piping system. Four more welds were identified to have linear crack-like indications which were also repaired.
AUGUST 2018										
King_G1	Forced	Boiler Piping System\Controls	08/21/2018	08/31/2018	**10**	12 superheaeter attemperator spray	12 superheater attemperator packing leak		No similar failures were reported during this reporting period.	12 superheater attemperator valve along with other attemperator valves were repacked to prevent future issues.
SHERCO_G1	Forced	Boiler Piping System	08/18/2018	08/22/2018	**5**	11 Boiler Circulating Pump	Unit taken off line to install blanking plate which was recently purchased from Hayward Tyler to facilitate removal and repair to 11 Boiler Circulating Pump while returning the Unit to an on line status. Unit was restored to on line on 8/20/18. The following day, 8/21/18, the installed blanking plate developed a leak on the drain plug which forced the unit off line for repair.		Associated events on 7/1/18 and 9/5/18.	Seal welded the drain plug in the blanking plate. Blanking plate will remain on site as a contingency to facilitate removal of a pump and returning to on line status during any future required repairs to all the boiler circ pumps.
SHERCO_G2	Forced	Boiler Tube Leaks	08/01/2018	08/02/2018	**1**	Sootblower Supply Piping	Unit taken off line to repair a previously identified leak in the penthouse. Leak was on the sootblower supply piping coming off of the west inlet SH pendant platen header on the fillet weld of the stub tube to the header.		No similar failures were reported during this reporting period. This is a continuation of the 7/28/18 event.	Through wall weld repair completed on the leak. MT survey was completed on the rest of the welds on the piping system. Four more welds were identified to have linear crack-like indications which were also repaired.
SEPTEMBER 2018										
BayFrnt_G5	Forced	Boiler Internals and Structures	09/01/2018	09/03/2018	**2**	Boiler #1 Grating System - Corrected I	The retaining pins on 2 of the boiler grates failed causing the grates to jam up.		1 similar failure during this reporting period.	Inspected retaining pins on other grates and replaced those showing wear. The entire boiler grating system was replaced in March 2019 as a planned capital project.
King_G1	Forced	Controls	09/01/2018	09/02/2018	**1**	Feedwater transmitter braided hose	Feedwater transmitter braided hose failure		No similar failures were reported during this reporting period.	All feedwater transmitter braided hoses were hard piped and fittings replaced to prevent future failure
Blue_Lk_G7	Forced	Electrical	09/19/2018	09/21/2018	**2**	Generator Circuit Breaker Charging Motor Power Supply Breaker	Power supply breaker for the GCB charging system failed. This component is typically very reliable.		No similar failures were reported during this reporting period	Replaced power supply breaker.
Blue_Lk_G8	Forced	Generator	09/17/2018	09/30/2018	**13**	#1 Generator Bearing	High Temperature		No similar failures were reported during this reporting period	Alignment Adjustment
SHERCO_G1	Forced	Boiler Piping System	09/05/2018	09/08/2018	**2**	11 Boiler Circulating Pump	This was a maintenance outage to remove the recently installed blanking plate and restore the refurbished 11 Boiler Circulating Pump to service prior to the planned boiler chemical clean outage.		Associated events on 7/1/18 and 8/18/18.	Thrust disc assembly and other resultant damage to the pump was refurbished by Hayward Tyler. A blanking plate was purchased to facilitate removal of a pump and returning to on line status during any future required repairs to all the boiler circ pumps.
SHERCO_G1	Forced	Boiler Tube Leaks	09/29/2018	09/30/2018	**1**	Steam Cooled Wall Screen Tube	Vibration snubber originally installed on the unit had deteriorated through the years. This caused the initiating failure of both this and the 1/17/19 event to be the #5 steam cooled wall screen tube due to reverse bending fatigue failure. In addition, there was collateral damage to the primary superheat assemblies. However, during this first event, the evidence found in the damage lead engineering to believe the initiating event was on the leading edge tube of the primary superheat from short term overheating precipitated by oxide blockage. The sheared steam cooled wall screen tube was originally thought to be caused by the impact of the superheat rupture which careened the U-bend into the team cooled wall screen tube.		Similar failure occurred on 1/17/19 of this reporting period.	Tube replacements consisting of 23 total tube welds and 12 pad welds were completed. An air test was completed to confirm no further leads were present.

Unit Outage Information
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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Duration (Days)	O1. Equipment that resulted in the forced outage	O2. Description of Equipment Failure	Q3. Change in Energy Costs	O4. Failure History During Reporting Period	O5. Steps Taken to Alleviate Reoccurrence
OCTOBER 2018										
BayFrnt_G5	Forced	Condensing System	10/01/2018	10/19/2018	19	Condenser Low Vacuum Trip Bellows - Note that outage started 9/4/2018	Leak developed in the condenser low vacuum trip bellows assembly - could not draw a vacuum in the condenser		No similar failures were reported during this reporting period.	Replaced the low vacuum trip bellows assembly and purchased a spare unit.
Blk_Dog_G52	Forced	Total site gas supply outage to install relief va	10/07/2018	10/16/2018	9	Gas supply regulating station	Gas supply regulating station outage to install additional overpressurization protection in the fuel gas yard. Work scope was added to the fall outage plan. Outside of plant jurisdiction.		No similar failures were reported during this reporting period.	Equipment was installed as planned during the outage.
SHERCO_G1	Forced	Boiler Tube Leaks	10/01/2018	10/06/2018	6	Steam Cooled Wall Screen Tube	Vibration snubber originally installed on the unit had deteriorated through the years. This caused the initiating failure of both this and the 1/17/19 event to be the #5 steam cooled wall screen tube due to reverse bending fatigue failure. In addition, there was signifigant collateral damage to the primary superheat assemblies. However, during this first event, the evidence found in the damage lead engineering to believe the initiating event was on the leading edge tube of the primary superheat from short term overheating precipitated by oxide blockage. The sheared steam cooled wall screen tube was originally thought to be caused by the impact of the superheat rupture which careened the U-bend into the team cooled wall screen tube.		Similar failure occurred on 1/17/19 of this reporting period. This is a continuation of the 9/29/18 event.	Tube replacements consisting of 23 total tube welds and 12 pad welds were completed. An air test was completed to confirm no further leads were present.
SHERC3	Forced	Boiler Tube Leaks	10/04/2018	10/14/2018	10	Finishing Superheat Tube	Initiating tube failure was short term overheating due to oxide exfoliation pluggage, tube #14 on assembly #41. Significant collateral damge spread across 3 assemblies on the finishing superheat.		Similar failure occurred on 10/16/18, 5/27/19, and 10/11/19 during this reporting period.	19 Tube replacements were completed in additon to pad welding on 4 other tubes. An air test was completed prior to returning the unit to service. Continue practice of ramping through the 50-100 MW range druing startup to avoid oxide collection in the superheat section.
SHERC3	Forced	Boiler Tube Leaks	10/16/2018	10/22/2018	6	Finishing Superheat Tube	Initiating tube failure was short term overheating due to oxide exfoliation pluggage, tube #3 on assembly #74. Collateral damage was minimal because the leak was identified immediately. Following analysis of the oxide sample removed during this outage, it was determined that the source of the oxide was 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 failure occurred on 10/4/18, 5/27/19, and 10/11/19 during this reporting period.	Tube section was replaced. TEAM Industrial Services was brought in to perform digital radiography on a select number of lower loops on the finishing superheat. If the 5 assemblies, two tubes were found with oxide pluggage on Pendant 42, loops 4 and 5. These tubes were cut, oxide removed, and welded back together. Oxide sample sent to Xcel metallurgist for analysis.
Redwing_2	Forced	Circulating Water Systems	10/21/2018	10/24/2018	2	Condenser	Took unit 2 off-line to coincide with river dredging near plant intake screenhouse		No similar failures were reported during this reporting period	Completed dredging and returned unit to service.
NOVEMBER 2018										
BayFrnt_G4	Forced	T4-Generator Rotor Failed Inspction/Waiting	11/15/2018	11/30/2018	15	Unit 4 Generator Rotor	During unit overhaul multiple cracks were found during the boresonic inspection of the generator rotor		Yes, this is the initial event relating to multiple events during this reporting period	Decision was made to retire the unit due to age and cost to replace the rotor
SHERCO_G2	Forced	Scrubber module cleaning and maintenance.	11/09/2018	11/10/2018	1	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance. With 2 modules out for major clean at a time we lose our normal redundancy.		Multiple similar derates during this reporting period.	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. We are persuing ways of minimizing the amount of time required to complete a major clean.
SHERCO_G2	Forced	9 Module operation - loss of 203 Spray pump	11/17/2018	11/19/2018	1	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance. With 2 modules out for major clean at a time we lose our normal redundancy.		Multiple similar derates during this reporting period.	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. We are persuing ways of minimizing the amount of time required to complete a major clean.
King_G1	Forced	Forced outage due to generator pot transform	11/09/2018	11/12/2018	3	Generator pot transformer fuse	Generator pot transformer fuse clip failure		No similar failures were reported during this reporting period.	Installlation of new style clip for holding fuses in place were installed preventing the stretching that occurred on old style clips
SHERC3	Forced	repair steamleak on DP supply line	11/01/2018	11/03/2018	2	Deaerator Steam Supply Piping	Crack in the weld on the aux steam supply piping to the deaerator about eight inches long, in a weld at the end of a 60 degree elbow.		No similar failures were reported during this reporting period.	Damaged area was excavated and re-welded. Other welds on the elbow were inspected for cracking. Additional inspections are planned for upcoming overhauls to ensure this condition is corrected.

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DECEMBER 2018										
BayFrnt_G4	Forced	Miscellaneous (Generator)	12/01/2018	12/14/2018	14	Unit 4 Generator Rotor	During unit overhaul multiple cracks were found (November 2018) during the boresonic inspection of the generator rotor		This is a continuance of the initial event found during overhaul beginning 11/15/2018. No similar failures were reported during this reporting period.	Awaiting approval for retirement of unit
BayFrnt_G4	Forced	Miscellaneous (Generator)	12/17/2018	12/31/2018	14	Unit 4 Generator Rotor	During unit overhaul multiple cracks were found (November 2018) during the boresonic inspection of the generator rotor		This is a continuance of the initial event found during overhaul beginning 11/15/2018. No similar failures were reported during this reporting period.	Awaiting approval for retirement of unit
BayFrnt_G4	Forced	Boiler Piping System	12/14/2018	12/17/2018	3	Boiler 2 Attemperator Valve	Valve body material failed		No similar failures were reported during this reporting period.	Valve was replaced
SHERC3	Forced	Boiler Fuel Supply from Bunkers to Boiler	12/13/2018	12/18/2018	5	301 Coal Mill Motor	306 Mill was out for major overhaul and 302 mill was out for internal inspections when this motor failed which forced us into a derate with only 7 mlls available.		No similar failures were reported during this reporting period.	Motor was swapped with the motor previously on 306 mill. Original motor was sent to Lewis Motor for refurbishment.
SHERCO_G1	Forced	Wet Scrubbers	12/01/2018	12/03/2018	2	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance. With 2 modules out for major clean at a time we lose our normal redundancy. In this instnace, 24 hour high voltage cleans needed to be completed.		Multiple similar derates during this reporting period.	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. We are persuing ways of minimizing the amount of time required to complete a major clean. When high voltage cleans are required, which typically is every thirty days on each module, we can normally wait until the weekend and perform multiple high voltage cleans during that time period.
SHERCO_G1	Forced	Wet Scrubbers	12/08/2018	12/10/2018	2	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance. With 2 modules out for major clean at a time we lose our normal redundancy. In this instnace, 24 hour high voltage cleans needed to be completed.		Multiple similar derates during this reporting period.	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. We are persuing ways of minimizing the amount of time required to complete a major clean. When high voltage cleans are required, which typically is every thirty days on each module, we can normally wait until the weekend and perform multiple high voltage cleans during that time period.
JANUARY 2019										
BayFrnt_G4	Forced	Miscellaneous (Generator)	01/01/2019	01/31/2019	31	Unit 4 Generator Rotor	During unit overhaul multiple cracks were found (November 2018) during the boresonic inspection of the generator rotor		This is a continuance of the initial event found during overhaul beginning 11/15/2018. No similar failures were reported during this reporting period.	Awaiting approval for retirement of unit
SHERCO_G1	Forced	Loss of 12 Transfer Hopper Feeder Belt - Onl	01/02/2019	01/03/2019	1	12 Transfer Hopper Feeder Belt	Tensioner on 12 feeder belt failed causing the belt to run off the pulley, damaging the belt to an unusable state.		No similar failures were reported during this reporting period.	The belt and tensioner were replaced. Maintenance plans created to inspect feeder belts and tensioners on the units.
SHERCO_G2	Forced	Must remove 22 FD fan from service. Duct w	01/07/2019	01/08/2019	1	22 Forced Draft Fan ductwork lagging	Large section of ductwork lagging was found hanging/loose in the Unit 2 fan room. Due to safety implications, 22 forced draft fan was removed from service so loose tin could be accessed by scaffold and removed.		No similar failures were reported during this reporting period.	Loose tin was removed. Permanent repair made during the Febuary 2019 maintenance outage.
SHERCO_G2	Forced	Sherco 2 derate due to Reheater tube leak. [	01/20/2019	01/31/2019	11	Reheat Tube leak	Unit 2 had a known reheat leak which was being monitored with the projection that we could operate until the 2/9/19 schedule maintenance outage. Unit 1 was forced off line for its own tube leak on 1/17/19. The rate of degradation on the Unit 2 reheater leak increased, so a management decision was made to conservatively derate the unit to lower reheat pressure to prevent a second Sherco Unit from being forced off line. Once Unit 1 was stabile following its return, the derate was terminated.		No similar failures were reported during this reporting period.	Tube #2 on assembly #1 was repaired during the scheduled maintenance outage along with minor repairs to the rear reheat, mainly leading edge tube shields. The failure was caused by sootblower tube thinning.
SHERC3	Forced	Derated due to max steam flow limitations wi	01/24/2019	01/31/2019	7	Aux Steam header supply valve	PAS 2701, pegging aux steam supply valve from Unit 2 was inoperable. With Unit 1 off line for tube leak repair and extreme cold temperatures, building heating needed to be supplied by steam from Unit 3. This caused us to challenge our environmental administrative steam flow limit. The unit needed to be derated to maintain compliance until Unit 1 returned to service.		No similar failures were reported during this reporting period.	PAS 2701. aux steam header supply valve, was repaired during the Unit 2 overhaul.

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Redwing_2	Forced	Repair rails on DC conveyor	01/21/2019	01/21/2019	1	Distribution Conveyor - Corrected date	Chain Derailment		No similar failures were reported during this reporting period	Modified load rails for better chain tracking
CC Highbridge1	Forced	Circulating Water Systems Work	01/18/2019	01/19/2019	1	Circ Water T-screens	Plugged with Frazil Ice		No similar failures were reported during this reporting period	Requesting future capital funds to install screenhouse T-Screen warming line
SHERCO_G1	Forced	Unit coming off line because of tube leak	01/17/2019	01/31/2019	15	Steam Cooled Wall Screen Tube	Vibration snubber originally installed on the unit had deteriorated through the years. This caused the initiating failure of both this and the 1/17/19 event to be the #5 steam cooled wall screen tube due to reverse bending fatigue failure. In addition, there was signifigant collateral damage to the finishing superheat assemblies.		Similar failure occurred on 9/29/18 during this reporting period.	Total of 23 tube replacements and 7 pad welds completed between the steam cooled wall screen tube and finishing superheat tube damage. A vibration snubber consiting of stainless steel angle iron affixed to the tubes with staninless steel U-bolts was completed to add rigidity to the tubes. Vibration snubber for Unit 2 was inspected during the 2019 overhauland found to be intact.
Wheaton_3	Forced	Turbine Heaters failed	01/25/2019	01/26/2019	1	Turbine heater	Turbine heater electric contractor coil failed.		No similar failures were reported during this reporting period	Rebuilt the contactor for the heater.
Wheaton_3	Forced	GF STP VLV OPN TO NOT 20FG TRIP	01/30/2019	01/31/2019	1	Stop Valve	Control air supply to purge valves contained water and froze which prevented valves from operating.		No similar failures were reported during this reporting period	Constructed temporary structure and heating to thaw piping and blew down with nitrogen. Installing heat tape and insulation for long term correction.
FEBRUARY 2019										
King_G1	Forced	Feedwater	02/18/2019	02/20/2019	1	Feedwater line radiograph plug	Derate of the unit while attempting isolation and repair of the feedwater line radiograph plug leak. The isolation was unsuccessful.		Initial derate relating to event on 2/20/2019	Repaired leaking plug, inspected piping and replaced section that was found to have areas that had thin spots to prevent future leaks.
BayFrnt_G4	Forced	Miscellaneous (Generator)	02/01/2019	02/28/2019	28	Unit 4 Generator Rotor	During unit overhaul multiple cracks were found (November 2018) during the boresonic inspection of the generator rotor		This is a continuance of the initial event found during overhaul beginning 11/15/2018. No similar failures were reported during this reporting period.	Awaiting approval for retirement of unit
SHERCO_G2	Forced	Boiler Tube Leaks	02/01/2019	02/05/2019	5	Reheat Tube leak	Unit 2 had a known reheat leak which was being monitored with the projection that we could operate until the 2/9/19 schedule maintenance outage. Unit 1 was forced off line for its own tube leak on 1/17/19. The rate of degradation on the Unit 2 reheater leak increased, so a management decision was made to conservatively derate the unit to lower reheat pressure to prevent a second Sherco Unit from being forced off line. Once Unit 1 was stabile following its return, the derate was terminated.		This is a continuation of the 1/20/19 event.	Tube #2 on assembly #1 was repaied during the scheduled maintenance outage along with minor repairs to the rear reheat, mainly leading edge tube shields. The failure was caused by sootblower tube thinning.
SHERC3	Forced	Other Operating Environmental Limitations	02/01/2019	02/03/2019	3	Aux Steam header supply valve	PAS 2701, pegging aux steam supply valve from Unit 2 was inoperable. With Unit 1 off line for tube leak repair and extreme cold temperatures, building heating needed to be supplied by steam from Unit 3. This caused us to challenge our environmental administrative steam flow limit. The unit needed to be derated to maintain compliance until Unit 1 returned to service.		This is a continuation of the 1/24/19 event.	PAS 2701. aux steam header supply valve, was repaired during the Unit 2 overhaul.
King_G1	Forced	Feedwater	02/20/2019	02/22/2019	3	Feedwater line radiograph plug	Offline repair of the feedwater line radiograph plug leak		Forced outage repair relating to event on 2/18/2019	Repaired leaking plug, inspected piping and replaced section that was found to have areas that had thin spots to prevent future leaks.
SHERCO_G1	Forced	Boiler Tube Leaks	02/01/2019	02/03/2019	3	Steam Cooled Wall Screen Tube	Vibration snubber originally installed on the unit had deteriorated through the years. This caused the initiating failure of both this and the 1/17/19 event to be the #5 steam cooled wall screen tube due to reverse bending fatigue failure. In addition, there was signifigant collateral damage to the finishing superheat assemblies.		Similar failure occurred on 9/29/18 during this reporting period. This is a continuation of the 1/17/19 event.	Total of 23 tube replacements and 7 pad welds completed between the steam cooled wall screen tube and finishing superheat tube damage. A vibration snubber consiting of stainless steel angle iron affixed to the tubes with staninless steel U-bolts was completed to add rigidity to the tubes. Vibration snubber for Unit 2 was inspected during the 2019 overhauland found to be intact.
MARCH 2019										
SHERC3	Forced	Miscellaneous (Pollution Control Equipment)	03/09/2019	03/16/2019	6	33 Baghouse	High dp and high opacity in 33 baghouse due to aging bags.		No similar failures were reported during this reporting period.	Capital project to begin bag replacement in 2020 was moved up to this year and is in progress.
King_G1	Forced	Exciter	03/18/2019	03/19/2019	1	Exciter	High vibrations on exciter		There were several attempts to start the unit after repairs/adjustments to the exciter/generator bearings. These attempts were not successful and resulted in more extensive repairs to solve the issue. This was initially discovered on 3/18/2019 and resolved 5/7/2019	The exciter collector rings and brush assemblies were repairedr. Generator shaft bearings and associated seals were also repaired. The plant has limited ramp rate in an attempt to prevent future failure.
King_G1	Forced	Exciter	03/19/2019	03/31/2019	12	Exciter	High vibrations on exciter		There were several attempts to start the unit after repairs/adjustments to the exciter/generator bearings. These attempts were not successful and resulted in more extensive repairs to solve the issue. This was initially discovered on 3/18/2019 and resolved 5/7/2019	The exciter collector rings and brush assemblies were repairedr. Generator shaft bearings and associated seals were also repaired. The plant has limited ramp rate in an attempt to prevent future failure.
Wilmarth_1	Forced	Ash building roof collapsed, cannot haul out a	03/10/2019	03/14/2019	4	Ash load out building/discharge from C-9	03/09/2019 - Heavy unseasonable rainfall following snow storms caused excessive weight on building roof causing it to colapse		No similar failures were reported during this reporting period	Emergent capital project 2019 to replace structure. Continue structureal inspections per SAP maintenance plan 10012853.
Wilmarth_2	Forced	Ash building roof collapsed, cannot haul out a	03/09/2019	03/14/2019	4	Ash load out building/discharge from C-9	03/09/2019 - Heavy unseasonable rainfall following snow storms caused excessive weight on building roof causing it to colapse		No similar failures were reported during this reporting period	Emergent capital project 2019 to replace structure. Continue structureal inspections per SAP maintenance plan 10012853.

Unit Outage Information
2019 AAA Reporting Period: July 1, 2018 - December 31, 2019
Updated since originally filed in monthly FCAs due to further analysis.

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Duration (Days)	O1. Equipment that resulted in the forced outage	O2. Description of Equipment Failure	Q3. Change in Energy Costs	O4. Failure History During Reporting Period	O5. Steps Taken to Alleviate Reoccurrence
APRIL 2019										
BayFrnt_G4	Forced	T4-Generator Waiting retirement approval	04/01/2019	04/30/2019	30	Unit 4 Generator Rotor	During unit overhaul multiple cracks were found (November 2018) during the boresonic inspection of the generator rotor		This is a continuance of the initial event found during overhaul beginning 11/15/2018. No similar failures were reported during this reporting period.	Awaiting approval for retirement of unit. Retirement was approved and unit officially retired on 6/01/2019.
SHERC3	Forced	Boiler Fuel Supply from Bunkers to Boiler	04/23/2019	04/26/2019	3	308 Coal Mill	306 Mill was out for major overhaul and 302 mill was out for a coal leak repair. 308 mill was removed from service for internal inspection. 3 bolts and welds on the rotating throat assembly had failed.		No similar failures were reported during this reporting period.	This was an upgraded design provided by the OEM installed after a previous failure, however, the bolts used were Grade 8. We have sweitched to a more ductile bolt, Grade 5 Heavy Duty.
King_G1	Forced	Unit Tripped due to excier, issues are on goin	04/01/2019	04/30/2019	30	Exciter	High vibrations on exciter		There were several attempts to start the unit after repairs/adjustments to the exciter/generator bearings. These attempts were not successful and resulted in more extensive repairs to solve the issue. This was initially discovered on 3/18/2019 and resolved 5/7/2019	The exciter collector rings and brush assemblies were repairedr. Generator shaft bearings and associated seals were also repaired. The plant has limited ramp rate in an attempt to prevent future failure.
MAY 2019										
King_G1	Forced	Exciter	05/07/2019	05/16/2019	9	Exciter	High vibrations on exciter		There were several attempts to start the unit after repairs/adjustments to the exciter/generator bearings. These attempts were not successful and resulted in more extensive repairs to solve the issue. This was initially discovered on 3/18/2019 and resolved 5/7/2019	The exciter collector rings and brush assemblies were repairedr. Generator shaft bearings and associated seals were also repaired. The plant has limited ramp rate in an attempt to prevent future failure.
SHERCO_G2	Forced	Boiler Air and Gas Systems	05/02/2019	05/03/2019	1	22 Primary Air Fan motor	Broken connection on the motor side of the A-phase connector.		No similar failures were reported during this reporting period.	Motor was meggered to ensure motor winding integrity and connector was replaced.
King_G1	Forced	Exciter	05/01/2019	05/07/2019	6	Exciter	High vibrations on exciter		There were several attempts to start the unit after repairs/adjustments to the exciter/generator bearings. These attempts were not successful and resulted in more extensive repairs to solve the issue. This was initially discovered on 3/18/2019 and resolved 5/7/2019	The exciter collector rings and brush assemblies were repairedr. Generator shaft bearings and associated seals were also repaired. The plant has limited ramp rate in an attempt to prevent future failure.
SHERC3	Forced	Boiler Fuel Supply from Bunkers to Boiler	05/23/2019	05/24/2019	1	306 Coal Mill	Excessive slag buildup was noted on the burners of 306 mill during the internal boiler inspection due to the long duration 306 mill had been out for overhaul.		No similar failures were reported during this reporting period.	Slag buildup was removed. Different options are being looked at to imporve mill overhaul turn around time.
SHERC3	Forced	Boiler Tube Leaks	05/27/2019	05/31/2019	4	Finishing Superheat Tube	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 failure occurred on 10/4/18, 10/16/18, and 10/11/19 during this reporting period.	Eight tubes were identified for replacement; tubes 10 through 15 on pendant 80 and tubes 10 and 11 on pendant 79. Ultrasonic thickness testing (UT) was performed on surrounding tubes to identify collateral damage that did not result in a tube rupture. Four tubes were identified for pad welding; tubes 16 and 17 on pendant 80 and tubes 9 and 12 on pendant 79. Changes to the startup procedure were made to incorporate a strategy of maximizing steam velocity to sweep debris from the pendants including runing at full load and steam flow for six hours following a startup.
JUNE 2019										
NONE					0					
JULY 2019										
Redwing_1	Forced	Unit 1 OFA fan motor failure	07/06/2019	07/09/2019	3	Over Fired Air Fan	Motor Failure		No similar failures were reported during this reporting period	Replaced motor
CCRiverside1	Forced	Significant rain/river debris resulted in trip of	07/15/2019	07/16/2019	1	#6 Debris Filter	Backwash discharge valve failed in closed position which prevented backwashing of the debris filter screen. The filter screen plugged to the point that #6 circulating water pump had to be removed from service. With 1 of 2 circulating pumps out of service, condenser vacuum could not be maintained and the steam turbine (unit 7) tripped off line. With the steam turbine not available, both combustion turbing units are also not available.		No similar failures during this reporting period.	Valve plug was removed during this short forced outage to allow for continuous backwashing of the debris filter. The valve will be replaced during the next planned outage (October 14-18, 2019).
CCRiverside2	Forced	Significant rain/river debris resulted in trip of	07/15/2019	07/16/2019	1	#6 Debris Filter	Backwash discharge valve failed in closed position which prevented backwashing of the debris filter screen. The filter screen plugged to the point that #6 circulating water pump had to be removed from service. With 1 of 2 circulating pumps out of service, condenser vacuum could not be maintained and the steam turbine (unit 7) tripped off line. With the steam turbine not available, both combustion turbing units are also not available.		No similar failures during this reporting period.	Valve plug was removed during this short forced outage to allow for continuous backwashing of the debris filter. The valve will be replaced during the next planned outage (October 14-18, 2019).
AUGUST 2019										
NONE										
SEPTEMBER 2019										
Blk_Dog_G52	Forced	Forced Outage due to the failure of 5 GSU pr	09/23/2019	09/25/2019	2	Generator Transformer Protective Relay DPR-102	Protective relay was found to be in alarm and required the unit to be taken out of service. The relay was replaced.		No similar failures were reported during this reporting period.	A new protective relay was installed.
Blue_Lk_G7	Forced	gas valve dcs issue	09/03/2019	09/30/2019	28	Emergency Gas Isolation Valve Solen	Lightning Stike Caused U7 & U8 Solenoids to Fail		Initial event. Same event on U7 - 9/3/2019	Spares are in Stock now due to long lead time
Blue_Lk_G8	Forced	gas valve dcs issue	09/03/2019	09/30/2019	28	Emergency Gas Isolation Valve Solen	Lightning Stike Caused U7 & U8 Solenoids to Fail		Initial event. Same event on U8 - 9/3/2019	Spares are in Stock now due to long lead time

Unit Outage Information
2019 AAA Reporting Period: July 1, 2018 - December 31, 2019
Updated since originally filed in monthly FCAs due to further analysis.

[PROTECTED DATA BEGINS

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Duration (Days)	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
OCTOBER 2019										
SHERC3	Forced	Loss of Mills due to water valve open	10/26/2019	10/30/2019	**4**	Wash Water introduced into coal silos 308,309,and 310.	Water was being used by employees cleaning 4 transfer house, drain line was left open in 32 cascade house after wash pump was shut down. When pump was restarted later, water entered 308, 309, and 310 coal silos, inhibiting the ability to reach full load.		No similar failures were reported during this reporting period.	Training for new employees has been restructured to include wash water and system interconnections.
Blue_Lk_G7	Forced	gas valve dcs issue\B-disconnect fail	10/01/2019	10/31/2019	**31**	Emergency Gas Isolation Valve Solenc	Lightning Stike Caused U7 & U8 Solenoids to Fail		Continuation of event on 9/3/2020	Spares are in Stock now due to long lead time
Blue_Lk_G8	Forced	gas valve dcs issue	10/01/2019	10/28/2019	**27**	Emergency Gas Isolation Valve Solenc	Lightning Stike Caused U7 & U8 Solenoids to Fail		Continuation of event on 9/3/2020	Spares are in Stock now due to long lead time
SHERC3	Forced	Boiler tube leak. Must begin immediate unit s	10/11/2019	10/20/2019	**9**	Finishing Superheat Tube	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 failure occurred on 10/4/18, 10/16/18, and 5/27/19 during this reporting period.	Twenty tubes were identified for replacement; tubes 5 through 10 on pendant 48, tubes 8 through 10 on pendant 49, tubes 7 through 11 on pendant 66, tubes 5 through 10 on pendant 67, and tubes 8 and 9 on pendant 68. In addition to the changes in the startup procedure and maximation of steam flow velocity as implemented previously, the shutdown procedure has been modified in the boiler cooldown section to minimize any condensate flashing occuring in the pendants which may be causing the exfoliation to be carried from the header into the pendants.
NOVEMBER 2019										
SHERCO_G1	Forced	112 module	11/09/2019	11/11/2019	**1**	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emmissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are persuing ways of minimizing the amount of time required to complete a major clean.
SHERCO_G2	Forced	Scrubber module High Voltage cleaning	11/16/2019	11/18/2019	**2**	Scrubber Modules	Ash buildup on fields, spargers, and other components resulting in inefficient particulate removal and high stack opacity. Aging of equipment requires regular maintenance. Unit needed to be derated to perform other normal cleaning functions such as flushing, high voltage cleaning, and manual nightly cleaning. Upgrades to emmissions control equipment have resulted in the need for more aggressive cleaning in addition to normal equipment maintenance.		Multiple similar derates during this reporting period.	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. We are persuing ways of minimizing the amount of time required to complete a major clean.
SHERCO_G1	Forced	8N17 Breaker Failure (OMC)	11/03/2019	11/05/2019	**1**	GCB 8N17 345KV Generator Output Breaker	During startup of Unit 1, with the generator field breaker closed, generator output breaker 345KV 8N17 experienced a failure on the B phase. Resultant of this failure was a lockout on Sherco 345KV Bus 2 due to incorrect settings on secondary relays, and generator lockouts on all 3 Sherco Units due to auto transfer of 345KV bus pot paralleling scheme being in an off normal configuration.		No similar failures were reported during this reporting period.	B Phase of 8N17 has been replaced. Team has been formed to improve communication with transmission and the plant for abnormal substation configurations.
Anson_G4	Forced	Exhaust Repairs	11/08/2019	11/15/2019	**7**	Exhaust Silencer Baffles	Maintenance overhaul to repair silencers that are degrading and failing causing foreign material to escape out the stack during equipment operation		No similar failures were reported during this reporting period	Boilermakers were brought in to do weld repairs as they are every fall. The degradation was worse than previous years and 3 of the baffles had to be removed as they were beyound repair. A capital project for replacement is in place for 2021 and 2022
Redwing_2	Forced	Boiler Air and Gas Systems	11/22/2019	11/30/2019	**8**	Boiler	Routine boiler cleaning due to tube fouling. This is a planned evolution which occurs multiple times per year.		Similar event on 7/8/2018, and U1 event on 7/10/2018	Routine Boiler Cleaning
DECEMBER 2019										
Redwing_2	Forced	VFD for Unit 2 ID fan faulted	12/01/2019	12/31/2019	**31**	Induced Draft Fan Variable Frequency	VFD faulted		No similar failures were reported during this reporting period	Replaced unit 2 ID Fan VFD

PROTECTED DATA ENDS]

The 2016-2030 Resource Plan Update modeling was based on ICAP ratings that were developed by the company's Performance Testing and Monitoring group. The Company then developed UCAP rating for use in the Strategist planning model.

	2016-2030 Resource Plan	2016-2030 Resource Plan	July, 2018	July, 2018
Network Resource	ICAP (Summer)	UCAP (Summer)	ICAP (summer) (1)	UCAP (summer) (1)
NSP.ALDRIHERC	34	0	24	24
NSP.ANSON2	109	83	93	83
NSP.ANSON3	109	76	94	78
NSP.ANSON4	168	144	156	117
NSP.BAYFRN	41	64	25	25
NSP.BIGFALL_A	4	3	5	5
NSP.CC.BLKD52	298	247	281	274
NSP.BLKDO6	232	0	0	0
NSP.BLUEL1	50	35	40	37
NSP.BLUEL2	49	39	40	38
NSP.BLUEL3	46	38	40	37
NSP.BLUEL4	48	41	46	41
NSP.BLUE_LK7	174	154	152	127
NSP.BLUE_LK8	177	150	154	135
OTP.BRDRS1	150	0	150	34
NSP.CANFLSG1	179	157	157	156
NSP.CANFLSG2	179	155	158	154
NSP.CEDARFAL	3	2	5	5
NSP.CHEMOLSPO	262	235	238	232
NSP.CHPFAL	9	7	10	10
NSP.CORNEL	15	11	20	20
OTP.COURTENAY	200	0	200	50
OTP.FIBROMIN	55	47	40	40
NSP.FRENCH1	16	15	5	5
NSP.FRENCH2	0	0	5	5
NSP.FRENCH3	81	56	60	60
NSP.FRENCH4	81	56	60	54
NSP.GDMEADOW	101	14	100	15
NSP.GRANCT1	16	9	13	13
NSP.GRANCT2	16	12	14	14
NSP.GRANCT3	16	12	14	14
NSP.GRANCT4	16	11	13	11
NSP.HENNIPIN1	14	0	11	11
NSP.CC.HIBRDG	575	515	535	532
NSP.HOLCOM	15	11	23	23
NSP.INVRHL1	62	41	49	47
NSP.INVRHL2	62	46	48	46
NSP.INVRHL3	62	44	49	43
NSP.INVRHL4	62	40	48	43
NSP.INVRHL5	61	41	46	43
NSP.INVRHL6	61	39	47	44
NSP.JIMFL	24	18	30	30

	2016-2030 Resource Plan	2016-2030 Resource Plan	July, 2018	July, 2018
Network Resource	ICAP (Summer)	UCAP (Summer)	ICAP (summer) (1)	UCAP (summer) (1)
NSP.KING1	511	519	529	491
NSP.CC.MANKATO	357	277	295	290
NSP.MARSHSOLAR	62	32	46	46
NSP.MENOMOA	2	2	3	3
NSP.MNMETHANE	5	1	4	4
NSP.MNTCEL1	648	608	644	617
NSP.NOBLES	201	34	200	35
NSP.NSTARSOLAR	99	52	68	68
NSP.ODELL1	200	0	200	0
NSP.PVALEY	200	0	200	36
NSP.PINEBEND	12	5	3	4
NSP.PKFLSFLAM	16	11	0	0
NSP.PRISL	1092	1035	1053	989
NSP.RAPIDA1	0	0	2	2
NSP.REDWIN1	18	20	8	8
NSP.REDWIN2	0	0	8	8
NSP.CC.RIVRSD	487	443	460	455
NSP.SHAKOBIO1	12	12	12	12
NSP.SHERCO1	680	694	711	686
NSP.SHERCO2	682	667	699	662
NSP.SHERC3	515	515	534	524
NSP.SPGSPG1 (St. Paul Co-Gen)	25	25	23	23
NSP.STCLOUD1	9	7	6	6
NSP.STCRO	15	11	15	15
NSP.WHEATO1	56	40	47	42
NSP.WHEATO2	70	48	53	35
NSP.WHEATO3	56	42	48	43
NSP.WHEATO4	61	45	48	44
NSP.WHEATO5	70	42	0	0
NSP.WHEATO6	70	31	53	45
NSP.WILMAR1	18	17	8	8
NSP.WILMAR2	0	0	8	8
NSP.WISSOT	17	12	22	22
MHEB (375/325 MW System Purchase)	371	363	371	368
MHEB (350 MW Diversity Exchange)	350	342	350	343
MHEB (75 MW)	75	73	75	62
Laurentian Energy Authority	35	32	36	33
Aurora Distributed Generation	100	70	66	68
Solar Aggregate PPA's	7	4	2	2
Solar Community Solar Gardens	138	64	37	38
Hydro Aggregate PPA's	191	17	23	23
Wind Aggregate PPA's	1573	181	1346	200
Total	13,037	9,062	11,607	9,137

(1) Resources and Capacity as reported in the 2018/2019 MISO GVTC

Northern States Power Company
Electric Operations - State of Minnesota
Unusual Items Over $500,000/Errors During FCA Reporting Period

FCA Filing Period	Item Pertaining To	Period Affected	Descriptions	Amounts	FCA Impact
Jul-18	None				
Aug-18	High Bridge Plant Volumes Reclass	June 2013 - May 2018	An issue was identified at the High Bridge plant whereby SCADA meter data was being provided to NNG as opposed to more accurate volumes from the MV90 meter. This resulted in a total credit to gas commodity expenses of $6M over 5 AAA years (2013-2018). An entry for this amount was booked during month-end close. At the time of the monthly FCA filing in which this was first reported, the Company noted the $6M would be recovered through the electric FCA over the subsequent 12 months beginning in October 2018. As noted below, this recovery was substantially modified by the Commission's November 13, 2019 Order in Docket No. E999/AA-18-373.	$6,004,319	Yes
Sep-18	None				
Oct-18	MISO resettlement	January 2018 - March 2018	The prior period adjustment is the result of market wide resettlement concerning revised meter data between January and March 2018. NSP was impacted by previously unaccounted for energy in NSP's local balancing authority (LBA). Unaccounted for energy in the NSP LBA is assigned to NSP's load. In this case a market participant in NSP's LBA submitted inaccurate meter data to MISO. The resettlement started October 15 and will end on November 7, 2018. The entire impact has been accrued for in the October accounting month.	$2,831,004	Yes
Nov-18	Solar garden cost recovery	November and December 2018	There was an overstatement of the November uneconomic amount. The actual amount should have been $2,901,923 and the true up entry of $1,092,419 will be reflected in December solar garden cost recovery.	$1,092,419	Yes
Dec-18	Coal	December 2018	There was an inventory adjustment made based on the Sherco semi-annual survey which decreased coal expense by ($3,262,987).	($3,262,987)	Yes
Dec-18	Sherco 3 Outage Settlement Refund	December 2018	The Company settled its lawsuit with GE on September 20, 2018. The Minnesota jurisdictional portion of the Settlement Amount to be refunded is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**	**[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**	Yes
Jan-19	None				
Feb-19	None				

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NOT PUBLIC DATA HAS BEEN EXCISED

Northern States Power Company Docket No. E999/AA-20-171
Electric Operations - State of Minnesota Part K, Section 4
Unusual Items Over $500,000/Errors During FCA Reporting Period Schedule 4

FCA Filing Period	Item Pertaining To	Period Affected	Descriptions	Amounts	FCA Impact
Mar-19	Coal	February and March 2019	In February there was a coal adjustment that was incorrectly booked. This was reversed and corrected in March resulting in a prior period adjustment increasing coal cost by $1,232,030.	$1,232,030	Yes
Apr-19	None				
May-19	None				
Jun-19	None				
Jul-19	None				
Aug-19	None				
Sep-19	LT Purchased Energy (Other) - IPP	September 2019	**[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**	**[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**	Yes
Oct-19	High Bridge Refund	June 2013 - June 2017	Pursuant to the Commission's November 13, 2019 Order in Docket No. E999/AA-18-373, the Company is authorized to recover the High Bridge Plant misallocated gas cost during 2017-2018 AAA period. The Company had previously recovered $4,325,217 from customers for the 2013-2018 period cost misallocation. Netting the $1,270,879 amount the Company can retain, a $3,054,338 refund was included in the December FCA.	$3,054,338	Yes
Nov-19	None				
Dec-19	None				

We provide this report in compliance with order point 30 of the the Commission's April 6, 2012 Order in Docket Nos. E999/AA-09-961 and E999/AA-10-884 and order point 5 of the Commission's November 13, 2019 Order in Docket No. E999/AA-18-373.

2011 AAA Ordered Reporting Requirements

On August 16, 2013, the Commission issued its ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING REFUND OF CERTAIN CURTAILMENT COSTS, AND REQUIRING ADDITIONAL FILINGS in Docket No. E999/AA-11-792, the 2011 AAA report docket. In compliance with this Order, the Company has included the following information as part of this report:

1. MISO Schedule 10 Costs

Order Point 18 of the Commission Order states:

> *…The electric utilities shall provide in the initial filing of all future electric AAA reports the Minnesota jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable. Additionally, the electric utilities shall 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.*

Part I Section 1 provides the MISO Schedule 10 costs and allocation factors for the 2017-2018 AAA reporting period as well as for the 2016-2017 AAA reporting period for comparison. The accompanying support for why the allocation factors are reasonable, and the support for theincrease in costs, is also included in Part I, Section 1.

2. Congestion Costs

Order Point 20 of the Commission Order requests data relating congested paths, including related costs and revenues.

a. Hourly LMP Data

Subpart a) requires utilities to:

> *Provide hourly data on Day-Ahead Locational Marginal Price (LMP) basis, including energy, line losses, and congestion charges for each generation node, each load node, and Minnesota Hub for the current AAA period. The Department requests that utilities send this data to the DOC in Access file format and include a separate reference guide defining all column headers.*

Part K Section 5 Schedule 1 provides the specified information for 2018-2019 to be sent to the Department on a CD as an Access database. Two of the data fields ("MW" and "NativeMW") are Not Public data. The following fields are included on the CD:

Field	**Description**
Date_Time	Time and Hour
Location	Common Name
LMP Node	MISO Node Name
LoadAward	Load for Load Nodes, Award for Generation Nodes, and Market for MINN.HUB
Type	NAE – Non-Asset Energy, Asset Energy
MW	Total MWs awarded in Day-Ahead Markets (Positive for Loads, negative for Generators). **This field is NOT PUBLIC**.
NativeMW	MWs assigned to Native. **This field is NOT PUBLIC.**
LMP	Day-Ahead Locational Marginal Price for the Node
MCC_DayAhead	The Marginal Congestion Cost Component of the Day-Ahead LMP
MLC_DayAhead	the Marginal Loss Cost Component of the Day-Ahead LMP

b. Congestion Analysis

Subparts b) and c) require utilities to:

b. Perform the following analysis based on the above requested data:
i. Identify hours in which congestion costs are incurred between a generation node and load node (path);
ii. Sum the qualifying congestion costs by path (multiplying MW times difference in Marginal congestion costs Mcc for each path); and
iii. Identify the ten paths with the highest amount of congestion costs for current AAA period.
c. Include the ten paths identified above and the total of their congestion costs. For each path, also answer the following questions:
i. What is the Company's Financial Transmission Rights (FTRs) hedging positions and Auction Revenue Rights (ARRs) for these ten paths?
ii. Identify all FTR revenues, ARR revenues, congestion expenses, and the resulting net congestion cost or revenue for these ten paths.
iii. Based on the Company responses to a, b, and c.i. and c.ii., what cost-effective improvements could be considered to reduce the congestion amounts for the identified paths?

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	Net 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	Summer 2018	
[PROTECTED DATA BEGINS		**Peak**	**Peak Off**
			PROTECTED DATA ENDS]

Generation Node	Load Node	Fall 2018	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Winter 2018-19	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Spring 2019	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Summer 2019	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Fall 2019	
[PROTECTED DATA BEGINS		Peak	Peak Off
			PROTECTED DATA ENDS]

Generation Node	Load Node	Winter 2019-20	
[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]		

3. Transmission Maintenance Expense

Order Point 22 states:

In future AAA filings, Xcel, Minnesota Power, Otter Tail Power, and Interstate Power and Light shall provide the information needed for the Department's Table 8 in its Report (Actual Transmission Maintenance Expense Compared to Amounts Built into Rates).

The table below shows the actual transmission maintenance expense for 2017 and 2018 compared to the amounts built into the Company's original 2016 test year filed in Docket No. E002/GR-15-826. A Settlement was approved in this case which did not specifically quantify O&M expense levels included in base rates. The table below shows State of Minnesota jurisdictional amounts.

2018 Actual	2019 Actual	Two-Year Average	2016 Test Year As Filed	2017 Plan Year As Filed	2018 Plan Year As Filed
$10,125,412	$12,184,075	$11,154,743	$14,519,959	$13,706,950	$13,442,288

4. Transformer Reporting

Order Point 23a requires utilities to:

…use Xcel's reporting format for the table found in Part H, Sections 1 – 8, page 3 of 6, but with the incorporation of all transformers on a utility's system, and with status of each transformer identified as one of these four categories: in-service standalone, in-service duplicate, on-order, or storage.

Part H, Section 4 provides a table illustrating the NSP system spare transformer inventory including whether the transformers are on-order or in storage.

Part H, Section 4, Schedule 1 provides a list of all in-service NSP system transformers over 100 kV, including whether the transformers are in either the in-service standalone or in-service duplicate categories.

1. Policy on Backup Strategies for Transformers

Order Point 23b requires utilities to:

…provide information regarding policy on backup strategies for transformers

We submit with MISO our policy which includes the criteria used by the Transmission Planning area when studying the performance of the NSP System. The most current policy can be accessed on the MISO website at: https://www.misoenergy.org/planning/transmission-planning/#nt=%2Freport-study-analysistype%3ATO%20Planning%20Criteria&t=10&p=4&s=&sd=asc. For convenience of review, we attach the policy to this report as Part K, Section 5, Schedule 2. Below we provide additional information about the Company's transformer backup strategy.

Xcel Energy's transformer backup strategy is a three-pronged approach consisting of our Spare Transformer Fleet designed to meet the needs of our back-up requirements, and participation in two industry programs. Each is discussed in turn below.

Xcel Energy maintains an independent fleet of spare transmission transformers in each Operating Area, including the Northern States Power Company region consisting of NSPM and NSPW.[1] Each fleet is designed based on two main concerns: operational failure rates and non-traditional threats (such as geomagnetic disturbance, electromagnetic pulse, and physical attack). More specifically, the Spare Transformer Fleets are first designed based on the population of transformers in service in each voltage class and historical failure rates for those transformers. This design principle results in at least one spare transformer for most voltage classes. Each fleet is then supplemented with additional spare transformers in the voltage classes identified in critical substations. With the current Spare Transformer Fleet design, each Operating Area is able to recover the system for two, and sometimes three, substation complete loss events. For planning and normal operational purposes, each Operating Area's spare fleet is separate and independent. In an extreme emergency, spare transformers could be used throughout the Xcel Energy System as necessary and appropriate.

Xcel Energy also participates in two industry transformer programs. Spare Transformer Equipment Program (STEP) is a voluntary program managed by Edison Electric Institute (EEI). Participation in STEP comes with binding obligations, where a participating utility has legal "call rights" to purchased transformers of other participating utilities in the event of a triggering event, which must be terrorism-related. There are currently more than 50 participating utilities, including most of the investor owned utilities in the United States. Xcel Energy also participates in

[1] See Part H, Section 4.

SpareConnect, another voluntary program managed by EEI. SpareConnect matches utilities that have a transformer need with utilities that have similar equipment. There are currently more than 100 participating utilities in the United States and Canada.

The Company believes that it maintains a reasonable level of transformers in inventory in order to: (1) maintain the reliability of the system; (2) remain consistent with North American Electric Reliability Corporation (NERC) reliability criteria; and (3) balance the economic benefit to ratepayers. Participation in these voluntary programs provides added assurance to support our spare transformer inventory.

2. Transformer Maintenance Policy

Order Point 23c requires utilities to:

> …*provide their policy for transformer maintenance*

Part K, Section 5, Schedule 3 provides the Company's policy of the maintenance program for power transformers and load tap changers on the bulk electric system.

Part K, Section 5, Schedule 1

This attachment has been submitted to the Department of Commerce separately on disk as an Access database due to its voluminous nature.

Transmission Planning Criteria Document	
Xcel Energy	Northern States Power Company
Transmission Planning Criteria Manual For The NSPM and NSPW Transmission System	**Version: 6.0**
File Name : NSP-POL-Transmission Planning Criteria Document	**Page 1 of 16**

PURPOSE

This document, effective December 1st, 2019 defines the criteria that are used to evaluate the system performance of Northern States Power Company - Minnesota and Northern States Power Company - Wisconsin (jointly referred to as NSP) transmission facilities. This includes voltage, line loading, transient stability, flicker, and transmission line reclosing criteria. These criteria apply to the NSP transmission system, and compliance with NERC standard TPL-001-4. The document also provides guidance for acceptable forms of mitigation plans and NSP's policy for use of remedial action schemes.

This document may be revised from time to time in response to changes in industry standards, new system conditions, new technologies and new operating procedures, as appropriate. The criteria described in this document will be subject to change at any time at NSP's discretion. Situations that could precipitate such a change could include, but are not limited to, new system conditions, extraordinary events, safety issues, operation issues, maintenance issues, customer requests, regulatory requirements and Regional Entity or NERC requirements.

APPLICABILITY AND RESPONSIBILITIES

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VERSION HISTORY

Effective Date	Version Number	Supersedes	Change
2/4/2013	1.0	N/A	Initial ProjectWise Document. Original document version is 1.0—ProjectWise version
3/18/2015	2.0	1.0	-Updated the nuclear plant voltage requirements -Added the criterion for Ferranti voltage rise -Added transformer loading criteria for planning -Updated damping criteria for stability analysis -Update Criteria for TPL-001-4 Standard -Update interim mitigation plans in Transmission Plans section -Replaced Special Protection Systems (SPS) with Remedial Action Schemes (RAS)
1/13/2017	3.0	2.0	-Updated bus voltage criteria Table 2 -Changed Section 3 from Voltage Deviation to Rapid Voltage Change to better align with IEEE 1453 terminology -Removed RAS exception for sub-synchronous resonance
7/01/2019	4.0	3.0	- Defined the 88 kV operating voltage - Clarified the applicability of this criteria, and included Transmission Operator Quick Reference for Transmission Voltage and Reactive Operation as attachment - For transient voltage response, specified low voltage levels and maximum length of time that transient voltages may remain below the levels
12/01/2019	5.0	4.0	- Added the criteria for the Extreme events. - Added the criteria for rotor angle instability. - Updated the transient stability voltage criteria
01/01/2020	6.0	5.0	- Clarified the themal loading criteria languages.

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WORKS CITED **15**

1. Voltage Criteria

When performing steady state analysis, the following voltage criteria applies to NSP's buses under system intact (pre contingent) and post contingent (Planning Events P1- P7) conditions:

Table 1

Facility	Maximum voltage (p.u.)	Minimum voltage (p.u.)	Maximum voltage (p.u.)	Minimum voltage (p.u.)
	Pre Contingent		Post Contingent	
Default for all buses > 100 kV	1.05	0.95	1.05	0.92
Default for all buses < 100 kV*	1.05	0.95	1.05	0.92
Default for all generator buses**	1.05	0.95	1.05	0.95

* Wisconsin 88 kV is operated as 92 kV. For 34.5 kV and below non-generation buses, pre and post contingent voltage of 0.9PU would be acceptable.

**For all Category P0, P1, P2, P4, P5, and P7 contingencies. [1] After a Category P3 or P6 contingency, generator bus voltage would be allowed to drop to 0.92 PU.

Table 1 above presents the general voltage criteria for most of the NSP owned facilities; however specific voltage criteria exist for some of the high voltage buses, these criteria are listed below in Table 2

Table 2

Facility	Maximum (p.u.)	Minimum (p.u.)	Maximum (p.u.)	Minimum (p.u.)
	Pre Contingent		Post Contingent	
Roseau 500 kV bus	1.10	0.95	1.10	0.92
Prairie 115 kV main bus	1.09	0.95	1.09	0.90
Prairie 115 kV capacitor bus	1.15	0.95	1.15	0.92
Sheyenne 115 kV capacitor bus	1.15	0.95	1.15	0.92
Running 230 kV capacitor bus	1.10	0.95	1.10	0.92
Roseau 230 kV capacitor bus	1.05	0.95	1.10	0.92
Chisago 500 kV bus	1.10	0.95	1.10	0.92
Forbes 500 kV bus	1.10	0.95	1.10	0.92
Bison 345 kV bus	1.05	0.95	1.10	0.92
Briggs Road 345 kV bus	1.05	0.95	1.10	0.92

In order to comply with the NUC-001 standard, for nuclear plant off-site source requirements, specific voltage criteria has to be met for Prairie Island and Monticello substation buses. The Nuclear Plant Interface Requirements (NPIR) provides the voltage requirements for the nuclear plants. Contact NSP's transmission planning group to obtain the most up to date voltage criteria for the nuclear plants.

The voltage criteria is solely defined for transmission system performance evaluation and developing transmission system expansion plans. For NSP transmission system voltage operating limit, please see attachment – Transmission Operator Quick Reference for Transmission Voltage and Reactive Operation.

1.1 Ferranti Voltage Rise

Voltage rise on open end of a long line, due to charging current, has to be taken into account when performing line energization studies. The maximum permissible voltage on the open end of the line is 1.05 PU unless the equipment (CCVTs, PTs and Breakers) at the open end of the line are rated to withstand higher voltage. [2]

2. Facility Loading Criteria

The ratings for facilities (transmission lines, transformers and series compensators) owned by NSP are specified in the NSP Ratings Database. The winter and summer ratings of facilities account for the thermal limit of all equipment, and relay loadability limits, as specified in NERC FAC-008-3 standards.

When planning NSP's system, for system intact condition, the current flowing through a facility should not exceed the normal rating of that facility. When studying contingency conditions, the current flowing through a facility should not exceed the emergency rating of that facility.

Certain facilities on NSP's system are dynamically rated, the ratings of these facilities change based on the ambient conditions, such as wind speed. When monitoring these facilities for overloads, appropriate ratings have to be chosen. The up-to-date list of dynamically rated transmission lines can be obtained from NSP's Transmission Planning or Transmission Operations Departments.

2.1 Transformer Loading Criteria for Planning Studies

When performing transmission planning studies for NSP's system the applicable transformer ratings are as follows (the percentages are based on the continuous rating of the transformer):

Table 3

Contingency	Summer	Winter
System Intact (Category P0)	100%	100%
Post Contingent (Category P1-P7)	115%	130%

The overload capability of the transformer is applicable only if there are no other limiting elements (such as bus conductor, CTs, bushings, switches or breakers) on the transformer branch. In the presence of a limiting element, the transformer branch rating would be limited by the lowest rated equipment.

3. Rapid Voltage Change Criteria

When performing planning studies for the transmission system, the following criteria applies to the NSP's system:

- The maximum voltage deviation caused by switching of any shunt device (motor load, capacitor or inductor), under system intact condition, should not exceed more than 3% at any load serving bus. [3]
- The maximum voltage deviation caused by switching of any shunt device (motor load, capacitor, or inductor), during prior outage of the largest fault current contributing element, should not exceed more than 5% at any load serving bus.

4. Voltage stability criteria

Voltage stability analysis is performed as part of load serving studies, as well as generation outlet studies, to identify the maximum transfer capability of the transmission system before a voltage collapse occurs. While performing this analysis, sufficient voltage margin has to be maintained by operating at or below Pcrit. Pcrit is determined by developing PV (Power-voltage) curves for those buses that have the largest contribution to voltage instability for any given outage. P_{limit} is calculated as the lesser of

- (0.9) * P_{crit} [where P_{crit} is defined as the maximum power transfer or system demand (nose of PV curve)] or
- The maximum power transfer or system demand which does not result in a post-contingent voltage violation as defined in Tables 1 and 2.

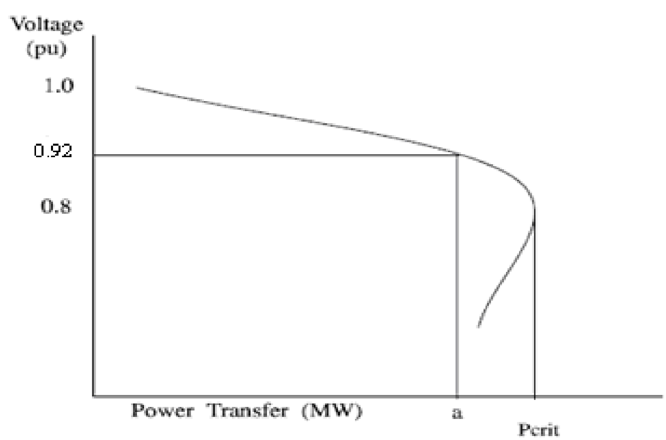

Figure 4.1

5. Steady state planning contingencies evaluated

The contingencies used for planning studies are based on the currently effective NERC TPL-001-4 standard. Refer to Table 1 of TPL-001-4 standard for the category P0 to P7 contingency events evaluated for NSP's Bulk Electric System.

For facilities not classified as Bulk Electric System, only category P0, P1, and P2.1 (opening of line section without fault) contingencies are evaluated.

In addition to Planning Events P0 through P7, NERC Reliability Standard TPL-001-4 Table 1 also includes a description of Extreme Events to be evaluated. If the analysis around such Extreme Events concludes that cascading, Voltage instability, or uncontrolled islanding would result from the occurrence of an Extreme Event, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the widespread event will be conducted.

6. Transient Voltage Criteria

When performing transient stability studies, after the fault (Planning Events P1- P7) is cleared, the following criteria apply to post fault voltages on NSP's buses.

- NSP does expect the voltage to quickly (within 5 cycles) recover to above 0.7 pu immediately following the fault clearing.
- NSP does not allow the extra-high voltage (EHV) facility transient voltage to dip back below .7 p.u. for any amount of time after the initial voltage recovery.
- After the fault clearing, the voltage must not exceed 2 seconds below .8 p.u., and shall recover to 0.90. p.u. within 10 seconds.
- NSP does not allow the transient voltage to swing above 1.2 p.u. for more than 3 cycles after the fault clearing, except for Fast Switched Capacitor buses. For Fast Switched Capacitor buses, the transient voltage is allowed up to 1.65 p.u. for no more than 5 cycles.

In addition to Events P0 through P7, NERC Reliability Standard TPL- 001-4 Table 1 also includes a description of Extreme Events to be evaluated. Slow stability recovery for an Extreme Event is allowed. However, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the widespread event will be conducted, if the stability simulation for an Extreme Event concludes that cascading, system instability, system collapse would result from the occurrence of the Extreme Event.

7. Damping Criteria for Transient Stability Studies

When performing transient stability studies, the following criteria apply to generator rotor angle oscillations:

- The generator rotor angles should always be positively damped
- The successive peak ratio (SPPR), defined by
  SPPR=Successive swing amplitude / Previous swing amplitude
  should be less than 0.95

- The damping factor defined by
  %Damping factor = (1-SPPR)*100
  should be at least 5%

Prony analysis could be used to identify the modes. The damping factors of the modes could be calculated using the following expression:

$$\text{Damping ratio } \zeta = -\sigma / \sqrt{(\sigma^2+\omega^2)}$$

Where $\sigma \pm j\omega$ represents the mode and the frequency of the mode is given by $\omega/2\pi$.

The damping ratio, for disturbances with faults, should be at least 0.0081633. The damping ratio, for disturbances without faults, should be at least .016766.

If the synchronous generator rotor angle deviation with respect to a "reference" generator is more than 180 degrees, the generator has a tendency to slip poles and thus lose synchronism with the remainder of the interconnected system. In stability studies, any deviation of rotor angle beyond 180 degrees is considered as instability of the generator. Further evaluation is necessary in order to determine whether this instability is limited to a specific generator or sets of generators that could cause a larger area to become unstable and result in Cascading Outages.

8. Distance Relaying - Apparent Impedance Criteria

The transient apparent impedance swings on all lines can be monitored by the PSS/E model "MRELY1" against a three zone mho circle characteristics described below:

Circle A = 1.00 x line impedance
Circle B = 1.25 x line impedance
Circle C = 1.50 x line impedance

Apparent impedance transient swings into Circles A or B are considered unacceptable. Any violation of this criterion has to be investigated to ensure that additional transmission elements do not trip after the fault is cleared. Any valid violation has to be appropriately mitigated.

In addition to the generic distance relay model, specific models are included for the out of step relays on the tie lines between US and Manitoba Hydro system. When performing planning studies, it should be ensured that relay margins for the out of step relays are respected as required by the respective transmission owner. Any unintended tripping of the out of step relays is not acceptable. Any valid violation of these criteria has to be communicated with the transmission owner and should be mitigated if required.

9. Types of Disturbances Studied

The disturbances simulated for the planning studies are based on the currently effective NERC TPL-001-4 standard. Refer to Table 1 of TPL-001-4 standard for the category P0 to P7 contingency events evaluated for NSP's Bulk Electric System.

For facilities not classified as Bulk Electric System, category P0, P1, and P2.1 (opening of line section without fault) contingencies will be simulated if there is any localized stability concern.

In addition to Planning Events P0 through P7, NERC Reliability Standard TPL- 001-4 Table 1 also includes a description of Extreme Events to be evaluated. If the analysis around such Extreme Events concludes that cascading, voltage instability, or uncontrolled islanding would result from the occurrence of an Extreme Event, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the widespread event will be conducted.

10. Sync Check Relay - Angle Separation Criteria

When reclosing a transmission line, sync check relays are used to ensure that the angle separation between the two ends of the line is not too large. This is to ensure generators, close to either end of the transmission line, do not sustain damage due to large change in power. NSP allows a maximum angle separation of 30 degrees for reclosing of a transmission line.

Under certain conditions, lines could be allowed to reclose at angle separation greater than 30 degrees. In order to allow reclosing lines, with angle separation greater than 30 degrees, switching studies have to be performed to demonstrate that the change in power at any generator does not exceed 50% of its rated power. [1]

11. Short Circuit Criteria

When planning the transmission system, the fault current design capabilities of the facilities should be respected. This includes

- Fault interrupting device capabilities
- Ground grid burn off, and Step and Touch potentials
- Structural strength of bus spans, insulators, etc.
- Personal Protection Equipment for maintenance

Any violation of facilities' capability or personal safety has to be mitigated appropriately.

12. Transmission Plans

Any valid violation of criteria, listed in sections 1 through 11, identified through planning study or assessment has to be addressed by developing an appropriate transmission plan. The plans could involve building new transmission facilities or upgrading existing transmission facilities or re-configuring existing transmission system without causing any new violations.

In addition, use of under-voltage load shedding, reverse power relays, and over current relays could be an acceptable interim mitigation plan for violations of this criteria due to single initiating events. When determining settings on relays to trigger automatic action, operational considerations should be evaluated against the Planning criteria. Settings higher or lower than the established Planning criteria may be necessary to achieve optimal system operation. Deviations from this criterion in the operational timeframe should be evaluated on a case-by-case basis.

Operating guides are used by system operators to address specific challenges that are encountered during the day to day operation of the transmission system and to meet the NERC TOP standards. For long term planning purpose, use of operating guides to meet the NERC TPL standards should be limited to address violations associated with prior outage conditions or to address violations associated with category P6 contingencies.

13. Other Studies

Additional technical studies should be performed as required to maintain system reliability and to follow good utility practice. These include studies related to voltage imbalance, harmonics, sub-synchronous resonance, small signal stability, etc.

14. NSP's policy for use of Remedial Action Schemes

It is NSPM and NSPW (jointly NSP) policy not to install, own or administer new Remedial Action Schemes (RAS), or to expand any existing RAS, to mitigate pre- or post-contingent system reliability concerns on the NSP transmission system (NSP System) or the transmission system of an interconnected neighboring utility transmission system. Reliability concerns include, but are not limited to thermal overloads, voltage violations, and system stability violations.

14.1 Retirement of existing RASs owned by NSP

For each RAS already placed in service on the NSP System, periodic reviews will be performed to ensure that the RAS is deactivated by NSP when the conditions requiring its use no longer exist, or system improvements necessary to remove the RAS are in service.

14.2 Modification of existing RASs Owned by NSP

Modification of existing RASs would be allowed if a new transmission project requires altering the facilities associated with an existing RAS. This type of modification should be backed by a supporting technical study that demonstrates that the system reliability would not be degraded due to the modification. In addition, the required approvals from the regional reliability organization should also be obtained in accordance with NERC PRC-15 standard.

The modification of existing RASs would not be allowed for generator or load interconnections, transmission service requests or to avoid generation curtailment of existing generation resources.

14.3 New Temporary RAS

New temporary RASs could be allowed on NSP's transmission system only if the following conditions are met:

1. If the RAS is needed as a temporary measure to maintain system reliability during construction of a transmission project, such that the RAS could be retired after the completion of the project.
2. If the RAS is proposed as a short term measure to provide transmission service or allow generator or load interconnection. This would be allowed only if there is a written agreement with NSP, with a committed in-service date for the transmission facilities that would eliminate the need for the RAS.

In order to install the temporary RAS, technical studies have to be performed to demonstrate that the system reliability is not degraded. In addition, approval has to be obtained from the regional reliability organization in accordance with the NERC PRC-015 standard.

Midwest reliability Organization (MRO) reviews the effectiveness of each RAS every 5 years. NSP would not participate in this review of temporary RAS at the end of the fourth year, and will retire the temporary RAS at the end of fourth year. This could result in the generator or load losing its ability to stay interconnected to the transmission system or lose its transmission service, if the transmission facilities required for retiring the RAS are not in-service.

Temporary RASs would not be installed to avoid generation curtailment of existing or future generators that are designated "Energy Resource".

14.4 RASs Owned by Entities Other Than NSP

NSP would not support or participate in the installation of RASs by any entity on NSP's system that would require tripping or switching of NSP's transmission facilities or any generating facility interconnected to NSP's transmission system.

For a RAS owned and administered by an entity other than NSP, that does not require tripping of NSP's transmission facilities or generating facilities interconnected to NSP's transmission system, that requires installation of monitoring and communication equipment on the NSP System, NSP will cooperate with installation of such monitoring and communications equipment on the NSP System, provided the following conditions are met:

1) The entity owning and administering the RAS agrees to perform the necessary technical studies required to support the need, and the impact of the RAS on the transmission system, as required by applicable NERC standards for Remedial Action Schemes, and obtain the necessary approval from the applicable regional entity (e.g., the Midwest Reliability Organization)

2) The entity owning the RAS agrees to be responsible for complying with misoperation reporting requirements as required by the applicable NERC standards for RASs, and will be responsible for coordinating any corrective actions with the NSP System.

3) The entity identified as the Transmission Operator of the RAS, for the RAS owner, would be solely responsible for monitoring the status of the RAS and notifying affected entities of changes in the status of the RAS, including any degradation or potential failure to operate as expected as required by PRC-001-1 R6 and IRO-005-3a R9.

Works Cited

[1] IEEE Std C50.13™-2014, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above.

[2] IEEE Std 37.012™-2014, IEEE Guide for the Application of Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V

[3] IEEE Std 1453™-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.

Attachment
Transmission Operator Quick Reference
Transmission Voltage and Reactive Operation

ProjectWise Link:

NSP-PRO-D-036 Transmission Voltage Operation.doc

Maintenance Plan for Transmission & Distribution Power Transformers and Load Tap Changers	VERSION: 1.0
File Name : Maintenance Plan for T&D Transformers.doc	PAGE 1 OF 13

1.0 PURPOSE

- Define the time-condition-event based prioritization system to be utilized to predict the need for inspection and maintenance.
- Define the maintenance and diagnostic testing plans.
- Define the specific maintenance and diagnostic testing procedures for power transformers and load tap changers (LTCs).
- Document the required data to plan and schedule maintenance and diagnostic testing activities.
- Document the required data to be collected during the substation inspections, diagnostic testing, and maintenance of the power transformers and LTCs.

2.0 APPLICABILITY AND RESPONSIBILITIES

- To define a consistent and common plan and procedures for all Xcel Energy Operating Companies for the maintenance of transmission and distribution substation power transformers and LTCs.

3.0 APPROVERS

Name	Title
Dave Cenedella	Director, System Sustainability
Greg Bennett	Director, Substation CO&M
Philippa Narog	Director, Transmission Business Operations

4.0 VERSION HISTORY

Effective Date	Version Number	Supercedes	Change
11/25/2014	1.0	n/a	Initial version

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Document Structure and Governance Process

THIS SECTION IS THE SAME FOR ALL SUBSTATION MAINTENANCE PLAN/PROCEDURE DOCUMENTS

This document is part of a set of documents describing Xcel Energy's overall Substation Maintenance Plan/Procedures. These documents define the Substation Maintenance philosophy, policy, plans and procedures for all operating companies.

Substation Maintenance Plan and Procedures
For
Power Transformers and Load Tap Changers

Purpose

Background

This document has been developed to define a consistent plan and procedure for all Xcel Energy Operating Companies for the maintenance of transmission and distribution substation transformers and on-load tap changers[1] (this document uses LTC specifically for the on-load tap changer). Transformers in this procedure include power transformers, grounding banks, and include all transformers where it is possible to take an oil sample without removing the transformer from service. Proper and appropriate maintenance and diagnostic testing of transformers that may or may not have a LTC to manage voltage is essential to system reliability and operations; failure of transformers of any type is expensive, requiring extensive effort to repair and or install a new unit and may adversely affect thousands of customers and reliability statistics.

The overall plan and specific procedures establish requirements for:

- Annual or quarterly ***DGA Testing*** of oil filled transformer compartments including the main tank and the LTC compartment or compartments (i.e. independent selector switch compartments) to evaluate the condition of the asset including the transformer windings, water, dissolved gases, LTC contact condition, etc. The frequency of the DGA test is dependent upon:
    - Initial installation testing of new or rebuilt transformers
    - Voltage and size of the transformer
    - Previous DGA testing that had shown any issues in the transformer
- Annual ***Infrared Inspection*** of the transformer including the on-load LTC and no-load tap changer[2] compartments.
- Annual ***Comprehensive Oil Testing*** of samples taken from every transformer compartment including the main tank and the LTC compartment or compartments (i.e. independent selector switch compartments) to evaluate the condition of the asset through oil condition including the transformer windings, water, furans, LTC contact condition, etc.
- Periodic complete diagnostic inspection and testing of ***Ancillary Transformer Equipment*** based on the transformer cooling design and the size of the transformer.

The purpose of this plan and procedure is to:

- Define the periodic transformer diagnostic inspection plan: dissolved gas analysis, complete oil analysis, and infrared inspection.
- Define the annual on-load LTC diagnostic inspection plan: dissolved gas analysis, complete oil analysis, and infrared inspection.

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[1] On-load tap changers are capable of making adjustments to the transformer turns ratio while energized and carrying load.
[2] Transformers are often equipped with a no load tap changer that is set to the proper turns ratio (voltage ratio of high side and low side of the transformer) before the transformer is energized.

- Define the diagnostic testing plan of the peripheral (ancillary) apparatus portion of the transformer[3] based on a Maintenance number formula that ties the transformer cooling system, MVA size, overall condition and the value of the asset to the Xcel system and time since the previous ancillary diagnostic inspection to the scheduling of the work.
- Document the required data to plan, schedule and record maintenance and diagnostic testing activities.
- Document the required data to be collected during the substation inspections, DGA, diagnostic oil testing, infrared scanning and maintenance of the peripheral portions of the transformer.
- Document the storage of data for easy retrieval and reference for future inspections.

Scope

The Transmission and Distribution Transformer and LTC plan establishes the maintenance drivers and minimum required periodic visual inspection, quarterly and annual diagnostic testing, evaluation of the test results, and diagnostics of the transformer ancillary assets. No internal inspections are scheduled based on time or the Maintenance number for either the main transformer tank or the integral LTC. The goal of the plan is to monitor key diagnostic tools that predict the need for further investigations and possible repairs. This document describes the maintenance plan established to achieve this goal and the procedures used to accomplish it.

This document does not include the routine substation and equipment inspection procedures but does list the required visual inspections of the transformers.

For the purposes of this plan all oil filled substation transformers and the associated LTC within the substation fence will be included. For Xcel Energy substations, this includes looking at the two types of assets (transformers and LTC's), documenting their maintenance requirements and procedures and then defining how the two asset categories, will be inspected and diagnostically tested to minimize the required effort while maximizing the assets' life and preventing preventable failures. The following is a brief description of the two categories:

- *Power Transformer (XFMR)* - A static device consisting of a winding and two or more coupled windings, with a magnetic core for introducing mutual coupling between electric circuits. Transformers are extensively used in electric power systems to transfer power by electromagnetic induction between circuits at the same frequency, usually with changed values of voltage and current.

- *On-Load Tap Changer (LTC)* - A controlled device used to automatically or manually change the primary or secondary voltage level of a transformer while under load (effectively the turns ratio)normally up to 10% to maintain the voltage in a preset bandwidth suitable for the downstream users of the energy. There are many applications:

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[3] Peripherals include items such as temperature gauges, LTC drag hands, fans and pumps, etc.

- Transmission system where under heavy loads the voltage may sag, the LTC can be used to maintain the transmission voltage at acceptable levels.
- Distribution system to maintain the distribution substation bus voltage at acceptable levels to maintain the voltage level on individual circuits (aka feeders).
- The LTC on a smaller transformer may be used for individual feeder voltage control.
- The LTC may be used to re-direct the flow of VARs on the transmission system.
- System ties, where the voltage between electrical systems may vary and LTC's may be used to correct the voltage levels.

Equipment types included in this procedure include all transformer winding configurations; and are categorized according to the various cooling methods, oil preservation sealing system, size and voltage. LTC's have been similarly categorized according to the various technologies used to facilitate the ability to change the voltage while in service and under load and if an identifiable oil sample can be obtained to determine the LTC condition. On LTCs, where oil sampling is not possible, the Xcel Energy procedures development team has analyzed the alternatives and recommends that necessary modifications be made to the transformer to facilitate sampling. Until such changes are installed, those transformers will be removed from service to allow for LTC DGA and oil sampling to determine the LTC's condition and any need for maintenance.

Transformers: the following types of transformers are included in this plan for voltages from 4kV up to 500kV for all MVA ratings. A key factor in the maintenance and inspection of transformers, is to prevent the overheating of the insulating medium including the core and coils with load management and adequate operating cooling, fans, and if so designed oil pumps to assist natural convection. Xcel Energy's plan is based on operating transformers in the designed range of load and temperature to maximize life; a major maintenance driver is the type of designed cooling and is used here to sort the various transformer categories.

The Maintenance number formula used to schedule the complete diagnostic inspection of the transformer ancillary equipment includes an Apparatus Condition (APK) factor ranging from 1 – 5, with 5 having the least amount of ancillary cooling equipment. For transformers, the factors are based on cooling equipment regardless of arrangement. They are:

- APK = 5 is not presently used.
- APK = 4 for transformers that are self-cooled.
- APK = 3 for transformers that use fans to cool the transformer.
- APK = 2 for transformers that use both fans and oil pumps to cool the transformer.
- APK = 2 for transformers that are water cooled.
- APK = 1 is not presently used.

The cooling design for each transformer can be found on the name plate and is designated with standard letter configurations. Key to determining the APK are the IEEE designations indicating air cooling, forced air, and forced oil.

In addition the transformer Maintenance number formula uses a service constant (SK) used as a prioritizing factor in the Maintenance number formulas; the Maintenance number grows at different rates depending on how important, as expressed by the SK, each transformer is to the operation of the Xcel Energy system. Service constants are assigned and used on both the transmission and distribution transformers; the specific SK values depend on the operating voltage class of the transformer.

Service constants used in Xcel Energy's Maintenance number formulas for transformers range in value from 1 to 5, with 5 being a transformer that has the greatest consequence of failure. An asset with a service constant of 5 would be subject to ancillary diagnostics sooner than equipment with the same oil cooling methodology but with a lower service constant. For transformers, the factors are based on the MVA size of the transformers:

- SK = 5 for transformers with EHV primary voltage and larger than 200 MVA.
- SK = 4 for transformer larger than 200 MVA.
- SK = 3 for transformers 20 MVA but less than 200 MVA.
- SK = 2 for transformers 5 MVA but less than 20 MVA.
- SK = 1 is a transformer less than 5 MVA.

On-Load Tap Changers: LTCs used at Xcel Energy include units based on resistive, reactive, and vacuum switching arrangements. They are applied to power transformers that have a variable load. When a transformer's load increases the transformer impedance causes the voltage to drop. When the load decreases the voltage rises. The LTC control senses the change in voltage and adjusts/regulates the LTC to keep the voltage within acceptable limits. LTCs are mechanical devices that vary the turns-ratio of a transformer. It performs this function without opening or disconnecting the power that is flowing through the transformer. The LTC's contacts are connected to the taps of a regulating winding. The mechanical drive mechanism physically moves the position of electrical contacts to select the appropriate ratio taps of the regulating winding. Resistors or reactors are used to limit the amount of circulating current during the switching transition from tap to tap.

Differences in voltage between the tap positions cause arcing to take place as the electrical contacts connect and part. This in turn causes burning of the contacts and degradation of the insulating fluid; both can be detected in dissolved gas analysis to evaluate the LTC condition.
Vacuum bottle tap changers are not designed to cause arcing in oil, and use a Vacuum Protection system to detect issues with the vacuum interrupters.

Most Xcel Energy substation regulating transformers have a 10% tap winding with higher or lower ranges for special applications. The tap winding typically varies the transformers ratio in .625% increments for a total of 16 steps. The polarity of the tap winding can be reversed under load. This gives the transformer the ability to lower or raise the voltage ratio by 10% above or below the nominal voltage rating. Details of LTC types and operation can be found in the equipment section below.

General

Diagnostic testing, careful analysis of the results, and when required proper maintenance activities including complete diagnostic of the transformer[4] is essential to system reliability and operations. Following the plan and procedures in this document, will ensure equipment performance and system reliability, and reduce the probability of unplanned failures. To ensure the proper implementation of these guidelines, maintenance personnel shall have a thorough understanding of the apparatus in their area of responsibility; be able to perform all required DGA and oil sampling, perform diagnostic tests, adjustments, repairs, inspections, and collect and record the correct performance and evaluation data for each asset. Test reports and other information collected during the diagnostic and laboratory testing, must be accurately interpreted and correct prompt actions taken when required, based on an understanding of the implications. All employees and Xcel Energy mutually share the responsibility to develop training, work as a team to stay current on procedures and equipment, and to recognize areas requiring additional focus.

Planning and Scheduling Transformer and LTC Diagnostics and Maintenance

Xcel Energy utilizes both time and a common planning and scheduling tool across the transmission and distribution asset[5] fleet, including the transmission and distribution transformers and LTCs based on a combination of factors including time, condition of the asset, the importance of the asset to the system and events that occur, such as fault operations while the equipment is in service. This Xcel Energy methodology, called Adaptable Reliability Centered Maintenance (ARCM) utilizes traditional diagnostic testing as well as modern diagnostic techniques such as transformer and LTC dissolved gas analysis (DGA), comprehensive oil testing, infrared scanning and periodic ancillary transformer diagnostics, as well as periodic visual inspections. If there is a need to perform further tests, make repairs, or order a transformer off-line to make repairs these tools and diagnostics provide the information required to make timely decisions. The goal, to increase reliability, requires Xcel Energy to perform all diagnostic testing the right way at the right time. Both on-site diagnostics and laboratory investigations will be used to determine the condition and if there is a need for further tests or actions on the transformer and/or the LTC if present.

While DGA, oil testing and infrared is done on a periodic (time based) schedule, each transformer and LTC in the system is represented by an algorithm[6] that grows the need for the ancillary diagnostic inspection either faster or slower depending on several factors such as previous diagnostic inspections and results. The algorithm for transformers is based on the type of construction and cooling of the unit (air only, fans, forced oil, or water cooling) to determine the apparatus constant (APK), the Service Constant (SK) based on the size of the unit in MVA to determine the value to the company (reliability, cost, risk, etc.). In addition the current and previous DGA tests, complete oil testing, and infrared results will all be used to evaluate the health of a transformer and the appropriate activities to ensure continued reliable operation of the unit. The

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[4] Transformers will be used generically in the general text to indicate transformers and on-line tap changers - LTCs
[5] **Asset:** An item with an independent physical and functional identity and age, within a facility (e.g. transformer, circuit breaker, pole, tower).
[6] Several algorithms are required for the complete fleet of substation assets assigned major grouping such as breakers, transformers, LTCs, etc. to generate the correct indication for maintenance activity.

Maintenance number for transformers triggers a diagnostic for the ancillary transformer equipment (temperature gauge, fans, pumps, etc.). Diagnostic testing of the transformer and LTC is as follows:

- DGA sampling and laboratory analysis: Every 12 months for all transformers and LTCs with the following exceptions:
    - Transformers operating at 345 kV or greater and larger than 200 MVA in size will have a DGA sample drawn and analyzed every 3 months unless continually monitored, then annually.
    - New transformers and repaired transformers when initially energized will have a DGA sample at 1 day, 1 week, and 1 month, unless required more often by warranty. Depending on voltage and size, the transformer will then be scheduled on either a quarterly or annual basis.
    - Transformers indicating internal issues and/or potential failures will have testing done, depending on the severity, often enough to monitor the rate of gassing and the total combustibles.

- Complete Oil Analysis by laboratory: Every 12 months for all transformers and LTCs

- Infrared Scanning and Analysis: Every 12 months for all transformers and LTCs

- Diagnostic of ancillary equipment such as gauges, pumps, fans, etc. is scheduled based on the apparatus condition and overall importance to the Xcel Energy system using the Maintenance number methodology and the formula. The formula generates a Maintenance Number (or MN_{TA}) that can be used to plan and schedule the ancillary diagnostic inspection. The formula is:

$$MN_{TA} = \left(1 + \frac{SK}{APK}\right) x \left(\frac{250xTAE}{TK}\right)$$

Definitions of the terms:

MN_{TA} is the Maintenance number indicating the need for an ancillary equipment diagnostic
SK is a service constant 1-5 where 5 is the most important asset
APK is an apparatus constant 1-5 where 5 is the best condition
TAE is the time since there was an ancillary equipment diagnostic done
TK is a time constant (unit is years). Xcel Energy's TK is initially set at 8 years

Note: The LTC is similarly tested at the same time and intervals as the transformer.

Requirements

Documentation

A comprehensive maintenance history for each transformer and LTC as installed and operating, is essential in developing an effective maintenance strategy and adapting the plan to improve reliability based on the actual field condition of the transformers. This information is also important when addressing failure trends and understanding cause and effect analysis. Consequently **all** diagnostic inspections, LTC voltage control operations, factory tests, repairs, adjustments, and failures must be clearly documented and said information securely and permanently stored in an easily retrievable and useable format. Life expectancy of transformers is greater than 75 years and records will be required for the entire service period.

In addition, a summary of the DGA, comprehensive oil tests, infrared inspections and peripheral diagnostic inspections and maintenance activities will be kept in a transformer assessment folder. The date, name of personnel, and brief description of the work performed, tests made, and counter readings shall be recorded. In addition, **all** work performed, required follow-on quantitative test results, transformer or LTC condition reports will be documented in Xcel Energy's PassPort™ Work Management System or other designated systems of record.

A comprehensive inspection, operation, diagnostic and maintenance history of each substation transformer, LTC, and peripheral equipment must be maintained. This is essential for establishing not only the "health" of the individual piece of equipment, but also other transformers in the fleet of the same model or class (sister units). This information is essential when addressing failure trends and understanding cause and effect analysis, establishing schedules, diagnostic, and maintenance requirements. It is critical to the success of the overall maintenance plan objectives to maintain the appropriate documentation and data for each piece of equipment.

Maintenance and Inspection Plans

The transformer inspection, diagnostic and maintenance plan consists of three basic inspection and diagnostic procedures. A fourth procedure, an internal inspection of the core and coils, bushing connections, LTC, etc. may be required based on the diagnostic testing of the assets, but is not specifically scheduled or planned. This procedure is not intended to establish the Substation Inspection Program and Procedures which are contained in a separate document. A brief overview of the Inspection requirements that provide data and input into the Transformer and LTC Plan and Procedures is included for completeness.

Transformer Visual Inspections:

The visual transformer inspection will be performed each time a station inspection is performed and appropriate data collected in the electronic device used for inspections and later transferred to the system of record. Included in this inspection are all external gauges such as top oil temperature, hot spot temperature, oil level, LTC drag hands, LTC counter, pressure relief indicator, etc. In addition the fans and pumps if present should be activated to insure they are operational (oil pumps flow indicator should be verified), and any oil leaks or other issues reported.

Annual DGA, Comprehensive Oil and Infrared Inspection:

Dissolved Gas Analysis (DGA): As discussed above, every transformer will have a unique sample drawn from each separate compartment for dissolved gas testing as a health index of the transformer and LTC apparatus condition.

Transformer oils perform four functions for the transformer and load tap changer. The first three are to provide insulation, provide cooling, and help extinguish arcs. In addition oil retains dissolved elements generated by:

- Oil degradation
- Moisture in the transformer paper insulation and oil
- Cellulose insulation
- Deterioration of the core and tank metals

Close observation of dissolved gases in the oil and other oil properties; provide the most valuable information about transformer health. It is important to note that while unusual, a buildup of combustible gas and failure events can occur very quickly. Through-faults, high moisture levels in a transformer, or air bubbles trapped in the windings are some of the possible causes.

The analysis of the DGA and comprehensive oil tests looks for trends by comparing information of the present laboratory results to previous DGAs from the same asset compartment (transformer or LTC), and understanding their meaning. Two specific IEEE combustible tables are used in this analysis; the total combustible gas levels and the acceptable rate of rise per day of combustible gas. The laboratory will issue consistent condition reports as to the status of the various transformers.

Xcel Energy will use DGA analysis for all substation transformers on annual or quarterly basis after being placed in service and the transformer's initial energized period where DGA samples will be taken more frequently to establish a base line and trend if any gases are forming typically after 1 day, 1 week, and 1 month. Transformers operating at 345kV or greater and 200 MVA or larger will be DGA tested quarterly, unless continually monitored, and then yearly. This is by far the most important tool for determining the health of a transformer and LTC.

After results are determined for each of the samples, the laboratory will compare the current gas levels and prior DGAs, so that trends can be recognized and rates of gas generation established. Transformers are very complex; aging, chemical actions and reactions, electric fields, magnetic fields, thermal contraction and expansion, load variations, gravity, and other forces all interact inside the tank. Externally, through-faults, voltage surges, wide ambient temperature changes, and other forces such as the earth's magnetic field and gravity affect the transformer. There are few, if any, "cut and dried" DGA interpretations; keeping accurate records of each individual transformer's operating history is paramount.

Xcel Energy will depend on the expertise of the laboratory to analyze the oil samples and rank the condition of the transformer using a pre-defined scale, indicating if there is any issue with the transformer, if a re-test is warranted, or if serious problems are found in the transformer.

DGA is also used for the LTC compartments to determine the condition of the insulating oil (gases and carbon levels), the wear on the contacts, and the remaining useful life of the LTC.

The laboratory will analyze the types of metals found in the oil samples to determine the source of the particulates and the changes in concentrations since the last testing.

Comprehensive Oil Analysis: In addition to the DGA tests, transformers and LTCs (all separate compartments) will have an annual comprehensive oil analysis, which will include:

- **Dielectric Strength of the Oil** – this test is done to see at what voltage the oil electrically breaks down which affords a good indication of the contaminants in the oil such as water and oxidation particles. The IEEE standard C57.106 sets the minimum breakdown voltages for transformer oil and the specified test methodologies. Oil not meeting the standard must be reclaimed or replaced.

- **Interfacial Tension (IFT)** - used to determine the interfacial tension between the oil sample and distilled water. As the oil ages, it is contaminated by tiny particles (oxidation products) of the oil and paper insulation. The more particles, the weaker the interfacial tension and the lower the IFT number. The IFT and acid numbers together are an excellent indication of when the oil needs to be reclaimed.

- **Acid Number** – this number (acidity) is the amount of potassium hydroxide (KOH) in milligrams (mg) that it takes to neutralize the acid in 1 gram (gm) of transformer oil. The higher the acid number, the more acid is in the oil. New transformer oils contain practically no acid.

- **Oxygen Inhibitor** - Oxygen inhibitor is a key to extending the life of transformers. The oxygen attacks the inhibitor instead of the cellulose insulation. As this occurs and the transformer ages, the inhibitor is used up and needs to be replaced. The ideal amount of inhibitor recommended by the manufacturer shall be followed but generally 0.3% by total weight of the oil (ASTM D-3487). The test is usually done at intervals of no more than 3-4 years.

- **Power Factor -** This measurement indicates the dielectric loss (leakage current) of the oil. This test may be done by the DGA laboratories or using field testing equipment such as Doble™ testing equipment or other power factor test sets. A high power factor indicates deterioration and/or contamination by-products such as water, carbon, or other conducting particles; metal soaps caused by acids (formed as mentioned above), attacking transformer metals, and products of oxidation. The DGA labs normally test the power factor at 25 °C and 100 °C. Current information indicates the in-service limit for power factor is less than 0.5% at 25 °C. If the power factor is greater than 0.5% and less than 1.0%, further investigation is required; the oil may require replacement or reclamation by some method. If the power factor is greater than 1.0% at 25 °C, the oil may cause failure of the transformer; replacement or reclaiming is required. Above 2%, the oil should be removed from service and reclaimed or replaced because equipment failure is a high probability.

- **Furans -** Furans are a family of organic compounds which are formed by degradation of paper insulation (ASTM D-5837). Overheating, oxidation, and degradation contribute to the destruction of insulation and form furanic compounds. Changes in furans between DGA tests are just as important as individual numbers. The same is true for dissolved gases. Transformers with a degree of polymerization lower than 250 should be investigated because paper insulation is being degraded. Also reexamine both the IFT and acid number. Furan testing will be done in conjunction with the ancillary diagnostic.

Infrared Inspection

The annual inspection of the power transformers and the LTC shall include a comprehensive infrared inspection to verify that there is no unusual heating of the tank and LTC as well as the connections to the bushings, etc. The inspection will include verifying the temperature of the transformer oil versus the top oil temperature gauge and also the level of the oil versus the transformer's oil level gauge.

Ancillary Diagnostic Inspection

Based on the type of transformer, specific diagnostic tests will be periodically performed based on the Maintenance number generator discussed above. At this time, the transformer will be inspected for any gauge or mechanism that can be examined safely without the transformer being de-energized.

2017 and 2018 AAA Ordered Reporting Requirements

On February 7, 2019, the Commission issued its ORDER ACCEPTING 2016-2017 REPORTS AND SETTING ADDITIONAL REQUIREMENTS in Docket Nos. E999/AA-17-492 and E999/AA-18-373, the 2017 and 2018 AAA report dockets. On November 13, 2019, the Commission issues its ORDER ACCEPTING 2017-2018 ELECTRIC REPORTS AND SETTING ADDITIONAL REQUIREMENTS in Docket No. E999/AA-18-373. In compliance with these Orders, the Company provides the following information.

A. Self-Commitment and Self-Scheduling Annual Compliance Report

In compliance with Order Point No. 5 of the Commission's February 7, 2019 Order and Order Point Nos. 8, 9, and 10 of the Commission's November 13, 2019 Order, we have submitted a compliance report analyzing the Company's options for seasonal dispatch, self-commitment and self-scheduling in the Commission's investigation docket which was opened to examine these issues, Docket No. E999/CI-19-704.

B. Errors Report

In compliance with Order Point No. 5 of the Commission's November 13, 2019 Order, Park K, Section 4, Schedule 4 incorporates any errors made in monthly FCA filings during the current AAA reporting period.

Annual Automatic Adjustment Report

Docket No. E999/AA-20-171

PART L

Trade Secret Justification

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 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.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-20-171

PART M

NOTICE OF REPORT AVAILABILITY, CERTIFICATE OF SERVICE, AND SERVICE LISTS

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF NORTHERN STATES POWER COMPANY ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT FOR ITS ELECTRIC OPERATION

DOCKET NO. E999/AA-20-171

NOTICE OF REPORT AVAILABILITY

On March 2, 2020, Northern States Power Company, doing business as Xcel Energy, filed a report with the Minnesota Public Utilities Commission for the 18 months ending December 31, 2019 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, Paget Pengelly, 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 NOS. **E999/AA-20-171**
E999/AA-18-373
E002/GR-15-826
E002/GR-13-868

Dated this 2nd day of March 2020

/s/
____
Paget Pengelly

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Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
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