Xcel Energy

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

September 1, 2016

- VIA ELECTRONIC FILING -

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: ANNUAL REPORT
2016 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT - ELECTRIC
DOCKET NO. E999/AA-16-523

Dear Mr. Wolf:

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. This report covers the Company's electric utility operations. The natural gas utility report is being filed separately.

Various attachments to this filing contain information that Xcel Energy considers trade secret. We provide justification for the identification of the data designated as Trade Secret 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 Tim Edman at 612-330-5570 or timothy.j.edman@xcelenergy.com or John Chow at 612-330-7588 or john.chow@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

AMY S. FREDREGILL
MANAGER, RESOURCE PLANNING AND STRATEGY

Enclosures
c Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

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

ANNUAL REPORT

DOCKET NO. E999/AA-16-523

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 for the period July 1, 2015 to June 30, 2016. This Report includes a summary of our fuel costs over the past 12 months, a forecast of fuel costs over the next five years, and information on our efforts to manage fuel costs.

We are pleased to report that our overall fuel costs have declined for the second year in a row. In 2015-2016, our total net system fuel cost was about $1.01 billion, and in 2014 – 2015 the total net system fuel cost was about $1.12 billion. On a total system energy basis, the cost has dropped from $27.39 per MWh in 2014 – 2015 to $24.74 per MWh in 2015 – 2016.

Equally important, we are pleased to report that our monthly fuel cost forecasts have proven to be well within an acceptable range of accuracy. With a 2015-2016 average monthly forecast-to-actual deviation of - 5.7 percent, we are under the threshold set by the Commission.

A major factor contributing to lower total net system costs is the favorable natural gas pricing that we have experienced over the past few years. Although gas pricing is not within our control, this benefit is passed on directly to our customers through the FCA. There are, however, strategic decisions and actions the Company has taken to manage risk. First and foremost, the Company maintains a diverse mix of resources both in terms of fuel type and ownership structure. This diversity of resources is critical to ensuring we are able to prudently manage costs. We strategically negotiate and manage more than 60 fuel contracts for uranium, coal, biomass and refuse-derived fuel purchases, along with five contracts for transporting fuel sources to our power plants. We continue to utilize the MISO market to make purchases and sales that benefit our customers. In addition, we have taken advantage of several major renewable generation opportunities. Since renewable generation does not include a fuel cost, these types of projects provide a valuable hedge against cost increases for other fuel types.

Looking ahead, for 2017, we are forecasting that our fuel costs will be higher than 2016. The total NSP System energy cost per MWh is projected to increase by about 10 percent in 2017, to $27.25 MWh, compared to the actual rate for the 2015 – 2016 AAA period. The forecast assumes cost increases due to (1) higher forward natural gas prices, (2) escalation factors in long-term purchased power agreements, and (3) the addition of several new solar projects.

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

Ryan Long
Principal Attorney
Xcel Energy
401 Nicollet Mall – 8th Floor
Minneapolis, Minnesota 55401
(612) 215-4659

C. Date of Filing and Date Modified Rates Take Effect

Consistent with the filing requirement in Minn. Rules 7825.2840, the date of this filing is September 1, 2016. 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

Amy S. Fredregill
Manager, Resource Planning and Strategy
Xcel Energy
401 Nicollet Mall – 7th Floor
Minneapolis, Minnesota 55401
(612) 215-5367

IV. 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. Rule7825.2840 at the end of our filing. Attachment L contains the justification for trade secret treatment of certain information contained in this filing.

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, 2015 and ending June 30, 2016. 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 12 months ending June 30, 2016. 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

This report contains a monthly five-year projection of fuel cost by energy source. This five-year projection, which contains trade secret information, is submitted as Part G. In addition, in compliance with the "FCA Settlement" in the Company's 2005 electric rate case (Docket No. E002/GR-05-1428), the Company is providing its quarterly 12-month FCA forecast provided 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 2016 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

V. 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.

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:

History of Nuclear Sinking Fund	E002/M-81-306	Part H, Section 1
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
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	Part J, Sections 1, 2, 3 and 5
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

The Commission's June 2, 2016 AAA Order in Docket E002/AA-14-579 requires the Company to allocate the asset-based wholesale portion of Day-Ahead Regulation Amount and Real-Time Regulation Amount separately under each charge type in future AAA filings. The Company is working with the Department on our MISO Day 2 and ASM reports. We anticipate the changes in MISO Day 2 and ASM reporting, including the asset-based wholesale allocation by charge type, will take place in the FYE 2017 AAA.

C. Request to Consolidate and Streamline Certain Compliance Reports

The Company has devised solutions to meet the challenges presented by the fundamental changes and volatilities in fuel costs and the energy market since 2004 in order to ensure that our ratepayers are affected as little as possible. Our due diligence efforts often result in additional reporting requirements to demonstrate their reasonableness and effectiveness.

The additional reporting requirements have cumulatively resulted in our AAA report becoming quite voluminous. The effects are also visible in our monthly FCA reports and prior Department of Commerce Quarterly FCA reporting efforts, Docket No. E999/DI-09-107. As indicated in prior AAA reports, there are some NSP-specific issues that have been thoroughly evaluated, and thus we believe the associated compliance reporting requirements can be revised or discontinued. These reporting requirements were discussed with Department staff in the fall of 2015. The Company proposes to continue working with the Department to consolidate and streamline the AAA report and monthly FCA reports in order to make them more concise and easier to review.

VI. MISCELLANEOUS INFORMATION

A. Service List

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:

Ryan Long Principal Attorney Xcel Energy 401 Nicollet Mall – 7th Floor Minneapolis, Minnesota 55401 Ryan.j.long@xcelenergy.com	Carl Cronin Regulatory Administrator Xcel Energy 401 Nicollet Mall – 7th Floor Minneapolis, Minnesota 55401 Regulatory.Records@xcelenergy.com

CONCLUSION

The Company submits this annual report for its electric utility operation pursuant to the Commission's rules regarding Automatic Adjustment of Charges.

Dated: September 1, 2016

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

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

ANNUAL REPORT

DOCKET NO. E999/AA-16-523

SUMMARY

Please take notice that on September 1, 2016, Northern States Power Company, doing business as Xcel Energy, filed with the Minnesota Public Utilities Commission the annual report for its electric operation pursuant to the Commission's rules (Minn. R. Parts 7825.2800 to 7825.2840) regarding Automatic Adjustment of Charges.

NORTHERN STATES POWER COMPANY
2015-2016
ANNUAL AUTOMATIC ADJUSTMENTS REPORTS
(Electric Utility)

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Docket No. E999/AA-16-523

September 1, 2016

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2015 – 2016 ELECTRIC AAA REPORT

A. OVERVIEW

This report provides an overview of fuel costs (actual and forecast) as well as other expenses the Company is authorized to recover through the fuel clause rider during the twelve-month period of July 1, 2015 – June 30, 2016. The Company has been providing detailed information in its monthly Fuel Clause Adjustment (FCA) filings during this reporting period. The Company will continue to provide this type of information in its monthly FCA filings to keep the agencies informed of any significant events.

B. REPORTING REQUIREMENTS

This report also includes the compliance reporting related to the effects of the Midcontinent Independent System Operator, Inc. (MISO)[1] Day 2 wholesale energy market adopted by the Commission in its Orders in Docket No. E002/M-04-1970 *et al.*[2] 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).[3] In addition to submitting additional compliance information in this AAA report and monthly FCA filings, the Company has been providing on a quarterly basis the 12-month fuel cost forecast information to customers who have signed protective agreements with the Company. Currently there are 15 representatives from the 2005 rate case intervening parties who have signed the protective agreements and are receiving the FCA forecast information.

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] MISO was formerly called the Midwest Independent Transmission System Operator, Inc. The name change was effective April 28, 2013.

[2] *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.

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

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-523

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 over-the-counter spot coal markets. A listing of current coal supply and transportation contracts and cost changes is shown on Part D, Section 1, Schedules 2, 3 and 5.

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 **[TRADE SECRET BEGINS**

TRADE SECRET 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 and sales 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 specific destinations, 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. **[TRADE SECRET BEGINS**

TRADE SECRET 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.

Nuclear:

Following the March 2011 events at the Fukushima-Daiichi Nuclear Plant in Japan, the market price for uranium dropped 30 percent from the high earlier in 2011. The market price for uranium during the first two quarters of 2016 has declined overall with a high spot market price of $34.85 per pound in January to a low of $26.15 per pound in June. The spot market ended the second quarter at $27.00 per pound. From the pre-Fukushima price peak in January 2011, the market price for uranium is at 37 percent of the pre-Fukushima price. The market continues to show no signs of immediate recovery to pre-Fukushima-Daiichi levels.

Even at today's market prices, the cost of nuclear fuel continues to be substantially 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 recent dramatic drop in market prices, the current prices are at a level that is impacting the forecast levels of expanded uranium production. 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. Prices will likely increase as demand increases with the restart of some reactors in Japan and construction and start-up of new nuclear power plants world-wide continues. Prices could be further impacted if supply predictions are not met. The current market analysis forecasts supply meeting demand until about 2020, 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.

The current unrest in the Ukraine along with sanctions imposed on Russia by the United States and European Union (EU) may also impact the supply of uranium. Numerous U.S. utilities have contracted for supply of enriched uranium from Russia. If the sanctions impact the supply of uranium in the form 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 listing of current nuclear fuel components of service contracts is shown on Part D, Section 1, Schedule 1.

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. 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 Willmarth, Minnesota, and French Island, Wisconsin). 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.

[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Conclusion:

Commodity fuel cost variability and the impact on purchased wholesale energy prices affects retail rates charged to our electric customers in Minnesota through the FCA. The Company has worked to respond to the various factors beyond our control to minimize the costs for our customers.

Nuclear Fuel Components of Services for the Period of July 2015 through June 2016

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[TRADE SECRET BEGINS				
1				
2				
3				
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9				
10				
11				
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13				
				TRADE SECRET ENDS]

Coal Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity or Volume (million tons/year)	Contract Expiration Date
[TRADE SECRET BEGINS				
				TRADE SECRET ENDS]

* New contracts

Transportation & Related Services Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[TRADE SECRET BEGINS				
				TRADE SECRET ENDS]

Wood and RDF Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[TRADE SECRET BEGINS …				

…TRADE SECRET ENDS]

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TRADE SECRET DATA EXCISED

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[TRADE SECRET BEGINS …				

…TRADE SECRET ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[TRADE SECRET BEGINS …				

…TRADE SECRET ENDS]

Cost Changes - July 1, 2015 to June 30, 2016

	Contract	Percent Change
[TRADE SECRET BEGINS		
Transportation Contracts		
		TRADE SECRET ENDS]

* New contracts

** The percent change represents the price delta between the current year and the preceding year of a multi-year agreement. Confirmation notices (CN) for coal are for terms of 1 to 3 years. For multi-year confirmation notices (CN), pricing increases year over year. Some CNs include a quarterly or annual escalator to account for changes in economic conditions (e.g. GDP).

Cost Changes - July 1, 2015 to June 30, 2016

	Contract	Percent Change
[TRADE SECRET BEGINS		
Wood and RDF Supply Contracts		
		TRADE SECRET ENDS]

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 close monitoring of our load and management of our generation system and purchased energy resources so as to provide the most economic loading of our own generation units in conjunction with our effort to minimize costs and risks by leveraging the competitive wholesale energy and fuel markets.

In addition to monitoring our load and managing our generation and purchased resources, Xcel Energy continually monitors weather patterns and energy market trends in the Midwest and other regions to obtain the lowest cost energy possible for our customers. In general, Xcel Energy will purchase energy for its customers on the wholesale market whenever the market price of energy is below our avoided cost of generation. Since market prices can be predicted with certainty, Xcel Energy must carefully assess potential needs in the face of varying market conditions. These assessments are an integral part of our cost and risk minimization efforts.

Xcel Energy also 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 providing our customers with the lowest possible energy prices and reliable energy services. The Company continues to purchase energy both in the bilateral market and 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 energy procurement and dispatch processes of Minnesota utilities within the context of the MISO Day 2 market were described in detail in the joint report dated June 22, 2006 in Docket Nos. E002/M-04-1970 *et al.* The Company incorporates that report by reference.

Detailed descriptions of MISO's administration of market procurement for these services are included in the joint filing dated May 9, 2008 in Docket No. E999/M-08-

528. The Company uses MISO ASM to co-optimize energy and ancillary services markets, resulting in a net benefit to ratepayers (See Part J, Section 6 of this AAA report).

Another component of the Company's dispatching policy is the ability to forecast 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. In the fall of 2009, Xcel Energy began using this tool to forecast output from all NSP system wind farms. In 2008, prior to this tool's use, the Mean Absolute Error (measure of accuracy) for our NSP wind energy production forecast was 18.7 percent. For 2015-2016, the NSP Mean Absolute Error was 9.08 percent, a decrease in forecast error of roughly 51 percent. Reductions in forecast error translate directly into a decrease in fuel and purchased power costs because an improved wind forecast from the Company helps MISO improve unit commitment.

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 dispatch 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. For more information on wind curtailment, please see Part H, Section 5. 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 **[TRADE SECRET BEGINS TRADE SECRET ENDS]** mills/kWh in 2015.

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

3. A contract has been completed **[TRADE SECRET BEGINS TRADE SECRET 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 $2.37/MBtu during 2014. (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html) During this same period, Northern States Power Company – Minnesota's average delivered coal cost was **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. NSP's average delivered coal cost for 2013 was **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

2. NSP has re-emphasized its program to review or modify, as appropriate, coal procurement strategy **[TRADE SECRET BEGINS TRADE SECRET ENDS]**

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

4. Xcel Energy Services Inc. negotiated terms with existing major coal suppliers on behalf of NSP **[TRADE SECRET BEGINS**

TRADE SECRET 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 2015 through June 2016, the Company disputed approximately three days of 104 MISO invoices. As a result, $447,971 in disputed amounts were granted by MISO for the NSP System (through adjustments to MISO settlements).

NSP MISO Dispute Status

Sum of Disputed $ Amount			Dispute Status			
YEAR	Op Month	Operating Date	GRANTED	DENIED	OPEN	TOTAL
2015	2015-10	09/01/15	$447,971.92	$300,000.00	$0.00	$747,971.92
	2015-7	07/12/15	$0.00	$510.08	$0.00	$510.08
2015 Total			$447,971.92	$300,510.08	$0.00	$748,482.00
2016	2016-02	09/01/15	$0.00	$500,419.07	$0.00	$500,419.07
2016 Total			$0.00	$500,419.07	$0.00	$500,419.07
TOTAL			$447,971.92	$800,929.15	$0.00	$1,248,901.07

The total dollar amount disputed in the 2015 – 2016 AAA period is higher than in the 2014 – 2015 AAA period. Recent disputes were primarily related to settlement issues with new wind units registered in the MISO market.

CONSERVATION AND LOAD MANAGEMENT POLICY

Xcel Energy's conservation and load management policy is designed to help our customers use energy wisely. In response to changing market needs and compliance requirements, the Company develops conservation and load management programs subject to regulation by the Minnesota Department of Commerce – Division of Energy Resources. These programs provide opportunities for customers to improve the efficiency with which they use energy.

The Company offers a wide variety of programs that assist customers in implementing conservation and load management 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 may experience an overall reduction in their utility bills. Both methods mitigate the Company's power producing and purchasing needs. Moreover, both are explicitly considered in the Company's integrated resource planning process and also in the daily operations in the MISO Day Ahead and Real Time energy markets.

The Company has two electric load management programs available to its electric customers: Electric Rate Savings and Saver's Switch®. 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 Xcel Energy. Customers must be able to reduce their electric loads by a minimum of 50 kW on control days. Participants save anywhere from 40 to 60 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 when Xcel Energy's load is expected to exceed peak capacity. 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 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 when Xcel Energy's load is expected to exceed peak capacity. 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.

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 its Conservation Improvement Program (CIP). To achieve our conservation goals, we adhere to the following principles:

- Comply with the electric energy savings goal requirements set forth in statute;
- Comply with the minimum electric CIP spending requirements set forth in statute;
- Work with the Department and the Commission to maximize energy savings (and thus customer bill savings) per CIP dollar the Company spends;
- Evaluate programs on the basis of cost-effectiveness of the total investment; and
- Balance the needs of all customers in the allocation of CIP resources.

The Company is also required to file with the Department no more than every three years, a CIP 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 CIP Triennial Plan for 2013-2015, which was filed on June 1, 2012 and approved on October 1, 2012.[1] In addition, the Company filed an extension for 2016 to the 2013-2015 CIP Triennial Plan, which was filed on June 1, 2015 and was approved on October 12, 2015. The Company filed its 2017-2019 CIP Triennial Plan on June 1, 2016. This Plan is currently under review by the Department.

On April 1 of each year, the Company is required to file with the Department an Annual Status Report, which details the cost-effectiveness and spending for the prior year's CIP program. The Deputy Commissioner of the Department approved the Company's 2015 Electric and Gas CIP Status Report on June 30, 2016.[2]

[1] Docket No. E,G002/CIP-12-447.
[2] Docket No. E,G002/CIP-12-447.08.

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. In this schedule, references to "the Commission" are references to the FERC, not the MPUC.

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

[1] As described elsewhere in this AAA Report, 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."

ensuring the development of transmission system additions that achieve maximum efficiency benefits.

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 be happy to provide the additional information upon request.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-523

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). In the associated docket, E002/MR-15-827, a new Base Cost of Energy of $0.02680 per kWh has been in effect since January 1, 2016.

The tables below show the Fuel Adjustment Factor (FAF) Ratio and Base Cost of Energy by the Service Category effective during the AAA reporting period:

Effective January 1, 2016 to Current[1]

Service Category	FAF Ratio	Base Cost of Energy
Residential	1.0185	$0.02730
C & I Non-Demand	1.0493	$0.02812
C & I Demand	1.0028	$0.02688
C & I Demand TOD On-Pk	1.2732	$0.03412
C & I Demand TOD Off-Pk	0.7987	$0.02141
Outdoor Lighting	0.7446	$0.01996

Effective November 1, 2015 to December 31, 2015[2]

Service Category	FAF Ratio	Base Cost of Energy
Residential	1.0185	$0.02831
C & I Non-Demand	1.0493	$0.02917
C & I Demand	1.0028	$0.02788
C & I Demand TOD On-Pk	1.2732	$0.03539
C & I Demand TOD Off-Pk	0.7987	$0.02220
Outdoor Lighting	0.7446	$0.02070

[1] 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).
[2] As part of rate case (Docket No. E002/GR-13-868) the new FAF ratios were approved by the MPUC on August 31, 2015. The new FAF ratios became effective November 1, 2015.

Effective October 24, 2014 to October 30, 2015[3]

Service Category	FAF Ratio	Base Cost of Energy
Residential	1.0132	$0.02817
C & I Non-Demand	1.0472	$0.02911
C & I Demand	1.0091	$0.02805
C & I Demand TOD On-Pk	1.2776	$0.03552
C & I Demand TOD Off-Pk	0.7940	$0.02207
Outdoor Lighting	0.7421	$0.02063

[3] Effective January 3, 2014, pursuant to the MPUC's acceptance of the proposed Base Cost of Energy with the implementation of the interim rate (Docket Nos. E002/GR-13-868 and E002/MR-13-869).

BILLING ADJUSTMENT AMOUNTS CHARGED CUSTOMERS FOR EACH TYPE OF ENERGY COST

Please refer to line item 34 of Part E, Section 5, Schedule 1, Page 2 of 4 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 Rule 7825.2810 and the Commission's Order granting the Company's Renewal of Forecast FCA Method Rule Variance (Docket No. E002/M-14-364).

2. Exemption of WindSource

Pursuant to Commission Orders[1] approving the Company's 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. Line 19a of Part E, Section 5, Schedule 1, Page 1 of 4 illustrates this amount of exempted energy.

As addressed in Company's Windsource Petition, 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]

In the 2011 rate case, 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

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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).

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

3. MISO Day 2 Energy Market Charges

Pursuant to the Commission's Orders dated April 7, 2005, December 21, 2005, February 24, 2006 and December 20, 2006 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. Schedule 16 and 17 costs were collected in interim rates outside of the FCA effective January 1, 2006. Line items 14b of Part E Section 5 Schedule 1, Page 1 of 4 contain the monthly MISO Day 2 charges and Schedules 16, 17 and 24 amounts excluded from monthly fuel clause.[5]

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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.

[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 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. Docket No. E002/GR-05-1428.

As a result of the obligations in the 2005 rate case and MISO Day 2 dockets, the following monthly refunds have been initiated 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

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

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

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 items 14d of Part E Section 5 Schedule 1, Page 1 of 4 contains the monthly MISO ASM charges.

5. Community Solar Garden Program Cost Recovery

Pursuant to the Commission's Order issued September 17, 2014, in our Community Solar Garden 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 Certificates (RECs) and unsubscribed energy. As of June 2016, the Company has been recovering the monthly fuel costs from three community solar gardens.

[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 37 of Part E Section 5 Schedule 1, Page 3 of 4, contains the Minnesota retail portion of NSP System fuel and purchased energy costs. (The "NSP System" refers to the integrated generation and transmission systems of Northern States Power Company, a Minnesota corporation and Northern States Power Company, a Wisconsin corporation.)

The class differentiated FCC method was adopted during the reporting period, July 2015 through June 2016. The individual class totals were reported on line items 37(i) through 37(vi).

REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED

Line items 39 and 43 of Part E Section 5 Schedule 1, Page 3 and Page 4 of 4, contain the Minnesota retail electric fuel revenues collected under both the fuel clause adjustment and the base of energy.

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 37(i) to (vi) are the actual fuel costs and 45(i) to (vi) are the individual class totals that included the forecast true-up and any applicable refunds during the AAA reporting period.

In compliance with the Commission Order dated December 7, 2005 in the Company's 2004 electric AAA filing (Docket No. G,E999/AA-04-1279), the Company has included in 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.

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	12 Months
	FORECASTED COST OF FUEL													
	Account 151 Fossil Fuel													
[1]	Coal	28,322,665	26,490,126	21,754,946	23,054,649	25,797,394	21,450,106	35,301,683	26,549,712	20,442,825	20,062,225	21,234,973	25,951,174	296,412,478
[2]	Wood/RDF	1,243,762	1,216,807	1,150,005	1,231,958	1,167,977	1,241,935	1,042,510	1,096,125	744,657	884,991	1,115,808	1,137,488	13,274,023
[3]	Natural Gas CC	14,931,198	11,890,906	9,478,011	9,615,152	10,490,322	12,291,638	8,421,796	9,827,584	12,204,938	5,778,459	5,811,116	9,470,090	120,211,210
[4]	Natural Gas / Oil CT	5,389,035	3,389,092	3,680,964	1,171,081	121,931	151,448	560,874	140,519	188,509	860,921	2,217,375	1,636,898	19,508,647
[5]	Total Fossil Fuel	49,886,660	42,986,931	36,063,926	35,072,840	37,577,624	35,135,127	45,326,863	37,613,940	33,580,929	27,586,596	30,379,272	38,195,650	449,406,358
[6]	Account 518 Nuclear Fuel	10,159,003	10,159,005	10,175,554	8,701,460	6,681,072	10,149,477	10,079,186	8,011,815	9,717,833	9,914,734	10,271,918	9,667,590	113,688,647
[7]	Account 555 Energy Purchases	52,735,804	49,522,013	46,028,146	43,700,742	41,144,299	42,355,241	42,421,695	43,856,834	39,864,872	43,512,205	45,424,967	43,198,805	533,765,623
[8]	Net System Cost	112,781,467	102,667,949	92,267,626	87,475,042	85,402,995	87,639,845	97,827,744	89,482,589	83,163,634	81,013,535	86,076,157	91,062,045	1,096,860,628
[9]	Forecasted System MWH Sales *	4,004,275	3,913,660	3,445,832	3,331,558	3,298,168	3,573,581	3,666,973	3,310,062	3,471,813	3,106,071	3,222,764	3,526,708	41,871,465
[10]	Forecasted Minn. Retail Sales Subject to FCC *	2,973,450	2,895,890	2,554,255	2,448,665	2,396,946	2,566,877	2,632,925	2,385,071	2,502,333	2,251,426	2,382,511	2,614,487	30,604,834
[11]	Forecasted Cost of Fuel Per kWh [8]/[9]/10 **	2.817	2.623	2.678	2.626	2.589	2.452	2.668	2.703	2.395	2.608	2.671	2.582	
	ACTUAL COST OF FUEL													
[12]	Account 151 Fossil Fuel	53,520,846	43,763,755	40,783,629	38,217,497	35,333,247	37,734,653	45,029,964	34,725,752	27,324,375	23,358,395	26,821,520	34,691,290	441,304,923
[13]	Account 518 Nuclear Fuel	10,925,142	10,914,377	10,542,939	9,063,923	5,996,735	7,947,135	7,094,043	7,279,561	10,696,586	10,504,918	10,864,217	10,468,675	112,298,251
[14]	Account 555 Economic Dispatch	42,025,361	43,961,855	43,475,095	39,894,348	41,424,289	38,195,073	38,317,328	38,306,607	38,819,576	42,618,294	37,171,078	36,365,507	480,574,412
[14] a	Acct 555 Wind Curtailment Payment	61,502	174,016	630,671	830,877	834,312	733,042	168,089	306,314	302,311	635,338	747,254	178,667	5,602,391
[14] b	Account 555 MISO Day 2	4,913,363	8,786,957	7,761,624	3,645,674	7,126,801	3,620,382	5,071,466	6,341,748	4,691,969	1,644,428	1,245,290	6,076,958	60,926,660
	- Account 555 MISO Day 2 - Sched. 16 & 17	651,713	598,233	593,350	566,709	594,950	641,276	679,780	662,862	580,054	566,192	613,484	657,465	7,406,067
	- Account 555 MISO Day 2 - Sched. 24	107,928	86,528	90,239	88,223	73,445	99,023	79,278	97,706	82,385	87,127	95,620	71,709	1,059,209
	- RSG/RNU Allocation Adjustment	30,594	43,258	81,605	77,614	45,551	63,807	71,515	29,474	(33,450)	38,365	128,869	(4,866)	572,337
	- Congestion and Loss Allocation Adjustment	256,865	403,977	804,527	762,450	315,106	500,401	340,903	345,045	581,556	753,763	570,837	155,112	5,790,543
[14] c	Account 555 MISO Day 2 - Net	3,866,262	7,654,960	6,191,904	2,150,678	6,097,750	2,315,875	3,899,990	5,206,661	3,481,424	198,981	(163,520)	5,197,537	46,098,503
[14] d	Account 555 MISO ASM	484,386	2,028,339	923,477	1,619,014	3,816,098	3,136,433	2,752,527	1,131,813	786,022	1,859,789	1,844,988	2,619,862	23,002,748
[15]	Fuel Cost - Intersystem Sales	8,211,120	7,792,001	9,309,967	10,060,412	5,175,231	9,646,144	7,335,842	6,168,145	6,558,736	9,933,338	4,502,564	4,709,292	89,402,791
[16] a	Net Windsource Program Expenses***	684,689	743,680	366,717	418,475	380,516	480,407	288,905	522,089	525,572	619,613	276,554	583,001	5,890,216
[16] b	Solar Gardens Program Costs (Excluded from System Costs)			356	445	328	138	574	1,264	5,233	597	2,157	9,127	
[17]	Final Adjusted Net System Cost	101,987,690	99,961,622	92,870,675	81,297,005	87,946,356	79,935,523	89,636,621	80,265,210	74,320,752	68,622,167	72,504,262	84,220,118	1,013,568,003
[18]	Total MWH Sales (Cal. Month)	3,914,116	3,847,861	3,543,271	3,314,295	3,233,894	3,422,020	3,557,831	3,228,305	3,268,372	2,948,008	3,229,447	3,602,708	41,110,128
[19]	To Retail State of Minnesota	2,920,992	2,858,348	2,631,584	2,455,729	2,356,063	2,487,413	2,567,047	2,338,418	2,372,681	2,162,456	2,378,549	2,662,417	30,191,697
[19] a	Minnesota Windsource MWh not subject to FCA	12,549	12,230	11,902	10,905	9,678	11,575	12,015	11,068	12,755	10,645	10,991	12,478	138,791
[19] b	To Retail State of Minnesota subject to FCA	2,908,443	2,846,118	2,619,682	2,444,824	2,346,385	2,475,838	2,555,032	2,327,350	2,359,926	2,151,811	2,367,558	2,649,939	30,052,906
[20]	Actual Cost of Fuel per kWh [17])/([18]-[19]a)/10**	2.614	2.606	2.630	2.461	2.728	2.344	2.528	2.495	2.283	2.336	2.253	2.346	
[21]	Deviation (Actual Vs. Forecast) [20] - [11] **	(0.203)	(0.017)	(0.048)	(0.165)	0.139	(0.108)	(0.140)	(0.208)	(0.112)	(0.272)	(0.418)	(0.236)	
	MONTHLY FUEL CLAUSE ADJUSTMENT FACTOR													
[22]	Prior (2 Months Lag) Unrecovered Expenses [26] from two months ago	$ 2,167,182	$ (1,024,291)	$ 3,419,078	$ (4,629,421)	$ (5,843,486)	$ (850,443)	$ (1,233,505)	$ (4,005,714)	$ 3,175,363	$ (2,667,448)	$ (3,285,550)	$ (4,011,834)	(18,790,069)
[23]	Prior (2 Months Lag) Recovered Expenses [27]X([19]b)X10 from two months ago	$ 2,135,674	$ (1,002,379)	$ 3,347,986	$ (4,555,604)	$ (5,988,853)	$ (848,728)	$ (1,208,818)	$ (3,853,915)	$ 3,072,475	$ (2,597,435)	$ (3,099,435)	$ (3,825,109)	(18,424,141)
[24]	Total Unrecovered Expenses (2 Months Lag) [21]X([19]b)X10 from two months ago	$ 3,387,570	$ (4,580,418)	$ (5,992,635)	$ (576,876)	$ (1,205,540)	$ (4,003,999)	$ 3,200,050	$ (2,515,649)	$ (3,388,438)	$ (4,717,542)	$ (2,667,310)	$ (5,725,448)	(28,786,235)
[25]	Saver's Switch Discount	$ -	$ (27,091)	$ 78,057	$ (199,750)	$ (173,332)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(322,115)
[26]	Balance of Unrecovered Expenses [22]-[23]+[24]+[25]	$ 3,419,078	$ (4,629,421)	$ (5,843,486)	$ (850,443)	$ (1,233,505)	$ (4,005,714)	$ 3,175,363	$ (2,667,448)	$ (3,285,550)	$ (4,011,834)	$ (2,853,425)	$ (5,912,173)	(28,698,557)
[27]	System True-Up Factor [26]/[10]/10 **	0.115	(0.160)	(0.229)	(0.035)	(0.051)	(0.156)	0.121	(0.112)	(0.131)	(0.178)	(0.120)	(0.226)	
[28]	Total System Refunds	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	
[28] a	System Asset Based Margins Sharing Refund	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	
[28] c	Other Refund & MN Solar Gardens Cost Recovery **	-	-	-	-	-	-	-	-	-	-	-	-	
[29]	Fuel Clause Charge [11]+[27]+[28] **	2.929	2.460	2.447	2.589	2.535	2.293	2.786	2.589	2.261	2.427	2.549	2.353	

* Calendar Month
** In Cents Per KWh
*** This item is the total amount of Wind Contracts Payments, RECs Purchases and REC-Related Fuel Costs

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	12 Months
RULE 7825.2810 SUBPART 1 A: COMMISSION-APPROVED BASE COST OF FUEL													
[30] System Base cost of Fuel **	2.780	2.780	2.780	2.780	2.780	2.780	2.680	2.680	2.680	2.680	2.680	2.680	
[30]-(i) Residential [30]*1.0132	2.817	2.817	2.817	2.817	2.831	2.831	2.730	2.730	2.730	2.730	2.730	2.730	
[30]-(ii) C & I Non-Demand [30]*1.0472	2.911	2.911	2.911	2.911	2.917	2.917	2.812	2.812	2.812	2.812	2.812	2.812	
[30]-(iii) C & I Demand Non-TOD [30]*1.0091	2.805	2.805	2.805	2.805	2.788	2.788	2.688	2.688	2.688	2.688	2.688	2.688	
[30]-(iv) C & I Demand TOD On-Peak [30]*1.2776	3.552	3.552	3.552	3.552	3.539	3.539	3.412	3.412	3.412	3.412	3.412	3.412	
[30]-(v) C & I Demand TOD Off-Peak [30]*0.7940	2.207	2.207	2.207	2.207	2.220	2.220	2.141	2.141	2.141	2.141	2.141	2.141	
[30]-(vi) Outdoor Lighting [30]*0.7421	2.063	2.063	2.063	2.063	2.070	2.070	1.996	1.996	1.996	1.996	1.996	1.996	
RULE 7825.2810 SUBPART 1 B: BILLING ADJUSTMENT AMOUNTS CHARGED TO CUSTOMERS FOR EACH TYPE OF ENERGY COST													
[31] System Fuel Cost Exces of Base Cost [11]-[30] **	0.037	(0.157)	(0.102)	(0.154)	(0.191)	(0.328)	(0.012)	0.023	(0.285)	(0.072)	(0.009)	(0.098)	
[31]-(i) Residential [31]*1.0132	0.037	(0.159)	(0.103)	(0.156)	(0.195)	(0.334)	(0.012)	0.023	(0.290)	(0.073)	(0.009)	(0.100)	
[31]-(ii) C & I Non-Demand [31]*1.0472	0.039	(0.164)	(0.107)	(0.161)	(0.200)	(0.344)	(0.013)	0.024	(0.299)	(0.076)	(0.009)	(0.103)	
[31]-(iii) C & I Demand Non-TOD [31]*1.0091	0.037	(0.158)	(0.103)	(0.155)	(0.192)	(0.329)	(0.012)	0.023	(0.286)	(0.072)	(0.009)	(0.098)	
[31]-(iv) C & I Demand TOD On-Peak [31]*1.2776	0.047	(0.201)	(0.130)	(0.197)	(0.243)	(0.418)	(0.015)	0.029	(0.363)	(0.092)	(0.011)	(0.125)	
[31]-(v) C & I Demand TOD Off-Peak [31]*0.7940	0.029	(0.125)	(0.081)	(0.122)	(0.153)	(0.262)	(0.010)	0.018	(0.228)	(0.058)	(0.007)	(0.078)	
[31]-(vi) Outdoor Lighting [31]*0.7421	0.027	(0.117)	(0.076)	(0.114)	(0.142)	(0.244)	(0.009)	0.017	(0.212)	(0.054)	(0.007)	(0.073)	
[32] System True-Up Factor [27] **	0.115	(0.160)	(0.229)	(0.035)	(0.051)	(0.156)	0.121	(0.112)	(0.131)	(0.178)	(0.120)	(0.226)	
[32]-(i) Residential [32]*1.0132	0.117	(0.162)	(0.232)	(0.035)	(0.052)	(0.159)	0.123	(0.114)	(0.134)	(0.181)	(0.122)	(0.230)	
[32]-(ii) C & I Non-Demand [32]*1.0472	0.120	(0.167)	(0.240)	(0.036)	(0.054)	(0.164)	0.127	(0.117)	(0.138)	(0.187)	(0.126)	(0.237)	
[32]-(iii) C & I Demand Non-TOD [32]*1.0091	0.116	(0.161)	(0.231)	(0.035)	(0.052)	(0.156)	0.121	(0.112)	(0.132)	(0.179)	(0.120)	(0.227)	
[32]-(iv) C & I Demand TOD On-Peak [32]*1.2776	0.147	(0.204)	(0.292)	(0.044)	(0.066)	(0.199)	0.154	(0.142)	(0.167)	(0.227)	(0.152)	(0.288)	
[32]-(v) C & I Demand TOD Off-Peak [32]*0.7940	0.091	(0.127)	(0.182)	(0.028)	(0.041)	(0.125)	0.096	(0.089)	(0.105)	(0.142)	(0.096)	(0.181)	
[32]-(vi) Outdoor Lighting [32]*0.7421	0.085	(0.119)	(0.170)	(0.026)	(0.038)	(0.116)	0.090	(0.083)	(0.098)	(0.133)	(0.089)	(0.168)	
[33] Refunds													
[33] a System Asset Based Margins Sharing Refund [28] a	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	
[33] a-(i) Residential [33] a*1.0132	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	
[33] a-(ii) C & I Non-Demand [33] a*1.0472	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	
[33] a-(iii) C & I Demand Non-TOD [33] a*1.0091	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	
[33] a-(iv) C & I Demand TOD On-Peak [33] a*1.2776	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	(0.003)	
[33] a-(v) C & I Demand TOD Off-Peak [33] a*0.7940	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	
[33] a-(vi) Outdoor Lighting [33] a*0.7421	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	(0.002)	
[33] c Other Refund & MN Solar Gardens Cost Recovery [28] c **	-	-	-	-	-	-	-	-	-	-	-	-	
[33] c-(i) Residential [33] c*1.0132	-	-	-	-	-	-	-	-	-	-	-	-	
[33] c-(ii) C & I Non-Demand [33] c*1.0472	-	-	-	-	-	-	-	-	-	-	-	-	
[33] c-(iii) C & I Demand Non-TOD [33] c*1.0091	-	-	-	-	-	-	-	-	-	-	-	-	
[33] c-(iv) C & I Demand TOD On-Peak [33] c*1.2776	-	-	-	-	-	-	-	-	-	-	-	-	
[33] c-(v) C & I Demand TOD Off-Peak [33] c*0.7940	-	-	-	-	-	-	-	-	-	-	-	-	
[33] c-(vi) Outdoor Lighting [33] c*0.7421	-	-	-	-	-	-	-	-	-	-	-	-	
[34] System Fuel Clause Charge Factor ** [29]	2.929	2.460	2.447	2.589	2.535	2.293	2.786	2.589	2.261	2.427	2.549	2.353	
[34] -(i) Residential	2.968	2.493	2.479	2.623	2.581	2.335	2.838	2.637	2.303	2.472	2.596	2.397	
[34] -(ii) C & I Non-Demand	3.067	2.576	2.562	2.711	2.660	2.406	2.923	2.716	2.372	2.547	2.674	2.469	
[34] -(iii) C & I Demand Non-TOD	2.956	2.483	2.469	2.612	2.542	2.300	2.794	2.596	2.268	2.434	2.556	2.360	
[34] -(iv) C & I Demand TOD On-Peak	3.743	3.144	3.126	3.307	3.227	2.919	3.547	3.296	2.879	3.090	3.245	2.996	
[34] -(v) C & I Demand TOD Off-Peak	2.326	1.953	1.942	2.055	2.024	1.831	2.226	2.068	1.806	1.939	2.036	1.880	
[34] -(vi) Outdoor Lighting	2.174	1.826	1.816	1.921	1.887	1.708	2.075	1.928	1.684	1.808	1.898	1.753	
RULE 7825.2810 SUBPART 1 D: TOTAL COST OF FUEL DELIVERED TO CUSTOMERS													
[35] Actual Cost of Fuel Per kWh [20] **	2.614	2.606	2.630	2.461	2.728	2.344	2.528	2.495	2.283	2.336	2.253	2.346	
[36] Minnesota MWh Retail Sales (Cal. Mo) [19]	2,920,992	2,858,348	2,631,584	2,455,729	2,356,063	2,487,413	2,567,047	2,338,418	2,372,681	2,162,456	2,378,549	2,662,417	30,191,697
[36]-(i) Residential	892,721	829,111	735,810	629,301	632,244	741,120	800,899	661,452	638,467	538,143	603,863	799,299	8,502,430
[36]-(ii) C & I Non-Demand	79,648	78,826	71,874	67,042	65,984	74,123	81,822	76,748	76,047	68,759	67,865	72,793	881,531
[36]-(iii) C & I Demand Non-TOD	890,509	885,445	815,673	781,516	733,884	754,002	774,011	732,269	743,136	691,027	768,364	827,341	9,397,177
[36]-(iv) C & I Demand TOD On-Peak	409,549	415,755	384,650	377,788	363,882	337,791	328,717	322,130	354,498	325,556	365,705	366,983	4,353,004
[36]-(v) C & I Demand TOD Off-Peak	640,710	636,476	612,011	584,637	542,187	562,010	563,333	529,042	545,585	525,112	562,487	586,895	6,890,485
[36]-(vi) Outdoor Lighting	7,855	12,735	11,566	15,445	17,882	18,367	18,265	16,777	14,948	13,859	10,265	9,106	167,070

* Calendar Month
** In Cents Per KWh

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	12 Months
RULE 7825.2810 SUBPART 1 D: TOTAL COST OF FUEL DELIVERED TO CUSTOMERS													
[36] a Minnesota WindSource KWh Not Subject to FCA (Cal. Mo.) ([19] a)	12,549	12,230	11,902	10,905	9,678	11,575	12,015	11,068	12,755	10,645	10,991	12,478	138,791
[36] a-(i) Residential	9,487	9,645	9,316	8,475	7,469	9,127	9,426	8,922	9,561	8,302	8,264	9,846	107,840
[36] a-(ii) C & I Non-Demand	98	101	97	98	81	92	95	96	99	86	90	102	1,135
[36] a-(iii) C & I Demand Non-TOD	2,299	1,840	1,862	1,557	1,534	1,684	1,799	1,450	2,513	1,678	1,873	1,917	22,006
[36] a-(iv) C & I Demand TOD On-Peak	274	265	258	319	240	271	280	242	235	234	310	248	3,176
[36] a-(v) C & I Demand TOD Off-Peak	387	375	365	451	349	394	407	351	341	340	450	361	4,571
[36] a-(vi) Outdoor Lighting	4	4	4	5	5	7	8	7	6	5	4	4	63
[36] b To Retail State of Minnesota subject to FCA ([19] b)	2,908,443	2,846,118	2,619,682	2,444,824	2,346,385	2,475,838	2,555,032	2,327,350	2,359,926	2,151,811	2,367,558	2,649,939	30,052,906
[36] b-(i) Residential	883,234	819,466	726,494	620,826	624,775	731,993	791,473	652,530	628,906	529,841	595,599	789,453	8,394,590
[36] b-(ii) C & I Non-Demand	79,550	78,725	71,777	66,944	65,903	74,031	81,727	76,652	75,948	68,673	67,775	72,691	880,396
[36] b-(iii) C & I Demand Non-TOD	888,210	883,605	813,811	779,959	732,350	752,318	772,212	730,819	740,623	689,349	766,491	825,424	9,375,171
[36] b-(iv) C & I Demand TOD On-Peak	409,275	415,490	384,392	377,469	363,642	337,520	328,437	321,888	354,263	325,322	365,395	366,735	4,349,828
[36] b-(v) C & I Demand TOD Off-Peak	640,323	636,101	611,646	584,186	541,838	561,616	562,926	528,691	545,244	524,772	562,037	586,534	6,885,914
[36] b-(vi) Outdoor Lighting	7,851	12,731	11,562	15,440	17,877	18,360	18,257	16,770	14,942	13,854	10,261	9,102	167,007
[37] Total Cost of Fuel Delivered [35]x([36] b)x10	$ 76,026,700	$ 74,169,835	$ 68,897,637	$ 60,167,119	$ 64,009,383	$ 58,033,643	$ 64,591,209	$ 58,067,383	$ 53,877,111	$ 50,266,305	$ 53,341,082	$ 62,167,569	$ 743,614,976
[37]-(i) Residential	$ 23,087,737	$ 21,355,284	$ 19,106,792	$ 15,278,528	$ 17,043,862	$ 17,157,916	$ 20,008,437	$ 16,280,624	$ 14,357,924	$ 12,377,086	$ 13,418,845	$ 18,520,567	$ 207,993,602
[37]-(ii) C & I Non-Demand	$ 2,079,437	$ 2,051,574	$ 1,887,735	$ 1,647,492	$ 1,797,834	$ 1,735,287	$ 2,066,059	$ 1,912,467	$ 1,733,893	$ 1,604,201	$ 1,526,971	$ 1,705,331	$ 21,748,281
[37]-(iii) C & I Demand Non-TOD	$ 23,217,809	$ 23,026,746	$ 21,403,229	$ 19,194,791	$ 19,978,508	$ 17,634,334	$ 19,521,519	$ 18,233,934	$ 16,908,423	$ 16,103,193	$ 17,269,042	$ 19,364,447	$ 231,855,975
[37]-(iv) C & I Demand TOD On-Peak	$ 10,698,449	$ 10,827,669	$ 10,109,510	$ 9,289,512	$ 9,920,154	$ 7,911,469	$ 8,302,887	$ 8,031,106	$ 8,087,824	$ 7,599,522	$ 8,232,349	$ 8,603,603	$ 107,614,054
[37]-(v) C & I Demand TOD Off-Peak	$ 16,738,043	$ 16,576,792	$ 16,086,290	$ 14,376,817	$ 14,781,341	$ 13,164,279	$ 14,230,769	$ 13,190,840	$ 12,447,921	$ 12,258,674	$ 12,662,694	$ 13,760,088	$ 170,274,548
[37]-(vi) Outdoor Lighting	$ 205,225	$ 331,770	$ 304,081	$ 379,978	$ 487,685	$ 430,358	$ 461,537	$ 418,412	$ 341,126	$ 323,629	$ 231,180	$ 213,533	$ 4,128,514
RULE 7825.2810 SUBPART 1 E: REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED													
[38] Minnesota MWh Retail Sales Subject to FCA (Cal. Mo) [36] b	2,908,443	2,846,118	2,619,682	2,444,824	2,346,385	2,475,838	2,555,032	2,327,350	2,359,926	2,151,811	2,367,558	2,649,939	30,052,906
[38]-(i) Residential	883,234	819,466	726,494	620,826	624,775	731,993	791,473	652,530	628,906	529,841	595,599	789,453	8,394,590
[38]-(ii) C & I Non-Demand	79,550	78,725	71,777	66,944	65,903	74,031	81,727	76,652	75,948	68,673	67,775	72,691	880,396
[38]-(iii) C & I Demand Non-TOD	888,210	883,605	813,811	779,959	732,350	752,318	772,212	730,819	740,623	689,349	766,491	825,424	9,375,171
[38]-(iv) C & I Demand TOD On-Peak	409,275	415,490	384,392	377,469	363,642	337,520	328,437	321,888	354,263	325,322	365,395	366,735	4,349,828
[38]-(v) C & I Demand TOD Off-Peak	640,323	636,101	611,646	584,186	541,838	561,616	562,926	528,691	545,244	524,772	562,037	586,534	6,885,914
[38]-(vi) Outdoor Lighting	7,851	12,731	11,562	15,440	17,877	18,360	18,257	16,770	14,942	13,854	10,261	9,102	167,007
[39] Base Cost Revenues [30]x [38] x10	$ 80,854,715	$ 79,122,080	$ 72,827,160	$ 67,966,107	$ 65,229,503	$ 68,828,296	$ 68,474,858	$ 62,372,980	$ 63,246,017	$ 57,668,535	$ 63,450,554	$ 71,018,365	$ 821,059,170
[39]-(i) Residential	$ 24,880,702	$ 23,084,357	$ 20,465,336	$ 17,488,668	$ 17,687,380	$ 20,722,722	$ 21,607,213	$ 17,814,069	$ 17,169,134	$ 14,464,659	$ 16,259,853	$ 21,552,067	$ 233,196,160
[39]-(ii) C & I Non-Demand	$ 2,315,701	$ 2,291,685	$ 2,089,428	$ 1,948,740	$ 1,922,391	$ 2,159,484	$ 2,298,163	$ 2,155,454	$ 2,135,658	$ 1,931,085	$ 1,905,833	$ 2,044,071	$ 25,197,693
[39]-(iii) C & I Demand Non-TOD	$ 24,914,291	$ 24,785,120	$ 22,827,399	$ 21,877,850	$ 20,417,918	$ 20,974,626	$ 20,757,059	$ 19,644,415	$ 19,907,946	$ 18,529,701	$ 20,603,278	$ 22,187,397	$ 257,427,000
[39]-(iv) C & I Demand TOD On-Peak	$ 14,537,448	$ 14,758,205	$ 13,653,604	$ 13,407,699	$ 12,869,290	$ 11,944,833	$ 11,206,270	$ 10,982,819	$ 12,087,454	$ 11,099,987	$ 12,467,277	$ 12,512,998	$ 151,527,884
[39]-(v) C & I Demand TOD Off-Peak	$ 14,131,929	$ 14,038,749	$ 13,499,027	$ 12,892,985	$ 12,028,804	$ 12,467,875	$ 12,052,246	$ 11,319,274	$ 11,673,674	$ 11,235,369	$ 12,033,212	$ 12,557,693	$ 149,930,837
[39]-(vi) Outdoor Lighting	$ 161,966	$ 262,641	$ 238,524	$ 318,527	$ 370,054	$ 380,052	$ 364,410	$ 334,729	$ 298,242	$ 276,526	$ 204,810	$ 181,676	$ 3,392,157
[39]-(vii) Total	$ 80,942,037	$ 79,220,757	$ 72,773,318	$ 67,934,469	$ 65,295,837	$ 68,649,592	$ 68,285,361	$ 62,250,760	$ 63,272,108	$ 57,537,327	$ 63,474,263	$ 71,035,902	$ 820,671,731
Fuel Clause Revenues													
[40] Fuel Cost Excess of Base [31]x[38]x10	$ 1,076,124	$ (4,468,405)	$ (2,672,076)	$ (3,765,029)	$ (4,481,595)	$ (8,120,749)	$ (306,604)	$ 535,290	$ (6,725,789)	$ (1,549,304)	$ (213,080)	$ (2,596,940)	$ (33,288,157)
[40]-(i) Residential	$ 331,107	$ (1,303,541)	$ (750,802)	$ (968,693)	$ (1,215,400)	$ (2,445,354)	$ (96,734)	$ 152,855	$ (1,825,544)	$ (388,543)	$ (54,599)	$ (787,977)	$ (9,353,225)
[40]-(ii) C & I Non-Demand	$ 30,822	$ (129,432)	$ (76,668)	$ (107,960)	$ (132,080)	$ (254,792)	$ (10,291)	$ 18,499	$ (227,123)	$ (51,882)	$ (6,401)	$ (74,749)	$ (1,022,057)
[40]-(iii) C & I Demand Non-TOD	$ 331,631	$ (1,399,887)	$ (837,639)	$ (1,212,064)	$ (1,402,707)	$ (2,474,509)	$ (92,928)	$ 168,556	$ (2,116,686)	$ (497,724)	$ (69,176)	$ (811,177)	$ (10,414,310)
[40]-(iv) C & I Demand TOD On-Peak	$ 193,468	$ (833,402)	$ (500,920)	$ (742,670)	$ (884,308)	$ (1,409,517)	$ (50,179)	$ 94,262	$ (1,285,486)	$ (298,223)	$ (41,871)	$ (457,590)	$ (6,216,436)
[40]-(v) C & I Demand TOD Off-Peak	$ 188,114	$ (792,951)	$ (495,360)	$ (714,319)	$ (826,585)	$ (1,471,288)	$ (53,951)	$ 97,121	$ (1,241,139)	$ (301,775)	$ (40,399)	$ (459,098)	$ (6,111,630)
[40]-(vi) Outdoor Lighting	$ 2,156	$ (14,833)	$ (8,752)	$ (17,645)	$ (25,424)	$ (44,840)	$ (1,631)	$ 2,872	$ (31,709)	$ (7,427)	$ (688)	$ (6,642)	$ (154,563)
[40]-(vii) Total	$ 1,077,298	$ (4,474,046)	$ (2,670,141)	$ (3,763,351)	$ (4,486,504)	$ (8,100,300)	$ (305,714)	$ 534,165	$ (6,727,687)	$ (1,545,574)	$ (213,134)	$ (2,597,233)	$ (33,272,221)
[41] True-Up [32]x[38]x10	$ 3,344,331	$ (4,549,861)	$ (5,993,177)	$ (849,112)	$ (1,207,497)	$ (3,863,644)	$ 3,081,420	$ (2,602,885)	$ (3,098,559)	$ (3,834,334)	$ (2,835,506)	$ (5,992,334)	$ (28,401,158)
[41]-(i) Residential	$ 1,029,012	$ (1,327,305)	$ (1,683,977)	$ (218,462)	$ (327,470)	$ (1,163,437)	$ 972,190	$ (743,284)	$ (841,023)	$ (961,598)	$ (726,518)	$ (1,818,221)	$ (7,810,093)
[41]-(ii) C & I Non-Demand	$ 95,789	$ (131,791)	$ (171,958)	$ (24,348)	$ (35,587)	$ (121,224)	$ 103,424	$ (89,953)	$ (104,635)	$ (128,402)	$ (85,172)	$ (172,480)	$ (866,337)
[41]-(iii) C & I Demand Non-TOD	$ 1,030,617	$ (1,425,405)	$ (1,878,740)	$ (273,352)	$ (377,937)	$ (1,177,310)	$ 933,913	$ (819,628)	$ (975,156)	$ (1,231,798)	$ (920,556)	$ (1,871,764)	$ (8,987,116)
[41]-(iv) C & I Demand TOD On-Peak	$ 601,254	$ (848,597)	$ (1,123,512)	$ (167,491)	$ (238,262)	$ (670,612)	$ 504,315	$ (458,346)	$ (592,221)	$ (738,068)	$ (557,173)	$ (1,055,867)	$ (5,344,580)
[41]-(v) C & I Demand TOD Off-Peak	$ 584,615	$ (807,403)	$ (1,111,037)	$ (161,095)	$ (222,712)	$ (699,998)	$ 542,238	$ (472,259)	$ (571,792)	$ (746,861)	$ (537,622)	$ (1,059,345)	$ (5,263,271)
[41]-(vi) Outdoor Lighting	$ 6,699	$ (15,103)	$ (19,629)	$ (3,980)	$ (6,850)	$ (21,334)	$ 16,395	$ (13,965)	$ (14,608)	$ (18,382)	$ (9,150)	$ (15,326)	$ (115,233)
[41]-(vii) Total	$ 3,347,986	$ (4,555,604)	$ (5,988,853)	$ (848,728)	$ (1,208,818)	$ (3,853,915)	$ 3,072,475	$ (2,597,435)	$ (3,099,435)	$ (3,825,109)	$ (2,836,191)	$ (5,993,003)	$ (28,386,630)
[42] Refunds Total [46]	$ (77,245)	$ (75,603)	$ (69,450)	$ (64,832)	$ (62,322)	$ (65,505)	$ (67,568)	$ (61,612)	$ (62,630)	$ (56,959)	$ (62,839)	$ (70,303)	$ (796,869)

* Calendar Month
** In Cents Per KWh

	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	12 Months
RULE 7825.2810 SUBPART 1 E: REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED													
[43] Fuel Clause Revenues [40]+[41]+[42]	$ 4,343,294	$ (9,093,774)	$ (8,734,753)	$ (4,679,002)	$ (5,751,342)	$ (12,050,077)	$ 2,707,031	$ (2,129,340)	$ (9,886,957)	$ (5,440,726)	$ (3,111,397)	$ (8,659,577)	$ (62,486,619)
[43]-(i) Residential	$ 1,336,377	$ (2,652,873)	$ (2,454,307)	$ (1,203,843)	$ (1,559,664)	$ (3,628,467)	$ 854,181	$ (607,969)	$ (2,683,472)	$ (1,364,383)	$ (797,127)	$ (2,627,419)	$ (17,388,966)
[43]-(ii) C & I Non-Demand	$ 124,401	$ (263,410)	$ (250,620)	$ (134,168)	$ (169,498)	$ (378,073)	$ 90,862	$ (73,584)	$ (333,868)	$ (182,192)	$ (93,456)	$ (249,249)	$ (1,912,853)
[43]-(iii) C & I Demand Non-TOD	$ 1,338,469	$ (2,848,947)	$ (2,738,166)	$ (1,506,297)	$ (1,800,250)	$ (3,671,960)	$ 820,312	$ (670,637)	$ (3,111,670)	$ (1,747,977)	$ (1,010,252)	$ (2,705,039)	$ (19,652,413)
[43]-(iv) C & I Demand TOD On-Peak	$ 780,850	$ (1,696,082)	$ (1,637,461)	$ (922,955)	$ (1,134,896)	$ (2,091,569)	$ 443,004	$ (374,994)	$ (1,889,715)	$ (1,047,318)	$ (611,429)	$ (1,525,887)	$ (11,708,452)
[43]-(v) C & I Demand TOD Off-Peak	$ 759,241	$ (1,613,753)	$ (1,619,281)	$ (887,720)	$ (1,060,711)	$ (2,183,116)	$ 476,429	$ (386,275)	$ (1,824,416)	$ (1,059,690)	$ (589,860)	$ (1,530,798)	$ (11,519,952)
[43]-(vi) Outdoor Lighting	$ 8,700	$ (30,187)	$ (28,609)	$ (21,929)	$ (32,626)	$ (66,535)	$ 14,405	$ (11,423)	$ (46,611)	$ (26,082)	$ (10,040)	$ (22,147)	$ (273,084)
[43]-(vii) Total	$ 4,348,039	$ (9,105,253)	$ (8,728,444)	$ (4,676,911)	$ (5,757,644)	$ (12,019,720)	$ 2,699,193	$ (2,124,882)	$ (9,889,752)	$ (5,427,642)	$ (3,112,164)	$ (8,660,539)	$ (62,455,720)
[44] Total Fuel Clause Revenues [39]+[40]	$ 81,930,839	$ 74,653,675	$ 70,155,084	$ 64,201,078	$ 60,747,908	$ 60,707,547	$ 68,168,254	$ 62,908,270	$ 56,520,228	$ 56,119,231	$ 63,237,474	$ 68,421,425	$ 787,771,013
[44]-(i) Residential	$ 25,211,809	$ 21,780,816	$ 19,714,534	$ 16,519,975	$ 16,471,980	$ 18,277,368	$ 21,510,479	$ 17,966,924	$ 15,343,590	$ 14,076,116	$ 16,205,254	$ 20,764,090	$ 223,842,935
[44]-(ii) C & I Non-Demand	$ 2,346,523	$ 2,162,253	$ 2,012,760	$ 1,840,780	$ 1,790,311	$ 1,904,692	$ 2,287,872	$ 2,173,953	$ 1,908,535	$ 1,879,203	$ 1,899,432	$ 1,969,322	$ 24,175,636
[44]-(iii) C & I Demand Non-TOD	$ 25,245,922	$ 23,385,233	$ 21,989,760	$ 20,665,786	$ 19,015,211	$ 18,500,117	$ 20,664,131	$ 19,812,971	$ 17,791,260	$ 18,031,977	$ 20,534,102	$ 21,376,220	$ 247,012,690
[44]-(iv) C & I Demand TOD On-Peak	$ 14,730,916	$ 13,924,803	$ 13,152,684	$ 12,665,029	$ 11,984,982	$ 10,535,316	$ 11,156,091	$ 11,077,081	$ 10,801,968	$ 10,801,764	$ 12,425,406	$ 12,055,408	$ 145,311,448
[44]-(v) C & I Demand TOD Off-Peak	$ 14,320,043	$ 13,245,798	$ 13,003,667	$ 12,178,666	$ 11,202,219	$ 10,996,587	$ 11,998,295	$ 11,416,395	$ 10,432,535	$ 10,933,594	$ 11,992,813	$ 12,098,595	$ 143,819,207
[44]-(vi) Outdoor Lighting	$ 164,122	$ 247,808	$ 229,772	$ 300,882	$ 344,630	$ 335,212	$ 362,779	$ 337,601	$ 266,533	$ 269,099	$ 204,122	$ 175,034	$ 3,237,594
[44]-(vii) Total	$ 82,019,335	$ 74,746,711	$ 70,103,177	$ 64,171,118	$ 60,809,333	$ 60,549,292	$ 67,979,647	$ 62,784,925	$ 56,544,421	$ 55,991,753	$ 63,261,129	$ 68,438,669	$ 787,399,510
[45] Total Fuel Clause Revenues including True-Up & Refund [39]+[43]	$ 85,198,009	$ 70,028,306	$ 64,092,407	$ 63,287,105	$ 59,478,161	$ 56,778,219	$ 71,181,889	$ 60,243,640	$ 53,359,060	$ 52,227,809	$ 60,339,157	$ 62,358,788	$ 758,572,551
[45]-(i) Residential	$ 26,217,079	$ 20,431,484	$ 18,011,029	$ 16,284,825	$ 16,127,716	$ 17,094,255	$ 22,461,394	$ 17,206,100	$ 14,485,662	$ 13,100,276	$ 15,462,726	$ 18,924,648	$ 215,807,194
[45]-(ii) C & I Non-Demand	$ 2,440,102	$ 2,028,275	$ 1,838,808	$ 1,814,572	$ 1,752,893	$ 1,781,411	$ 2,389,025	$ 2,081,870	$ 1,801,790	$ 1,748,893	$ 1,812,377	$ 1,794,822	$ 23,284,840
[45]-(iii) C & I Demand Non-TOD	$ 26,252,760	$ 21,936,173	$ 20,089,233	$ 20,371,553	$ 18,617,668	$ 17,302,666	$ 21,577,371	$ 18,973,778	$ 16,796,276	$ 16,781,724	$ 19,593,026	$ 19,482,358	$ 237,774,587
[45]-(iv) C & I Demand TOD On-Peak	$ 15,318,298	$ 13,062,123	$ 12,016,143	$ 12,484,744	$ 11,734,394	$ 9,853,264	$ 11,649,274	$ 10,607,825	$ 10,197,739	$ 10,052,669	$ 11,855,848	$ 10,987,111	$ 139,819,432
[45]-(v) C & I Demand TOD Off-Peak	$ 14,891,170	$ 12,424,996	$ 11,879,746	$ 12,005,265	$ 10,968,093	$ 10,284,759	$ 12,528,675	$ 10,932,999	$ 9,849,258	$ 10,175,679	$ 11,443,352	$ 11,026,895	$ 138,410,885
[45]-(vi) Outdoor Lighting	$ 170,666	$ 232,454	$ 209,915	$ 296,598	$ 337,428	$ 313,517	$ 378,815	$ 323,306	$ 251,631	$ 250,444	$ 194,770	$ 159,529	$ 3,119,073
[45]-(vii) Total	$ 85,290,076	$ 70,115,504	$ 64,044,874	$ 63,257,558	$ 59,538,193	$ 56,629,872	$ 70,984,554	$ 60,125,878	$ 53,382,356	$ 52,109,685	$ 60,362,099	$ 62,375,363	$ 758,216,011
RULE 7825.2810 SUBPART 1 G: AMOUNT OF REFUNDS CREDITED TO CUSTOMERS													
[46] a System Asset Based Margins Sharing Refund ([33] a)*[38]*10	$ (77,161)	$ (75,508)	$ (69,500)	$ (64,861)	$ (62,250)	$ (65,684)	$ (67,785)	$ (61,745)	$ (62,609)	$ (57,088)	$ (62,811)	$ (70,303)	$ (797,304)
[46] a-(i) Residential	$ (23,742)	$ (22,027)	$ (19,528)	$ (16,688)	$ (16,794)	$ (19,676)	$ (21,275)	$ (17,540)	$ (16,905)	$ (14,242)	$ (16,010)	$ (21,221)	$ (225,648)
[46] a-(ii) C & I Non-Demand	$ (2,210)	$ (2,187)	$ (1,994)	$ (1,860)	$ (1,831)	$ (2,057)	$ (2,271)	$ (2,130)	$ (2,110)	$ (1,908)	$ (1,883)	$ (2,020)	$ (24,459)
[46] a-(iii) C & I Demand Non-TOD	$ (23,779)	$ (23,655)	$ (21,787)	$ (20,881)	$ (19,606)	$ (20,141)	$ (20,673)	$ (19,565)	$ (19,828)	$ (18,455)	$ (20,520)	$ (22,098)	$ (250,987)
[46] a-(iv) C & I Demand TOD On-Peak	$ (13,872)	$ (14,083)	$ (13,029)	$ (12,794)	$ (12,326)	$ (11,440)	$ (11,132)	$ (10,910)	$ (12,008)	$ (11,027)	$ (12,385)	$ (12,430)	$ (147,436)
[46] a-(v) C & I Demand TOD Off-Peak	$ (13,488)	$ (13,399)	$ (12,884)	$ (12,306)	$ (11,414)	$ (11,830)	$ (11,858)	$ (11,137)	$ (11,485)	$ (11,054)	$ (11,839)	$ (12,355)	$ (145,051)
[46] a-(vi) Outdoor Lighting	$ (155)	$ (251)	$ (228)	$ (304)	$ (352)	$ (361)	$ (359)	$ (330)	$ (294)	$ (273)	$ (202)	$ (179)	$ (3,288)
[46] a-(vii) Total	$ (77,245)	$ (75,603)	$ (69,450)	$ (64,832)	$ (62,322)	$ (65,505)	$ (67,568)	$ (61,612)	$ (62,630)	$ (56,959)	$ (62,839)	$ (70,303)	$ (796,869)
[46] c Other Refund & MN Solar Gardens Cost Recovery ([33] c)*[38] *10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[46] c-(i) Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[46] c-(ii) C & I Non-Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[46] c-(iii) C & I Demand Non-TOD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[46] c-(iv) C & I Demand TOD On-Peak	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[46] c-(v) C & I Demand TOD Off-Peak	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[46] c-(vi) Outdoor Lighting	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[46] c-(vii) Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[46] Total System Refunds ([46]a)+([46]c)	$ (77,161)	$ (75,508)	$ (69,500)	$ (64,861)	$ (62,250)	$ (65,684)	$ (67,785)	$ (61,745)	$ (62,609)	$ (57,088)	$ (62,811)	$ (70,303)	$ (797,304)
[46]-(i) Residential	$ (23,742)	$ (22,027)	$ (19,528)	$ (16,688)	$ (16,794)	$ (19,676)	$ (21,275)	$ (17,540)	$ (16,905)	$ (14,242)	$ (16,010)	$ (21,221)	$ (225,648)
[46]-(ii) C & I Non-Demand	$ (2,210)	$ (2,187)	$ (1,994)	$ (1,860)	$ (1,831)	$ (2,057)	$ (2,271)	$ (2,130)	$ (2,110)	$ (1,908)	$ (1,883)	$ (2,020)	$ (24,459)
[46]-(iii) C & I Demand Non-TOD	$ (23,779)	$ (23,655)	$ (21,787)	$ (20,881)	$ (19,606)	$ (20,141)	$ (20,673)	$ (19,565)	$ (19,828)	$ (18,455)	$ (20,520)	$ (22,098)	$ (250,987)
[46]-(iv) C & I Demand TOD On-Peak	$ (13,872)	$ (14,083)	$ (13,029)	$ (12,794)	$ (12,326)	$ (11,440)	$ (11,132)	$ (10,910)	$ (12,008)	$ (11,027)	$ (12,385)	$ (12,430)	$ (147,436)
[46]-(v) C & I Demand TOD Off-Peak	$ (13,488)	$ (13,399)	$ (12,884)	$ (12,306)	$ (11,414)	$ (11,830)	$ (11,858)	$ (11,137)	$ (11,485)	$ (11,054)	$ (11,839)	$ (12,355)	$ (145,051)
[46]-(vi) Outdoor Lighting	$ (155)	$ (251)	$ (228)	$ (304)	$ (352)	$ (361)	$ (359)	$ (330)	$ (294)	$ (273)	$ (202)	$ (179)	$ (3,288)
[46] (vii) Total	$ (77,245)	$ (75,603)	$ (69,450)	$ (64,832)	$ (62,322)	$ (65,505)	$ (67,568)	$ (61,612)	$ (62,630)	$ (56,959)	$ (62,839)	$ (70,303)	$ (796,869)

* Calendar Month

** In Cents Per KWh

Northern States Power Company, a Minnesota Corporation and
Wholly Owned Corporation of Xcel Energy Inc.
Monthly Fuel Clause Adjustment July 2015 - June 2016
Fuel, Purchased Power and Other Costs

Docket No. E999/AA-16-523
Part E, Section 5
Schedule 2

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
A. Actual Costs of Fuel Used by Company to Generate Electricity														
	Account 151 Fossil Fuel													
[1]	Coal	33,141,408	27,001,491	25,516,901	26,617,477	23,719,211	21,667,123	30,036,562	21,208,266	15,774,405	12,034,713	15,318,558	21,155,821	273,191,936
[2]	Wood/Refuse-Derived Fuel	980,421	884,596	596,264	1,064,565	784,793	995,068	476,384	741,893	667,263	840,631	923,529	955,756	9,911,163
[3]	Natural Gas / Oil CC (611000)	42,016	99,514	45,608	28,940	49,872	48,014	70,173	68,907	49,831	38,209	37,236	31,208	609,528
[4]	Natural Gas / Oil CT (611100 612000 612100)	19,357,001	15,778,155	14,624,857	10,506,515	10,779,370	15,024,447	14,446,844	12,706,686	10,832,876	10,444,843	10,542,195	12,548,505	157,592,294
[5]	Total Fossil Fuel	53,520,846	43,763,756	40,783,630	38,217,497	35,333,246	37,734,652	45,029,963	34,725,752	27,324,375	23,358,396	26,821,518	34,691,290	441,304,921
[6]	Account 518 Nuclear Fuel	10,925,142	10,914,377	10,542,938	9,063,923	5,996,735	7,947,135	7,094,043	7,279,562	10,696,586	10,504,918	10,864,217	10,468,675	112,298,251
[7]	Total Own Generation	64,445,988	54,678,133	51,326,568	47,281,420	41,329,981	45,681,787	52,124,006	42,005,314	38,020,961	33,863,314	37,685,735	45,159,965	553,603,172
B. Cost of Energy/Power Purchased by Company														
	Account 555 Energy Purchases													
[8]	Long Term Energy Purchase Contract Total (632000/632160)	25,999,208	24,267,445	22,642,397	19,422,652	17,249,704	17,904,749	18,197,709	16,794,346	16,856,020	14,347,637	18,184,730	17,264,008	229,130,605
[8A]	MISO	5,389,836	10,807,026	8,647,656	5,276,577	10,932,318	6,778,455	7,823,019	7,474,028	5,489,135	3,505,346	3,102,976	8,691,917	83,918,289
[8B]	Less: MISO Schedule 16 and 17	(651,713)	(598,233)	(593,350)	(566,709)	(594,950)	(641,276)	(679,780)	(662,862)	(580,054)	(566,192)	(613,484)	(657,465)	(7,406,068)
[8C]	Less: MISO Schedule 24	(107,928)	(86,528)	(90,239)	(88,223)	(73,445)	(99,023)	(79,278)	(97,706)	(82,384)	(87,127)	(95,620)	(71,709)	(1,059,210)
[8D]	Less: RSG/RNU	(30,594)	(43,258)	(81,605)	(77,614)	(45,551)	(63,807)	(71,515)	(29,474)	33,450	(38,365)	(128,869)	(150,209)	(727,411)
[8E]	Less: MISO ARR													-
[8F]	Less: MISO Congestion & Loss	(248,952)	(395,708)	(767,083)	(774,339)	(304,525)	(522,040)	(339,929)	(345,512)	(592,701)	(754,892)	(583,535)	4,866	(5,624,350)
[9]	Short Term & Market Purchases 632100	-	-	-	-	-	-	-	-	-	-	17,267	(17,267)	(0)
[10]	Others - Wind 634000+634005+634100	9,784,118	13,697,866	14,528,302	17,791,839	22,453,176	17,807,537	17,076,931	18,273,980	18,894,660	23,457,593	15,093,311	13,697,208	202,556,521
[12]	Others - Tolling (Plant Gas & Oil) 632050+632060	1,933,484	2,205,412	2,327,723	91,729	(2,388)	264,820	1,115,092	1,842,760	1,324,231	1,718,458	2,377,105	2,233,976	17,432,401
[13]	Others - Qualifying Facilities 632200	193,784	185,726	180,022	259,138	75,006	175,171	201,039	173,192	165,351	181,982	179,986	188,053	2,158,449
[14]	Solar 634500	5,764	8,437	7,081	8,770	4,315	1,176	574	1,264	5,233	11,883	24,383	37,261	116,140
[15]	Others - Asset Based 633400	765,622	895,326	1,757,125	196,414	440,942	490,595	1,076,528	344,274	1,207,028	2,047,614	1,124,095	1,079,567	11,425,130
[16]	Others - Non-Asset Based 632105	3,404,883	2,875,658	2,663,116	2,954,684	2,037,847	2,284,067	817,546	1,183,105	669,363	1,488,465	917,455	2,044,100	23,340,289
[17]	Other - REC Related Fuel Costs	(239,311)	(225,250)	(46,625)	(23,923)	34,567	(44,359)	12,138	(111,018)	(100,578)	(100,438)	2,540	(161,400)	(1,003,657)
[18]	Total Purchases	46,198,201	53,593,919	51,174,520	44,470,994	52,207,015	44,336,065	45,150,073	44,840,377	43,288,753	45,211,964	39,602,340	44,182,907	554,257,129
C. Fuel-Related Costs Recovered through Intersystem Sales														
[19]	Estimated Energy Generated by Company Total	4,040,615	4,021,016	4,889,726	6,909,314	2,696,442	6,871,481	5,441,769	4,640,766	4,682,345	6,397,259	2,461,014	1,585,624	54,637,371
[20]	Estimated Energy Purchased by Company Total	4,170,505	3,770,984	4,420,241	3,151,098	2,478,789	2,774,662	1,894,074	1,527,379	1,876,391	3,536,079	2,041,550	3,123,667	34,765,419
[21]	Total	8,211,120	7,792,000	9,309,967	10,060,412	5,175,231	9,646,143	7,335,842	6,168,145	6,558,736	9,933,338	4,502,564	4,709,291	89,402,790
D. Other Deductions or Additions to Fuel Clause Adjustment Calculation														
	Deduction from Account 555													
[22]	Purchased Power for WindSource Program	445,377	518,430	320,092	394,552	415,083	436,048	301,043	411,071	424,994	519,175	279,094	404,334	4,869,293
[23]	Purchased Power for Solar Gardens	-	-	356	445	328	138	574	1,264	5,233	597	2,157	9,127	20,219
E. TOTAL														
[24]	Total [7]+[18]-[21]-[22]-[23]	101,987,692	99,961,622	92,870,673	81,297,005	87,946,354	79,935,523	89,636,620	80,265,211	74,320,751	68,622,168	72,504,260	84,220,119	1,013,567,999
	Tie to FCA	101,987,692	99,961,622	92,870,674	81,297,005	87,946,355	79,935,523	89,636,621	80,265,210	74,320,752	68,622,167	72,504,261	84,220,119	1,013,568,001
	Difference	(0)	(0)	(1)	0	(1)	(0)	(1)	1	(1)	1	(1)	0	(2)

Northern States Power Company, a Minnesota Corporation and
Wholly Owned Corporation of Xcel Energy Inc.
Monthly Fuel Clause Adjustment July 2015 - June 2016
Company Generation, Purchased and Other MWh

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
F. MWh of Generation														
	Account 151 Fossil Fuel													
[1]	Coal	1,461,921	1,139,583	1,129,165	1,180,980	1,060,638	1,081,701	1,367,517	961,059	716,588	544,699	727,099	958,931	12,329,881
[2]	Wood/Refuse-Derived Fuel	42,282	41,860	32,612	39,289	39,712	41,569	35,502	29,112	38,164	40,190	43,113	42,103	465,508
[3]	Natural Gas CC	500	828	547	145	370	534	377	399	541	(4,280)	466	624	1,051
[4]	Natural Gas / Oil CT	728,118	555,524	536,364	365,494	358,316	713,089	587,478	547,146	509,076	587,592	533,624	536,413	6,558,234
[5]	Total Fossil Fuel	2,232,821	1,737,795	1,698,688	1,585,908	1,459,036	1,836,893	1,990,874	1,537,716	1,264,369	1,168,201	1,304,302	1,538,071	19,354,674
[6]	Account 518 Nuclear Fuel	1,257,580	1,268,715	1,233,247	1,102,812	750,711	967,089	886,821	909,547	1,293,337	1,254,592	1,275,493	1,215,999	13,415,943
[7]	Total Own Generation	3,490,401	3,006,510	2,931,935	2,688,720	2,209,747	2,803,982	2,877,695	2,447,263	2,557,706	2,422,793	2,579,795	2,754,070	32,770,617
G. Purchased Energy/Power MWh														
	Account 555 Energy Purchases	*[TRADE SECRET DATA BEGINS…*												
[8]	Long Term Energy Purchase Contract Total													
[8A]	MISO													
[8B]	Less: MISO Schedule 16 and 17													
[8C]	Less: MISO Schedule 24													
[8D]	Less: RSG/RNU													
[8E]	Less: MISO ARR													
[9]	Short Term & market Purchases													
[10]	Others - Wind													
[12]	Others - Tolling													
[13]	Others - Qualifying Facilities													
[14]	Others - Solar													
[15]	Others - Asset Based													
[16]	Others - Non-Asset Based													
[17]	Other - REC Related Fuel Costs													
[18]	Total Purchases													
H. Intersystem Sales MWh														
[19]	Estimated Energy Generated by Company Total													
[20]	Estimated Energy Purchased by Company Total													
[21]	Total													
I. MWh Related to Other Deductions or Additions to Fuel Clause Adjustment Calculation														
	Deduction from Account 555													
[22]	Purchased Power for WindSource Program													
[23]	Purchased Power for Solar Gardens													
J. TOTAL MWH														***...TRADE SECRET DATA ENDS]***
[24]	Total [7]+[18]-[21]-[22]-[23]	4,089,311	3,750,608	3,556,748	3,064,353	3,092,811	3,145,621	3,474,540	3,079,052	3,028,097	2,760,186	3,029,791	3,499,612	39,570,729

Northern States Power Company, a Minnesota Corporation and
Wholly Owned Corporation of Xcel Energy Inc.
Monthly Fuel Clause Adjustment July 2015 - June 2016
Estimated Fuel-Related Costs per MWh

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

(in $/MWh)	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Total
K. Estimated Company's Generated Electricity Sold to Retail Customers													
Account 151 Fossil Fuel	*[TRADE SECRET DATA BEGINS…*												
[1] Coal													
[2] Wood/Refuse-Derived Fuel													
[3] Natural Gas CC													
[4] Natural Gas / Oil CT													
[5] Total Fossil Fuel													
[6] Account 518 Nuclear Fuel													
[7] Total Own Generation													
L. Estimated Purchased Energy/Power Sold to Retail Customers													
Account 555 Energy Purchases													
[8] Long Term Energy Purchase Contract Total													
[8A] MISO													
[8B] Less: MISO Schedule 16 and 17													
[8C] Less: MISO Schedule 24													
[8D] Less: RSG/RNU													
[8E] Less: MISO ARR													
[9] Short Term & market Purchases													
[10] Others - Wind													
[12] Others - Tolling													
[13] Others - Qualifying Facilities													
[14] Others - Solar													
[15] Others - Asset Based													
[16] Others - Non-Asset Based													
[17] Other - REC Related Fuel Costs													
Total Purchases													
M. Estimated Intersystem Sales-Related													
[19] Estimated Energy Generated by Company Total													
[20] Estimated Energy Purchased by Company Total													
[21] Total													
N. Other Deductions or Additions													
Deduction from Account 555													
[21] Purchased Power for WindSource Program													
[23] Purchased Power for Solar Gardens													
O. SYSTEM TOTAL													***...TRADE SECRET DATA ENDS]***
[24] Total [7]+[18]-[21]-[22]-[23]	$ 24.94	$ 26.65	$ 26.11	$ 26.53	$ 28.44	$ 25.41	$ 25.80	$ 26.07	$ 24.54	$ 24.86	$ 23.93	$ 24.07	$ 25.61

Northern States Power Company, a Minnesota Corporation and
Wholly Owned Corporation of Xcel Energy Inc.
Monthly Fuel Clause Adjustment July 2015 - June 2016
Costs Recovered from Sales of Energy to Other Utilities

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	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-16-523

PART F

AUDITOR'S REPORT

Xcel Energy℠

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

July 11, 2016

Ms. Andrea Perdomo
Audit Senior
Deloitte & Touche LLP
50 South Sixth Street, Suite 2800
Minneapolis, MN 55402

RE: 2015 - 2016 ANNUAL AUTOMATIC ADJUSTMENT (AAA) CHARGES REPORT – ELECTRIC OPERATION DOCKET NO. E999/AA-16-523

Dear Ms. Perdomo:

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 new requirements established by the Minnesota Public Utilities Commission for the upcoming Annual Automatic Adjustment (AAA) of Charges Report – Electric Operations filing. The Company's 2015-2016 AAA Electric Report will be filed with the Commission and Minnesota Department of Commerce – Division of Energy Resources by September 1, 2016.

Scope of the Electric AAA Report

The Company's Electric AAA Report, among other things, will provide detailed results of the Company's fuel clause for the reporting period July 2015 to June 2016. 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.

AAA Report Independent Audit Requirements

The rules governing the automatic adjustment clauses for Minnesota electric utilities and AAA Reports are set forth in Minn. Rule 7825.2600 *et seq*. Minn. Rule 7825.2820 requires an annual independent auditor's report evaluating the utility's accounting for automatic adjustments for the reporting year. Pursuant to the Commission's 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 Fuel of $0.02680 per kWh was approved (a decrease of $0.0100 over the previous Base Cost of Fuel) along with the interim rates that have been in effect since January 1, 2016.

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

Customer Class Category	**Current Base Cost of Energy[1]**	**Prior Base Cost of Energy ($/kWh)[2]**	**Prior Base Cost of Energy ($/kWh)[3]**	**Prior Base Cost of Energy ($/kWh)[4]**
Residential	$0.02730	$0.02831	$0.02817	$0.02765
C & I Non-Demand	$0.02812	$0.02917	$0.02911	$0.02858
C & I Demand	$0.02688	$0.02788	$0.02805	$0.02754
C & I Demand Time of Day On-Peak	$0.03412	$0.03539	$0.03552	$0.03487
C & I Demand Time of Day Off-Peak	$0.02141	$0.0220	$0.02207	$0.02167
Outdoor Lighting	$0.01996	$0.02070	$0.02063	$0.02025

1 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).
2 As part of rate case (Docket No. E002/GR-13-868) the new FAF ratios were approved by the MPUC on August 31, 2015. The new FAF ratios became effective November 1, 2015.
3 Effective January 3, 2014, pursuant to the MPUC's acceptance of the proposed Base Cost of Energy with the implementation of the interim rate (Docket Nos. E002/GR-13-868 and E002/MR-13-869).
4 Effective December 1, 2013, pursuant to the MPUC's acceptance of the proposed Fuel Adjustment Factor (FAF) Ratio in the final rate case Order dated September 3, 2013 (Docket No. E002/GR-12-961).

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 under the following dockets:

- Wind, Biomass and Others – E002/M-95-244, E002/M-96-934, and E,G002/M-97-985
- 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, and E002/M-14-364

For the twelve months reporting period ending June 30, 2016, computations of the monthly fuel clause adjustment factors also reflected the MISO Day 2 and ASM charges recovery, wind contracts curtailment payments, Windsource exemption and end-of-life nuclear fuel accrual authorized pursuant to Orders under these 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
  - 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[5]
  - Goodhue South, LLC, E002/M-09-1350, Order dated April 28, 2010[5]
  - 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[6]
  - WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010

[5] 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.
[6] The amended PPA was approved by the Commission's September 8, 2014 Order in Docket No. E002/M-14-490.

  - Big Blue, LLC, E002/M-10-733, Notice of Approval dated August 26, 2010[7]
  - 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
  - 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`
- WindSource Exemption – E002/M-01-1479, E002/M-09-1177 [8]
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648

The 2015-2016 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.[9]

In order to more promptly report REC purchases with Windsource energy needs, beginning with May 2013 the Windsource "brown energy" credit had been computed and returned to retail customers on a quarterly basis instead of annually as previously done. Shortly thereafter, in agreement with the Department of Commerce's recommendation, beginning with July 2013 actuals, the "brown energy" credit has been computed and returned to customers on a monthly basis.

During the 2013 legislative session, the statute establishing Minnesota's Renewable Energy Standard (RES)[10] was amended to add a Solar Energy Standard (SES) to promote electricity production from Solar PV systems. The SES will impact future

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[7] The amended PPA was approved by the Commission's February 27, 2014 Order in Docket No. E002/M-13-1002.
[8] ORDER ALLOWING ADDITION OF LIMITED SOLAR ENERGY TO WINDSOURCE PROGRAM, REQUIRING CUSTOMER NOTIFICATION AND REQUIRING COMPLIANCE FILING, June 21, 2010.
[9] 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.
[10] Minn. Stat. § 216B.1691

FCA recoveries. Pursuant to Commission's Order issued on September 17, 2014, in our Community Solar Gardens Program (Docket No.002/M-13-867), we are authorized to recover the program cost through the Minnesota Fuel Clause Rider. These costs include customer bill credits, additional REC credits and unsubscribed energy. For the 2015-2016 AAA period, there has been one community solar garden in operation effective in September 2015. We imitated recovery starting wth the December 2015 fuel cost charge.

Spent Nuclear Fuel Disposal Fee
The Company received notification from the Department of Energy (DOE) on May 12, 2014 that the Spent Nuclear Fuel Disposal Fee would be reduced from 1.0 to 0.0 mill per kWh of electricity generated and sold effective May 16, 2014. This Disposal Fee is an authorized component of FERC account 518 and has been recovered from customers through the monthly fuel clause. We no longer collect this disposal fee from customers and will not do so unless the DOE changes the rate again in the future.

AAA Report Additional Independent Audit Requirements
In compliance with the Commission's 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 preparation of the auditor's report to be submitted with the Company's 2015-2016 AAA Report - Electric to be filed by September 1, 2016, the Company's external auditors should include a statement certifying the following:

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

Status of 2014-2015 Electric AAA Report (Docket No. E999/AA-15-611)
The 2014-2015 Electric AAA Report is still pending Commission approval. However, we believe our reports are in general compliance with the past Commission Orders and Minn. Rules, Parts 7825.2390 through 7825.2920.

Audit Completion Date
We are requesting the completion of this audit by no later than August 15, 2016. If this is not possible, please let us know soon and we will gladly meet with you to resolve a revised schedule. The Deloitte & Touche independent audit report should be provided to Amy Fredregill, Resource Planning and Strategy Manager, 401 Nicollet Mall, 7th Floor, Minneapolis, Minnesota 55401.

Thank you for your attention to this matter. Please do not hesitate to call me at 612-330-2952 with any questions. If necessary, we will gladly conduct a follow-up meeting within the next two weeks to ensure that all the audit requirements are understood.

Sincerely,

/s/

TIMOTHY J. EDMAN
REGULATORY CASE SPECIALIST

cc: Amy Fredregill
John Chow

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, 2015 to June 30, 2016, and Independent Accountants' Report

Deloitte.

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INDEPENDENT ACCOUNTANTS' REPORT

Northern States Power Company, a Minnesota Corporation

We have examined the accompanying Schedule of Fuel Adjustment Clause Factors ("the Schedule") of Northern States Power Company, a Minnesota Corporation (the "Company"), for the period from July 1, 2015 to June 30, 2016. This Schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the Schedule based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants and, accordingly, included examining, on a test basis, evidence supporting the Schedule and performing such other procedures as we considered necessary in the circumstances. We believe that our examination provides a reasonable basis for our opinion.

In our opinion, such Schedule presents, in all material respects, the fuel adjustment clause factors of the Company for the period from July 1, 2015 to June 30, 2016, as calculated in accordance with the criteria established by 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, 5-91.2, and 5-91.3 of the electric rates filed by the Company with the Commission, including the following revisions ("Commission Revisions"):

- Docket No. E002/M-95-244 (dated May 17, 1995, and supplemented September 5, 1995)
- Docket No. E002/M-96-934 (dated November 12, 1996)
- Docket No. E002/M-01-1479 (dated February 26, 2002, and supplemented May 7, 2002, January 10, 2003, September 15, 2003, September 29, 2005, and July 16, 2006, September 15, 2008, and July 14, 2009)
- Docket No. E002/M-01-1953 (dated March 20, 2002)
- Docket No. E002/CN-01-1958 (dated February 11, 2002, and supplemented March 11, 2003, May 16, 2003, November 21, 2003, and July 13, 2004)
- Docket No. E002/M-02-51 (dated July 17, 2002)
- Docket No. E,G002/M-97-985 (dated September 10, 1997)
- Docket No.E002/M-14-364 (dated October 24, 2014)
- Docket No. E002/M-08-528(dated August 23, 2010)
- Docket No. E002/GR-05-1428 (dated September 1, 2006)

- Docket No. E002/M-05-1648 (dated March 23, 2006, and supplemented July 20, 2006)
- Docket No. E002/M-13-867 (dated September 17, 2014)
- Docket No. E002/MR-13-869 (dated January 2, 2014)
- Docket No. E002/GR-13-868 (dated August 31, 2015)
- Docket No. E002/MR-15-827 (dated December 22, 2015)

This report is intended solely for the information and use of management and 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 these specified parties.

Deloitte & Touche LLP

August 26, 2016

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, 2015 TO JUNE 30, 2016
(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, 2015	2.962	3.061	2.949	3.734	2.320	2.169
August 1, 2015	2.484	2.567	2.473	3.132	1.946	1.819
September 1, 2015	2.465	2.548	2.455	3.109	1.931	1.805
October 1, 2015	2.605	2.692	2.594	3.285	2.041	1.908
November 1, 2015	2.570	2.648	2.531	3.212	2.015	1.879
December 1, 2015	2.324	2.394	2.288	2.905	1.822	1.699
January 1, 2016	2.838	2.923	2.794	3.547	2.226	2.075
February 1, 2016	2.628	2.707	2.588	3.284	2.061	1.921
March 1, 2016	2.285	2.353	2.250	2.855	1.792	1.670
April 1, 2016	2.432	2.505	2.395	3.040	1.908	1.778
May 1, 2016	2.578	2.656	2.538	3.222	2.022	1.885
June 1, 2016	2.410	2.482	2.373	3.012	1.890	1.762

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, 5-91.2, and 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-16-523

PART G

FIVE-YEAR PROJECTION

ANNUAL FIVE-YEAR PROJECTION

In compliance with the reporting requirement, the following schedules contain the trade secret five-year (2017 - 2021) projection of fuel cost by energy source:

Part G, Section 1, Schedule 1 – 5-Year Fuel Cost Forecast – Per Unit Summary
Part G, Section 1, Schedule 2 – 5-Year Fuel Cost Forecast – Cost Summary
Part G, Section 1, Schedule 3 – 5-Year Fuel Cost Forecast – Energy Summary

These estimates are developed by applying inflation projections either to current market prices or to inflation escalation clauses contained in fuel contracts with existing and potential suppliers. Fossil fuel price projections are developed by projecting several fuel price components. These components include mine prices, freight rates, oil, natural gas, wood commodity prices, and related items. The price projections are accomplished by escalating each individual component based on published price index forecasts developed by IHS Global Insight, CERA, Wood Mackenzie, PIRA and NYMEX. Long-term coal pricing is based on forecasts provided by JD Energy and the John T. Boyd Company. We utilize price forecasts from Ux Consulting, LLC and Energy Resources International for the future prices of uranium concentrates, conversion services and enrichment services. Forecasted escalations rates for current contracts with escalation indices are provided by Xcel Energy.

The detailed trade secret information is provided as follows:

Part G, Section 1, Schedule 4 – Fossil Fuel Costs
Part G, Section 1, Schedule 5 – Coal Burn Expenses
Part G, Section 1, Schedule 6 – Nuclear Fuel Expenses

The energy and peak demand forecasts in Part G Section 1 Schedule 7 were used as assumptions in developing the projection of fossil and nuclear fuel costs. Fuel cost projections for 2017 through 2021 are based on Xcel Energy's June 2016 forecast. Part G, Section 1, Schedule 8 includes the estimated load management impact for the same period.

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2017 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)
Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[TRADE SECRET BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Total Cost													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2018 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)
Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[TRADE SECRET BEGINS**												
Hydro (MN)													
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Solar													
Wind (MN)													
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Coal (MN)													
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Wood (WI)													
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Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Total Cost													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
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	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
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Coal (MN)													
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Wood (WI)													
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RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Total Cost													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

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	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
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Natural Gas 1 (MN)													
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Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Total Cost													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2021 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)
Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[TRADE SECRET BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
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Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
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Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Total Cost													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)

2021 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)

Cost Summary ($1000s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[TRADE SECRET BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
RDF (WI)													
Natural Gas 1 (MN)													
Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil Cost													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchase Cost													
Net MISO Costs													
Total Cost													
REVENUE													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET COST													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2017 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)
Cost Summary ($1000s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[TRADE SECRET BEGINS**												
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RDF (WI)													
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Natural Gas 2 (MN)													
Natural Gas (WI)													
Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil Cost													
Nuclear													
Purchase - Energy (other)													
Purchase - Energy (WI)													
Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchase Cost													
Net MISO Costs													
Total Cost													
REVENUE													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET COST													

TRADE SECRET ENDS]

Northern States Power Company
2016 Electric Production Forecast
Cost Summary ($1000s)

Docket No. E999/AA-16-523
Part G, Section 1
Schedule 2

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2018 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)
Cost Summary ($1000s)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[TRADE SECRET BEGINS**												
Hydro (MN)													
Hydro (WI)													
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Net MISO Costs													
Total Cost													
REVENUE													
Sale - Demand													
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Total Gross Revenue													
NET COST													

TRADE SECRET ENDS]

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Total Gross Revenue													
NET COST													

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Total Fossil Cost													
Nuclear													
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Total Cost													
REVENUE													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Revenue													
NET COST													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)

2017 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)

Energy Summary (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[TRADE SECRET BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
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Natural Gas 1 (MN)													
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Total Fossil													
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Purchase - Energy (other)													
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Purchase - Wind Energy													
Purchase - Solar Energy													
Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Total GWh													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)

2018 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)

Energy Summary (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[TRADE SECRET BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
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Fuel Oil (MN)													
Fuel Oil (WI)													
Total Fossil													
Nuclear													
Purchase - Energy (other)													
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Purchase - Wind Energy													
Purchase - Solar Energy													
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Mkt Purchase - Demand													
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Total GWh													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)

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Fuel Oil (MN)													
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Total Fossil													
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Purchase - Energy (other)													
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Purchase - Demand													
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Total Purchases													
Total GWh													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
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Energy Summary (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[TRADE SECRET BEGINS**												
Hydro (MN)													
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Total Fossil													
Nuclear													
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Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Total GWh													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2021 - NSP Preliminary Production Budget 2017-2021 (COB 160516 pricing)
Energy Summary (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[TRADE SECRET BEGINS**												
Hydro (MN)													
Hydro (WI)													
Solar													
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Purchase - Wind Energy													
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Purchase - Gas Energy													
Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Total GWh													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

TRADE SECRET ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2017

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2017 Total AVG
		[TRADE SECRET DATA BEGINS…												
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
Flambeau	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
High Bridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1G	Gas													
Inver Hills 1F	Oil													
Inver Hills 2G	Gas													
Inver Hills 2F	Oil													
Inver Hills 3G	Gas													
Inver Hills 3F	Oil													
Inver Hills 4G	Gas													
Inver Hills 4F	Oil													
Inver Hills 5G	Gas													
Inver Hills 5F	Oil													
Inver Hills 6G	Gas													
Inver Hills 6F	Oil													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

… TRADE SECRET DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2018

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

[TRADE SECRET DATA BEGINS…

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2018 Total AVG
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
Flambeau	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1G	Gas													
Inver Hills 1F	Oil													
Inver Hills 2G	Gas													
Inver Hills 2F	Oil													
Inver Hills 3G	Gas													
Inver Hills 3F	Oil													
Inver Hills 4G	Gas													
Inver Hills 4F	Oil													
Inver Hills 5G	Gas													
Inver Hills 5F	Oil													
Inver Hills 6G	Gas													
Inver Hills 6F	Oil													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

… TRADE SECRET DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2019

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2019 Total AVG
		[TRADE SECRET DATA BEGINS…												
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
Flambeau	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1G	Gas													
Inver Hills 1F	Oil													
Inver Hills 2G	Gas													
Inver Hills 2F	Oil													
Inver Hills 3G	Gas													
Inver Hills 3F	Oil													
Inver Hills 4G	Gas													
Inver Hills 4F	Oil													
Inver Hills 5G	Gas													
Inver Hills 5F	Oil													
Inver Hills 6G	Gas													
Inver Hills 6F	Oil													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

… TRADE SECRET DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2020

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

[TRADE SECRET DATA BEGINS…

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020 Total AVG
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG COST													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG COST													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
Flambeau	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	AVG COST													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1G	Gas													
Inver Hills 1F	Oil													
Inver Hills 2G	Gas													
Inver Hills 2F	Oil													
Inver Hills 3G	Gas													
Inver Hills 3F	Oil													
Inver Hills 4G	Gas													
Inver Hills 4F	Oil													
Inver Hills 5G	Gas													
Inver Hills 5F	Oil													
Inver Hills 6G	Gas													
Inver Hills 6F	Oil													
Inver Hills	AVG COST													
LS Power	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG COST													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	AVG COST													
SYSTEM MN	AVG COST													

… TRADE SECRET DATA ENDS]

Fossil Fuel Cost ($/Mbtu)
All Plants and All Fuels
2021

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2021 Total AVG
		[TRADE SECRET DATA BEGINS…												
Allen S King 1	Coal													
Angus Anson 2	Gas													
Angus Anson 2	Oil													
Angus Anson 3	Gas													
Angus Anson 3	Oil													
Angus Anson 4	Gas													
Angus Anson	AVG COST													
Black Dog 25 CC	Gas													
Black Dog 6	Gas													
Black Dog	AVG													
Blue Lake 1	Oil													
Blue Lake 2	Oil													
Blue Lake 3	Oil													
Blue Lake 4	Oil													
Blue Lake 7	Gas													
Blue Lake 8	Gas													
Blue Lake	AVG													
Calpine I	Gas													
Calpine II	Gas													
Calpine	AVG COST													
Flambeau	AVG COST													
French Island 1	Gas													
French Island 1	Wood/RDF													
French Island 2	Gas													
French Island 2	Wood/RDF													
French Island 3	Oil													
French Island 4	Oil													
French Island	AVG COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	AVG													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	AVG													
Invenergy 1	Gas													
Invenergy 1	Oil													
Invenergy 2	Gas													
Invenergy 2	Oil													
Invenergy	AVG COST													
Inver Hills 1G	Gas													
Inver Hills 1F	Oil													
Inver Hills 2G	Gas													
Inver Hills 2F	Oil													
Inver Hills 3G	Gas													
Inver Hills 3F	Oil													
Inver Hills 4G	Gas													
Inver Hills 4F	Oil													
Inver Hills 5G	Gas													
Inver Hills 5F	Oil													
Inver Hills 6G	Gas													
Inver Hills 6F	Oil													
Inver Hills	AVG													
LS Power	AVG COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	AVG													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	AVG													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	AVG													
Wheaton 1	Gas													
Wheaton 1	Oil													
Wheaton 2	Gas													
Wheaton 2	Oil													
Wheaton 3	Gas													
Wheaton 3	Oil													
Wheaton 4	Gas													
Wheaton 4	Oil													
Wheaton 5	Oil													
Wheaton 6	Oil													
Wheaton	AVG COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	AVG													
SYSTEM MN	AVG													

Coal Expense
$/Mbtu
2017

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2017
	[TRADE SECRET DATA BEGINS ...												
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

…TRADE SECRET DATA ENDS]

Coal Expense
$/Mbtu
2018

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2018
	[TRADE SECRET DATA BEGINS ...												
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

…TRADE SECRET DATA ENDS]

Coal Expense
$/Mbtu
2019

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2019
	[TRADE SECRET DATA BEGINS ...												
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

…TRADE SECRET DATA ENDS]

Coal Expense
$/Mbtu
2020

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020
	[TRADE SECRET DATA BEGINS ...												
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

…TRADE SECRET DATA ENDS]

Coal Expense
$/Mbtu
2021

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

[TRADE SECRET DATA BEGINS ...

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2021
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

[TRADE SECRET DATA BEGINS …

Item ID	Item Description (AAA-2014 08-14-13 11:12:38)	Jan 2017	Feb 2017	Mar 2017	Apr 2017	May 2017	Jun 2017	Jul 2017	Aug 2017	Sep 2017	Oct 2017	Nov 2017	Dec 2017
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refuelin												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Ohter Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

[TRADE SECRET DATA BEGINS …

Item ID	Item Description (AAA-2014 08-14-13 11:12:38)	Jan 2018	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
7	Prairie Island 1 - Monthly Minor Outage Rate (%)												
8	Prairie Island 1 - Days Offline in Month for Refuelin												
9	Prairie Island 1 - Refueling Outage Start Date												
10	Prairie Island 1 - Refueling Outage Start Time (HH.MM												
11	Prairie Island 1 - Refueling Outage End Date												
12	Prairie Island 1 - Refueling Outage End Time (HH.MM)												
13	Prairie Island 1 - Fuel Expense - Dollars												
14	Prairie Island 1 - Fuel Expense - Cents/MBTU												
15	Prairie Island 1 - Fuel Expense - Cents/Kwhe												
16	Prairie Island 2 - Heat Generation (1000 MBTU)												
17	Prairie Island 2 - Net Electric Generation (MWHe-Net)												
18	Prairie Island 2 - Maximum Capacity (MWe-Net)												
19	Prairie Island 2 - Current Capability (MWe-Net)												
20	Prairie Island 2 - Thermal Capability (MWth)												
21	Prairie Island 2 - Monthly Capacity Factor (%)												
22	Prairie Island 2 - Monthly Minor Outage Rate (%)												
23	Prairie Island 2 - Days Offline in Month for Refuelin												
24	Prairie Island 2 - Refueling Outage Start Date												
25	Prairie Island 2 - Refueling Outage Start Time (HH.MM												
26	Prairie Island 2 - Refueling Outage End Date												
27	Prairie Island 2 - Refueling Outage End Time (HH.MM)												
28	Prairie Island 2 - Fuel Expense - Dollars												
29	Prairie Island 2 - Fuel Expense - Cents/MBTU												
30	Prairie Island 2 - Fuel Expense - Cents/Kwhe												
31	Monticello - Heat Generation (1000 MBTU)												
32	Monticello - Net Electric Generation (MWHe-Net)												
33	Monticello - Maximum Capacity (MWe-Net)												
34	Monticello - Current Capability (MWe-Net)												
35	Monticello - Thermal Capability (MWth)												
36	Monticello - Monthly Capacity Factor (%)												
37	Monticello - Monthly Minor Outage Rate (%)												
38	Monticello - Days Offline in Month for Refuelin												
39	Monticello - Refueling Outage Start Date												
40	Monticello - Refueling Outage Start Time (HH.MM												
41	Monticello - Refueling Outage End Date												
42	Monticello - Refueling Outage End Time (HH.MM)												
43	Monticello - Fuel Expense - Dollars												
44	Monticello - Fuel Expense - Cents/MBTU												
45	Monticello - Fuel Expense - Cents/Kwhe												
46	Prairie Island 1 - Cents/Kwhe - Fuel Commodities												
47	Prairie Island 1 - Cents/Kwhe - Fuel Services												
48	Prairie Island 1 - Cents/Kwhe - DOE Disposal Fee												
49	Prairie Island 1 - Cents/Kwhe - D&D Fee												
50	Prairie Island 1 - Cents/Kwhe - End of Life Recovery												
51	Prairie Island 1 - Cents/Kwhe - Ohter Global Costs												
52	Prairie Island 1 - Cents/Kwhe - AFUDC and A&G												
53	Prairie Island 2 - Cents/Kwhe - Fuel Commodities												
54	Prairie Island 2 - Cents/Kwhe - Fuel Services												
55	Prairie Island 2 - Cents/Kwhe - DOE Disposal Fee												
56	Prairie Island 2 - Cents/Kwhe - D&D Fee												
57	Prairie Island 2 - Cents/Kwhe - End of Life Recovery												
58	Prairie Island 2 - Cents/Kwhe - Ohter Global Costs												
59	Prairie Island 2 - Cents/Kwhe - AFUDC and A&G												
60	Monticello - Cents/Kwhe - Fuel Commodities												
61	Monticello - Cents/Kwhe - Fuel Services												
62	Monticello - Cents/Kwhe - DOE Disposal Fee												
63	Monticello - Cents/Kwhe - D&D Fee												
64	Monticello - Cents/Kwhe - End of Life Recovery												
65	Monticello - Cents/Kwhe - Ohter Global Costs												
66	Monticello - Cents/Kwhe - AFUDC and A&G												
67	Prairie Island 1 - EOL Recovery Expense - Dollars												
68	Prairie Island 2 - EOL Recovery Expense - Dollars												
69	Monticello - EOL Recovery Expense - Dollars												

…TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT - TRADE SECRET DATA EXCISED

[TRADE SECRET DATA BEGINS …

Item ID	Item Description (AAA-2014 08-14-13 11:12:38)	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019
1	Prairie Island 1 - Heat Generation (1000 MBTU)												
2	Prairie Island 1 - Net Electric Generation (MWHe-Net)												
3	Prairie Island 1 - Maximum Capacity (MWe-Net)												
4	Prairie Island 1 - Current Capability (MWe-Net)												
5	Prairie Island 1 - Thermal Capability (MWth)												
6	Prairie Island 1 - Monthly Capacity Factor (%)												
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2017 Electric Production Forecast
Peak Demand and Energy Requirements
(2017 Budget)

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,406	4,004,883	84.03%
February	6,169	3,515,710	84.80%
March	5,963	3,696,844	83.32%
April	5,522	3,409,038	85.75%
May	7,138	3,535,079	66.57%
June	8,553	3,851,336	62.54%
July	9,235	4,408,274	64.16%
August	8,719	4,210,866	64.91%
September	7,918	3,648,494	64.00%
October	5,780	3,541,847	82.37%
November	5,901	3,488,510	82.11%
December	6,474	3,817,807	79.26%
Annual	**9,235**	**45,128,687**	**55.79%**

2018 Electric Production Forecast
Peak Demand and Energy Requirements
(2017 Budget)

	Base Peak Demand (MW)	**Energy Requirements (MWH)**	**Load Factor (%)**
January	6,433	3,994,899	83.47%
February	6,191	3,504,155	81.32%
March	5,982	3,677,723	82.64%
April	5,537	3,397,009	85.21%
May	7,211	3,522,703	65.66%
June	8,605	3,834,428	61.89%
July	9,274	4,397,528	63.73%
August	8,759	4,199,486	64.44%
September	7,961	3,636,824	63.45%
October	5,785	3,535,044	82.13%
November	5,913	3,514,169	82.54%
December	6,489	3,848,214	79.71%
Annual	**9,274**	**45,062,182**	**55.47%**

2019 Electric Production Forecast
Peak Demand and Energy Requirements
(2017 Budget)

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,444	3,978,822	82.99%
February	6,204	3,543,560	82.06%
March	6,003	3,769,817	84.41%
April	5,557	3,420,205	85.49%
May	7,282	3,483,640	64.30%
June	8,669	3,944,975	63.20%
July	9,325	4,424,137	63.77%
August	8,810	4,173,247	63.67%
September	8,023	3,708,543	64.20%
October	5,807	3,518,474	81.44%
November	5,945	3,547,719	82.88%
December	6,529	3,910,000	80.49%
Annual	**9,325**	**45,423,138**	**55.61%**

2020 Electric Production Forecast
Peak Demand and Energy Requirements
(2017 Budget)

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,472	4,028,157	83.66%
February	6,227	3,675,925	84.81%
March	6,009	3,717,200	83.14%
April	5,560	3,436,199	85.84%
May	7,364	3,560,452	64.98%
June	8,710	3,872,324	61.75%
July	9,349	4,430,646	63.70%
August	8,848	4,233,228	64.31%
September	8,056	3,675,062	63.36%
October	5,811	3,560,983	82.37%
November	5,956	3,542,591	82.60%
December	6,535	3,883,363	79.87%
Annual	**9,349**	**45,616,130**	**55.70%**

2021 Electric Production Forecast
Peak Demand and Energy Requirements
(2017 Budget)

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,487	4,035,642	83.62%
February	6,243	3,560,687	84.87%
March	6,030	3,722,615	82.97%
April	5,576	3,444,327	85.79%
May	7,433	3,575,812	64.66%
June	8,767	3,893,350	61.68%
July	9,388	4,447,964	63.68%
August	8,873	4,220,864	63.94%
September	8,100	3,678,551	63.08%
October	5,821	3,567,798	82.38%
November	5,981	3,564,397	82.77%
December	6,569	3,897,734	79.75%
Annual	**9,388**	**45,609,740**	**55.46%**

Estimated Load Management Impact

Summer Peak (MW)

	System Base Peak	Total Load Mgmt/ Load Relief	Net Peak
2016	9,142	634	8,507
2017	9,235	637	8,598
2018	9,274	641	8,633
2019	9,325	644	8,680
2020	9,349	648	8,701
2021	9,388	653	8,735
2022	9,414	657	8,757
2023	9,454	662	8,792
2024	9,451	667	8,784
2025	9,471	671	8,800
2026	9,469	671	8,798
2027	9,485	671	8,813
2028	9,491	671	8,820
2029	9,522	671	8,851
2030	9,584	671	8,913
2031	9,663	671	8,991
2032	9,737	671	9,066

Average Annual Growth Rates

2016-2026	0.35%		0.34%
2026-2032	0.47%		0.50%
2016-2032	0.39%		0.40%

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-523

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 by the Commission's Orders 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)

Pursuant to the Commission Order dated July 14, 1981 in the referenced docket, Part H Section 1 Schedule 1 provides a history of the nuclear fuel sinking fund established for payments to the U.S. Department of Energy for the permanent disposal of spent nuclear fuel.

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 therefore has attached the June and July data as Part H, Section 2, Schedule 1. Since the Company will not have the August 2016 data available until mid-September, the Company will report the September data in a subsequent supplemental filing after the data has been booked.

3. Natural Gas Financial Instruments (Docket Nos. E002/M-01-1953 and E,G999/AA-02-951)

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.

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	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
230	115	112	Minnesota	Minn Valley	Storage
230	115	50	Minnesota	Minn Valley	Storage
230	115	50	Minnesota	Minn Valley	Storage
161	115	187	Minnesota	Maple Grove	Storage
161	115	62.5	Wisconsin	Pine Lake	Storage
161	115	46.7	Wisconsin	Tremval	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 Order of April 4, 2006 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 period July 1, 2015 through June 30, 2016 .

Part H, Section 5, Schedule 2 contains an explanation of the factors affecting wind curtailment costs for the 2015-2016 AAA reporting period, and our projection of expenses associated with wind curtailment for the next five years. The actual curtailment expenses will 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. The Company will continue to monitor and report such curtailment transactions in the monthly fuel clause adjustment filings.

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 August 6, 2015 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." There were three Community Solar Garden's placed in-service during the time period of July 2015 – July 2016. The location, start date and number of subscribers for these three gardens is as follows:

Location (County)	Start Date	Number of Subscribers
LeSueur	10/1/15	9
Lincoln	5/1/16	5
Ramsey	6/1/16	7

The total amount of bill credits issued for these three solar gardens during this reporting period was $13,718. We anticipate several more community solar gardens to be in place by our next AAA reporting period. The Company's first solar garden annual compliance report with bill credit information will be submitted in April 2017.

This schedule represents the activity for payments and disposal amounts in the Nuclear Fuel Sinking Fund. This includes historical numbers along with current year activity to show a running balance. Payments made to the DOE ended as of July 2014 so the account currently represents a zero ending balance.

DISPOSAL COST (after 1985, reflects only Interim Storage costs)								**PERMANENT DISPOSAL COSTS (utilizes accounts payable)**			
YEAR	Beginning Balance	Combined Interim & Per-manent Disposal	Interim Sinking Disposal	Permanent Disposal (1 mill/Kwr)	Total Disposal Provision	Transfers and Adjustments	Ending Balance	Beginning Balance	Permanent Disposal (1 mill/Kwhr)	Payments made to DOE	Ending Balance (5)
								A	**B**	**C**	**D=A+B+C**
1981	0.00	5,942,298.28			5,942,298.28 (1)	68,334,106.49 (2)	74,276,404.77				
1982	74,276,404.77	15,159,153.11			15,159,153.11 (1)		89,435,557.88				
1983A	89,435,557.88	4,688,862.71			4,688,862.71 (1)		94,124,420.59				
1983B	94,124,420.59		1,340,373.13		1,340,373.13		95,464,793.72	0.00	9,023,957.00	(6,041,538.00)	2,982,419.00
1984	95,464,793.72		1,954,606.32		1,954,606.32		97,419,400.04	2,982,419.00	8,837,917.00	(9,833,846.00)	1,986,490.00
1985	97,419,400.04		2,123,381.06		2,123,381.06	(94,124,420.59) (3)	5,418,360.51	1,986,490.00	12,046,342.00	(10,968,643.00)	3,064,189.00
1986	5,418,360.51		2,306,917.10		2,306,917.10		7,725,277.61	3,064,189.00	9,602,191.00	(9,797,027.00)	2,869,353.00
1987	7,725,277.61		2,506,137.24		2,506,137.24		10,231,414.85	2,869,353.00	11,555,883.00	(11,800,094.00)	2,625,142.00
1988	10,231,414.85		2,722,562.04		2,722,562.04		12,953,976.89	2,625,142.00	12,288,175.00	(11,505,493.00)	3,407,824.00
1989	12,953,976.89		2,957,676.43		2,957,676.43	(1,512,985.13) (4)	14,398,668.19	3,407,824.00	10,929,877.00	(11,593,607.00)	2,744,094.00
1990	14,398,668.19		3,269,456.96		3,269,456.96		17,668,125.15	2,744,094.00	12,139,302.00	(11,596,282.00)	3,287,114.00
1991	17,668,125.15		3,669,302.67		3,669,302.67		21,337,427.82	3,287,114.00	11,852,674.00	(11,841,208.00)	3,298,580.00
1992	21,337,427.82		3,986,175.86		3,986,175.86		25,323,603.68	3,298,580.00	6,826,888.00	(8,658,834.00) *	1,466,634.00
1993	25,323,603.68		0.00		0.00		25,323,603.68	1,466,634.00	8,745,574.00	(7,520,644.00) **	2,691,564.00
1994	25,323,603.68		0.00		0.00	(531,731.96) (6)	24,791,871.72	2,691,564.00	10,558,803.00	(10,298,792.82) ***	2,951,574.18
1995	24,791,871.72		0.00		0.00	(15,646,551.31) (6)	9,145,320.41	2,951,574.18	12,283,138.27	(11,973,751.45) ****	3,260,961.00
1996	9,145,320.41		0.00		0.00	(6,448,412.98) (6)	2,696,907.43	3,260,961.00	11,276,720.00	(11,272,148.00)	3,265,533.00
1997	2,696,907.43		0.00		0.00	0.00	2,696,907.43	3,265,533.00	10,072,912.00	(10,838,257.00)	2,500,188.00
1998	2,696,907.43		0.00		0.00	(2,696,907.43) (7)	0.00	2,500,188.00	10,837,906.00	(10,820,840.00)	2,517,254.00
1999	0.00		0.00		0.00		0.00	2,517,254.00	12,409,567.00	(11,537,557.00)	3,389,264.00
2000	0.00		0.00		0.00		0.00	3,389,264.00	12,175,415.00	(12,228,910.00)	3,335,769.00
2001	0.00		0.00		0.00		0.00	3,335,769.00	11,198,939.00	(11,690,486.00)	2,844,222.00
2002	0.00		0.00		0.00		0.00	2,844,222.00	13,112,782.90	(16,113,905.00)	(156,900.10)
2002								ADJ		3,421,618.00	
2002								2,844,222.00	13,112,782.90	(12,692,287.00)	(156,900.10)
2003	0.00		0.00		0.00		0.00		12,878,239.00	(9,339,193.00)	
2003								ADJ		(3,421,618.00)	
2003								(156,900.10)	12,878,239.00	(12,760,811.00)	3,382,145.90
2004	0.00		0.00		0.00		0.00	3,382,145.90	12,873,788.82	(13,410,964.00)	2,844,970.72
2005	0.00		0.00		0.00		0.00	2,844,970.72	12,422,088.82	(11,689,615.00)	3,577,444.54
2006	0.00		0.00		0.00		0.00	3,577,444.54	12,659,380.87	(13,107,624.00)	3,129,201.41
2007	0.00		0.00		0.00		0.00	3,129,201.41	12,552,219.53	(12,202,312.00)	3,479,108.94
2008								3,479,108.94	12,549,214.01	(12,903,839.00)	3,124,483.95
2009								3,124,483.95	11,983,298.31	(12,272,758.55)	2,835,023.71
2010								2,835,023.71	12,700,047.24	(12,378,771.00)	3,156,299.95
2011								3,156,299.95	11,471,020.73	(11,646,196.17)	2,981,124.51
2012								2,981,124.51	11,570,200.51	(11,896,472.00)	2,654,853.02
2013								2,654,853.02	10,346,868.68	(10,603,002.00)	2,398,719.70
2014								2,398,719.70	4,869,797.30	(7,268,517.00)	0.00
2015								0.00	0.00	0.00	0.00
201606								0.00	0.00	0.00	**0.00**
								Post 4/6/83	356,651,126.99	(356,651,126.99)	
								Pre 4/7/83	94,124,420.59	(94,124,420.59)	
								Total to date	450,775,547.58	(450,775,547.58)	0.00

Notes:

(1) Until April 1983, there was no separation of the permanent and interim sinking fund.

(2) Transfer of removal expense recovered through a negative salvage from fuel account.

(3) Payment to DOE for permanent disposal of all fuel associated with energy generated prior to April 7, 1983. After this point, the numbers in this account represent only interim storage funds.

(4) Prairie Island storage demonstration of rod consolidation.

(5) The ending balance merely reflects the one month delay between the end of the quarter and the payment due to the DOE.

YEAR 1983A represents time from 1/1/83 through 4/6/83.

YEAR 1983B represents time from 4/7/83 through 12/31/83.

(6) Prairie Island dry cask storage project (Independent Spent Fuel Storage Installation - ISFSI)

(7) Remaining Sinking Fund dollars applied to plant account 41.12.10-19-8639 ($2,548,118.69) and the reserve account 51.12.10-19-8639 ($148,788.74).

N/A = Not Available

* THESE PAYMENTS THAT WERE MADE TO DOE HAVE BEEN REDUCED BY THE FOLLOWING DOE CREDITS:
JULY 1992 - $646,846.00
OCTOBER 1992 - $3,095,827.00

** THESE PAYMENTS TO THE DOE HAVE BEEN REDUCED BY THE FOLLOWING DOE CREDITS:
JANUARY 1993 - $316,857.00
APRIL 1993 - $27,170.00
OCTOBER 1993 - $2,224,896.00

*** THESE PAYMENTS TO THE DOE HAVE BEEN REDUCED BY THE FOLLOWING DOE CREDIT:
JANUARY 1994 - $669,711.00
OCTOBER 1994 - $56,878.18

**** THESE PAYMENTS TO THE DOE HAVE BEEN REDUCED IN THE JULY 1995 PAYMENT BY $48,437.55.

Northern States Power Company, a Minnesota Company
Electric Operations - State of Minnesota
Compliance Reports

Docket No. E999/AA-16-523
Part H, Section 2
Schedule 1

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Table 1: GENERATION COSTS ALLOCATION BETWEEN RETAIL & WHOLESALE CLASS

[TRADE SECRET DATA BEGINS…

	Retail		Wholesale		Retail & Wholesale	
	MWh	Cost ($/MWh)	MWh	Cost ($/MWh)	MWh	Cost ($/MWh)
	[1]	[2]	[3]	[4]	[5]	[6]
					[1] + [3]	{[1]x[2]+[3]x[4]}/[5]
June 2016						
July 2016						
August 2016						

… TRADE SECRET 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	345	115	448	Minnesota	Allen S King Substation	In-service standalone
3	230	115	336	Minnesota	Blue Lake Substation	In-service duplicate
4	345	115	336	Minnesota	Blue Lake Substation	In-service duplicate
5	345	161	448	Wisconsin	Briggs Road Substation	In-service standalone
6	345	115	448	Minnesota	Brookings County Substation	In-service duplicate
7	345	115	448	Minnesota	Brookings County Substation	In-service duplicate
8	345	115	448	Minnesota	Chisago County Substation	In-service duplicate
9	345	115	448	Minnesota	Chisago County Substation	In-service duplicate
10	500	345	1200	Minnesota	Chisago County Substation	In-service duplicate
11	500	345	1200	Minnesota	Chisago County Substation	In-service duplicate
12	161	115	187	Minnesota	Collville Substation	In-service standalone
13	345	115	672	Minnesota	Coon Creek Substation	In-service duplicate
14	345	115	672	Minnesota	Coon Creek Substation	In-service duplicate
15	161	115	186	Wisconsin	Crystal Cave Substation	In-service standalone
16	345	161	300	Wisconsin	Eau Claire Substation	In-service duplicate
17	345	161	300	Wisconsin	Eau Claire Substation	In-service duplicate
18	345	115	448	Minnesota	Eden Prairie Substation	In-service duplicate
19	345	115	448	Minnesota	Eden Prairie Substation	In-service duplicate
20	345	115	448	Minnesota	Elm Creek Substation	In-service standalone
21	161	115	187	Wisconsin	Gingles Substation	In-service standalone
22	345	230	336	Minnesota	Hazel Creek Substation	In-service standalone
23	161	115	187	Wisconsin	Hydro Lane Substation	In-service standalone
24	345	115	672	Minnesota	Inver Hills Substation	In-service standalone
25	345	115	448	Minnesota	King Substation	In-service standalone
26	345	115	448	Minnesota	Kohlman Lake Substation	In-service duplicate
27	345	115	448	Minnesota	Kohlman Lake Substation	In-service duplicate
28	161	115	336	Wisconsin	Lawrence Creek	In-service standalone
29	345	115	448	Minnesota	Lyon County	In-service standalone
30	230	115	187	Minnesota	Maple River Substation	In-service duplicate
31	230	115	186	Minnesota	Maple River Substation	In-service duplicate
32	230	115	187	Minnesota	Minnesota Valley Substation	In-service duplicate
33	230	115	186	Minnesota	Minnesota Valley Substation	In-service duplicate
34	345	230	336	Minnesota	Monticello Substation	In-service duplicate
35	345	115	336	Minnesota	Monticello Substation	In-service duplicate
36	345	115	672	Minnesota	Nobles County Substation	In-service duplicate
37	345	115	672	Minnesota	Nobles County Substation	In-service duplicate
38	345	161	672	Minnesota	North Rochester	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	672	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	448	Minnesota	Split Rock Substation	In-service duplicate
60	345	115	448	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

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
For January 2014 to June 2016

Production Month	Date Paid: Delivered MWh	Date Paid: Lost MWh	Wind Production Delivered: MWh Delivered	Wind Production Delivered: Amount Xcel Energy Paid	Lost Production: Lost MWh	Lost Production: Amount Xcel Energy Paid	Total Xcel Energy Paid	
Jan-14			507,892.00	$ 19,914,105.03	38,688.00	$ 1,728,478.18	$ 21,642,583.21	
Feb-14			411,263.00	$ 16,252,377.79	27,021.00	$ 1,176,362.64	$ 17,428,740.43	
Mar-14			428,808.00	$ 16,884,342.05	30,844.00	$ 1,235,263.17	$ 18,119,605.22	
Apr-14			447,797.00	$ 17,496,382.62	33,695.00	$ 1,282,537.48	$ 18,778,920.10	
May-14			346,548.00	$ 13,755,595.85	4,989.00	$ 213,648.70	$ 13,969,244.55	
Jun-14			278,947.00	$ 11,122,900.96	12,122.00	$ 456,963.40	$ 11,579,864.36	
Jul-14			276,189.00	$ 11,076,232.75	24,695.00	$ 881,555.84	$ 11,957,788.59	
Aug-14			126,515.00	$ 5,120,318.25	4,310.00	$ 146,982.80	$ 5,267,301.05	
Sep-14			300,800.00	$ 11,917,192.20	8,370.00	$ 324,867.51	$ 12,242,059.71	
Oct-14			374,552.00	$ 14,959,305.81	33,839.00	$ 1,224,208.32	$ 16,183,514.13	
Nov-14			482,136.00	$ 19,152,652.62	35,733.00	$ 1,370,340.36	$ 20,522,992.98	
Dec-14			359,336.00	$ 14,274,263.33	10,171.00	$ 339,594.95	$ 14,613,858.28	
Total-14			4,340,783.00	$ 171,925,669.26	264,477.00	$ 10,380,803.35	$ 182,306,472.61	
Jan-15			430,437.00	$ 17,187,922.21	7,463.00	$ 324,572.35	$ 17,512,494.56	
Feb-15			375,215.00	$ 14,988,985.89	12,581.00	$ 541,829.04	$ 15,530,814.93	
Mar-15			419,845.00	$ 16,848,980.29	31,819.00	$ 1,176,441.15	$ 18,025,421.44	
Apr-15			444,726.00	$ 17,770,333.68	12,767.00	$ 479,324.70	$ 18,249,658.38	*
May-15			399,998.00	$ 16,011,402.43	8,816.00	$ 356,905.79	$ 16,368,308.22	
Jun-15			216,697.00	$ 8,736,210.07	3,410.00	$ 176,449.87	$ 8,912,659.94	
Jul-15			200,183.00	$ 8,092,588.32	2,577.00	$ 118,268.76	$ 8,210,857.08	
Aug-15			269,190.00	$ 10,815,986.71	15,005.00	$ 597,523.91	$ 11,413,510.62	
Sep-15			310,398.00	$ 12,462,108.19	21,572.00	$ 840,782.35	$ 13,302,890.54	
Oct-15			359,268.00	$ 14,602,680.23	25,830.00	$ 932,119.67	$ 15,534,799.90	
Nov-15			458,603.00	$ 18,509,657.58	17,089.00	$ 664,226.12	$ 19,173,883.70	
Dec-15			355,133.00	$ 14,327,449.33	8,881.00	$ 395,910.08	$ 14,723,359.41	
Total-15			4,239,693.00	$ 170,354,304.93	167,810.00	$ 6,604,353.79	$ 176,958,658.72	
Jan-16			374,389.00	$ 15,077,234.58	5,120.00	$ 222,057.33	$ 15,299,291.91	
Feb-16			388,803.00	$ 15,722,028.86	7,923.00	$ 302,623.95	$ 16,024,652.81	
Mar-16			386,342.00	$ 15,537,502.86	17,246.00	$ 688,637.00	$ 16,226,139.86	
Apr-16			488,078.00	$ 19,628,605.94	16,513.00	$ 699,027.88	$ 20,327,633.82	
May-16			300,210.00	$ 12,086,544.34	12,797.00	$ 476,908.17	$ 12,563,452.51	
Jun-16			283,453.00	$ 11,516,998.71	8,251.00	$ 313,710.81	$ 11,830,709.52	
Jul-16				$ -		$ -		
Aug-16				$ -		$ -		
Sep-16				$ -		$ -		
Oct-16				$ -		$ -		
Nov-16				$ -		$ -		
Dec-16				$ -		$ -		
Total-16			2,221,275.00	$ 89,568,915.29	67,850.00	$ 2,702,965.14	$ 92,271,880.43	

* Due to a formula error, the 'Production Delivered Amount Xcel Energy Paid' in April 2014 was wrong. It was corrected in March 2015 FCC report.
This change did not affect the curtailment payment amount and the fuel cost factor.

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 1 (ATC)
For January 2014 to June 2016

	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-14			0.00	$ -	0.00	$ -	
Feb-14			0.00	$ -	0.00	$ -	
Mar-14			0.00	$ -	0.00	$ -	
Apr-14			0.00	$ -	0.00	$ -	
May-14			0.00	$ -	0.00	$ -	
Jun-14			0.00	$ -	0.00	$ -	
Jul-14			0.00	$ -	0.00	$ -	
Aug-14			0.00	$ -	0.00	$ -	
Sep-14			0.00	$ -	0.00	$ -	
Oct-14			0.00	$ -	0.00	$ -	
Nov-14			0.00	$ -	0.00	$ -	
Dec-14			0.00	$ -	0.00	$ -	
Total-14							
Jan-15			0.00	$ -	0.00	$ -	
Feb-15			0.00	$ -	0.00	$ -	
Mar-15			0.00	$ -	0.00	$ -	
Apr-15			0.00	$ -	0.00	$ -	
May-15			0.00	$ -	0.00	$ -	
Jun-15			0.00	$ -	0.00	$ -	
Jul-15			10,048.00	$ 266,278.63	722.00	$ 19,129.47	$ 285,408.10
Aug-15			0.00	$ -	0.00	$ -	
Sep-15			0.00	$ -	0.00	$ -	
Oct-15			0.00	$ -	0.00	$ -	
Nov-15			0.00	$ -	0.00	$ -	
Dec-15			0.00	$ -	0.00	$ -	
Total-15			10,048.00	$ 266,278.63	722.00	$ 19,129.47	$ 285,408.10
Jan-16			0.00	$ -	0.00	$ -	
Feb-16			0.00	$ -	0.00	$ -	
Mar-16			0.00	$ -	0.00	$ -	
Apr-16			0.00	$ -	0.00	$ -	
May-16			0.00	$ -	0.00	$ -	
Jun-16			0.00	$ -	0.00	$ -	
Jul-16			0.00	$ -	0.00	$ -	
Aug-16			0.00	$ -	0.00	$ -	
Sep-16			0.00	$ -	0.00	$ -	
Oct-16			0.00	$ -	0.00	$ -	
Nov-16			0.00	$ -	0.00	$ -	
Dec-16			0.00	$ -	0.00	$ -	
Total-16							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 2 (Low Load)
For January 2014 to June 2016

	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-14			0.00	$ -	0.00	$ -	
Feb-14			0.00	$ -	0.00	$ -	
Mar-14			0.00	$ -	0.00	$ -	
Apr-14			0.00	$ -	0.00	$ -	
May-14			0.00	$ -	0.00	$ -	
Jun-14			0.00	$ -	0.00	$ -	
Jul-14			0.00	$ -	0.00	$ -	
Aug-14			0.00	$ -	0.00	$ -	
Sep-14			0.00	$ -	0.00	$ -	
Oct-14			0.00	$ -	0.00	$ -	
Nov-14			0.00	$ -	0.00	$ -	
Dec-14			0.00	$ -	0.00	$ -	
Total-14							
Jan-15			0.00	$ -	0.00	$ -	
Feb-15			0.00	$ -	0.00	$ -	
Mar-15			0.00	$ -	0.00	$ -	
Apr-15			0.00	$ -	0.00	$ -	
May-15			0.00	$ -	0.00	$ -	
Jun-15			0.00	$ -	0.00	$ -	
Jul-15			0.00	$ -	0.00	$ -	
Aug-15			0.00	$ -	0.00	$ -	
Sep-15			0.00	$ -	0.00	$ -	
Oct-15			0.00	$ -	0.00	$ -	
Nov-15			0.00	$ -	0.00	$ -	
Dec-15			0.00	$ -	0.00	$ -	
Total-15							
Jan-16			0.00	$ -	0.00	$ -	
Feb-16			0.00	$ -	0.00	$ -	
Mar-16			0.00	$ -	0.00	$ -	
Apr-16			0.00	$ -	0.00	$ -	
May-16			0.00	$ -	0.00	$ -	
Jun-16			0.00	$ -	0.00	$ -	
Jul-16			0.00	$ -	0.00	$ -	
Aug-16			0.00	$ -	0.00	$ -	
Sep-16			0.00	$ -	0.00	$ -	
Oct-16			0.00	$ -	0.00	$ -	
Nov-16			0.00	$ -	0.00	$ -	
Dec-16			0.00	$ -	0.00	$ -	
Total-16							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)
For January 2014 to June 2016

	Date Paid		Wind Production Delivered			Lost Production			Total Xcel Energy Paid
Production Month	Delivered MWh	Lost MWh	MWh Delivered		Amount Xcel Energy Paid	Lost MWh		Amount Xcel Energy Paid	
Jan-14			370,021.00	$	14,326,083.51	38,688.00	$	1,728,478.18	$ 16,054,561.69
Feb-14			306,417.00	$	12,227,400.48	27,021.00	$	1,176,362.64	$ 13,403,763.12
Mar-14			313,040.00	$	12,270,317.48	30,805.00	$	1,234,106.87	$ 13,504,424.35
Apr-14			257,997.00	$	9,888,827.56	33,651.00	$	1,281,262.53	$ 11,170,090.09
May-14			137,551.00	$	5,259,198.52	4,989.00	$	213,648.70	$ 5,472,847.22
Jun-14			196,092.00	$	7,764,350.85	12,122.00	$	456,963.40	$ 8,221,314.25
Jul-14			184,316.00	$	7,332,372.22	24,695.00	$	881,555.84	$ 8,213,928.06
Aug-14			50,900.00	$	2,013,327.92	4,310.00	$	146,982.80	$ 2,160,310.72
Sep-14			179,299.00	$	6,870,476.62	8,370.00	$	324,867.51	$ 7,195,344.13
Oct-14			274,412.00	$	10,884,349.98	33,839.00	$	1,224,208.32	$ 12,108,558.30
Nov-14			357,732.00	$	14,199,215.53	35,733.00	$	1,370,340.36	$ 15,569,555.89
Dec-14			166,565.00	$	6,401,989.27	10,171.00	$	339,594.95	$ 6,741,584.22
Total-14			2,794,342.00	$	109,437,909.94	264,394.00	$	10,378,372.10	$ 119,816,282.04
Jan-15			214,847.00	$	8,505,929.28	7,463.00	$	324,572.35	$ 8,830,501.63
Feb-15			202,707.00	$	7,762,179.09	12,581.00	$	541,829.04	$ 8,304,008.13
Mar-15			186,585.00	$	7,230,936.47	31,819.00	$	1,176,441.15	$ 8,407,377.62
Apr-15			187,399.00	$	7,228,526.78	12,767.00	$	479,324.70	$ 7,707,851.48
May-15			166,367.00	$	6,379,664.46	8,816.00	$	356,905.79	$ 6,736,570.25
Jun-15			144,139.00	$	5,783,838.31	3,410.00	$	176,449.87	$ 5,960,288.18
Jul-15			86,720.00	$	3,504,694.82	1,855.00	$	99,139.29	$ 3,603,834.11
Aug-15			202,098.00	$	8,208,070.21	15,005.00	$	597,523.91	$ 8,805,594.12
Sep-15			203,241.00	$	8,157,473.75	21,572.00	$	840,782.35	$ 8,998,256.10
Oct-15			212,770.00	$	8,688,670.93	25,830.00	$	932,119.67	$ 9,620,790.60
Nov-15			345,575.00	$	13,665,674.96	17,089.00	$	664,226.12	$ 14,329,901.08
Dec-15			249,957.00	$	9,774,198.91	8,881.00	$	395,910.08	$ 10,170,108.99
Total-15			2,402,405.00	$	94,889,857.97	167,088.00	$	6,585,224.32	$ 101,475,082.29
Jan-16			225,468.00	$	9,135,666.90	5,120.00	$	222,057.33	$ 9,357,724.23
Feb-16			230,076.00	$	9,421,305.86	7,923.00	$	302,623.95	$ 9,723,929.81
Mar-16			251,333.00	$	10,190,224.97	17,246.00	$	688,637.00	$ 10,878,861.97
Apr-16			332,804.00	$	13,160,914.46	16,513.00	$	699,027.88	$ 13,859,942.34
May-16			133,588.00	$	5,630,125.73	10,341.00	$	413,404.76	$ 6,043,530.49
Jun-16			162,054.00	$	6,295,487.53	8,251.00	$	313,710.81	$ 6,609,198.34
Jul-16			0.00	$	-	0.00	$	-	
Aug-16			0.00	$	-	0.00	$	-	
Sep-16			0.00	$	-	0.00	$	-	
Oct-16			0.00	$	-	0.00	$	-	
Nov-16			0.00	$	-	0.00	$	-	
Dec-16			0.00	$	-	0.00	$	-	
Total-16			1,335,323.00	$	53,833,725.45	65,394.00	$	2,639,461.73	$ 56,473,187.18

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 4 (Other-Paid)
For January 2014 to June 2016

	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-14			0.00	$ -	0.00	$ -	
Feb-14			0.00	$ -	0.00	$ -	
Mar-14			0.00	$ -	39.00	$ 1,156.30	$ 1,156.30
Apr-14			0.00	$ -	44.00	$ 1,274.95	$ 1,274.95
May-14			0.00	$ -	0.00	$ -	
Jun-14			0.00	$ -	0.00	$ -	
Jul-14			0.00	$ -	0.00	$ -	
Aug-14			0.00	$ -	0.00	$ -	
Sep-14			0.00	$ -	0.00	$ -	
Oct-14			0.00	$ -	0.00	$ -	
Nov-14			0.00	$ -	0.00	$ -	
Dec-14			0.00	$ -	0.00	$ -	
Total-14					83.00	$ 2,431.25	$ 2,431.25
Jan-15			0.00	$ -	0.00	$ -	
Feb-15			0.00	$ -	0.00	$ -	
Mar-15			0.00	$ -	0.00	$ -	
Apr-15			0.00	$ -	0.00	$ -	
May-15			0.00	$ -	0.00	$ -	
Jun-15			0.00	$ -	0.00	$ -	
Jul-15			0.00	$ -	0.00	$ -	
Aug-15			0.00	$ -	0.00	$ -	
Sep-15			0.00	$ -	0.00	$ -	
Oct-15			0.00	$ -	0.00	$ -	
Nov-15			0.00	$ -	0.00	$ -	
Dec-15			0.00	$ -	0.00	$ -	
Total-15							
Jan-16			0.00	$ -	0.00	$ -	
Feb-16			0.00	$ -	0.00	$ -	
Mar-16			0.00	$ -	0.00	$ -	
Apr-16			0.00	$ -	0.00	$ -	
May-16			0.00	$ -	0.00	$ -	
Jun-16			0.00	$ -	0.00	$ -	
Jul-16			0.00	$ -	0.00	$ -	
Aug-16			0.00	$ -	0.00	$ -	
Sep-16			0.00	$ -	0.00	$ -	
Oct-16			0.00	$ -	0.00	$ -	
Nov-16			0.00	$ -	0.00	$ -	
Dec-16			0.00	$ -	0.00	$ -	
Total-16							

2015 – 2016 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, an estimate of potential curtailment payments over the next five years, and the assumptions used to develop our forecast.

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 last several 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.

Some of the information in this report will be familiar, because while an event may be reported during a particular AAA period, the recovery and restoration from these events often continues across several AAA periods. Such is the case with work required as a result of a major ice storm that occurred in April 2013 in parts of southwestern Minnesota and eastern South Dakota.

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 along southern Minnesota and all through Iowa.

Significant transmission improvements in southwestern Minnesota and the region such as the CapX2020 transmission projects (CapX2020) are now in-service and will positively impact curtailment by reducing local congestion. However, the Company believes future curtailment in this area will still 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. Congestion, and likely curtailment, will also occur as other companies take transmission facilities out of service to construct new transmission lines such as the MISO Multi-Value Projects (MVPs) discussed later in this report.

To better manage regional congestion, MISO and the industry have implemented DIR reform measures which will provide better management of the wind resources. Under this system, a number of PPA wind facilities that are capable of operating as DIR have been 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. Manual curtailment of non-DIR PPA wind facilities, which were developed prior to DIR reform measures, also continues to be used to manage the wind resources when appropriate.

The existing PPA wind facilities associated with this report that are registered and that operate as DIR are listed in the following table.

Table 1
DIR PPA Facilities

Wind Project	MW
Fenton	200
Prairie Rose	200
MinnDakota	150
Mower County	100
Moraine II	50
Big Blue	36
Valley View	10
Community Wind South (Zephyr)	30

The federal Production Tax Credit (PTC), which provides tax benefits to wind generating plants has been extended again. In the past, the uncertainty of PTC expiration was closely connected with increases in wind curtailment, since wind projects were put into service to meet PTC eligibility requirements even though the necessary transmission upgrades were not completed. The Company is aware of

2,295 MW of wind generation in Minnesota and Iowa that has gone into service over the last couple of years, or that is expected to go into service in 2016. In addition to this generation, the Company is adding 750 MW of Company-owned and PPA wind facilities that went into service in 2015 or will go into service in 2016. MidAmerican Energy[1] has announced they will add 1,600 MW of wind generation in Iowa by the end of 2016 and 2,000 MW of wind in Iowa by 2020. The required transmission upgrades for these wind projects will not all be in-service by the time the projects begin producing energy. This will have a negative effect on LMP pricing in the MISO regional 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 scheduling.

III. Transmission System Improvements

Since 1994, the Company's wind energy resources have been the dominant factor in determining the need for transmission infrastructure improvements in southwestern Minnesota. To meet this need, the Company, often in cooperation with other utilities, has planned, engineered and constructed a number of projects designed to increase the transmission capacity in that area. The following table shows the southwest Minnesota projects that increased the available transmission outlet from 260 MW to the current limit of 1,950 MW.

[1] In May 2013, MidAmerican Energy Company announced plans to develop up to 1,050 MW of wind generation in Iowa by year-end 2015. In May 2015, MidAmerican Energy Company announced plans to develop an additional 552 MW of wind generation by the end of 2016. In May 2016, MidAmerican Energy Company announced plans to develop 2,000 MW of wind generation.[2] Completion of a majority of 425MW transmission facilities, and creation of the SW MN Wind operating guide, allowed the increase of the SW MN Wind limit to 425 MW in October 2004. All 425 MW transmission facilities were completed in December 2006.

Table 2
Southwest Minnesota Wind Limits

Transmission Project	Wind Outlet Increase	SW MN Wind Limit
425 MW Wind Transmission Expansion Project	October 2004[2]	425 MW
825 MW Wind Transmission Expansion Project	December 2007[3]	880 MW
Buffalo Ridge Incremental Generation Outlet (BRIGO)	December 2009[4]	1250 MW
Brookings County - Southeast Twin Cities 345 kV Line	March 2015[5]	1950 MW

The Company is also participating in the development of three CapX2020 transmission projects two of which have been completed and the third will be completed by the end of 2016. These CapX2020 transmission projects, listed below in the following table, will increase transmission capacity and help reduce wind curtailment on the NSP system.

Table 3
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 2015
Fargo North Dakota - Northwest Twin Cities 345 kV Line	Xcel Energy, Great River Energy	April 2015
Southeast Twin Cities - LaCrosse, Wisconsin 345 kV Line	Xcel Energy, SMMPA and non-MISO	Late 2016

[2] Completion of a majority of 425MW transmission facilities, and creation of the SW MN Wind operating guide, allowed the increase of the SW MN Wind limit to 425 MW in October 2004. All 425 MW transmission facilities were completed in December 2006.
[3] Completion of a majority of 825 MW transmission facilities, and update to the SW MN Wind operating guide, allowed the increase to SW MN Wind limit to 880 MW in December 2007. All 825 MW transmission facilities were completed in June 2008.
[4] With the completion of the BRIGO facilities, the southwest Minnesota operating guide no longer uses a total SW MN Wind Limit. The operating guide now includes limits for various facilities. The SW MN Wind limit referenced in this document is an estimate of the total limit.
[5] The CapX2020 Brookings County to Twin Cities 345 kV line increased the transmission limit in southwest Minnesota to an estimated 1,950 MW. The transmission facilities were completed in March 2015.

In addition to transmission projects developed by the Company, MISO has identified and approved several new transmission infrastructure projects including 17 MVPs designed to accommodate the planned and expected generation expansion in the MISO footprint.[6] The completion of the MVP projects, particularly the ones listed in the following table, have or will have a positive impact on Company-owned and PPA wind facilities by decreasing constraints related to curtailments.

Table 4
MVP Projects

Transmission Project	Transmission Owner	Planned/Actual In-Service Date
Pleasant Prairie - Zion Energy Center 345 kV Line	American Transmission Company	December 2013
Big Stone South to Brookings County 345 kV Line	Ottertail Power Company, Xcel Energy	End 2017
Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien County - Kossuth County - Webster 345 kV Line	MidAmerica Energy, ITC Midwest	Mid 2018
North LaCrosse - North Madison	American Transmission Company, Xcel Energy*	End 2018
Winco to Hazleton 345 kV Line	MidAmerica Energy, ITC Midwest	End 2018
Ellendale to Big Stone South 345 kV Line	Ottertail Power Company, Montana Dakota Utilities	End 2019
North Madison - Cardinal - Spring Green - Dubuque area 345 kV Line	American Transmission Company, ITC Midwest	End 2020

* On April 23, 2015, the Wisconsin Commission granted ATC, NSP-Wisconsin, Dairyland Power Cooperative, SMMPA Wisconsin, LLC, and WPPI Energy a Certificate of Public Convenience and Necessity to construct this line.

[6] 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.

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, along with wind purchases for projects on-line or scheduled to come on-line through 2016.

CHART 1
NSP Wind Development
(1993 – 2016)

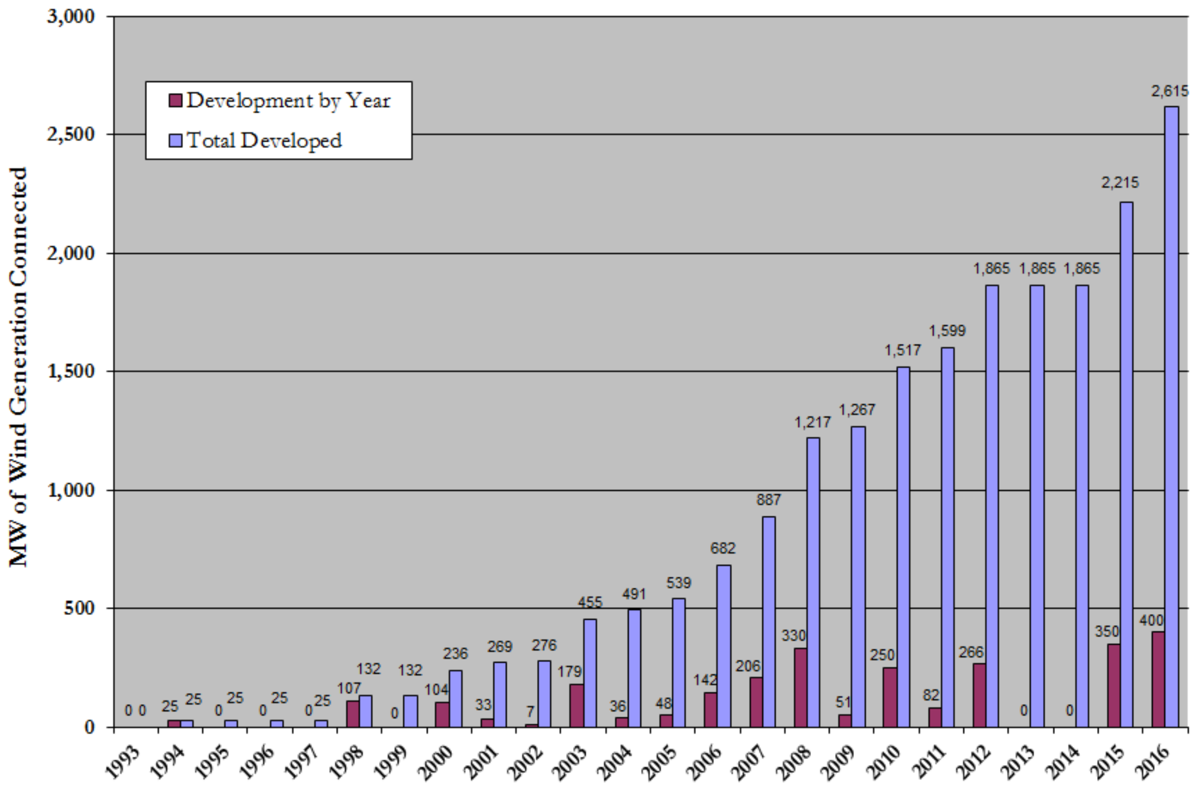
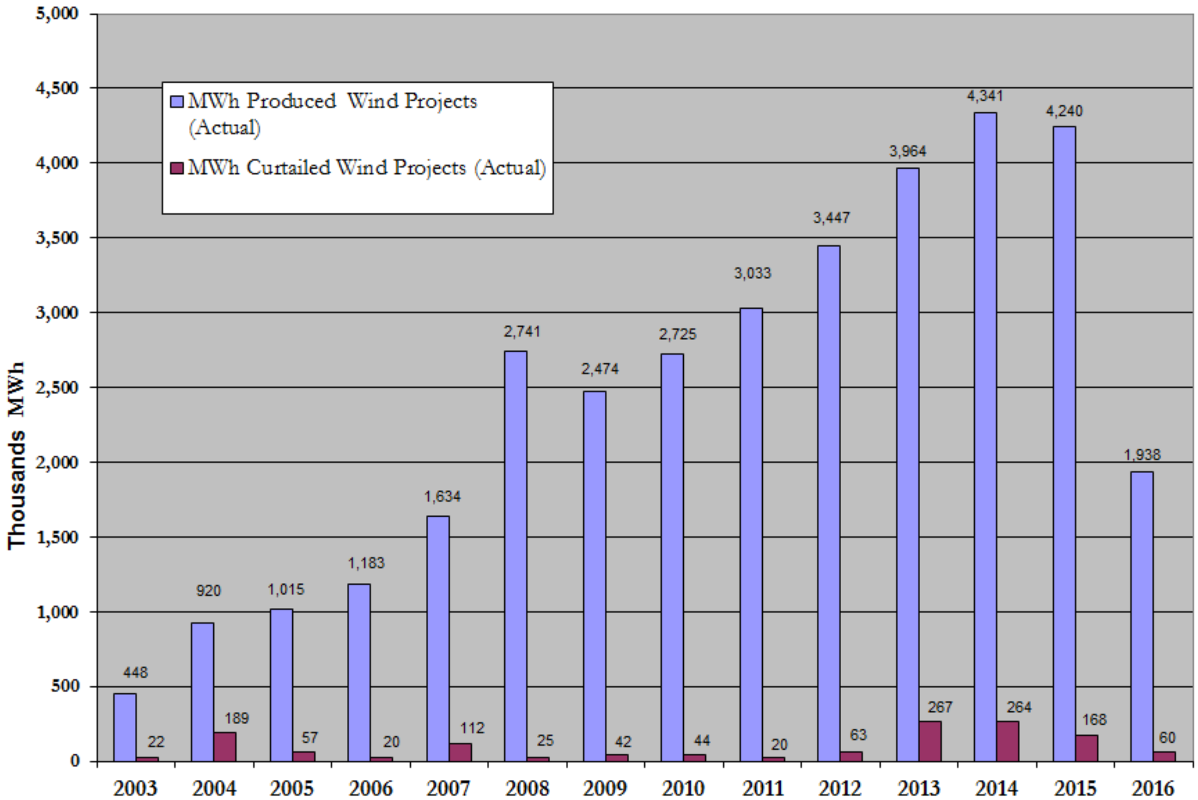


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through May 2016[7]. Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation delivered.

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.

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

Chart 2
NSP Wind Production & Curtailment (MWh)
(2003 – 2015 Full Calendar Years, 2016 Partial Year through May)



Curtailment during July 2015 to June 2016 was broken up into three categories to better explain the reasons for the curtailment and its cause. To support the analysis the Company identified hours during the 2015/2016 fiscal year where transmission-related outages impacted wind projects. During hours where transmission outages did not occur, or where transmission outages did not impact a specific wind farm, the hours were assigned as either manual curtailment or DIR curtailment 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. A total of $5,986,803 in curtailment payments[8] were made during this reporting period for these three categories:

[8] The curtailment analysis in this section used Company data – not AAA Part H, Section 5, Schedule 1 data and included June of 2015.

1) Transmission Events ($1,066,857). This includes storm related repair/restoration on the Split Rock-Nobles County-Lakefield Junction 345 kV lines, Buffalo Ridge 115 kV lines and transformer, feeder breaker and substation outages at the Buffalo Ridge, Chanarambie, Yankee, Fenton and Nobles County substations (Transmission Events);
2) DIR Curtailments Events ($2,481,635) This was driven by negative LMP related reasons; and
3) Manual Curtailments Events ($2,438,311). This was also driven by negative LMP related reasons.

The MWh and curtailment costs determined during the curtailment analysis are compiled in Table 5 and Table 6 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 5
2015/2016 Wind Curtailment MWh

Events	MWh		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	29,494	29,180	314
DIR Curtailment Events	42,133	34,244	7,889
Manual Curtailment Events	79,616	79,616	0
Total	151,242	143,040	8,203

Table 6
2015/2016 Wind Curtailment Costs

Events	Costs		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	$1,066,857	$1,041,828	$25,028
DIR Curtailment Events	$2,481,635	$1,855,379	$626,256
Manual Curtailment Events	$2,438,311	$2,438,311	$0
Total	$5,986,803	$5,335,519	$651,284

As can be seen in Tables 5 and 6, the majority of the curtailment was related to DIR and Manual Curtailment Events. The tables show that the bulk of the curtailment occurred at projects that are no longer eligible for the PTC. Curtailment of the PTC eligible projects, including for Transmission Events, were DIR related, where MISO controls the output. These events can be attributed to regional congestion resulting in negative LMP. The remaining was related to transmission related outages – both planned and unplanned.

It is important to note that of the $5,986,803 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.[9]

Transmission Curtailment Events

Wind curtailment costs totaling $1,066,857 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.

Split Rock – Nobles County – Lakefield Junction 345 kV lines

A severe winter storm the week of April 8, 2013 produced significant, wide-spread icing from Sioux Falls all across southern Minnesota. Unprecedented damage occurred from the combination of ice weight and wind, causing a phenomenon known as 'galloping conductor,'[10] bringing down and/or weakening equipment, conductor and ground wires all along one of the key high-voltage transmission lines

[9] 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.

[10] Conductor gallop is thought to be often caused by asymmetric conductor aerodynamics due to ice build up on one side of a wire, increasing the tendency of the normally round wire profile, to move and oscillate vertically, horizontally or in a rotational manner.

providing electric service support as well as wind generation outlet across the southern portion of Minnesota – the Split Rock-Nobles County-Lakefield Junction 345 kV line. Significant (but temporary) repairs were performed as quickly as possible and the line was placed back into service on May 13, 2013, however, because of the extensive damage, more work was needed and a permanent repair plan was developed. This work continued through the 2014/2015 and 2015/2016 reporting periods.

The Outage of the Split Rock-Nobles County-Lakefield Junction 345 kV line required reductions to the allowable amount of wind generation production that can be injected to the system at the Chanarambie, Fenton and Nobles County substations. Only wind generation connected to these specific substations can be used to manage this transmission event and include: Lake Benton II, Chanarambie Power Partners, Ridgewind, Moraine I, Moraine II, Fenton, and Zephyr.

In addition to developing plans for damage repair, the Company also initiated an effort to proactively identify solutions to the galloping conductor issue and evaluate alternate conductor options for consideration in certain parts of the route where the geographic orientation may combine unfavorably with prevailing winter winds and icing conditions. Additional outages were required in 2014 and 2015 and include activities such as installing various anti-galloping devices, phase spacers and reconductoring especially sensitive areas along the line route. In a preventative effort, the Company has been working in collaboration with the Electric Power Research Institute (EPRI) on ways to mitigate galloping (involving installation of new technology on the 345 kV line in the Split Rock-Lakefield Junction area) and to evaluate various devices and conductor configurations that mitigate galloping. While the EPRI research project is still underway, the Company has implemented a number of findings from the research which include: 1) update Company specifications to require the installation of twisted pair conductors on new transmission facilities in areas that are "highly" prone to galloping; 2) update Company specifications to require the installation of "interphase anti-galloping devices" on new transmission facilities in areas that are prone to galloping; 3) perform cost/benefit analysis to determine if it is cost-effective to reconductor existing transmission facilities with twisted pair conductors, or interphase anti-galloping devices; and 4) implement the most cost effective solution to transmission facilities prone to galloping. The galloping mitigation upgrades have been completed on the Nobles County - Lakefield Junction line section and are scheduled to be performed on the Split Rock – Nobles County line in the 2018 timeframe.

Buffalo Ridge, Chanarambie, Yankee, Fenton and Nobles County Substation Equipment Outages
The Company experienced a number of planned and unplanned outages of transformers and breakers at the Buffalo Ridge, Chanarambie, Yankee, Fenton and Nobles County substations that contributed to curtailment during this period. Rodents caused damage to Nobles County and Chanarambie transformer and breaker cables that required outages to make repairs. Buffalo Ridge, Chanarambie, Yankee, Fenton and Nobles County transformers were taken out of service for scheduled preventative maintenance including North American Electric Reliability Corporation (NERC) relay condition assessments which ensure protective equipment is operating properly. In addition, Buffalo Ridge feeders were taken out of service to allow road work and to repair failed equipment. Only wind generation connected to each specific substation could be used to manage these transmission events. Buffalo Ridge outages could impact Lake Benton I, Lake Benton II and Wind Power Partners 1993. Chanarambie outages could impact Lake Benton II, Chanarambie Power Partners, Ridgewind, Moraine I, and Moraine II. Fenton outages could impact Fenton. Nobles County outages could impact Zephyr Wind.

Curtailment Procedures
The Company has detailed wind curtailment guidelines in place to ensure that wind resources are managed economically and for the reliability of the system, consistent with the terms of the related purchased power contracts. NSP Generation Control and Dispatch strives to minimize total generation costs including the consideration of wind farm curtailment costs and production tax credits. Specific curtailment procedures are in place that take into account how the asset is registered in the MISO Market, whether the wind farm is equipped with setpoint control equipment, which wind farms are registered as DIR, and which are Intermittent. A curtailment matrix has been established and is maintained that lists CP Node location, contract price, compensable curtailment threshold, and curtailment for economics. The list is organized from highest to lowest curtailment threshold, that is, the market price below which it is economic to curtail if curtailment is compensable.

For DIR units, MISO performs a 10-minute forecast every five minutes. This forecast 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 manual curtailment. Non-DIR units are not equipped with setpoint control. When these units must be curtailed, a phone call or e-mail to the wind farm operator is required to initiate a manual curtailment.

DIR Curtailment Events

Wind curtailment costs totaling $2,481,635 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, as well as the higher levels of wind generation present where all required transmission improvements have not been completed.

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.

Manual Curtailment Events

Wind curtailment costs totaling $2,438,311 were due to the Manual Curtailment Events as described below.

Concerning the prudency of non-transmission limited, manual economic, congestion and negative LMP related curtailments, NSP performed an analysis of the economic impact of this curtailment type and determined that the curtailments produced customer economic value by reducing costs by $304,251 as shown in Table 7.

Table 7
Manual Actions Related to Economics
(July 2015 – May 2016)

Connection Node	MWh	Curtailment Benefit $	Average Benefit $/MWh	PTC or No PTC
Chanarambie	18,801	$94,934	$5.05	No PTC
Lake Benton I	25,393	$79,926	$3.15	No PTC
Lake Benton II	18,511	$57,585	$3.11	No PTC
Moraine	8,577	$32,193	$3.75	No PTC
Ridgewind Power Partners	5,630	$24,264	$4.31	No PTC
Wind Power Partners 1993	2,705	$15,350	$5.68	No PTC
Total	79,616	$304,251	$3.82	

To perform this analysis the Company started with estimated hourly averaged curtailment volumes[11] and hourly averaged LMP values for all non-DIR wind farms. The Company then manually subtracted the curtailment volumes for hours that were specifically identified as Transmission Curtailment Events. The resulting hourly curtailment data represents all manual curtailments that were made for economic reasons and not due to a transmission limitation. The hourly curtailment volume for each wind farm was then multiplied by the corresponding hourly LMP for that wind farm to determine the hourly settlement impact of the curtailed wind generation. It is important to note that the bulk of these total costs are associated with the contractual energy price of the PPA. These are contractually obligated sunk costs which are not economically relevant to the decision to curtail the generation from a wind farm. The only economically relevant factor in the decision whether or not to curtail a wind farm is whether the real-time LMP is above or below the dispatch price for the wind farm.

III. Wind Production and Curtailment Payments

Chart 3 shows the corresponding production and curtailment costs through May, 2016[12]. As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

[11] NSP used hourly averaged curtailment data based on the Company's analysis and estimated volumes from curtailment events and not based on the customer submitted invoices. As a result, the data does not perfectly match the curtailment volumes on the customer invoices, which is the basis for the volumes used in the Company's response to Information Request No. DOC-008, Attachment B in Docket No. E002/AA-14-579.

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

Chart 3
NSP Wind Production & Curtailment Payments
(2003 – 2015 Full Calendar Years, 2016 Partial Year through May)

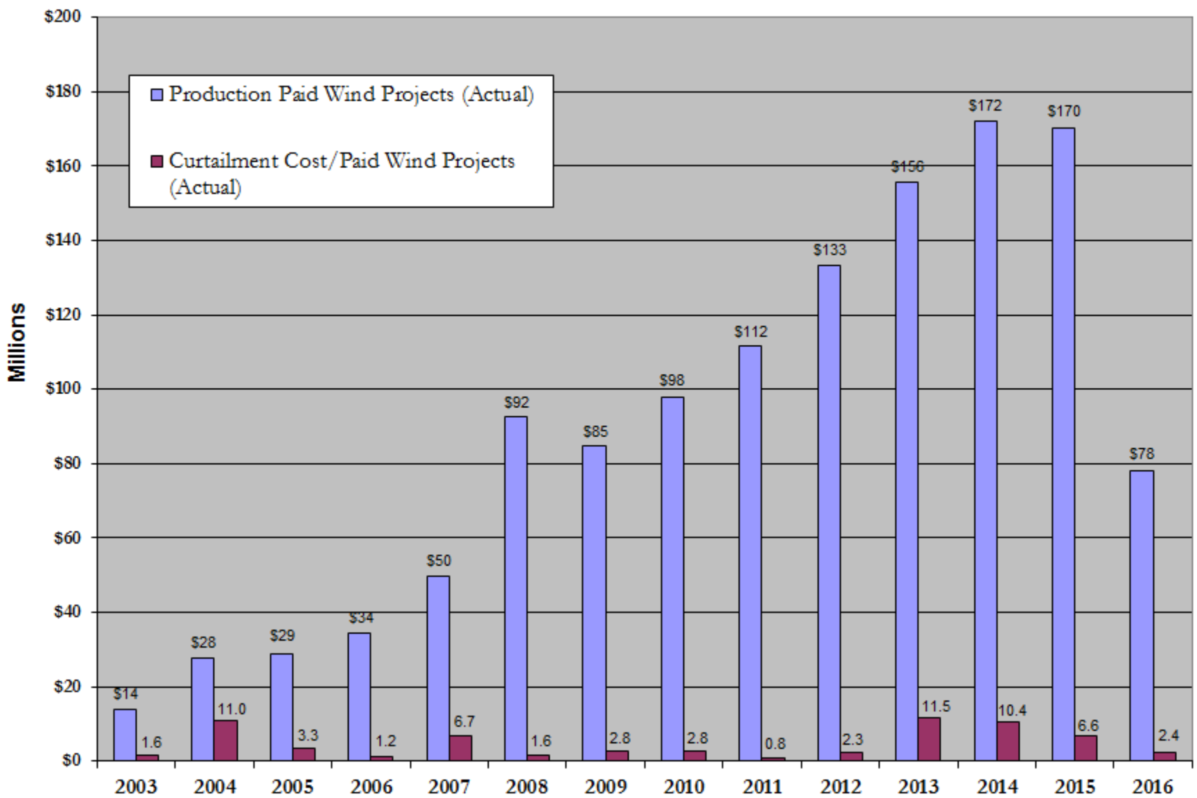
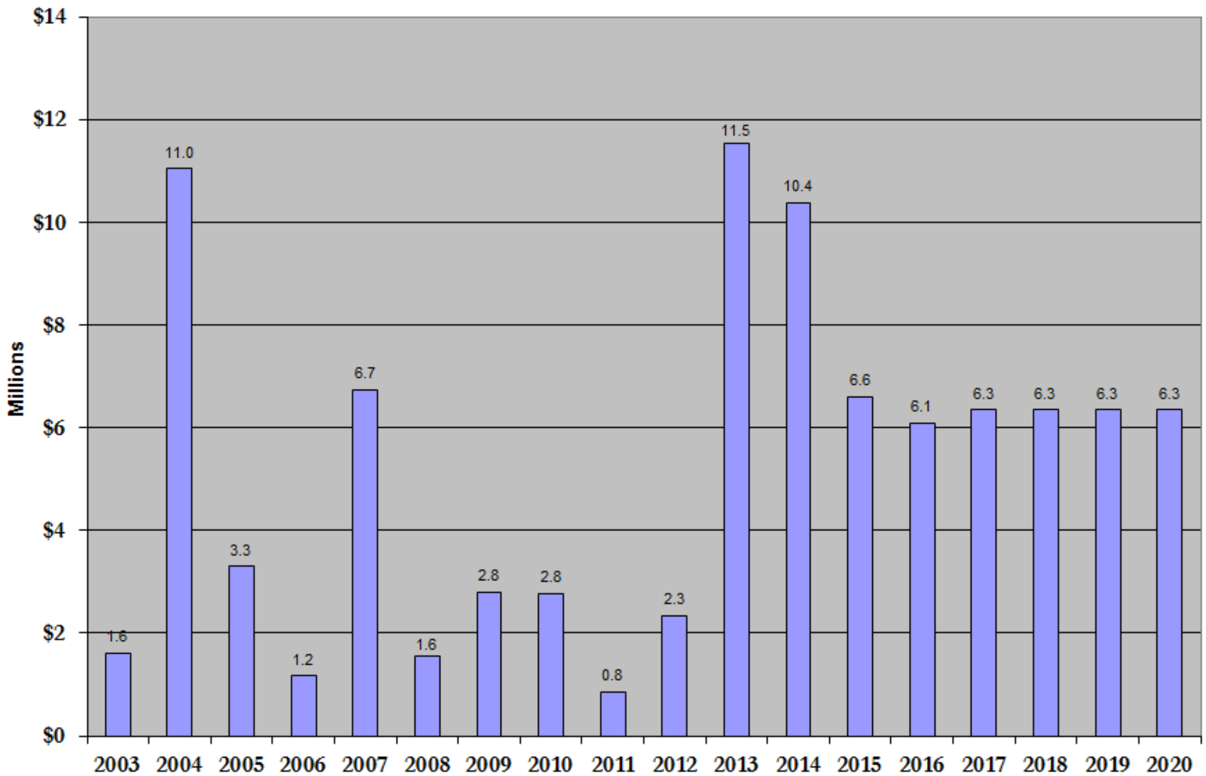


Chart 4 shows the Company's historical wind curtailment costs along with the five-year estimate of future costs[13]. Over the next five years, we anticipate that the wind generation curtailment and associated payments to vendors will result from planned and unplanned transmission outages and negative LMP prices.

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

Chart 4
NSP Wind Curtailment Payments
(2003 –2015 Actual, 2016 – 2020 Projected)



As was the case in the 2014 - 2015 AAA Report, we are projecting future curtailment will occur due to negative LMP events, congestion and transmission outages in the MISO market and have used the average of the last five years of historical curtailment data to project the level of future curtailment. This approach will help capture and reflect ongoing trends with wind and transmission development, as well as the outages necessary for maintenance, repair and construction activity.

Future wind generation additions and completion of the CapX2020 and other MVP transmission projects will likely impact the amount of future curtailment experienced. It is reasonable to expect curtailment levels will be reduced once the new transmission lines are in service. However, there is no certainty as to when, and if, the numerous wind generation projects currently in the development queue will actually come to fruition. As such, the Company did not try to predict the specific impact that future wind generation or completion of the CapX2020 and MVP transmission projects would have on curtailment.

VI. CONCLUSION

The Company anticipates that wind generation curtailment and associated payment to vendors will occur over the next five years as the result of transmission capacity limitations caused by planned and unplanned transmission outages and negative LMP in the MISO energy market. 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.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-523

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

2015-2016 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
July 2015	$807,496.84	87.2593%	84.5789%	$595,956.54
August 2015	$1,062,951.01	87.2593%	84.5789%	$784,489.27
September 2015	$901,588.36	87.2593%	84.5789%	$665,398.86
October 2015	$745,457.61	87.2593%	84.5789%	$550,169.75
November 2015	$795,248.49	87.2593%	84.5789%	$586,916.89
December 2015	$959,469.50	87.2593%	84.5789%	$708,116.85
January 2016	$878,116.44	87.3461%	84.1349%	$645,315.07
February 2016	$799,918.32	87.3461%	84.1349%	$587,848.41
March 2016	$811,493.99	87.3461%	84.1349%	$596,355.20
April 2016	$874,892.74	87.3461%	84.1349%	$642,946.02
May 2016	$879,362.26	87.3461%	84.1349%	$646,230.61
June 2016	$904,475.44	87.3461%	84.1349%	$ 664,685.92
Total	**$10,420,471.00**			**$7,674,429.39**

*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.

2014-2015 AAA Period

Period*	Invoiced Amount (NSP System)	Juris Trans Alloc	Interchange Alloc	MN Jurisdiction Net of Interchange
July 2014	$1,026,757.75	87.5284%	84.7923%	762,032.33
August 2014	$778,766.86	87.5284%	84.7923%	577,980.08
September 2014	$880,193.31	87.5284%	84.7923%	653,256.09
October 2014	$757,951.64	87.5284%	84.7923%	562,531.57
November 2014	$814,082.76	87.5284%	84.7923%	604,190.60
December 2014	$853,407.56	87.5284%	84.7923%	633,376.42
January 2015	$875,014.93	87.2593%	84.5789%	645,786.88
February 2015	$800,794.52	87.2593%	84.5789%	591,010.03
March 2015	$910,150.10	87.2593%	84.5789%	671,717.68
April 2015	$791,689.78	87.2593%	84.5789%	584,290.46
May 2015	$792,038.90	87.2593%	84.5789%	584,548.12
June 2015	$1,114,334.94	87.2593%	84.5789%	822,412.13
Total	**$10,395,183.05**			**$7,693,132.39**

*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 and Northern States Power Company, a Wisconsin corporation (the NSP System).

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

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

The Company allocates costs recorded in these accounts between the NSP-Minnesota and NSP-Wisconsin Companies as well as to NSP-Minnesota jurisdictions

(Minnesota, North Dakota and South Dakota) based on a demand allocator. The Interchange Agreement demand allocator (36 month coincident peak demand) decreased the NSP System allocation to the Company effective January 1, 2014, pursuant to the annual update to the Interchange Agreement allocation factors accepted by FERC in Docket No. ER14-1325-000, letter order dated June 10, 2014. The 2015 Interchange Agreement demand allocator was approved in FERC Docket No. ER15-1575-000, and the letter order approving that filing was issued on June 22, 2015.

The State of Minnesota jurisdictional demand allocator (12 month coincident peak demand) decreased effective January 1, 2014 based on State of Minnesota demands. The net impact of the decrease in the 2014 Interchange Agreement demand allocator and the decrease in the 2014 State of Minnesota jurisdictional demand allocator is an overall decrease in the 2014 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, the2014-2015 amount invoiced for MISO Schedule 10 administrative charges was $10.39 million. The amount invoiced for the 2015-2016 AAA reporting period was$10.42 million.

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

MISO has 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 that will be recovered 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, 2015 to June 30, 2016 , 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 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 "Library" tab at the MISO home page.

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).[1] Mr. Benuning'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 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.

[1] 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.

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 used 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. So 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 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-16-523

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 cost minimization plans for fuel costs	AAA	First reported in Attachment D of 2005-2006 AAA. See Part J, Section 4 for this year's report.
7B	Item 2		Annual FCA forecast and explanation of previous year's forecast deviation (Note: Quarterly for Xcel Energy per FCA Settlement Agreement)	AAA (FCA)	Quarterly FCA forecast of 12-monthly FCA provided to customers who signed the protective agreement since 4th quarter in 2006. Monthly deviation explained in FCA filings and during meeting with customers.[1]
7C	Item 3		Provide to customers who signed protective agreement summary of AAA filing stating key factors affecting costs and update FCA forecast	Same Time as AAA	Separate mailing to customers who signed protective agreement after September AAA filing.
7G			Monthly MISO reporting using format per June 22, 2006 Joint Report and Recommendation, Exhibit D	FCA and AAA	Joint Report format listed in Part J Section 3 Schedule 3 of this AAA report.
		Paragraphs 21, 22 & 24	Provide MISO information according to spreadsheet in DOC IR201 in 2007 AAA		Part J Section 5 Schedule 7 of this AAA report
		Paragraph 18	Actual and budget comparison of generation plant maintenance		Part J Section 6 Schedule 1 of this AAA report

[1] 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.* The Company has conducted the required meetings.

2. Level of Activity in the Real-Time Market

The Company's strategy currently is **[TRADE SECRET BEGINS**

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

TRADE SECRET ENDS].

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

As results 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, *inter alia*, its plans to hedge volatility in fuel and purchased energy costs. This discussion and the following Quarterly Forecast (see next section) will also be provided to interested parties who have signed a protective agreement with the Company.

A. Managing Price Risk Volatility

The Company addresses fuel and purchased power price risk through an integrated analysis of its future costs over the next twelve months. The first step is to develop a forecast of the incremental cost of serving NSP System[2] full requirements customers (e.g., retail and wholesale "native load" customers). This forecast is developed using PLEXOS®, a system dispatch model that optimizes the Company's generation and purchased power portfolio to achieve the lowest expected cost portfolio to serve native load customers. Key inputs for the PLEXOS® model include expected fuel and purchased power costs, planned outages at generation facilities, and expected unplanned outage probabilities at generation facilities. This forecast provides the

[2] As discussed in detail in Docket No. E002/GR-05-1428, the "NSP System" refers to the combined systems of the Company and Northern States Power Company, a Wisconsin corporation (NSPW). The Company and NSPW operate a single integrated generation and transmission system. The NSP System costs are allocated between the Company and NSPW pursuant to the Interchange Agreement.

Company with "buy signals" whereby trading personnel can lower expected costs by purchasing energy at prices below the predicted incremental cost of serving native load customers. These buy signals also address potential price volatility that can occur due to planned and unplanned unit outages, since these potential occurrences are incorporated into the PLEXOS® model.

In a separate analysis, the Company analyzes its Financial Transmission Rights (FTR) position in the MISO market to ensure that the Company is appropriately hedged against congestion cost risk. Additionally, the Company develops a summer hedge plan to address unique risks that typically arise when loads respond to severe summer weather. Finally, the Company reviews its exposure to fuel price risk, which has typically been a long-term challenge issue for the NSP System due to the amount of coal and nuclear energy in our generation fleet. However, the increase in natural gas-fired generation and purchased power in the resource portfolio help mitigate this risk by balancing our portfolio.

A description of all of these activities is provided in greater detail below.

i. Incremental Cost Forecast and Buy Signals

The Company develops an incremental cost forecast for the NSP System using the PLEXOS® model as opportunities for bi-lateral transactions dictate on an as-needed basis. The PLEXOS® model incorporates all key load and resource data, including hourly loads, production costs, and generation resource availability. Thus, key generation unit or scheduled transmission outages are taken into account and are incorporated into the purchase instructions provided to trading personnel.

ii. FTR and Congestion Analysis

The Company operates in the MISO wholesale energy and ASM ancillary services market, which uses security constrained regional dispatch with LMP locational marginal pricing (LMP) and FTRs to provide a hedge against congestion risk. The Company periodically reviews its FTR portfolio to ensure that it is properly hedged against congestion cost risk in the MISO day-ahead market (there is no FTR protection in the real-time market). The Company analyzes key congestion risks between our generation and purchase power nodes and our load nodes to determine the optimal FTR portfolio. The Company has the ability to adjust this portfolio annually through the MISO FTR allocation process and monthly through the FTR auction process. **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]

iii. Fuel Hedging

Xcel Energy's current coal acquisition strategy **[TRADE SECRET BEGINS**

TRADE SECRET ENDS].
Implementation of this strategy **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]
Xcel Energy's strategy is **[TRADE SECRET BEGINS**

TRADE SECRET ENDS] Xcel Energy's coal acquisition strategy also **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]

The Company contracts for natural gas storage to provide operational flexibility and ensure availability of fuel for power plant operations. Storage also provides price certainty during the winter months as gas is purchased and stored during the summer when natural gas prices tend to be less volatile. Gas in storage is projected to cover approximately 69 percent of the 2016-2017 winter gas generation requirements. With such a significant portion of winter requirements covered through the use of storage, the Company does not use financial instruments to hedge natural gas as there could be a risk of being over hedged due to the variability between forecasted and actual natural gas burns.

iv. Outage Management

The Company attempts to schedule maintenance for its generating facilities during periods when energy demand, and prices, is expected to be relatively low. These periods typically occur in the fall and spring when weather conditions are more moderate. Please see the Outage Report in Part K for more information.

B. Summary of 2016 - 2017 Fuel and Purchased Energy Costs

In this section the Company explains the main factors contributing to changes in forecast fuel and purchase power expense for 2017 as compared to actual and forecast costs for 2016, prior to cost adjustment for wholesale sales revenues. Forecast costs for 2017 are projected to be slightly higher than actual costs through April 2016 plus the forecast for the remainder of the year. The total NSP system production for 2017 is projected to be 1.2 percent higher than 2016, and the cost per MWh is projected to increase by approximately 7.9 percent in 2017 versus the blended actual and forecast rate for 2016. NSP System fuel costs for 2017 are projected to increase by about $91.0 million compared to actual and forecast costs for 2016 based on current assumptions.

The cost change between 2016 and 2017 is driven by a number of different factors that are discussed below. For 2017, cost increases for long-term purchased power and solar generation resources are assumed along with higher volumes of natural gas, owned renewables, and nuclear generation. These cost increases are offset by lower purchase volumes and costs paid to MISO due to other changes in the balance of the resources supplying the NSP system.

i. Cost Drivers for Company-Owned Coal Generation

In 2017, fuel costs for the Company's base load coal generating units are expected to increase by approximately $39.7 million due to **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Coal production is forecast to rise by **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in 2017. This small increase is driven by lower assumed coal plant outage days and increased dispatch of coal generation given higher forward natural gas prices in 2017.

ii. Cost Drivers for Company-Owned Nuclear Generation

Compared to 2016, fuel costs for the Company's base load nuclear generating units are expected to increase by approximately $1.3 million on relatively flat generation between 2016 and 2017. The increase in costs is driven by assumed escalation in the contract prices for the components required to manufacture nuclear fuel.

iii. Company-Owned Natural Gas Generation and Prices

Total costs for Company-owned natural gas generation are projected to decrease by $21.7 million due to lower forecast generation of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. As of May 2016, forward prices for natural gas are projected to be 30.6 percent higher for 2017 than 2016. The decrease in natural gas generation is driven by the combination of higher forecast production from coal generation and renewable wind and solar resources.

iv. Company-Owned Renewable Generation

Company owned renewable generation is projected to increase by **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in 2017. This is due to the addition of the 200 MW Courtenay owned wind project late in 2016. Since owned wind is a fuel cost-free resource in the production cost model, additional owned wind generation helps to offset other higher cost resources in 2017.

v. Long-Term Purchase Power Contracts

Costs for purchases of energy from long-term purchase power agreements (PPAs) increase by $71.0 million for 2017 as compared to 2016. This is driven primarily by additions of new wind and solar PPAs that come into service at various times during 2016 but primarily contribute to costs in 2017 as the new PPAs are assumed to be in service for the entire year of 2017. These drivers are discussed in subsections vi. and vii.

Costs for purchases from non-wind and solar PPAs are forecast to increase by $13.9 million. These PPAs are primarily comprised of the Manitoba Hydro PPA, the biomass PPAs, the natural gas PPAs, and other small PPAs. The increase in costs results from typical escalation in contract prices for these PPAs. Offsetting the cost increase due to escalation is a decrease in forecast purchases from these PPAs of **[TRADE SECRET BEGINS TRADE SECRET ENDS].** Fewer purchases from dispatchable natural gas PPAs are the primary contributor as the increase in coal and renewable generation is requiring fewer purchases from natural gas generation PPAs. A secondary impact is from the termination of the Rapidan hydro PPA.

vi. Purchased Wind Generation and Costs

Costs for purchases of energy from long-term wind purchase power contracts are forecast to increase by $10.5 million in 2017 as compared to 2016. This is primarily driven by the addition of the new PPA with the 200 MW Odell wind facility in 2016. More energy is forecast to be purchased in 2017 from Odell than in 2016 as the project is in service for the entire year of 2017 versus a partial year in 2016. The cost per MWh for Odell is lower than many existing wind PPAs and as such the energy purchased from Odell lowers the overall average cost of wind energy in 2017. Price escalation for existing wind PPAs also partially contributes to the overall increase in costs for 2017. In total the forecast assumes an increase in total purchases of wind energy from PPAs of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for 2017.

vii. Purchased Solar Generation and Costs

Costs for purchases of energy from long-term solar purchase power contracts are forecast to increase in 2017 as compared to 2016 by $46.6 million. Solar generation is forecast to increase by **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in 2017. The primary contributors to this increase are three new Solar PPA projects: Aurora, North Star, and Marshall, which are set to go online in late 2016, but primarily contribute to cost increases in 2017 when they are assumed in service for the entire year as opposed to partial service in 2016.

viii. Market Purchases and MISO Forward Prices

For 2017, forecast costs for purchases of energy from the MISO market and other market charges are relatively flat when compared to 2016. MISO prices for 2017 are projected to increase by 17.8 percent in the on-peak and 9.6 percent in the off-peak, as compared to prices for 2016 in response to higher forward natural gas prices. While purchase volumes from MISO are expected to be higher in 2017, they will occur in different hours due to different dispatching resulting in lower costs. Thus, when the market energy charges are added to non-modeled MISO costs, 2017 and 2016 are essentially flat.

C. Other Considerations for the 2017 Forecast

Certain factors may serve to affect a portion of forecast 2017 costs going forward.

For example, the Minnesota jurisdictional share of NSP System wholesale sales margins will continue be credited to customers through the FCA pursuant to the Stipulation and Settlement Agreement on Asset Based Margins (Margins Settlement) in the 2005 rate case.[3] Depending on market conditions, margins from these sales will serve to reduce fuel costs as these margins are credited back to customers through the FCA. However, Asset Based sales are subject to many uncertainties, including higher than normal loads, unforeseen generating plant outages, and market price volatility, which make them prone to change.

In addition, bill credits to community solar gardens customers will be included in the FCA as a cost to non-solar garden customers. This has the potential to increase costs relative to those forecast for 2017.

Finally, there is a significant amount of uncertainty in the many variables impacting fuel and purchased energy costs that could result in materially different costs than are reflected in this filing. For example, market gas and electric prices could rise substantially because of forces or events in the broader markets; the NSP System could experience higher than normal loads resulting in increased dependence on gas generation or purchases; planned and unplanned outages could increase at low cost base load plants, resulting in higher costs for replacement energy; or some combination of all of these could materialize resulting in costs that come in higher than projected in this compliance report. Alternatively, reduced wholesale prices or loads resulting from broader market events (e.g., reduced economic activity) or cooler than normal weather could result in lower costs than projected in this compliance report.

[3] Docket No. E002/GR-05-1428.

QUARTERLY FORECAST OF 12 MONTHLY FCC AND DEVIATION ANALYSIS

During this AAA reporting period, the Company has prepared and distributed four proprietary quarterly forecasts dated October5, 2015 , January8, 2016, April4, 2016 and July 20, 2016 to interested parties who have signed a protective agreement with the Company. These quarterly forecasts are included as Part J, Section 4 Schedule 1. Currently there are 15 representatives of the 2005 electric rate case intervening parties who have signed protective agreements. The Company has been providing the forecast versus actual information, and when necessary, 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 2015 to June 2016 is included in Part J, Section 4 Schedule 2.

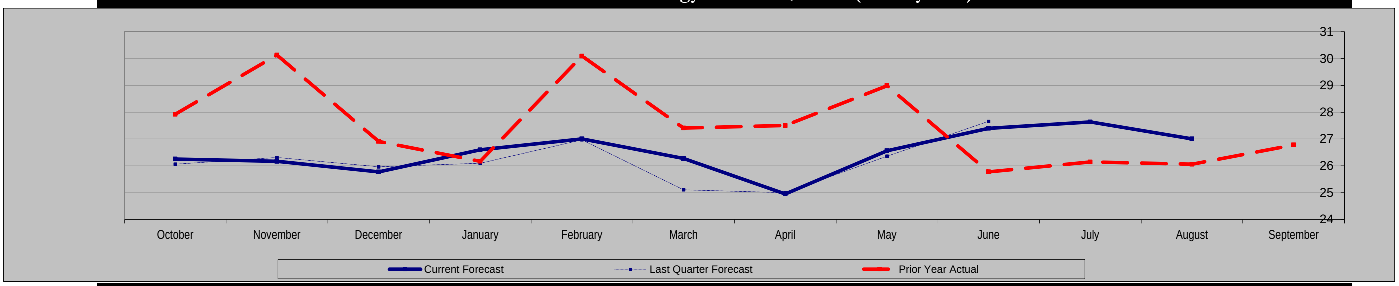
Northern States Power Company
Electric Operations - State of Minnesota

PUBLIC DOCUMENT - WITH TRADE SECRET INFORMATION EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(October 1st, 2015)

[TRADE SECRET BEGINS…

Fuel & Purchased Energy Costs in $/MWh (NSP System)



…TRADE SECRET ENDS]

		Quarterly Forecast				Prior Year			Deviation
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current FCST
October	2015	$26.26	$26.06	0.7%	2014	$27.92	$28.37	-1.6%	6.3%
November	2015	$26.16	$26.31	-0.5%	2014	$30.13	$29.08	3.6%	15.2%
December	2015	$25.77	$25.96	-0.7%	2014	$26.91	$28.84	-6.7%	4.4%
January	2016	$26.60	$26.09	1.9%	2015	$26.17	$28.80	-9.1%	-1.6%
February	2016	$27.00	$26.97	0.1%	2015	$30.09	$28.95	3.9%	11.4%
March	2016	$26.27	$25.11	4.6%	2015	$27.41	$26.51	3.4%	4.3%
April	2016	$24.95	$25.00	-0.2%	2015	$27.50	$28.04	-1.9%	10.2%
May	2016	$26.56	$26.36	0.8%	2015	$28.99	$27.55	5.2%	9.1%
June	2016	$27.40	$27.66	-0.9%	2015	$25.78	$27.59	-6.6%	-5.9%
July	2016	$27.63			2015	$26.14	$28.17	-7.2%	-5.4%
August	2016	$27.01			2015	$26.06	$26.23	-0.6%	-3.5%
		[TRADE SECRET BEGINS…							*[TRADE SECRET BEGINS…*
September	2016				2015 *	$26.78	$26.78	0.0%	
		…TRADE SECRET ENDS							*…TRADE SECRET ENDS*
Average (Unweighted)		$26.51				$27.49	$27.91	-1.5%	3.7%

* From September 2015 FCC Forecast

Forecast Assumption Highlights

[TRADE SECRET BEGINS

Factors impacting costs in the forecast period:
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Other factors potentially contributing to costs in the forecast period:
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…TRADE SECRET ENDS]

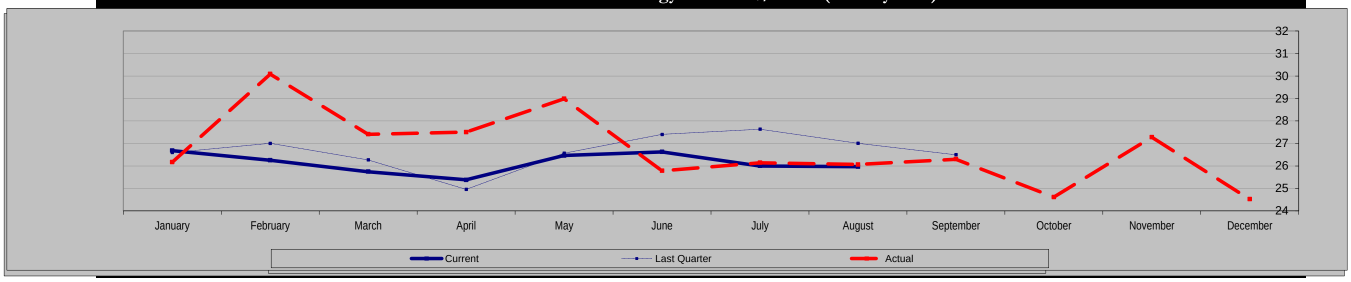
Disclaimer
The forecast of monthly fuel and purchased power costs, in $/MWh, provided in the FCA Forecast are forecasts only. NSP's actual electric rates are linked to the often-unpredictable current market prices for fuel (coal, natural gas, oil, nuclear fuel) and the cost of wholesale energy from third 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.

PUBLIC DOCUMENT - WITH TRADE SECRET INFORMATION EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(January 1st, 2016)

[TRADE SECRET BEGINS…

Fuel & Purchased Energy Costs in $/MWh (NSP System)



…TRADE SECRET ENDS]

		Quarterly Forecast			Prior Year				Deviation
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current FCST
January	2016	$26.68	$26.60	0.3%	2015	$26.17	$28.80	-9.1%	-1.9%
February	2016	$26.25	$27.00	-2.8%	2015	$30.09	$28.95	3.9%	14.6%
March	2016	$25.74	$26.27	-2.0%	2015	$27.41	$26.51	3.4%	6.5%
April	2016	$25.38	$24.95	1.7%	2015	$27.50	$28.04	-1.9%	8.4%
May	2016	$26.46	$26.56	-0.4%	2015	$28.99	$27.55	5.2%	9.6%
June	2016	$26.62	$27.40	-2.8%	2015	$25.78	$27.59	-6.6%	-3.2%
July	2016	$26.00	$27.63	-5.9%	2015	$26.14	$28.17	-7.2%	0.5%
August	2016	$25.96	$27.01	-3.9%	2015	$26.06	$26.23	-0.6%	0.4%
		[TRADE SECRET BEGINS…		*[TRADE SECRET BEGINS…*					*[TRADE SECRET BEGINS…*
September	2016		$26.50		2015	$26.30	$26.78	-1.8%	
October	2016				2015	$24.61	$26.26	-6.3%	
November	2016				2015	$27.28	$25.89	5.4%	
December	2016				2015 *	$24.52	$24.52	0.0%	
		…TRADE SECRET ENDS]		*…TRADE SECRET ENDS]*					*…TRADE SECRET ENDS]*
Average (Unweighted)		$26.14				$26.74	$27.11	-1.4%	2.3%

* From December 2015 FCC Forecast

Forecast Assumption Highlights

[TRADE SECRET BEGINS

Factors impacting costs in the forecast period:
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Other factors potentially contributing to costs in the forecast period:
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…TRADE SECRET ENDS]

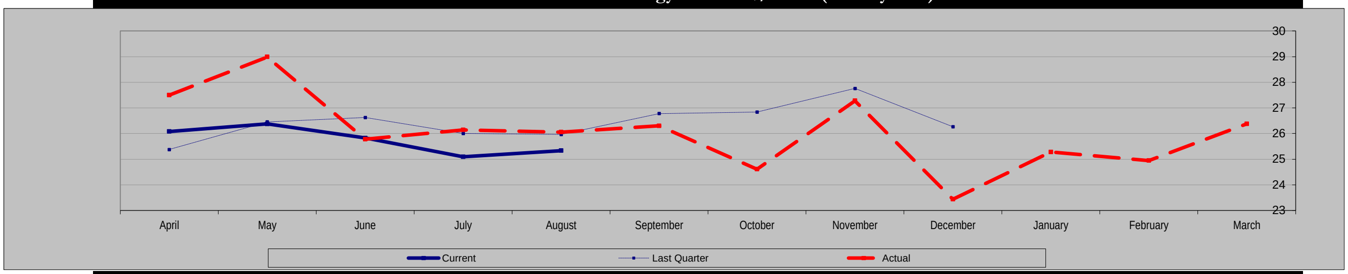
TRADE SECRET ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET INFORMATION EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(April 1st, 2016)

[TRADE SECRET BEGINS…

Fuel & Purchased Energy Costs in $/MWh (NSP System)



…TRADE SECRET ENDS]

		Quarterly Forecast				Prior Year			Deviation
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current FCST
April	2016	$26.08	$25.38	2.8%	2015	$27.50	$28.04	-1.9%	5.4%
May	2016	$26.37	$26.46	-0.3%	2015	$28.99	$27.60	5.0%	9.9%
June	2016	$25.82	$26.62	-3.0%	2015	$25.78	$27.15	-5.0%	-0.2%
July	2016	$25.09	$26.00	-3.5%	2015	$26.14	$28.53	-8.4%	4.2%
August	2016	$25.33	$25.96	-2.4%	2015	$26.06	$26.54	-1.8%	2.9%
		[TRADE SECRET BEGINS…		*[TRADE SECRET BEGINS…*					*[TRADE SECRET BEGINS…*
September	2016		$26.78		2015	$26.30	$27.47	-4.3%	
October	2016		$26.84		2015	$24.61	$26.36	-6.6%	
November	2016		$27.76		2015	$27.28	$27.69	-1.5%	
December	2016		$26.27		2015	$23.44	$26.51	-11.6%	
January	2017				2016	$25.28	$26.51	-4.6%	
February	2017				2016	$24.95	$26.66	-6.4%	
March	2017				2016 *	$26.38	$26.38	0.0%	
		…TRADE SECRET ENDS]		*…TRADE SECRET ENDS]*					*…TRADE SECRET ENDS]*
Average (Unweighted)		$25.74				$26.06	$27.12	-3.9%	1.2%

* From December 2015 FCC Forecast

Forecast Assumption Highlights

[TRADE SECRET BEGINS

Factors impacting costs in the forecast period:
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Other factors potentially contributing to costs in the forecast period:
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…TRADE SECRET ENDS]

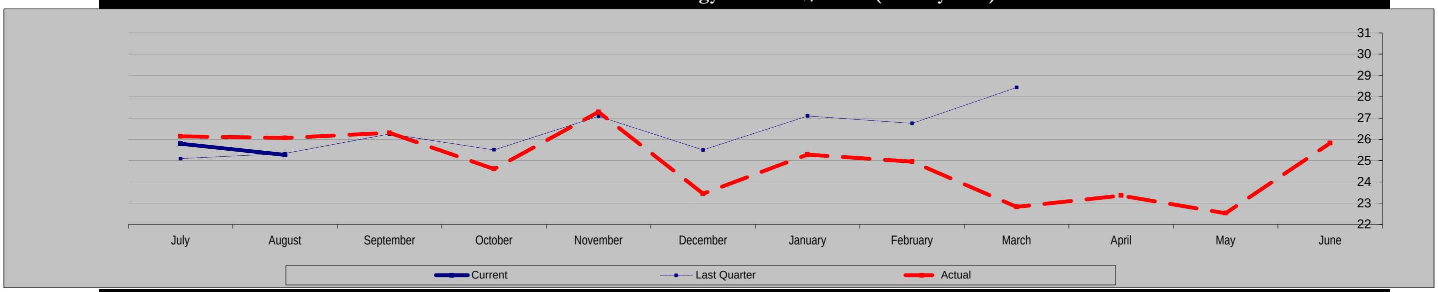
Disclaimer
The forecast of monthly fuel and purchased power costs, in $/MWh, provided in the FCA Forecast are forecasts only. NSP's actual electric rates are linked to the often-unpredictable current market prices for fuel (coal, natural gas, oil, nuclear fuel) and the cost of wholesale energy from third 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.

PUBLIC DOCUMENT - WITH TRADE SECRET INFORMATION EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(July 1st, 2016)

[TRADE SECRET BEGINS…

Fuel & Purchased Energy Costs in $/MWh (NSP System)



…TRADE SECRET ENDS]

		Quarterly Forecast				Prior Year			Deviation
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current FCST
July	**2016**	$25.80	$25.09	2.8%	**2015**	$26.14	$28.17	-7.2%	1.3%
August	**2016**	$25.26	$25.33	-0.3%	**2015**	$26.06	$26.23	-0.6%	3.2%
		[TRADE SECRET BEGINS…		*[TRADE SECRET BEGINS…*					*[TRADE SECRET BEGINS…*
September	**2016**		$26.25		**2015**	$26.30	$26.78	-1.8%	
October	**2016**		$25.51		**2015**	$24.61	$26.26	-6.3%	
November	**2016**		$27.08		**2015**	$27.28	$25.89	5.4%	
December	**2016**		$25.50		**2015**	$23.44	$24.52	-4.4%	
January	**2017**		$27.10		**2016**	$25.28	$26.68	-5.2%	
February	**2017**		$26.75		**2016**	$24.95	$27.03	-7.7%	
March	**2017**		$28.44		**2016**	$22.83	$23.95	-4.7%	
April	**2017**				**2016**	$23.36	$26.08	-10.4%	
May	**2017**				**2016**	$22.53	$26.71	-15.6%	
June	**2017**				**2016 ***	$25.82	$25.82	0.0%	
		…TRADE SECRET DATA ENDS]		*…TRADE SECRET DATA ENDS]*					*…TRADE SECRET DATA ENDS]*
Average (Unweighted)		$25.53				$24.88	$26.18	-4.9%	-2.5%

* From June 2016 FCC Forecast

Forecast Assumption Highlights

[TRADE SECRET BEGINS

Factors impacting costs in the forecast period:
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Other factors potentially contributing to costs in the forecast period:
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…TRADE SECRET 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-16-523
Electric Operations - State of Minnesota | Part J, Section 4
Deviation Analysis | Schedule 2
Actual Costs and Projected Costs (July 2015 - June 2016) | Page 1 of 1

Monthly Forecast & Quarterly Forecast Deviation

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
1	Monthly Forecast - Current Month	2.817¢	2.623¢	2.678¢	2.626¢	2.589¢	2.452¢	2.668¢	2.703¢	2.395¢	2.608¢	2.671¢	2.582¢
		2015 3rd Quarter (7/1/2015)			2015 4th Quarter (10/1/2015)			2016 1st Quarter (1/1/2016)			2016 2nd Quarter (4/1/2016)		
2	Quarterly Forecast - Most Recent Quarter	2.817¢	2.687¢	2.696¢	2.626¢	2.616¢	2.577¢	2.668¢	2.625¢	2.574¢	2.608¢	2.637¢	2.582¢
3	Deviation	0.000	-0.064	-0.018	0.000	-0.027	-0.125	0.000	0.078	-0.179	0.000	0.034	0.000
4	In Percent	0.0%	-2.4%	-0.7%	0.0%	-1.0%	-4.9%	0.0%	3.0%	-7.0%	0.0%	1.3%	0.0%
		2015 2nd Quarter (4/1/2015)			2015 3rd Quarter (7/1/2015)			2015 4th Quarter (10/1/2015)			2016 1st Quarter (1/1/2016)		
5	Quarterly Forecast - Previous Quarter	2.853¢	2.654¢	2.747¢	2.606¢	2.631¢	2.596¢	2.660¢	2.700¢	2.627¢	2.538¢	2.646¢	2.662¢
6	Deviation	-0.036	-0.031	-0.069	0.020	-0.042	-0.144	0.008	0.003	-0.232	0.070	0.025	-0.080
7	In Percent	-1.3%	-1.2%	-2.5%	0.8%	-1.6%	-5.5%	0.3%	0.1%	-8.8%	2.8%	0.9%	-3.0%

Actual and Forecasted Cost Deviation

		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
8	Actual System Costs	2.614¢	2.606¢	2.630¢	2.461¢	2.728¢	2.344¢	2.528¢	2.495¢	2.283¢	2.336¢	2.253¢	2.346¢
9	Forecasted System Costs (From Filing 2 Months Ago)	2.817¢	2.623¢	2.678¢	2.626¢	2.589¢	2.452¢	2.668¢	2.703¢	2.395¢	2.608¢	2.671¢	2.582¢
10	Deviation	-0.203¢	-0.017¢	-0.048¢	-0.165¢	0.139¢	-0.108¢	-0.140¢	-0.208¢	-0.112¢	-0.272¢	-0.418¢	-0.236¢
11	In Percent	-7.2%	-0.6%	-1.8%	-6.3%	5.4%	-4.4%	-5.2%	-7.7%	-4.7%	-10.4%	-15.6%	-9.1%

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	July 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 7,692,379.41	$ 3,591,831.00	$ 11,284,210.41
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,183,357.19	$ (48,824.22)	$ 1,134,532.97
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,283,251.62	$ (135,463.91)	$ 3,147,787.71
1	Day-Ahead Asset Energy Amount	$ 12,158,988.22	$ 3,407,542.87	$ 15,566,531.09
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (5,035.63)		$ (5,035.63)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (70.21)		$ (70.21)
4	Day-Ahead Market Administration Amount	$ 603,358.36	$ (10,041.65)	$ 593,316.71
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,614,280.97)		$ (12,614,280.97)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 329,157.33	$ (13,580.73)	$ 315,576.60
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,251,554.12	$ (51,637.96)	$ 1,199,916.16
5	Day-Ahead Non-Asset Energy Amount	$ (11,033,569.52)	$ (65,218.69)	$ (11,098,788.21)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 5,035.63		$ 5,035.63
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 70.21		$ 70.21
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	$ 153,978.86	$ (6,353.02)	$ 147,625.84
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (22,281.74)	$ (1,739.35)	$ (24,021.09)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 574,075.32	$ 1,089,671.94	$ 1,663,747.26
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 128,797.38	$ (5,314.06)	$ 123,483.32
13 c	Real-Time Asset Energy Amount - Loss Component	$ 50,389.81	$ (2,079.04)	$ 48,310.77
13	Real-Time Asset Energy Amount	$ 753,262.51	$ 1,082,278.84	$ 1,835,541.35
14	Real-Time Distribution of Losses Amount	$ (1,618,305.61)		$ (1,618,305.61)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 1.00		$ 1.00
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 0.07		$ 0.07
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1.00)		$ (1.00)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (0.07)		$ (0.07)
19	Real-Time Market Administration Amount	$ 35,141.17	$ (2,812.19)	$ 32,328.98
20	Real-Time Miscellaneous Amount	$ (47,233.47)	$ 40,902.19	$ (6,331.28)
21	Real-time Net inadvertent Distribution	$ (43,696.74)		$ (43,696.74)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 401,830.71		$ 401,830.71
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 297.79	$ (12.29)	$ 285.50
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,138.44)	$ 46.97	$ (1,091.47)
22	Real-Time Non-Asset Energy Amount	$ 400,990.06	$ 34.68	$ 401,024.74
23	Real-Time Revenue Neutrality Uplift Amount	$ 390,146.59	$ (8,143.95)	$ 382,002.64
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 197,385.63	$ (16,097.09)	$ 181,288.54
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (82,384.43)	$ 35,469.81	$ (46,914.62)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,393,667.94)	$ -	$ (1,393,667.94)
29	Financial Transmission Rights Market Administration Amount	$ 26,067.44	$ -	$ 26,067.44
30	Financial Transmission Rights Monthly Allocation Amount	$ (99,094.55)		$ (99,094.55)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 87,199.99	$ (1,443.05)	$ 85,756.94
34	Real -Time Schedule 24 Allocation Amount	$ (98,216.85)	$ 120,388.25	$ 22,171.40
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (58,202.42)		$ (58,202.42)
37	Financial Transmission Guarantee Uplift Amount	$ 55,575.36		$ 55,575.36
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,516,999.68		$ 3,516,999.68
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,588,338.38)	$ -	$ (3,588,338.38)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (83,283.16)		$ (83,283.16)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 67,063.94		$ 67,063.94
43	Real Time Price Volatility Make Whole Payment	$ (237,766.76)	$ 11,019.53	$ (226,747.23)
	TOTAL MISO CHARGES	**$ 40,116.24**	**$ 4,585,787.19**	**$ 4,625,903.43**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 651,713.13**
	SCHEDULE 24 (FOR RETAIL)			**$ 107,928.34**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,866,261.96**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	August 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 10,278,133.89	$ 4,354,104.31	$ 14,632,238.20
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,747,104.92	$ (142,048.93)	$ 2,605,055.99
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,835,603.89	$ (146,625.09)	$ 2,688,978.80
1	Day-Ahead Asset Energy Amount	$ 15,860,842.70	$ 4,065,430.30	$ 19,926,273.00
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,770.96		$ 4,770.96
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (179.30)		$ (179.30)
4	Day-Ahead Market Administration Amount	$ 542,745.68	$ (11,766.12)	$ 530,979.56
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,838,109.40)		$ (11,838,109.40)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 653,486.41	$ (33,790.86)	$ 619,695.55
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,347,824.92	$ (69,694.13)	$ 1,278,130.79
5	Day-Ahead Non-Asset Energy Amount	$ (9,836,798.07)	$ (103,484.99)	$ (9,940,283.06)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,770.96)		$ (4,770.96)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 179.30		$ 179.30
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	$ 111,277.01	$ (5,753.98)	$ 105,523.03
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (50,206.19)	$ 8,687.42	$ (41,518.77)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 974,556.75	$ 1,004,003.84	$ 1,978,560.59
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 201,610.41	$ (10,424.99)	$ 191,185.42
13 c	Real-Time Asset Energy Amount - Loss Component	$ 28,539.58	$ (1,475.74)	$ 27,063.84
13	Real-Time Asset Energy Amount	$ 1,204,706.74	$ 992,103.11	$ 2,196,809.85
14	Real-Time Distribution of Losses Amount	$ (1,557,344.15)		$ (1,557,344.15)
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	$ 36,294.41	$ (2,691.51)	$ 33,602.90
20	Real-Time Miscellaneous Amount	$ (40,469.85)	$ 42,258.91	$ 1,789.06
21	Real-time Net inadvertent Distribution	$ 7,060.53		$ 7,060.53
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 18,844.12		$ 18,844.12
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (713.91)	$ 36.92	$ (676.99)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (882.25)	$ 45.62	$ (836.63)
22	Real-Time Non-Asset Energy Amount	$ 17,247.96	$ 82.54	$ 17,330.50
23	Real-Time Revenue Neutrality Uplift Amount	$ 498,449.63	$ (11,730.37)	$ 486,719.26
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 226,855.29	$ (25,774.13)	$ 201,081.16
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (119,088.00)	$ 51,979.48	$ (67,108.52)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,116,717.17)	$ -	$ (3,116,717.17)
29	Financial Transmission Rights Market Administration Amount	$ 33,650.16	$ -	$ 33,650.16
30	Financial Transmission Rights Monthly Allocation Amount	$ (253,555.01)		$ (253,555.01)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 83,182.21	$ (1,801.03)	$ 81,381.18
34	Real -Time Schedule 24 Allocation Amount	$ (99,721.35)	$ 104,868.28	$ 5,146.93
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (123,309.40)		$ (123,309.40)
37	Financial Transmission Guarantee Uplift Amount	$ 115,322.48		$ 115,322.48
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,516,999.68		$ 3,516,999.68
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,588,338.38)	$ -	$ (3,588,338.38)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (92,074.58)		$ (92,074.58)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 66,234.82		$ 66,234.82
43	Real Time Price Volatility Make Whole Payment	$ (213,755.26)	$ 7,821.08	$ (205,934.18)
	TOTAL MISO CHARGES	**$ 3,229,491.89**	**$ 5,110,228.98**	**$ 8,339,720.87**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 598,232.62**
	SCHEDULE 24 (FOR RETAIL)			**$ 86,528.11**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,654,960.14**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	September 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 6,386,106.36	$ 5,544,813.92	$ 11,930,920.28
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 5,490,819.21	$ (426,037.17)	$ 5,064,782.04
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,644,294.03	$ (205,172.95)	$ 2,439,121.08
1	Day-Ahead Asset Energy Amount	$ 14,521,219.60	$ 4,913,603.80	$ 19,434,823.40
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 17,359.37		$ 17,359.37
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,269.94		$ 3,269.94
4	Day-Ahead Market Administration Amount	$ 551,580.38	$ (15,954.74)	$ 535,625.64
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,378,475.04)		$ (11,378,475.04)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,012,893.58	$ (78,591.25)	$ 934,302.33
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,021,615.40	$ (79,267.98)	$ 942,347.42
5	Day-Ahead Non-Asset Energy Amount	$ (9,343,966.06)	$ (157,859.22)	$ (9,501,825.28)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (17,359.37)		$ (17,359.37)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,269.94)		$ (3,269.94)
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	$ 117,657.19	$ (9,129.12)	$ 108,528.07
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (108,124.53)	$ 50,832.92	$ (57,291.61)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (517,359.41)	$ 1,757,695.13	$ 1,240,335.72
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 144,299.24	$ (11,196.30)	$ 133,102.94
13 c	Real-Time Asset Energy Amount - Loss Component	$ 57,163.18	$ (4,435.34)	$ 52,727.84
13	Real-Time Asset Energy Amount	$ (315,896.99)	$ 1,742,063.50	$ 1,426,166.51
14	Real-Time Distribution of Losses Amount	$ (1,226,063.07)		$ (1,226,063.07)
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	$ 38,029.43	$ (5,571.65)	$ 32,457.78
20	Real-Time Miscellaneous Amount	$ (63,780.52)	$ 33,304.72	$ (30,475.80)
21	Real-time Net inadvertent Distribution	$ 9,693.52		$ 9,693.52
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,595.58		$ 8,595.58
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (1,621.78)	$ 125.84	$ (1,495.94)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (621.95)	$ 48.26	$ (573.69)
22	Real-Time Non-Asset Energy Amount	$ 6,351.85	$ 174.09	$ 6,525.94
23	Real-Time Revenue Neutrality Uplift Amount	$ 529,022.80	$ (31,428.28)	$ 497,594.52
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 405,051.46	$ (41,047.31)	$ 364,004.15
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (307,907.79)	$ 138,699.53	$ (169,208.26)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,806,681.63)	$ -	$ (3,806,681.63)
29	Financial Transmission Rights Market Administration Amount	$ 25,266.24	$ -	$ 25,266.24
30	Financial Transmission Rights Monthly Allocation Amount	$ (318,211.73)		$ (318,211.73)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 87,805.56	$ (2,534.81)	$ 85,270.75
34	Real -Time Schedule 24 Allocation Amount	$ (95,065.04)	$ 100,032.99	$ 4,967.95
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (68,287.15)		$ (68,287.15)
37	Financial Transmission Guarantee Uplift Amount	$ 72,603.84		$ 72,603.84
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,850,841.75		$ 2,850,841.75
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,859,231.18)	$ -	$ (2,859,231.18)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (400,833.24)		$ (400,833.24)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 101,528.16		$ 101,528.16
43	Real Time Price Volatility Make Whole Payment	$ (255,207.60)	$ 12,911.09	$ (242,296.51)
	TOTAL MISO CHARGES	**$ 147,395.25**	**$ 6,728,097.51**	**$ 6,875,492.76**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 593,349.66**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,238.70**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,191,904.40**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	October 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,632,816.97	$ 7,235,721.75	$ 8,868,538.72
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,465,996.27	$ (173,165.46)	$ 1,292,830.81
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,268,303.51	$ (267,935.07)	$ 2,000,368.44
1	Day-Ahead Asset Energy Amount	$ 5,367,116.75	$ 6,794,621.22	$ 12,161,737.97
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,231.39)		$ (8,231.39)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (380.42)		$ (380.42)
4	Day-Ahead Market Administration Amount	$ 539,384.60	$ (28,312.03)	$ 511,072.57
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (10,360,122.10)		$ (10,360,122.10)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,625,945.01	$ (192,058.82)	$ 1,433,886.19
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,077,313.93	$ (127,253.78)	$ 950,060.15
5	Day-Ahead Non-Asset Energy Amount	$ (7,656,863.16)	$ (319,312.59)	$ (7,976,175.75)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,231.39		$ 8,231.39
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 380.42		$ 380.42
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	$ 119,650.77	$ (14,133.31)	$ 105,517.46
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (191,308.74)	$ 16,040.55	$ (175,268.19)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (175,137.66)	$ 787,375.84	$ 612,238.18
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 39,650.00	$ (4,683.51)	$ 34,966.49
13 c	Real-Time Asset Energy Amount - Loss Component	$ (9,133.89)	$ 1,078.91	$ (8,054.98)
13	Real-Time Asset Energy Amount	$ (144,621.55)	$ 783,771.24	$ 639,149.69
14	Real-Time Distribution of Losses Amount	$ (738,769.12)		$ (738,769.12)
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	$ 36,784.13	$ (3,895.07)	$ 32,889.06
20	Real-Time Miscellaneous Amount	$ 28,587.50	$ (8,805.23)	$ 19,782.27
21	Real-time Net inadvertent Distribution	$ (41,932.81)		$ (41,932.81)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 56,481.99		$ 56,481.99
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (8,547.94)	$ 1,009.69	$ (7,538.25)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (4,725.75)	$ 558.21	$ (4,167.54)
22	Real-Time Non-Asset Energy Amount	$ 43,208.30	$ 1,567.91	$ 44,776.21
23	Real-Time Revenue Neutrality Uplift Amount	$ 376,490.64	$ (19,009.43)	$ 357,481.21
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 160,931.36	$ (44,471.58)	$ 116,459.78
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (144,093.10)	$ 54,353.72	$ (89,739.38)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,522,933.66)	$ -	$ (1,522,933.66)
29	Financial Transmission Rights Market Administration Amount	$ 22,747.52	$ -	$ 22,747.52
30	Financial Transmission Rights Monthly Allocation Amount	$ (69,809.70)		$ (69,809.70)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 80,474.18	$ (4,222.77)	$ 76,251.41
34	Real -Time Schedule 24 Allocation Amount	$ (88,264.19)	$ 100,235.76	$ 11,971.57
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 131,266.47		$ 131,266.47
37	Financial Transmission Guarantee Uplift Amount	$ (127,112.24)		$ (127,112.24)
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,850,841.75		$ 2,850,841.75
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,859,231.18)	$ -	$ (2,859,231.18)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (406,713.43)		$ (406,713.43)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 101,942.72		$ 101,942.72
43	Real Time Price Volatility Make Whole Payment	$ (394,320.32)	$ 23,728.10	$ (370,592.22)
	TOTAL MISO CHARGES	**$ (4,526,546.51)**	**$ 7,332,156.48**	**$ 2,805,609.97**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 566,709.15**
	SCHEDULE 24 (FOR RETAIL)			**$ 88,222.98**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,150,677.84**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	November 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 4,857,047.65	$ 2,263,598.27	$ 7,120,645.92
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,945,799.48	$ (94,511.25)	$ 1,851,288.23
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,308,182.43	$ (112,112.89)	$ 2,196,069.54
1	Day-Ahead Asset Energy Amount	$ 9,111,029.56	$ 2,056,974.13	$ 11,168,003.69
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (10,146.47)		$ (10,146.47)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 563.53		$ 563.53
4	Day-Ahead Market Administration Amount	$ 543,492.38	$ (9,845.09)	$ 533,647.29
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,967,760.53)		$ (5,967,760.53)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,563,305.22	$ (75,932.76)	$ 1,487,372.46
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 588,179.30	$ (28,569.01)	$ 559,610.29
5	Day-Ahead Non-Asset Energy Amount	$ (3,816,276.01)	$ (104,501.77)	$ (3,920,777.78)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 10,146.47		$ 10,146.47
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (563.53)		$ (563.53)
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	$ 72,414.94	$ (3,517.33)	$ 68,897.61
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (75,184.36)	$ 450.45	$ (74,733.91)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 10,824.40	$ 895,920.02	$ 906,744.42
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 75,881.98	$ (3,685.73)	$ 72,196.25
13 c	Real-Time Asset Energy Amount - Loss Component	$ 6,064.00	$ (294.54)	$ 5,769.46
13	Real-Time Asset Energy Amount	$ 92,770.38	$ 891,939.74	$ 984,710.12
14	Real-Time Distribution of Losses Amount	$ (980,115.94)		$ (980,115.94)
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	$ 46,295.87	$ (4,135.12)	$ 42,160.75
20	Real-Time Miscellaneous Amount	$ 13,749.29	$ 12,121.76	$ 25,871.05
21	Real-time Net inadvertent Distribution	$ (70,807.91)		$ (70,807.91)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (0.73)		$ (0.73)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 64.32	$ (3.12)	$ 61.20
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (63.60)	$ 3.09	$ (60.51)
22	Real-Time Non-Asset Energy Amount	$ (0.01)	$ (0.03)	$ (0.04)
23	Real-Time Revenue Neutrality Uplift Amount	$ 776,563.16	$ (4,314.32)	$ 772,248.84
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 88,823.29	$ (37,719.18)	$ 51,104.11
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 26,552.33	$ 782.26	$ 27,334.59
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,381,013.39)	$ -	$ (1,381,013.39)
29	Financial Transmission Rights Market Administration Amount	$ 19,141.60	$ -	$ 19,141.60
30	Financial Transmission Rights Monthly Allocation Amount	$ (100,477.08)		$ (100,477.08)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 82,305.92	$ (1,497.10)	$ 80,808.82
34	Real -Time Schedule 24 Allocation Amount	$ (95,092.03)	$ 87,727.71	$ (7,364.32)
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (293,392.53)		$ (293,392.53)
37	Financial Transmission Guarantee Uplift Amount	$ 295,869.36		$ 295,869.36
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,850,841.75		$ 2,850,841.75
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,859,231.18)	$ -	$ (2,859,231.18)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (406,713.43)		$ (406,713.43)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 101,942.72		$ 101,942.72
43	Real Time Price Volatility Make Whole Payment	$ (204,581.14)	$ 42,770.37	$ (161,810.77)
	TOTAL MISO CHARGES	**$ 3,838,907.54**	**$ 2,927,236.48**	**$ 6,766,144.02**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 594,949.64**
	SCHEDULE 24 (FOR RETAIL)			**$ 73,444.50**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,097,749.88**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	December 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (3,161,849.70)	$ 7,138,201.73	$ 3,976,352.03
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,259,584.78	$ (135,699.55)	$ 1,123,885.23
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,276,066.79	$ (245,208.78)	$ 2,030,858.01
1	Day-Ahead Asset Energy Amount	$ 373,801.87	$ 6,757,293.40	$ 7,131,095.27
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,423.75		$ 4,423.75
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,891.51		$ 2,891.51
4	Day-Ahead Market Administration Amount	$ 594,528.51	$ (29,955.39)	$ 564,573.12
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,904,338.05)		$ (5,904,338.05)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 676,085.05	$ (72,837.05)	$ 603,248.00
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 431,685.77	$ (46,507.05)	$ 385,178.72
5	Day-Ahead Non-Asset Energy Amount	$ (4,796,567.23)	$ (119,344.10)	$ (4,915,911.33)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,423.75)		$ (4,423.75)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,891.51)		$ (2,891.51)
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	$ 44,692.68	$ (4,814.90)	$ 39,877.78
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (160,724.75)	$ 19,411.64	$ (141,313.11)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (35,573.90)	$ 790,783.22	$ 755,209.32
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 3,338.29	$ (359.65)	$ 2,978.64
13 c	Real-Time Asset Energy Amount - Loss Component	$ (1,960.06)	$ 211.16	$ (1,748.90)
13	Real-Time Asset Energy Amount	$ (34,195.67)	$ 790,634.74	$ 756,439.07
14	Real-Time Distribution of Losses Amount	$ (687,512.97)		$ (687,512.97)
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	$ 52,570.68	$ (3,278.41)	$ 49,292.27
20	Real-Time Miscellaneous Amount	$ 1,072,002.52	$ 52,588.75	$ 1,124,591.27
21	Real-time Net inadvertent Distribution	$ (40,441.71)		$ (40,441.71)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 505.06		$ 505.06
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (0.18)	$ 0.02	$ (0.16)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 4.02	$ (0.43)	$ 3.59
22	Real-Time Non-Asset Energy Amount	$ 508.90	$ (0.41)	$ 508.49
23	Real-Time Revenue Neutrality Uplift Amount	$ 478,236.54	$ (7,470.29)	$ 470,766.25
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 69,340.38	$ (51,522.13)	$ 17,818.25
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (3,854.63)	$ 1,886.63	$ (1,968.00)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (992,388.90)	$ -	$ (992,388.90)
29	Financial Transmission Rights Market Administration Amount	$ 27,410.96	$ -	$ 27,410.96
30	Financial Transmission Rights Monthly Allocation Amount	$ (91,420.53)		$ (91,420.53)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 86,505.76	$ (4,282.16)	$ 82,223.60
34	Real -Time Schedule 24 Allocation Amount	$ (92,003.82)	$ 108,803.14	$ 16,799.32
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (18,226.83)		$ (18,226.83)
37	Financial Transmission Guarantee Uplift Amount	$ 4,048.29		$ 4,048.29
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,770,129.38		$ 3,770,129.38
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,771,745.17)	$ 9,706.72	$ (3,762,038.45)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (186,462.01)		$ (186,462.01)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 66,371.33		$ 66,371.33
43	Real Time Price Volatility Make Whole Payment	$ (239,720.33)	$ 11,633.29	$ (228,087.04)
	TOTAL MISO CHARGES	**$ (4,475,116.75)**	**$ 7,531,290.52**	**$ 3,056,173.77**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 641,276.35**
	SCHEDULE 24 (FOR RETAIL)			**$ 99,022.92**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,315,874.50**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	January 2016 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,058,567.50	$ 4,942,322.68	$ 6,000,890.18
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,014,802.89	$ (72,979.33)	$ 941,823.56
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,885,053.71	$ (207,478.02)	$ 2,677,575.69
1	Day-Ahead Asset Energy Amount	$ 4,958,424.10	$ 4,661,865.32	$ 9,620,289.42
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,928.72	$ -	$ 1,928.72
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,425.24	$ -	$ 3,425.24
4	Day-Ahead Market Administration Amount	$ 629,120.42	$ (17,932.66)	$ 611,187.76
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,524,620.37)	$ -	$ (6,524,620.37)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 328,700.35	$ (23,638.42)	$ 305,061.93
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 498,934.65	$ (35,880.78)	$ 463,053.87
5	Day-Ahead Non-Asset Energy Amount	$ (5,696,985.37)	$ (59,519.20)	$ (5,756,504.57)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,928.72)	$ -	$ (1,928.72)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,425.24)	$ -	$ (3,425.24)
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	$ 85,143.26	$ (6,123.06)	$ 79,020.20
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (161,378.93)	$ 26,336.73	$ (135,042.20)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 598,900.77	$ 1,188,959.01	$ 1,787,859.78
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (9,139.67)	$ 0.58	$ (9,139.09)
13 c	Real-Time Asset Energy Amount - Loss Component	$ (4,407.52)	$ 0.37	$ (4,407.15)
13	Real-Time Asset Energy Amount	$ 585,353.58	$ 1,188,959.95	$ 1,774,313.53
14	Real-Time Distribution of Losses Amount	$ (1,483,744.46)	$ -	$ (1,483,744.46)
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	$ 46,128.84	$ (5,387.46)	$ 40,741.38
20	Real-Time Miscellaneous Amount	$ (56,138.65)	$ 17,534.72	$ (38,603.93)
21	Real-time Net inadvertent Distribution	$ (192,702.88)	$ -	$ (192,702.88)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 13.15	$ -	$ 13.15
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (8.04)	$ (16.47)	$ (24.51)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (5.09)	$ (911.01)	$ (916.10)
22	Real-Time Non-Asset Energy Amount	$ 0.02	$ (927.47)	$ (927.45)
23	Real-Time Revenue Neutrality Uplift Amount	$ 847,747.47	$ (60,965.58)	$ 786,781.89
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 61,556.02	$ (4,426.79)	$ 57,129.23
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (30,005.93)	$ (14,822.44)	$ (44,828.37)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (598,278.53)	$ -	$ (598,278.53)
29	Financial Transmission Rights Market Administration Amount	$ 27,851.04	$ -	$ 27,851.04
30	Financial Transmission Rights Monthly Allocation Amount	$ (11,899.73)	$ -	$ (11,899.73)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 86,365.51	$ (2,439.52)	$ 83,925.99
34	Real -Time Schedule 24 Allocation Amount	$ (101,463.72)	$ 96,815.23	$ (4,648.49)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 73,446.38	$ -	$ 73,446.38
37	Financial Transmission Guarantee Uplift Amount	$ (72,033.63)	$ -	$ (72,033.63)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,770,129.38	$ -	$ 3,770,129.38
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,771,745.17)	$ 52,033.25	$ (3,719,711.92)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (187,052.38)	$ -	$ (187,052.38)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 66,371.33	$ -	$ 66,371.33
43	Real Time Price Volatility Make Whole Payment	$ (106,348.56)	$ 20,187.20	$ (86,161.36)
	TOTAL MISO CHARGES	**$ (1,232,140.59)**	**$ 5,891,188.23**	**$ 4,659,047.64**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 679,780.18**
	SCHEDULE 24 (FOR RETAIL)			**$ 79,277.50**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,899,989.96**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	February 2016 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 3,035,356.88	$ 5,187,954.01	$ 8,223,310.89
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 767,967.04	$ (69,037.75)	$ 698,929.29
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,308,250.90	$ (207,504.27)	$ 2,100,746.63
1	Day-Ahead Asset Energy Amount	$ 6,111,574.82	$ 4,911,412.00	$ 11,022,986.82
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (1,465.68)	$ -	$ (1,465.68)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,590.42	$ -	$ 3,590.42
4	Day-Ahead Market Administration Amount	$ 616,949.69	$ (22,682.53)	$ 594,267.16
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,803,517.39)	$ -	$ (5,803,517.39)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 395,989.01	$ (35,598.13)	$ 360,390.88
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 432,183.65	$ (38,851.91)	$ 393,331.74
5	Day-Ahead Non-Asset Energy Amount	$ (4,975,344.73)	$ (74,450.04)	$ (5,049,794.77)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 1,465.68	$ -	$ 1,465.68
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,590.42)	$ -	$ (3,590.42)
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	$ 69,540.20	$ (6,251.44)	$ 63,288.76
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (61,971.11)	$ 26,470.54	$ (35,500.57)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 70,666.43	$ 1,057,763.35	$ 1,128,429.78
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (4,387.08)	$ (38.40)	$ (4,425.48)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 9,583.55	$ (25.98)	$ 9,557.57
13	Real-Time Asset Energy Amount	$ 75,862.90	$ 1,057,698.97	$ 1,133,561.87
14	Real-Time Distribution of Losses Amount	$ (1,344,475.97)	$ -	$ (1,344,475.97)
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	$ 41,726.26	$ (5,702.00)	$ 36,024.26
20	Real-Time Miscellaneous Amount	$ (40,153.45)	$ 1,252.48	$ (38,900.97)
21	Real-time Net inadvertent Distribution	$ 177,367.44	$ -	$ 177,367.44
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (716.14)	$ -	$ (716.14)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 427.16	$ 5,749.71	$ 6,176.87
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 288.99	$ 262.07	$ 551.06
22	Real-Time Non-Asset Energy Amount	$ 0.01	$ 6,011.78	$ 6,011.79
23	Real-Time Revenue Neutrality Uplift Amount	$ 248,209.81	$ (22,313.26)	$ 225,896.55
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 10,117.32	$ (909.51)	$ 9,207.81
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (8,821.22)	$ (7,012.43)	$ (15,833.65)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (743,219.43)	$ -	$ (743,219.43)
29	Financial Transmission Rights Market Administration Amount	$ 32,570.16	$ -	$ 32,570.16
30	Financial Transmission Rights Monthly Allocation Amount	$ (28,067.47)	$ -	$ (28,067.47)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 83,352.50	$ (3,070.88)	$ 80,281.62
34	Real -Time Schedule 24 Allocation Amount	$ (96,299.03)	$ 113,723.29	$ 17,424.26
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (5,613.72)	$ -	$ (5,613.72)
37	Financial Transmission Guarantee Uplift Amount	$ 3,899.71	$ -	$ 3,899.71
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,770,129.38	$ -	$ 3,770,129.38
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,771,745.17)	$ 50,303.72	$ (3,721,441.45)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (187,052.38)	$ -	$ (187,052.38)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 66,371.33	$ -	$ 66,371.33
43	Real Time Price Volatility Make Whole Payment	$ (110,199.47)	$ 8,040.28	$ (102,159.19)
	TOTAL MISO CHARGES	**$ (65,291.62)**	**$ 6,032,520.98**	**$ 5,967,229.36**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 662,861.58**
	SCHEDULE 24 (FOR RETAIL)			**$ 97,705.88**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,206,661.90**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	March 2016 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 409,306.78	$ 5,491,329.65	$ 5,900,636.43
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,928,154.26	$ (222,916.78)	$ 1,705,237.48
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,664,381.79	$ (192,421.65)	$ 1,471,960.14
1	Day-Ahead Asset Energy Amount	$ 4,001,842.83	$ 5,075,991.22	$ 9,077,834.05
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (3,463.42)	$ -	$ (3,463.42)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 655.03	$ -	$ 655.03
4	Day-Ahead Market Administration Amount	$ 545,190.14	$ (28,205.53)	$ 516,984.61
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,894,607.14)	$ -	$ (5,894,607.14)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 898,444.99	$ (103,870.56)	$ 794,574.43
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 638,278.79	$ (73,792.36)	$ 564,486.43
5	Day-Ahead Non-Asset Energy Amount	$ (4,357,883.36)	$ (177,662.92)	$ (4,535,546.28)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 3,463.42	$ -	$ 3,463.42
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (655.03)	$ -	$ (655.03)
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	$ 88,711.46	$ (10,256.06)	$ 78,455.40
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (8,755.73)	$ 15,453.92	$ 6,698.19
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 193,304.14	$ 1,258,482.48	$ 1,451,786.62
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 75,576.87	$ -	$ 75,576.87
13 c	Real-Time Asset Energy Amount - Loss Component	$ 20,822.99	$ -	$ 20,822.99
13	Real-Time Asset Energy Amount	$ 289,704.00	$ 1,258,482.48	$ 1,548,186.48
14	Real-Time Distribution of Losses Amount	$ (30,110.52)	$ -	$ (30,110.52)
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	$ 40,509.00	$ (4,909.96)	$ 35,599.04
20	Real-Time Miscellaneous Amount	$ 81,777.61	$ 19,100.32	$ 100,877.93
21	Real-time Net inadvertent Distribution	$ 823,222.09	$ -	$ 823,222.09
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (11,690.73)	$ -	$ (11,690.73)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ -	$ 9,237.62	$ 9,237.62
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ 2,207.23	$ 2,207.23
22	Real-Time Non-Asset Energy Amount	$ (11,690.73)	$ 11,444.85	$ (245.88)
23	Real-Time Revenue Neutrality Uplift Amount	$ (395,848.84)	$ 45,764.67	$ (350,084.17)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 17,807.07	$ (2,058.70)	$ 15,748.37
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ -	$ -	$ -
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,748,669.69)	$ -	$ (2,748,669.69)
29	Financial Transmission Rights Market Administration Amount	$ 27,470.08	$ -	$ 27,470.08
30	Financial Transmission Rights Monthly Allocation Amount	$ (222,739.77)	$ -	$ (222,739.77)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 85,462.09	$ (4,393.80)	$ 81,068.29
34	Real -Time Schedule 24 Allocation Amount	$ (95,476.93)	$ 96,793.14	$ 1,316.21
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 21,499.66	$ -	$ 21,499.66
37	Financial Transmission Guarantee Uplift Amount	$ (21,190.58)	$ -	$ (21,190.58)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,985,759.86	$ -	$ 2,985,759.86
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,988,827.34)	$ 35,708.23	$ (2,953,119.11)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (204,803.54)	$ -	$ (204,803.54)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 31,176.35	$ -	$ 31,176.35
43	Real Time Price Volatility Make Whole Payment	$ (156,050.21)	$ 14,525.07	$ (141,525.14)
	TOTAL MISO CHARGES	**$ (2,201,915.00)**	**$ 6,345,776.93**	**$ 4,143,861.93**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 580,053.73**
	SCHEDULE 24 (FOR RETAIL)			**$ 82,384.50**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,481,423.70**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	April 2016 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (6,107,897.64)	$ 7,549,986.95	$ 1,442,089.31
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,493,424.76	$ (208,652.77)	$ 1,284,771.99
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,282,266.73	$ (318,865.27)	$ 1,963,401.46
1	Day-Ahead Asset Energy Amount	$ (2,332,206.15)	$ 7,022,468.91	$ 4,690,262.76
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (2,538.97)	$ -	$ (2,538.97)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 19.85	$ -	$ 19.85
4	Day-Ahead Market Administration Amount	$ 530,857.26	$ (32,739.33)	$ 498,117.93
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,938,923.06)	$ -	$ (5,938,923.06)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,085,521.37	$ (151,662.84)	$ 933,858.53
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 692,322.88	$ (96,727.40)	$ 595,595.48
5	Day-Ahead Non-Asset Energy Amount	$ (4,161,078.81)	$ (248,390.24)	$ (4,409,469.05)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 2,538.97	$ -	$ 2,538.97
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (19.85)	$ -	$ (19.85)
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	$ 56,175.16	$ (7,848.47)	$ 48,326.69
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (62,704.14)	$ 17,637.38	$ (45,066.76)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 570,194.83	$ 930,664.85	$ 1,500,859.68
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 4,894.87	$ 147.89	$ 5,042.76
13 c	Real-Time Asset Energy Amount - Loss Component	$ 3,187.59	$ 75.73	$ 3,263.32
13	Real-Time Asset Energy Amount	$ 578,277.29	$ 930,888.47	$ 1,509,165.76
14	Real-Time Distribution of Losses Amount	$ (276,111.47)	$ -	$ (276,111.47)
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	$ 36,952.62	$ (4,878.26)	$ 32,074.36
20	Real-Time Miscellaneous Amount	$ 59,612.31	$ 9,393.60	$ 69,005.91
21	Real-time Net inadvertent Distribution	$ 31,431.11	$ -	$ 31,431.11
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 4,284.51	$ -	$ 4,284.51
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (1,058.49)	$ 20,395.33	$ 19,336.84
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (542.05)	$ 1,526.23	$ 984.18
22	Real-Time Non-Asset Energy Amount	$ 2,683.97	$ 21,921.56	$ 24,605.53
23	Real-Time Revenue Neutrality Uplift Amount	$ 44,806.03	$ (6,260.04)	$ 38,545.99
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 173,613.59	$ (24,256.30)	$ 149,357.29
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (33,083.25)	$ 9,842.50	$ (23,240.75)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (894,440.50)	$ -	$ (894,440.50)
29	Financial Transmission Rights Market Administration Amount	$ 36,000.00	$ -	$ 36,000.00
30	Financial Transmission Rights Monthly Allocation Amount	$ (66,083.22)	$ -	$ (66,083.22)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (395,567.97)	$ -	$ (395,567.97)
33	Day-Ahead Schedule 24 Allocation Amount	$ 89,915.02	$ (5,662.59)	$ 84,252.43
34	Real -Time Schedule 24 Allocation Amount	$ (97,618.09)	$ 100,492.27	$ 2,874.18
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 356,580.37	$ -	$ 356,580.37
37	Financial Transmission Guarantee Uplift Amount	$ (322,802.23)	$ -	$ (322,802.23)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,985,759.86	$ -	$ 2,985,759.86
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,988,827.34)	$ 38,172.66	$ (2,950,654.68)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (202,532.65)	$ -	$ (202,532.65)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 31,176.35	$ -	$ 31,176.35
43	Real Time Price Volatility Make Whole Payment	$ (169,044.68)	$ 19,777.25	$ (149,267.43)
	TOTAL MISO CHARGES	**$ (6,988,259.56)**	**$ 7,840,559.36**	**$ 852,299.80**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 566,192.29**
	SCHEDULE 24 (FOR RETAIL)			**$ 87,126.61**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 198,980.90**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	May 2016 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,903,282.78	$ 3,660,007.06	$ 5,563,289.84
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,269,099.16	$ (246,304.78)	$ 3,022,794.38
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,635,718.52	$ (123,240.46)	$ 1,512,478.06
1	Day-Ahead Asset Energy Amount	$ 6,808,100.46	$ 3,290,461.81	$ 10,098,562.27
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (9,375.18)	$ -	$ (9,375.18)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (1,002.89)	$ -	$ (1,002.89)
4	Day-Ahead Market Administration Amount	$ 566,372.19	$ (17,405.30)	$ 548,966.89
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,631,057.15)	$ -	$ (8,631,057.15)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,794,624.49	$ (135,212.97)	$ 1,659,411.52
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 999,416.43	$ (75,299.35)	$ 924,117.08
5	Day-Ahead Non-Asset Energy Amount	$ (5,837,016.23)	$ (210,512.32)	$ (6,047,528.55)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 9,375.18	$ -	$ 9,375.18
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 1,002.89	$ -	$ 1,002.89
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	$ 89,420.26	$ (6,737.22)	$ 82,683.04
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (12,957.18)	$ (10,198.91)	$ (23,156.09)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,392,570.33)	$ 647,739.20	$ (744,831.13)
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 114,328.40	$ 78.82	$ 114,407.22
13 c	Real-Time Asset Energy Amount - Loss Component	$ 54,203.17	$ 49.88	$ 54,253.05
13	Real-Time Asset Energy Amount	$ (1,224,038.76)	$ 647,867.89	$ (576,170.87)
14	Real-Time Distribution of Losses Amount	$ (586,154.43)	$ -	$ (586,154.43)
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	$ 38,592.01	$ (3,205.36)	$ 35,386.65
20	Real-Time Miscellaneous Amount	$ 25,178.84	$ 9,706.72	$ 34,885.56
21	Real-time Net inadvertent Distribution	$ (731,048.92)	$ -	$ (731,048.92)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 17,318.67	$ -	$ 17,318.67
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (1,046.11)	$ 6,055.14	$ 5,009.03
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (661.97)	$ 3,036.29	$ 2,374.32
22	Real-Time Non-Asset Energy Amount	$ 15,610.59	$ 9,091.43	$ 24,702.02
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,521,383.01	$ (114,626.05)	$ 1,406,756.96
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 99,617.27	$ (7,505.50)	$ 92,111.77
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (6,317.73)	$ 1,826.23	$ (4,491.50)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,394,360.59)	$ -	$ (3,394,360.59)
29	Financial Transmission Rights Market Administration Amount	$ 29,130.00	$ -	$ 29,130.00
30	Financial Transmission Rights Monthly Allocation Amount	$ (243,817.37)	$ -	$ (243,817.37)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 87,134.81	$ (2,795.97)	$ 84,338.84
34	Real -Time Schedule 24 Allocation Amount	$ (96,312.32)	$ 107,593.47	$ 11,281.15
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (20,228.52)	$ -	$ (20,228.52)
37	Financial Transmission Guarantee Uplift Amount	$ 24,475.48	$ -	$ 24,475.48
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,985,759.86	$ -	$ 2,985,759.86
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,988,827.34)	$ 38,183.66	$ (2,950,643.68)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (203,542.70)	$ -	$ (203,542.70)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 31,176.35	$ -	$ 31,176.35
43	Real Time Price Volatility Make Whole Payment	$ (189,261.18)	$ 25,770.76	$ (163,490.42)
	TOTAL MISO CHARGES	**$ (3,211,932.14)**	**$ 3,757,515.36**	**$ 545,583.22**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 613,483.54**
	SCHEDULE 24 (FOR RETAIL)			**$ 95,619.99**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ (163,520.31)**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	June 2016 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 7,039,423.55	$ 1,624,553.46	$ 8,663,977.01
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 30,704.84	$ (848.29)	$ 29,856.55
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,028,160.69	$ (56,032.81)	$ 1,972,127.88
1	Day-Ahead Asset Energy Amount	$ 9,098,289.08	$ 1,567,672.35	$ 10,665,961.43
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (10,697.44)	$ -	$ (10,697.44)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,221.02)	$ -	$ (2,221.02)
4	Day-Ahead Market Administration Amount	$ 579,962.07	$ (4,137.04)	$ 575,825.03
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (10,479,565.97)	$ -	$ (10,479,565.97)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,869,136.85	$ (51,639.40)	$ 1,817,497.45
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,250,965.17	$ (34,560.92)	$ 1,216,404.25
5	Day-Ahead Non-Asset Energy Amount	$ (7,359,463.95)	$ (86,200.31)	$ (7,445,664.26)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 10,697.44	$ -	$ 10,697.44
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,221.01	$ -	$ 2,221.01
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	$ 105,773.16	$ (2,922.24)	$ 102,850.92
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (42,116.71)	$ 4,792.22	$ (37,324.49)
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 2,613,263.40	$ 799,485.93	$ 3,412,749.33
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (154,385.45)	$ 999.61	$ (153,385.84)
13 c	Real-Time Asset Energy Amount - Loss Component	$ (23,100.88)	$ 533.74	$ (22,567.14)
13	Real-Time Asset Energy Amount	$ 2,435,777.07	$ 801,019.28	$ 3,236,796.35
14	Real-Time Distribution of Losses Amount	$ (177,928.43)	$ -	$ (177,928.43)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 32.60	$ -	$ 32.60
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 6.01	$ -	$ 6.01
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (32.60)	$ -	$ (32.60)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (6.01)	$ -	$ (6.01)
19	Real-Time Market Administration Amount	$ 48,947.38	$ (2,782.57)	$ 46,164.81
20	Real-Time Miscellaneous Amount	$ 2,271.42	$ 54,339.70	$ 56,611.12
21	Real-time Net inadvertent Distribution	$ 730,335.15	$ -	$ 730,335.15
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 244,045.95	$ -	$ 244,045.95
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (36,181.84)	$ (8,810.91)	$ (44,992.75)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (19,319.27)	$ (4,753.17)	$ (24,072.44)
22	Real-Time Non-Asset Energy Amount	$ 188,544.84	$ (13,564.08)	$ 174,980.76
23	Real-Time Revenue Neutrality Uplift Amount	$ (666,842.61)	$ 18,423.13	$ (648,419.48)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 384,950.52	$ (10,635.18)	$ 374,315.34
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (126,207.94)	$ 51,099.69	$ (75,108.25)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,404,238.41)	$ -	$ (1,404,238.41)
29	Financial Transmission Rights Market Administration Amount	$ 35,475.36	$ -	$ 35,475.36
30	Financial Transmission Rights Monthly Allocation Amount	$ (181,031.43)	$ -	$ (181,031.43)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 90,636.45	$ (779.95)	$ 89,856.50
34	Real -Time Schedule 24 Allocation Amount	$ (121,228.20)	$ 103,081.02	$ (18,147.18)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 82,809.64	$ -	$ 82,809.64
37	Financial Transmission Guarantee Uplift Amount	$ (85,118.38)	$ -	$ (85,118.38)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,398,660.25	$ -	$ 2,398,660.25
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,416,523.31)	$ 44,288.40	$ (2,372,234.91)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (78,450.07)	$ -	$ (78,450.07)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 78,282.87	$ -	$ 78,282.87
43	Real Time Price Volatility Make Whole Payment	$ (216,213.25)	$ 17,664.67	$ (198,548.58)
	TOTAL MISO CHARGES	**$ 3,385,352.56**	**$ 2,541,359.09**	**$ 5,926,711.65**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 657,465.20**
	SCHEDULE 24 (FOR RETAIL)			**$ 71,709.32**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,197,537.13**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	July 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 7,692,379.41	$ 3,591,831.00	$ 11,284,210.41	$ 8,411,872.15
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,283,251.62	$ (135,463.91)	$ 3,147,787.71	$ 2,346,534.38
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (70.21)	$ -	$ (70.21)	$ (52.34)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,614,280.97)	$ -	$ (12,614,280.97)	$ (9,403,380.02)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,251,554.12	$ (51,637.96)	$ 1,199,916.16	$ 894,483.61
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 70.21	$ -	$ 70.21	$ 52.34
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 574,075.32	$ 1,089,671.94	$ 1,663,747.26	$ 1,240,248.87
13 c	Real-Time Asset Energy Amount - Loss Component	$ 50,389.81	$ (2,079.04)	$ 48,310.77	$ 36,013.51
14	Real-Time Distribution of Losses Amount	$ (1,618,305.61)	$ -	$ (1,618,305.61)	$ (1,206,374.16)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 0.07	$ -	$ 0.07	$ 0.05
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (0.07)	$ -	$ (0.07)	$ (0.05)
21	Real-time Net inadvertent Distribution	$ (43,696.74)	$ -	$ (43,696.74)	$ (32,573.96)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 401,830.71	$ -	$ 401,830.71	$ 299,546.75
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,138.44)	$ 46.97	$ (1,091.47)	$ (813.64)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,183,357.19	$ (48,824.22)	$ 1,134,532.97	$ 845,743.38
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (5,035.63)	$ -	$ (5,035.63)	$ (3,753.84)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 329,157.33	$ (13,580.73)	$ 315,576.60	$ 235,248.19
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 5,035.63	$ -	$ 5,035.63	$ 3,753.84
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 128,797.38	$ (5,314.06)	$ 123,483.32	$ 92,051.27
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 1.00	$ -	$ 1.00	$ 0.75
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1.00)	$ -	$ (1.00)	$ (0.75)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 297.79	$ (12.29)	$ 285.50	$ 212.83
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,393,667.94)	$ -	$ (1,393,667.94)	$ (1,038,916.87)
30	Financial Transmission Rights Monthly Allocation Amount	$ (99,094.55)	$ -	$ (99,094.55)	$ (73,870.54)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (58,202.42)	$ -	$ (58,202.42)	$ (43,387.29)
37	Financial Transmission Guarantee Uplift Amount	$ 55,575.36	$ -	$ 55,575.36	$ 41,428.94
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 390,146.59	$ (8,143.95)	$ 382,002.64	$ 284,765.82
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 153,978.86	$ (6,353.02)	$ 147,625.84	$ 110,048.43
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (22,281.74)	$ (1,739.35)	$ (24,021.09)	$ (17,906.64)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 197,385.63	$ (16,097.09)	$ 181,288.54	$ 135,142.47
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (82,384.43)	$ 35,469.81	$ (46,914.62)	$ (34,972.74)
43	Real Time Price Volatility Make Whole Payment	$ (237,766.76)	$ 11,019.53	$ (226,747.23)	$ (169,029.88)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 603,358.36	$ (10,041.65)	$ 593,316.71	$ 442,290.96
19	Real-Time Market Administration Amount	$ 35,141.17	$ (2,812.19)	$ 32,328.98	$ 24,099.80
29	Financial Transmission Rights Market Administration Amount	$ 26,067.44	$ -	$ 26,067.44	$ 19,432.11
33	Day-Ahead Schedule 24 Allocation Amount	$ 87,199.99	$ (1,443.05)	$ 85,756.94	$ 63,927.95
34	Real -Time Schedule 24 Allocation Amount	$ (98,216.85)	$ 120,388.25	$ 22,171.40	$ 16,527.78
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	$ (47,233.47)	$ 40,902.19	$ (6,331.28)	$ (4,719.68)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,516,999.68	$ -	$ 3,516,999.68	$ 2,621,765.33
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,588,338.38)	$ -	$ (3,588,338.38)	$ (2,674,945.13)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (83,283.16)	$ -	$ (83,283.16)	$ (62,083.86)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 67,063.94	$ -	$ 67,063.94	$ 49,993.16
	TOTAL MISO CHARGES	**$ 40,116.24**	**$ 4,585,787.19**	**$ 4,625,903.43**	**$ 3,448,403.28**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 651,713.13**	**$ 485,822.87**
	SCHEDULE 24 (FOR RETAIL)			**$ 107,928.34**	**$ 80,455.73**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,866,261.96**	**$ 2,882,124.68**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	August 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 10,278,133.89	$ 4,354,104.31	$ 14,632,238.20	$ 10,857,425.16
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,835,603.89	$ (146,625.09)	$ 2,688,978.80	$ 1,995,278.22
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (179.30)	$ -	$ (179.30)	$ (133.04)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,838,109.40)	$ -	$ (11,838,109.40)	$ (8,784,123.46)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,347,824.92	$ (69,694.13)	$ 1,278,130.79	$ 948,399.64
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 179.30	$ -	$ 179.30	$ 133.04
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 974,556.75	$ 1,004,003.84	$ 1,978,560.59	$ 1,468,133.12
13 c	Real-Time Asset Energy Amount - Loss Component	$ 28,539.58	$ (1,475.74)	$ 27,063.84	$ 20,081.93
14	Real-Time Distribution of Losses Amount	$ (1,557,344.15)	$ -	$ (1,557,344.15)	$ (1,155,581.76)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 7,060.53	$ -	$ 7,060.53	$ 5,239.06
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 18,844.12	$ -	$ 18,844.12	$ 13,982.73
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (882.25)	$ 45.62	$ (836.63)	$ (620.80)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,747,104.92	$ (142,048.93)	$ 2,605,055.99	$ 1,933,005.74
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,770.96	$ -	$ 4,770.96	$ 3,540.15
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 653,486.41	$ (33,790.86)	$ 619,695.55	$ 459,826.99
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,770.96)	$ -	$ (4,770.96)	$ (3,540.15)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 201,610.41	$ (10,424.99)	$ 191,185.42	$ 141,863.56
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	$ (713.91)	$ 36.92	$ (676.99)	$ (502.34)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,116,717.17)	$ -	$ (3,116,717.17)	$ (2,312,668.98)
30	Financial Transmission Rights Monthly Allocation Amount	$ (253,555.01)	$ -	$ (253,555.01)	$ (188,143.09)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (123,309.40)	$ -	$ (123,309.40)	$ (91,498.14)
37	Financial Transmission Guarantee Uplift Amount	$ 115,322.48	$ -	$ 115,322.48	$ 85,571.68
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 498,449.63	$ (11,730.37)	$ 486,719.26	$ 361,155.82
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 111,277.01	$ (5,753.98)	$ 105,523.03	$ 78,300.29
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (50,206.19)	$ 8,687.42	$ (41,518.77)	$ (30,807.79)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 226,855.29	$ (25,774.13)	$ 201,081.16	$ 149,206.41
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (119,088.00)	$ 51,979.48	$ (67,108.52)	$ (49,795.92)
43	Real Time Price Volatility Make Whole Payment	$ (213,755.26)	$ 7,821.08	$ (205,934.18)	$ (152,807.45)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 542,745.68	$ (11,766.12)	$ 530,979.56	$ 393,997.88
19	Real-Time Market Administration Amount	$ 36,294.41	$ (2,691.51)	$ 33,602.90	$ 24,934.05
29	Financial Transmission Rights Market Administration Amount	$ 33,650.16	$ -	$ 33,650.16	$ 24,969.12
33	Day-Ahead Schedule 24 Allocation Amount	$ 83,182.21	$ (1,801.03)	$ 81,381.18	$ 60,386.53
34	Real -Time Schedule 24 Allocation Amount	$ (99,721.35)	$ 104,868.28	$ 5,146.93	$ 3,819.13
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	$ (40,469.85)	$ 42,258.91	$ 1,789.06	$ 1,327.52
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,516,999.68	$ -	$ 3,516,999.68	$ 2,609,686.93
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,588,338.38)	$ -	$ (3,588,338.38)	$ (2,662,621.73)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (92,074.58)	$ -	$ (92,074.58)	$ (68,321.25)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 66,234.82	$ -	$ 66,234.82	$ 49,147.61
	TOTAL MISO CHARGES	**$ 3,229,491.89**	**$ 5,110,228.98**	**$ 8,339,720.87**	**$ 6,188,246.39**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 598,232.62**	**$ 443,901.05**
	SCHEDULE 24 (FOR RETAIL)			**$ 86,528.11**	**$ 64,205.66**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,654,960.14** X	**$ 5,680,139.68**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
September 2015 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 6,386,106.36	$ 5,544,813.92	$ 11,930,920.28	$ 8,850,736.67
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,644,294.03	$ (205,172.95)	$ 2,439,121.08	$ 1,809,417.71
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,269.94	$ -	$ 3,269.94	$ 2,425.75
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,378,475.04)	$ -	$ (11,378,475.04)	$ (8,440,915.19)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,021,615.40	$ (79,267.98)	$ 942,347.42	$ 699,063.33
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,269.94)	$ -	$ (3,269.94)	$ (2,425.75)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (517,359.41)	$ 1,757,695.13	$ 1,240,335.72	$ 920,120.54
13 c	Real-Time Asset Energy Amount - Loss Component	$ 57,163.18	$ (4,435.34)	$ 52,727.84	$ 39,115.19
14	Real-Time Distribution of Losses Amount	$ (1,226,063.07)	$ -	$ (1,226,063.07)	$ (909,532.64)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 9,693.52	$ -	$ 9,693.52	$ 7,190.96
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,595.58	$ -	$ 8,595.58	$ 6,376.48
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (621.95)	$ 48.26	$ (573.69)	$ (425.58)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 5,490,819.21	$ (426,037.17)	$ 5,064,782.04	$ 3,757,216.63
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 17,359.37	$ -	$ 17,359.37	$ 12,877.73
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,012,893.58	$ (78,591.25)	$ 934,302.33	$ 693,095.23
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (17,359.37)	$ -	$ (17,359.37)	$ (12,877.73)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 144,299.24	$ (11,196.30)	$ 133,102.94	$ 98,740.00
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	$ (1,621.78)	$ 125.84	$ (1,495.94)	$ (1,109.74)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,806,681.63)	$ -	$ (3,806,681.63)	$ (2,823,917.68)
30	Financial Transmission Rights Monthly Allocation Amount	$ (318,211.73)	$ -	$ (318,211.73)	$ (236,059.60)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (68,287.15)	$ -	$ (68,287.15)	$ (50,657.58)
37	Financial Transmission Guarantee Uplift Amount	$ 72,603.84	$ -	$ 72,603.84	$ 53,859.84
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 529,022.80	$ (31,428.28)	$ 497,594.52	$ 369,131.47
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 117,657.19	$ (9,129.12)	$ 108,528.07	$ 80,509.58
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (108,124.53)	$ 50,832.92	$ (57,291.61)	$ (42,500.74)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 405,051.46	$ (41,047.31)	$ 364,004.15	$ 270,029.87
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (307,907.79)	$ 138,699.53	$ (169,208.26)	$ (125,524.08)
43	Real Time Price Volatility Make Whole Payment	$ (255,207.60)	$ 12,911.09	$ (242,296.51)	$ (179,743.27)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 551,580.38	$ (15,954.74)	$ 535,625.64	$ 397,344.16
19	Real-Time Market Administration Amount	$ 38,029.43	$ (5,571.65)	$ 32,457.78	$ 24,078.21
29	Financial Transmission Rights Market Administration Amount	$ 25,266.24	$ -	$ 25,266.24	$ 18,743.30
33	Day-Ahead Schedule 24 Allocation Amount	$ 87,805.56	$ (2,534.81)	$ 85,270.75	$ 63,256.56
34	Real -Time Schedule 24 Allocation Amount	$ (95,065.04)	$ 100,032.99	$ 4,967.95	$ 3,685.38
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	$ (63,780.52)	$ 33,304.72	$ (30,475.80)	$ (22,607.92)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,850,841.75	$ -	$ 2,850,841.75	$ 2,114,845.21
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,859,231.18)	$ -	$ (2,859,231.18)	$ (2,121,068.76)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (400,833.24)	$ -	$ (400,833.24)	$ (297,350.86)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 101,528.16	$ -	$ 101,528.16	$ 75,316.82
	TOTAL MISO CHARGES	**$ 147,395.25**	**$ 6,728,097.51**	**$ 6,875,492.76**	**$ 5,100,459.52**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 593,349.66**	**$ 440,165.68**
	SCHEDULE 24 (FOR RETAIL)			**$ 90,238.70**	**$ 66,941.94**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,191,904.40**	**$ 4,593,351.90**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	October 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,632,816.97	$ 7,235,721.75	$ 8,868,538.72	$ 6,563,565.40
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,268,303.51	$ (267,935.07)	$ 2,000,368.44	$ 1,480,463.63
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (380.42)	$ -	$ (380.42)	$ (281.55)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (10,360,122.10)	$ -	$ (10,360,122.10)	$ (7,667,479.51)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,077,313.93	$ (127,253.78)	$ 950,060.15	$ 703,135.22
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 380.42	$ -	$ 380.42	$ 281.55
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (175,137.66)	$ 787,375.84	$ 612,238.18	$ 453,114.71
13 c	Real-Time Asset Energy Amount - Loss Component	$ (9,133.89)	$ 1,078.91	$ (8,054.98)	$ (5,961.46)
14	Real-Time Distribution of Losses Amount	$ (738,769.12)	$ -	$ (738,769.12)	$ (546,759.68)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (41,932.81)	$ -	$ (41,932.81)	$ (31,034.28)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 56,481.99	$ -	$ 56,481.99	$ 41,802.07
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (4,725.75)	$ 558.21	$ (4,167.54)	$ (3,084.38)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,465,996.27	$ (173,165.46)	$ 1,292,830.81	$ 956,818.24
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (8,231.39)	$ -	$ (8,231.39)	$ (6,092.01)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,625,945.01	$ (192,058.82)	$ 1,433,886.19	$ 1,061,212.69
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8,231.39	$ -	$ 8,231.39	$ 6,092.01
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 39,650.00	$ (4,683.51)	$ 34,966.49	$ 25,878.54
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	$ (8,547.94)	$ 1,009.69	$ (7,538.25)	$ (5,579.02)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,522,933.66)	$ -	$ (1,522,933.66)	$ (1,127,116.31)
30	Financial Transmission Rights Monthly Allocation Amount	$ (69,809.70)	$ -	$ (69,809.70)	$ (51,665.84)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 131,266.47	$ -	$ 131,266.47	$ 97,149.72
37	Financial Transmission Guarantee Uplift Amount	$ (127,112.24)	$ -	$ (127,112.24)	$ (94,075.19)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 376,490.64	$ (19,009.43)	$ 357,481.21	$ 264,570.23
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 119,650.77	$ (14,133.31)	$ 105,517.46	$ 78,092.99
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (191,308.74)	$ 16,040.55	$ (175,268.19)	$ (129,715.19)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 160,931.36	$ (44,471.58)	$ 116,459.78	$ 86,191.35
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (144,093.10)	$ 54,353.72	$ (89,739.38)	$ (66,415.71)
43	Real Time Price Volatility Make Whole Payment	$ (394,320.32)	$ 23,728.10	$ (370,592.22)	$ (274,273.63)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 539,384.60	$ (28,312.03)	$ 511,072.57	$ 378,242.50
19	Real-Time Market Administration Amount	$ 36,784.13	$ (3,895.07)	$ 32,889.06	$ 24,341.04
29	Financial Transmission Rights Market Administration Amount	$ 22,747.52	$ -	$ 22,747.52	$ 16,835.34
33	Day-Ahead Schedule 24 Allocation Amount	$ 80,474.18	$ (4,222.77)	$ 76,251.41	$ 56,433.32
34	Real -Time Schedule 24 Allocation Amount	$ (88,264.19)	$ 100,235.76	$ 11,971.57	$ 8,860.10
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	$ 28,587.50	$ (8,805.23)	$ 19,782.27	$ 14,640.77
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,850,841.75	$ -	$ 2,850,841.75	$ 2,109,895.09
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,859,231.18)	$ -	$ (2,859,231.18)	$ (2,116,104.07)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (406,713.43)	$ -	$ (406,713.43)	$ (301,006.77)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 101,942.72	$ -	$ 101,942.72	$ 75,447.35
	TOTAL MISO CHARGES	**$ (4,526,546.51)**	**$ 7,332,156.48**	**$ 2,805,609.97**	**$ 2,076,419.25**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 566,709.15**	**$ 419,418.88**
	SCHEDULE 24 (FOR RETAIL)			**$ 88,222.98**	**$ 65,293.43**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,150,677.84**	**$ 1,591,706.94**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	November 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 4,857,047.65	$ 2,263,598.27	$ 7,120,645.92	$ 5,181,965.72
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,308,182.43	$ (112,112.89)	$ 2,196,069.54	$ 1,598,163.59
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 563.53	$ -	$ 563.53	$ 410.10
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,967,760.53)	$ -	$ (5,967,760.53)	$ (4,342,967.03)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 588,179.30	$ (28,569.01)	$ 559,610.29	$ 407,249.76
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (563.53)	$ -	$ (563.53)	$ (410.10)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 10,824.40	$ 895,920.02	$ 906,744.42	$ 659,872.51
13 c	Real-Time Asset Energy Amount - Loss Component	$ 6,064.00	$ (294.54)	$ 5,769.46	$ 4,198.66
14	Real-Time Distribution of Losses Amount	$ (980,115.94)	$ -	$ (980,115.94)	$ (713,267.76)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (70,807.91)	$ -	$ (70,807.91)	$ (51,529.62)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (0.73)	$ -	$ (0.73)	$ (0.53)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (63.60)	$ 3.09	$ (60.51)	$ (44.04)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,945,799.48	$ (94,511.25)	$ 1,851,288.23	$ 1,347,253.08
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (10,146.47)	$ -	$ (10,146.47)	$ (7,383.97)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,563,305.22	$ (75,932.76)	$ 1,487,372.46	$ 1,082,417.69
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 10,146.47	$ -	$ 10,146.47	$ 7,383.97
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 75,881.98	$ (3,685.73)	$ 72,196.25	$ 52,539.96
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	$ 64.32	$ (3.12)	$ 61.20	$ 44.53
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,381,013.39)	$ -	$ (1,381,013.39)	$ (1,005,016.14)
30	Financial Transmission Rights Monthly Allocation Amount	$ (100,477.08)	$ -	$ (100,477.08)	$ (73,121.00)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (293,392.53)	$ -	$ (293,392.53)	$ (213,512.94)
37	Financial Transmission Guarantee Uplift Amount	$ 295,869.36	$ -	$ 295,869.36	$ 215,315.42
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 776,563.16	$ (4,314.32)	$ 772,248.84	$ 561,994.95
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 72,414.94	$ (3,517.33)	$ 68,897.61	$ 50,139.42
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (75,184.36)	$ 450.45	$ (74,733.91)	$ (54,386.72)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 88,823.29	$ (37,719.18)	$ 51,104.11	$ 37,190.41
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 26,552.33	$ 782.26	$ 27,334.59	$ 19,892.42
43	Real Time Price Volatility Make Whole Payment	$ (204,581.14)	$ 42,770.37	$ (161,810.77)	$ (117,755.87)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 543,492.38	$ (9,845.09)	$ 533,647.29	$ 388,355.49
19	Real-Time Market Administration Amount	$ 46,295.87	$ (4,135.12)	$ 42,160.75	$ 30,681.99
29	Financial Transmission Rights Market Administration Amount	$ 19,141.60	$ -	$ 19,141.60	$ 13,930.07
33	Day-Ahead Schedule 24 Allocation Amount	$ 82,305.92	$ (1,497.10)	$ 80,808.82	$ 58,807.66
34	Real -Time Schedule 24 Allocation Amount	$ (95,092.03)	$ 87,727.71	$ (7,364.32)	$ (5,359.30)
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	$ 13,749.29	$ 12,121.76	$ 25,871.05	$ 18,827.35
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,850,841.75	$ -	$ 2,850,841.75	$ 2,074,666.31
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,859,231.18)	$ -	$ (2,859,231.18)	$ (2,080,771.62)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (406,713.43)	$ -	$ (406,713.43)	$ (295,980.88)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 101,942.72	$ -	$ 101,942.72	$ 74,187.61
	TOTAL MISO CHARGES	**$ 3,838,907.54**	**$ 2,927,236.48**	**$ 6,766,144.02**	**$ 4,923,981.16**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 594,949.64**	**$ 432,967.55**
	SCHEDULE 24 (FOR RETAIL)			**$ 73,444.50**	**$ 53,448.36**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,097,749.88**	**$ 4,437,565.24**

		System	Intersystem	System Retail	Minnestoa Retail
	December 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (3,161,849.70)	$ 7,138,201.73	$ 3,976,352.03	$ 2,886,664.12
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,276,066.79	$ (245,208.78)	$ 2,030,858.01	$ 1,474,317.39
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,891.51	$ -	$ 2,891.51	$ 2,099.11
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,904,338.05)	$ -	$ (5,904,338.05)	$ (4,286,300.79)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 431,685.77	$ (46,507.05)	$ 385,178.72	$ 279,623.53
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,891.51)	$ -	$ (2,891.51)	$ (2,099.11)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (35,573.90)	$ 790,783.22	$ 755,209.32	$ 548,250.16
13 c	Real-Time Asset Energy Amount - Loss Component	$ (1,960.06)	$ 211.16	$ (1,748.90)	$ (1,269.62)
14	Real-Time Distribution of Losses Amount	$ (687,512.97)	$ -	$ (687,512.97)	$ (499,105.46)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (40,441.71)	$ -	$ (40,441.71)	$ (29,358.98)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 505.06	$ -	$ 505.06	$ 366.65
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 4.02	$ (0.43)	$ 3.59	$ 2.60
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,259,584.78	$ (135,699.55)	$ 1,123,885.23	$ 815,893.35
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,423.75	$ -	$ 4,423.75	$ 3,211.46
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 676,085.05	$ (72,837.05)	$ 603,248.00	$ 437,932.64
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,423.75)	$ -	$ (4,423.75)	$ (3,211.46)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 3,338.29	$ (359.65)	$ 2,978.64	$ 2,162.37
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (0.18)	$ 0.02	$ (0.16)	$ (0.12)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (992,388.90)	$ -	$ (992,388.90)	$ (720,432.55)
30	Financial Transmission Rights Monthly Allocation Amount	$ (91,420.53)	$ -	$ (91,420.53)	$ (66,367.45)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (18,226.83)	$ -	$ (18,226.83)	$ (13,231.91)
37	Financial Transmission Guarantee Uplift Amount	$ 4,048.29	$ -	$ 4,048.29	$ 2,938.89
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 478,236.54	$ (7,470.29)	$ 470,766.25	$ 341,756.48
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 44,692.68	$ (4,814.90)	$ 39,877.78	$ 28,949.59
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (160,724.75)	$ 19,411.64	$ (141,313.11)	$ (102,587.37)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 69,340.38	$ (51,522.13)	$ 17,818.25	$ 12,935.30
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (3,854.63)	$ 1,886.63	$ (1,968.00)	$ (1,428.69)
43	Real Time Price Volatility Make Whole Payment	$ (239,720.33)	$ 11,633.29	$ (228,087.04)	$ (165,581.59)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 594,528.51	$ (29,955.39)	$ 564,573.12	$ 409,856.31
19	Real-Time Market Administration Amount	$ 52,570.68	$ (3,278.41)	$ 49,292.27	$ 35,784.11
29	Financial Transmission Rights Market Administration Amount	$ 27,410.96	$ -	$ 27,410.96	$ 19,899.20
33	Day-Ahead Schedule 24 Allocation Amount	$ 86,505.76	$ (4,282.16)	$ 82,223.60	$ 59,690.87
34	Real -Time Schedule 24 Allocation Amount	$ (92,003.82)	$ 108,803.14	$ 16,799.32	$ 12,195.60
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	$ 1,072,002.52	$ 52,588.75	$ 1,124,591.27	$ 816,405.90
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,770,129.38	$ -	$ 3,770,129.38	$ 2,736,955.17
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,771,745.17)	$ 9,706.72	$ (3,762,038.45)	$ (2,731,081.49)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (186,462.01)	$ -	$ (186,462.01)	$ (135,363.57)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 66,371.33	$ -	$ 66,371.33	$ 48,182.79
	TOTAL MISO CHARGES	**$ (4,475,116.75)**	**$ 7,531,290.52**	**$ 3,056,173.77**	**$ 2,218,653.46**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 641,276.35**	**$ 465,539.63**
	SCHEDULE 24 (FOR RETAIL)			**$ 99,022.92**	**$ 71,886.47**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,315,874.50**	**$ 1,681,227.36**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	January 2016 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,058,567.50	$ 4,942,322.68	$ 6,000,890.18	$ 4,324,100.98
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,885,053.71	$ (207,478.02)	$ 2,677,575.69	$ 1,929,398.36
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,425.24	$ -	$ 3,425.24	$ 2,468.15
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (6,524,620.37)	$ -	$ (6,524,620.37)	$ (4,701,488.69)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 498,934.65	$ (35,880.78)	$ 463,053.87	$ 333,665.78
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,425.24)	$ -	$ (3,425.24)	$ (2,468.15)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 598,900.77	$ 1,188,959.01	$ 1,787,859.78	$ 1,288,289.90
13 c	Real-Time Asset Energy Amount - Loss Component	$ (4,407.52)	$ 0.37	$ (4,407.15)	$ (3,175.69)
14	Real-Time Distribution of Losses Amount	$ (1,483,744.46)	$ -	$ (1,483,744.46)	$ (1,069,151.52)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (192,702.88)	$ -	$ (192,702.88)	$ (138,857.18)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 13.15	$ -	$ 13.15	$ 9.48
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (5.09)	$ (911.01)	$ (916.10)	$ (660.12)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,014,802.89	$ (72,979.33)	$ 941,823.56	$ 678,656.01
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,928.72	$ -	$ 1,928.72	$ 1,389.79
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 328,700.35	$ (23,638.42)	$ 305,061.93	$ 219,820.49
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,928.72)	$ -	$ (1,928.72)	$ (1,389.79)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (9,139.67)	$ 0.58	$ (9,139.09)	$ (6,585.42)
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	$ (8.04)	$ (16.47)	$ (24.51)	$ (17.66)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (598,278.53)	$ -	$ (598,278.53)	$ (431,105.50)
30	Financial Transmission Rights Monthly Allocation Amount	$ (11,899.73)	$ -	$ (11,899.73)	$ (8,574.67)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 73,446.38	$ -	$ 73,446.38	$ 52,923.74
37	Financial Transmission Guarantee Uplift Amount	$ (72,033.63)	$ -	$ (72,033.63)	$ (51,905.75)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 847,747.47	$ (60,965.58)	$ 786,781.89	$ 566,936.61
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 85,143.26	$ (6,123.06)	$ 79,020.20	$ 56,940.11
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (161,378.93)	$ 26,336.73	$ (135,042.20)	$ (97,308.25)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 61,556.02	$ (4,426.79)	$ 57,129.23	$ 41,165.99
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (30,005.93)	$ (14,822.44)	$ (44,828.37)	$ (32,302.27)
43	Real Time Price Volatility Make Whole Payment	$ (106,348.56)	$ 20,187.20	$ (86,161.36)	$ (62,085.86)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 629,120.42	$ (17,932.66)	$ 611,187.76	$ 440,407.59
19	Real-Time Market Administration Amount	$ 46,128.84	$ (5,387.46)	$ 40,741.38	$ 29,357.28
29	Financial Transmission Rights Market Administration Amount	$ 27,851.04	$ -	$ 27,851.04	$ 20,068.81
33	Day-Ahead Schedule 24 Allocation Amount	$ 86,365.51	$ (2,439.52)	$ 83,925.99	$ 60,475.10
34	Real -Time Schedule 24 Allocation Amount	$ (101,463.72)	$ 96,815.23	$ (4,648.49)	$ (3,349.59)
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	$ (56,138.65)	$ 17,534.72	$ (38,603.93)	$ (27,817.09)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,770,129.38	$ -	$ 3,770,129.38	$ 2,716,666.97
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,771,745.17)	$ 52,033.25	$ (3,719,711.92)	$ (2,680,337.33)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (187,052.38)	$ -	$ (187,052.38)	$ (134,785.57)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 66,371.33	$ -	$ 66,371.33	$ 47,825.63
	TOTAL MISO CHARGES	**$ (1,232,140.59)**	**$ 5,891,188.23**	**$ 4,659,047.64**	**$ 3,357,200.66**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 679,780.18**	**$ 489,833.68**
	SCHEDULE 24 (FOR RETAIL)			**$ 79,277.50**	**$ 57,125.51**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,899,989.96**	**$ 2,810,241.46**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	February 2016 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 3,035,356.88	$ 5,187,954.01	$ 8,223,310.89	$ 5,948,745.03
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,308,250.90	$ (207,504.27)	$ 2,100,746.63	$ 1,519,680.61
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,590.42	$ -	$ 3,590.42	$ 2,597.31
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,803,517.39)	$ -	$ (5,803,517.39)	$ (4,198,265.84)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 432,183.65	$ (38,851.91)	$ 393,331.74	$ 284,536.27
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,590.42)	$ -	$ (3,590.42)	$ (2,597.31)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 70,666.43	$ 1,057,763.35	$ 1,128,429.78	$ 816,306.37
13 c	Real-Time Asset Energy Amount - Loss Component	$ 9,583.55	$ (25.98)	$ 9,557.57	$ 6,913.95
14	Real-Time Distribution of Losses Amount	$ (1,344,475.97)	$ -	$ (1,344,475.97)	$ (972,594.23)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 177,367.44	$ -	$ 177,367.44	$ 128,307.65
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (716.14)	$ -	$ (716.14)	$ (518.06)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 288.99	$ 262.07	$ 551.06	$ 398.64
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 767,967.04	$ (69,037.75)	$ 698,929.29	$ 505,605.62
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (1,465.68)	$ -	$ (1,465.68)	$ (1,060.27)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 395,989.01	$ (35,598.13)	$ 360,390.88	$ 260,706.85
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 1,465.68	$ -	$ 1,465.68	$ 1,060.27
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (4,387.08)	$ (38.40)	$ (4,425.48)	$ (3,201.39)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 427.16	$ 5,749.71	$ 6,176.87	$ 4,468.35
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (743,219.43)	$ -	$ (743,219.43)	$ (537,645.11)
30	Financial Transmission Rights Monthly Allocation Amount	$ (28,067.47)	$ -	$ (28,067.47)	$ (20,304.01)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (5,613.72)	$ -	$ (5,613.72)	$ (4,060.97)
37	Financial Transmission Guarantee Uplift Amount	$ 3,899.71	$ -	$ 3,899.71	$ 2,821.05
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 248,209.81	$ (22,313.26)	$ 225,896.55	$ 163,413.62
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 69,540.20	$ (6,251.44)	$ 63,288.76	$ 45,783.10
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (61,971.11)	$ 26,470.54	$ (35,500.57)	$ (25,681.12)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 10,117.32	$ (909.51)	$ 9,207.81	$ 6,660.93
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (8,821.22)	$ (7,012.43)	$ (15,833.65)	$ (11,454.07)
43	Real Time Price Volatility Make Whole Payment	$ (110,199.47)	$ 8,040.28	$ (102,159.19)	$ (73,901.98)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 616,949.69	$ (22,682.53)	$ 594,267.16	$ 429,893.00
19	Real-Time Market Administration Amount	$ 41,726.26	$ (5,702.00)	$ 36,024.26	$ 26,059.96
29	Financial Transmission Rights Market Administration Amount	$ 32,570.16	$ -	$ 32,570.16	$ 23,561.26
33	Day-Ahead Schedule 24 Allocation Amount	$ 83,352.50	$ (3,070.88)	$ 80,281.62	$ 58,075.74
34	Real -Time Schedule 24 Allocation Amount	$ (96,299.03)	$ 113,723.29	$ 17,424.26	$ 12,604.71
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	$ (40,153.45)	$ 1,252.48	$ (38,900.97)	$ (28,140.97)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 3,770,129.38	$ -	$ 3,770,129.38	$ 2,727,312.48
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,771,745.17)	$ 50,303.72	$ (3,721,441.45)	$ (2,692,091.62)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (187,052.38)	$ -	$ (187,052.38)	$ (135,313.74)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 66,371.33	$ -	$ 66,371.33	$ 48,013.04
	TOTAL MISO CHARGES	**$ (65,291.62)**	**$ 6,032,520.98**	**$ 5,967,229.36**	**$ 4,316,695.11**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 662,861.58**	**$ 479,514.22**
	SCHEDULE 24 (FOR RETAIL)			**$ 97,705.88**	**$ 70,680.46**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,206,661.90**	**$ 3,766,500.44**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	March 2016 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 409,306.78	$ 5,491,329.65	$ 5,900,636.43	$ 4,277,243.09
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,664,381.79	$ (192,421.65)	$ 1,471,960.14	$ 1,066,991.91
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 655.03	$ -	$ 655.03	$ 474.82
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,894,607.14)	$ -	$ (5,894,607.14)	$ (4,272,872.59)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 638,278.79	$ (73,792.36)	$ 564,486.43	$ 409,183.94
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (655.03)	$ -	$ (655.03)	$ (474.82)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 193,304.14	$ 1,258,482.48	$ 1,451,786.62	$ 1,052,368.57
13 c	Real-Time Asset Energy Amount - Loss Component	$ 20,822.99	$ -	$ 20,822.99	$ 15,094.13
14	Real-Time Distribution of Losses Amount	$ (30,110.52)	$ -	$ (30,110.52)	$ (21,826.46)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 823,222.09	$ -	$ 823,222.09	$ 596,735.80
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (11,690.73)	$ -	$ (11,690.73)	$ (8,474.36)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ -	$ 2,207.23	$ 2,207.23	$ 1,599.97
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,928,154.26	$ (222,916.78)	$ 1,705,237.48	$ 1,236,089.59
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (3,463.42)	$ -	$ (3,463.42)	$ (2,510.56)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 898,444.99	$ (103,870.56)	$ 794,574.43	$ 575,969.73
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 3,463.42	$ -	$ 3,463.42	$ 2,510.56
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 75,576.87	$ -	$ 75,576.87	$ 54,784.03
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	$ -	$ 9,237.62	$ 9,237.62	$ 6,696.15
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,748,669.69)	$ -	$ (2,748,669.69)	$ (1,992,450.91)
30	Financial Transmission Rights Monthly Allocation Amount	$ (222,739.77)	$ -	$ (222,739.77)	$ (161,459.22)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 21,499.66	$ -	$ 21,499.66	$ 15,584.64
37	Financial Transmission Guarantee Uplift Amount	$ (21,190.58)	$ -	$ (21,190.58)	$ (15,360.59)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ (395,848.84)	$ 45,764.67	$ (350,084.17)	$ (253,768.40)
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 88,711.46	$ (10,256.06)	$ 78,455.40	$ 56,870.61
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (8,755.73)	$ 15,453.92	$ 6,698.19	$ 4,855.37
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 17,807.07	$ (2,058.70)	$ 15,748.37	$ 11,415.65
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ -	$ -	$ -	$ -
43	Real Time Price Volatility Make Whole Payment	$ (156,050.21)	$ 14,525.07	$ (141,525.14)	$ (102,588.50)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 545,190.14	$ (28,205.53)	$ 516,984.61	$ 374,750.91
19	Real-Time Market Administration Amount	$ 40,509.00	$ (4,909.96)	$ 35,599.04	$ 25,804.97
29	Financial Transmission Rights Market Administration Amount	$ 27,470.08	$ -	$ 27,470.08	$ 19,912.46
33	Day-Ahead Schedule 24 Allocation Amount	$ 85,462.09	$ (4,393.80)	$ 81,068.29	$ 58,764.64
34	Real -Time Schedule 24 Allocation Amount	$ (95,476.93)	$ 96,793.14	$ 1,316.21	$ 954.09
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	$ 81,777.61	$ 19,100.32	$ 100,877.93	$ 73,124.22
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,985,759.86	$ -	$ 2,985,759.86	$ 2,164,312.42
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,988,827.34)	$ 35,708.23	$ (2,953,119.11)	$ (2,140,651.85)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (204,803.54)	$ -	$ (204,803.54)	$ (148,457.63)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 31,176.35	$ -	$ 31,176.35	$ 22,599.06
	TOTAL MISO CHARGES	**$ (2,201,915.00)**	**$ 6,345,776.93**	**$ 4,143,861.93**	**$ 3,003,795.44**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 580,053.73**	**$ 420,468.34**
	SCHEDULE 24 (FOR RETAIL)			**$ 82,384.50**	**$ 59,718.73**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 3,481,423.70**	**$ 2,523,608.37**

Northern States Power Company

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

Docket No. E999/AA-16-523
Part J, Section 5
Schedule 2

		System	Intersystem	System Retail	Minnestoa Retail
	April 2016 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ (6,107,897.64)	$ 7,549,986.95	$ 1,442,089.31	$ 1,056,424.98
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,282,266.73	$ (318,865.27)	$ 1,963,401.46	$ 1,438,320.31
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 19.85	$ -	$ 19.85	$ 14.54
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (5,938,923.06)	$ -	$ (5,938,923.06)	$ (4,350,650.56)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 692,322.88	$ (96,727.40)	$ 595,595.48	$ 436,312.74
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (19.85)	$ -	$ (19.85)	$ (14.54)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 570,194.83	$ 930,664.85	$ 1,500,859.68	$ 1,099,478.13
13 c	Real-Time Asset Energy Amount - Loss Component	$ 3,187.59	$ 75.73	$ 3,263.32	$ 2,390.60
14	Real-Time Distribution of Losses Amount	$ (276,111.47)	$ -	$ (276,111.47)	$ (202,269.76)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 31,431.11	$ -	$ 31,431.11	$ 23,025.35
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 4,284.51	$ -	$ 4,284.51	$ 3,138.68
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (542.05)	$ 1,526.23	$ 984.18	$ 720.98
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,493,424.76	$ (208,652.77)	$ 1,284,771.99	$ 941,179.72
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (2,538.97)	$ -	$ (2,538.97)	$ (1,859.96)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,085,521.37	$ (151,662.84)	$ 933,858.53	$ 684,112.60
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 2,538.97	$ -	$ 2,538.97	$ 1,859.96
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 4,894.87	$ 147.89	$ 5,042.76	$ 3,694.15
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	$ (1,058.49)	$ 20,395.33	$ 19,336.84	$ 14,165.50
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (894,440.50)	$ -	$ (894,440.50)	$ (655,236.31)
30	Financial Transmission Rights Monthly Allocation Amount	$ (66,083.22)	$ -	$ (66,083.22)	$ (48,410.29)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (395,567.97)	$ -	$ (395,567.97)	$ (289,779.48)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 356,580.37	$ -	$ 356,580.37	$ 261,218.50
37	Financial Transmission Guarantee Uplift Amount	$ (322,802.23)	$ -	$ (322,802.23)	$ (236,473.80)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 44,806.03	$ (6,260.04)	$ 38,545.99	$ 28,237.46
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 56,175.16	$ (7,848.47)	$ 48,326.69	$ 35,402.47
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (62,704.14)	$ 17,637.38	$ (45,066.76)	$ (33,014.36)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 173,613.59	$ (24,256.30)	$ 149,357.29	$ 109,414.01
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (33,083.25)	$ 9,842.50	$ (23,240.75)	$ (17,025.37)
43	Real Time Price Volatility Make Whole Payment	$ (169,044.68)	$ 19,777.25	$ (149,267.43)	$ (109,348.18)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 530,857.26	$ (32,739.33)	$ 498,117.93	$ 364,904.05
19	Real-Time Market Administration Amount	$ 36,952.62	$ (4,878.26)	$ 32,074.36	$ 23,496.57
29	Financial Transmission Rights Market Administration Amount	$ 36,000.00	$ -	$ 36,000.00	$ 26,372.36
33	Day-Ahead Schedule 24 Allocation Amount	$ 89,915.02	$ (5,662.59)	$ 84,252.43	$ 61,720.43
34	Real -Time Schedule 24 Allocation Amount	$ (97,618.09)	$ 100,492.27	$ 2,874.18	$ 2,105.53
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	$ 59,612.31	$ 9,393.60	$ 69,005.91	$ 50,551.35
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,985,759.86	$ -	$ 2,985,759.86	$ 2,187,264.87
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,988,827.34)	$ 38,172.66	$ (2,950,654.68)	$ (2,161,548.03)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (202,532.65)	$ -	$ (202,532.65)	$ (148,368.45)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 31,176.35	$ -	$ 31,176.35	$ 22,838.72
	TOTAL MISO CHARGES	**$ (6,988,259.56)**	**$ 7,840,559.36**	**$ 852,299.80**	**$ 624,365.49**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 566,192.29**	**$ 414,772.98**
	SCHEDULE 24 (FOR RETAIL)			**$ 87,126.61**	**$ 63,825.95**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 198,980.90** X	**$ 145,766.56**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
	May 2016 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,903,282.78	$ 3,660,007.06	$ 5,563,289.84	$ 4,092,462.77
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,635,718.52	$ (123,240.46)	$ 1,512,478.06	$ 1,112,607.89
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (1,002.89)	$ -	$ (1,002.89)	$ (737.75)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,631,057.15)	$ -	$ (8,631,057.15)	$ (6,349,171.28)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 999,416.43	$ (75,299.35)	$ 924,117.08	$ 679,798.26
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 1,002.89	$ -	$ 1,002.89	$ 737.75
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,392,570.33)	$ 647,739.20	$ (744,831.13)	$ (547,912.07)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 54,203.17	$ 49.88	$ 54,253.05	$ 39,909.58
14	Real-Time Distribution of Losses Amount	$ (586,154.43)	$ -	$ (586,154.43)	$ (431,186.45)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (731,048.92)	$ -	$ (731,048.92)	$ (537,773.62)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 17,318.67	$ -	$ 17,318.67	$ 12,739.95
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (661.97)	$ 3,036.29	$ 2,374.32	$ 1,746.59
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,269,099.16	$ (246,304.78)	$ 3,022,794.38	$ 2,223,625.56
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (9,375.18)	$ -	$ (9,375.18)	$ (6,896.56)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,794,624.49	$ (135,212.97)	$ 1,659,411.52	$ 1,220,694.96
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 9,375.18	$ -	$ 9,375.18	$ 6,896.56
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 114,328.40	$ 78.82	$ 114,407.22	$ 84,160.14
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ -	$ -
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (1,046.11)	$ 6,055.14	$ 5,009.03	$ 3,684.74
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,394,360.59)	$ -	$ (3,394,360.59)	$ (2,496,956.79)
30	Financial Transmission Rights Monthly Allocation Amount	$ (243,817.37)	$ -	$ (243,817.37)	$ (179,356.74)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (20,228.52)	$ -	$ (20,228.52)	$ (14,880.49)
37	Financial Transmission Guarantee Uplift Amount	$ 24,475.48	$ -	$ 24,475.48	$ 18,004.63
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,521,383.01	$ (114,626.05)	$ 1,406,756.96	$ 1,034,837.42
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 89,420.26	$ (6,737.22)	$ 82,683.04	$ 60,823.23
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (12,957.18)	$ (10,198.91)	$ (23,156.09)	$ (17,034.06)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 99,617.27	$ (7,505.50)	$ 92,111.77	$ 67,759.19
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (6,317.73)	$ 1,826.23	$ (4,491.50)	$ (3,304.03)
43	Real Time Price Volatility Make Whole Payment	$ (189,261.18)	$ 25,770.76	$ (163,490.42)	$ (120,266.69)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 566,372.19	$ (17,405.30)	$ 548,966.89	$ 403,830.58
19	Real-Time Market Administration Amount	$ 38,592.01	$ (3,205.36)	$ 35,386.65	$ 26,031.10
29	Financial Transmission Rights Market Administration Amount	$ 29,130.00	$ -	$ 29,130.00	$ 21,428.59
33	Day-Ahead Schedule 24 Allocation Amount	$ 87,134.81	$ (2,795.97)	$ 84,338.84	$ 62,041.27
34	Real -Time Schedule 24 Allocation Amount	$ (96,312.32)	$ 107,593.47	$ 11,281.15	$ 8,298.63
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	$ 25,178.84	$ 9,706.72	$ 34,885.56	$ 25,662.49
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,985,759.86	$ -	$ 2,985,759.86	$ 2,196,382.25
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,988,827.34)	$ 38,183.66	$ (2,950,643.68)	$ (2,170,550.12)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (203,542.70)	$ -	$ (203,542.70)	$ (149,729.92)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 31,176.35	$ -	$ 31,176.35	$ 22,933.92
	TOTAL MISO CHARGES	**$ (3,211,932.14)**	**$ 3,757,515.36**	**$ 545,583.22**	**$ 401,341.49**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 613,483.54**	**$ 451,290.27**
	SCHEDULE 24 (FOR RETAIL)			**$ 95,619.99**	**$ 70,339.90**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ (163,520.31)**	**$ (120,288.68)**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	System Retail	Minnestoa Retail
June 2016 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 7,039,423.55	$ 1,624,553.46	$ 8,663,977.01	$ 6,394,857.87
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,028,160.69	$ (56,032.81)	$ 1,972,127.88	$ 1,455,622.22
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ (2,221.02)	$ -	$ (2,221.02)	$ (1,639.33)
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (10,479,565.97)	$ -	$ (10,479,565.97)	$ (7,734,939.15)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,250,965.17	$ (34,560.92)	$ 1,216,404.25	$ 897,824.67
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 2,221.01	$ -	$ 2,221.01	$ 1,639.32
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 2,613,263.40	$ 799,485.93	$ 3,412,749.33	$ 2,518,941.00
13 c	Real-Time Asset Energy Amount - Loss Component	$ (23,100.88)	$ 533.74	$ (22,567.14)	$ (16,656.74)
14	Real-Time Distribution of Losses Amount	$ (177,928.43)	$ -	$ (177,928.43)	$ (131,328.49)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ 6.01	$ -	$ 6.01	$ 4.44
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (6.01)	$ -	$ (6.01)	$ (4.44)
21	Real-time Net inadvertent Distribution	$ 730,335.15	$ -	$ 730,335.15	$ 539,058.39
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 244,045.95	$ -	$ 244,045.95	$ 180,129.65
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (19,319.27)	$ (4,753.17)	$ (24,072.44)	$ (17,767.80)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 30,704.84	$ (848.29)	$ 29,856.55	$ 22,037.03
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (10,697.44)	$ -	$ (10,697.44)	$ (7,895.75)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,869,136.85	$ (51,639.40)	$ 1,817,497.45	$ 1,341,489.93
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 10,697.44	$ -	$ 10,697.44	$ 7,895.75
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (154,385.45)	$ 999.61	$ (153,385.84)	$ (113,213.67)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 32.60	$ -	$ 32.60	$ 24.06
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (32.60)	$ -	$ (32.60)	$ (24.06)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (36,181.84)	$ (8,810.91)	$ (44,992.75)	$ (33,209.03)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,404,238.41)	$ -	$ (1,404,238.41)	$ (1,036,464.55)
30	Financial Transmission Rights Monthly Allocation Amount	$ (181,031.43)	$ -	$ (181,031.43)	$ (133,618.81)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 82,809.64	$ -	$ 82,809.64	$ 61,121.57
37	Financial Transmission Guarantee Uplift Amount	$ (85,118.38)	$ -	$ (85,118.38)	$ (62,825.64)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ (666,842.61)	$ 18,423.13	$ (648,419.48)	$ (478,596.66)
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 105,773.16	$ (2,922.24)	$ 102,850.92	$ 75,913.99
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (42,116.71)	$ 4,792.22	$ (37,324.49)	$ (27,549.10)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 384,950.52	$ (10,635.18)	$ 374,315.34	$ 276,281.13
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (126,207.94)	$ 51,099.69	$ (75,108.25)	$ (55,437.20)
43	Real Time Price Volatility Make Whole Payment	$ (216,213.25)	$ 17,664.67	$ (198,548.58)	$ (146,548.17)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 579,962.07	$ (4,137.04)	$ 575,825.03	$ 425,014.89
19	Real-Time Market Administration Amount	$ 48,947.38	$ (2,782.57)	$ 46,164.81	$ 34,074.12
29	Financial Transmission Rights Market Administration Amount	$ 35,475.36	$ -	$ 35,475.36	$ 26,184.27
33	Day-Ahead Schedule 24 Allocation Amount	$ 90,636.45	$ (779.95)	$ 89,856.50	$ 66,322.84
34	Real -Time Schedule 24 Allocation Amount	$ (121,228.20)	$ 103,081.02	$ (18,147.18)	$ (13,394.38)
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ 2,271.42	$ 54,339.70	$ 56,611.12	$ 41,784.51
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 2,398,660.25	$ -	$ 2,398,660.25	$ 1,770,444.61
40	Auction Revenue Rights - Monthly ARR Revenue	$ (2,416,523.31)	$ 44,288.40	$ (2,372,234.91)	$ (1,750,940.14)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (78,450.07)	$ -	$ (78,450.07)	$ (57,903.78)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 78,282.87	$ -	$ 78,282.87	$ 57,780.37
	TOTAL MISO CHARGES	**$ 3,385,352.56**	**$ 2,541,359.09**	**$ 5,926,711.65**	**$ 4,374,489.75**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 657,465.20**	**$ 485,273.28**
	SCHEDULE 24 (FOR RETAIL)			**$ 71,709.32**	**$ 52,928.45**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 5,197,537.13**	**$ 3,836,288.02**

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - SYSTEM

	July 15	August 15	September 15	October 15	November 15	December 15	January 16	February 16	March 16	April 16	May 16	June 16	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	$ 7,692,379.41	$ 10,278,133.89	$ 6,386,106.36	$ 1,632,816.97	$ 4,857,047.65	$ (3,161,849.70)	$ 1,058,567.50	$ 3,035,356.88	$ 409,306.78	$ (6,107,897.64)	$ 1,903,282.78	$ 7,039,423.55	$ 35,022,674.43
5 a Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,614,280.97)	$ (11,838,109.40)	$ (11,378,475.04)	$ (10,360,122.10)	$ (5,967,760.53)	$ (5,904,338.05)	$ (6,524,620.37)	$ (5,803,517.39)	$ (5,894,607.14)	$ (5,938,923.06)	$ (8,631,057.15)	$ (10,479,565.97)	$ (101,335,377.17)
13 a Real-Time Asset Energy Amount - Energy Component	$ 574,075.32	$ 974,556.75	$ (517,359.41)	$ (175,137.66)	$ 10,824.40	$ (35,573.90)	$ 598,900.77	$ 70,666.43	$ 193,304.14	$ 570,194.83	$ (1,392,570.33)	$ 2,613,263.40	$ 3,485,144.74
22 a Real-Time Non-Asset Energy Amount - Energy Component	$ 401,830.71	$ 18,844.12	$ 8,595.58	$ 56,481.99	$ (0.73)	$ 505.06	$ 13.15	$ (716.14)	$ (11,690.73)	$ 4,284.51	$ 17,318.67	$ 244,045.95	$ 739,512.14
SUBTOTAL	$ (3,945,995.53)	$ (566,574.64)	$ (5,501,132.51)	$ (8,845,960.80)	$ (1,099,889.21)	$ (9,101,256.59)	$ (4,867,138.95)	$ (2,698,210.22)	$ (5,303,686.95)	$ (11,472,341.36)	$ (8,103,026.03)	$ (582,833.07)	$ (62,088,045.86)
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	$ 3,283,251.62	$ 2,835,603.89	$ 2,644,294.03	$ 2,268,303.51	$ 2,308,182.43	$ 2,276,066.79	$ 2,885,053.71	$ 2,308,250.90	$ 1,664,381.79	$ 2,282,266.73	$ 1,635,718.52	$ 2,028,160.69	$ 28,419,534.61
3 Day-Ahead Financial Bilateral Transaction Loss Amount	$ (70.21)	$ (179.30)	$ 3,269.94	$ (380.42)	$ 563.53	$ 2,891.51	$ 3,425.24	$ 3,590.42	$ 655.03	$ 19.85	$ (1,002.89)	$ (2,221.02)	$ 10,561.68
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,251,554.12	$ 1,347,824.92	$ 1,021,615.40	$ 1,077,313.93	$ 588,179.30	$ 431,685.77	$ 498,934.65	$ 432,183.65	$ 638,278.79	$ 692,322.88	$ 999,416.43	$ 1,250,965.17	$ 10,230,275.01
13 c Real-Time Asset Energy Amount - Loss Component	$ 50,389.81	$ 28,539.58	$ 57,163.18	$ (9,133.89)	$ 6,064.00	$ (1,960.06)	$ (4,407.52)	$ 9,583.55	$ 20,822.99	$ 3,187.59	$ 54,203.17	$ (23,100.88)	$ 191,351.52
22 c Real-Time Non-Asset Energy Amount - Loss Component	$ (1,138.44)	$ (882.25)	$ (621.95)	$ (4,725.75)	$ (63.60)	$ 4.02	$ (5.09)	$ 288.99	$ -	$ (542.05)	$ (661.97)	$ (19,319.27)	$ (27,667.36)
14 Real-Time Distribution of Losses Amount	$ (1,618,305.61)	$ (1,557,344.15)	$ (1,226,063.07)	$ (738,769.12)	$ (980,115.94)	$ (687,512.97)	$ (1,483,744.46)	$ (1,344,475.97)	$ (30,110.52)	$ (276,111.47)	$ (586,154.43)	$ (177,928.43)	$ (10,706,636.14)
16 Real-Time Financial Bilateral Transaction Loss Amount	$ 0.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.01	$ 6.08
SUBTOTAL	$ 2,965,681.36	$ 2,653,562.69	$ 2,499,657.53	$ 2,592,608.26	$ 1,922,809.72	$ 2,021,175.06	$ 1,899,256.53	$ 1,409,421.54	$ 2,294,028.08	$ 2,701,143.53	$ 2,101,518.83	$ 3,056,562.27	$ 28,117,425.40
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	$ 603,358.36	$ 542,745.68	$ 551,580.38	$ 539,384.60	$ 543,492.38	$ 594,528.51	$ 629,120.42	$ 616,949.69	$ 545,190.14	$ 530,857.26	$ 566,372.19	$ 579,962.07	$ 6,843,541.68
19 Real-Time Market Administration Amount	$ 35,141.17	$ 36,294.41	$ 38,029.43	$ 36,784.13	$ 46,295.87	$ 52,570.68	$ 46,128.84	$ 41,726.26	$ 40,509.00	$ 36,952.62	$ 38,592.01	$ 48,947.38	$ 497,971.80
29 Financial Transmission Rights Market Administration Amount	$ 26,067.44	$ 33,650.16	$ 25,266.24	$ 22,747.52	$ 19,141.60	$ 27,410.96	$ 27,851.04	$ 32,570.16	$ 27,470.08	$ 36,000.00	$ 29,130.00	$ 35,475.36	$ 342,780.56
33 Day-Ahead Schedule 24 Allocation Amount	$ 87,199.99	$ 83,182.21	$ 87,805.56	$ 80,474.18	$ 82,305.92	$ 86,505.76	$ 86,365.51	$ 83,352.50	$ 85,462.09	$ 89,915.02	$ 87,134.81	$ 90,636.45	$ 1,030,340.00
34 Real -Time Schedule 24 Allocation Amount	$ (98,216.85)	$ (99,721.35)	$ (95,065.04)	$ (88,264.19)	$ (95,092.03)	$ (92,003.82)	$ (101,463.72)	$ (96,299.03)	$ (95,476.93)	$ (97,618.09)	$ (96,312.32)	$ (121,228.20)	$ (1,176,761.57)
35 Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -							$ -
SUBTOTAL	$ 653,550.11	$ 596,151.11	$ 607,616.57	$ 591,126.24	$ 596,143.74	$ 669,012.09	$ 688,002.09	$ 678,299.58	$ 603,154.38	$ 596,106.81	$ 624,916.69	$ 633,793.06	$ 7,537,872.47
Congestion Related Charges													
1 b Day-Ahead Asset Energy Amount - Congestion Component	$ 1,183,357.19	$ 2,747,104.92	$ 5,490,819.21	$ 1,465,996.27	$ 1,945,799.48	$ 1,259,584.78	$ 1,014,802.89	$ 767,967.04	$ 1,928,154.26	$ 1,493,424.76	$ 3,269,099.16	$ 30,704.84	$ 22,596,814.80
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 329,157.33	$ 653,486.41	$ 1,012,893.58	$ 1,625,945.01	$ 1,563,305.22	$ 676,085.05	$ 328,700.35	$ 395,989.01	$ 898,444.99	$ 1,085,521.37	$ 1,794,624.49	$ 1,869,136.85	$ 12,233,289.66
13 b Real-Time Asset Energy Amount - Congestion Component	$ 128,797.38	$ 201,610.41	$ 144,299.24	$ 39,650.00	$ 75,881.98	$ 3,338.29	$ (9,139.67)	$ (4,387.08)	$ 75,576.87	$ 4,894.87	$ 114,328.40	$ (154,385.45)	$ 620,465.24
22 b Real-Time Non-Asset Energy Amount - Congestion Component	$ 297.79	$ (713.91)	$ (1,621.78)	$ (8,547.94)	$ 64.32	$ (0.18)	$ (8.04)	$ 427.16	$ -	$ (1,058.49)	$ (1,046.11)	$ (36,181.84)	$ (48,389.02)
2 Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (5,035.63)	$ 4,770.96	$ 17,359.37	$ (8,231.39)	$ (10,146.47)	$ 4,423.75	$ 1,928.72	$ (1,465.68)	$ (3,463.42)	$ (2,538.97)	$ (9,375.18)	$ (10,697.44)	$ (22,471.38)
15 Real-Time Financial Bilateral Transaction Congestion Amount	$ 1.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32.60	$ 33.60
28 Financial Transmission Rights Hourly Allocation Amount	$ (1,393,667.94)	$ (3,116,717.17)	$ (3,806,681.63)	$ (1,522,933.66)	$ (1,381,013.39)	$ (992,388.90)	$ (598,278.53)	$ (743,219.43)	$ (2,748,669.69)	$ (894,440.50)	$ (3,394,360.59)	$ (1,404,238.41)	$ (21,996,609.84)
30 Financial Transmission Rights Monthly Allocation Amount	$ (99,094.55)	$ (253,555.01)	$ (318,211.73)	$ (69,809.70)	$ (100,477.08)	$ (91,420.53)	$ (11,899.73)	$ (28,067.47)	$ (222,739.77)	$ (66,083.22)	$ (243,817.37)	$ (181,031.43)	$ (1,686,207.59)
32 Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (395,567.97)	$ -	$ -	$ (395,567.97)
31 Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -							$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	$ (58,202.42)	$ (123,309.40)	$ (68,287.15)	$ 131,266.47	$ (293,392.53)	$ (18,226.83)	$ 73,446.38	$ (5,613.72)	$ 21,499.66	$ 356,580.37	$ (20,228.52)	$ 82,809.64	$ 78,341.95
37 Financial Transmission Guarantee Uplift Amount	$ 55,575.36	$ 115,322.48	$ 72,603.84	$ (127,112.24)	$ 295,869.36	$ 4,048.29	$ (72,033.63)	$ 3,899.71	$ (21,190.58)	$ (322,802.23)	$ 24,475.48	$ (85,118.38)	$ (56,462.54)
38 Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -							$ -
SUBTOTAL	$ 141,185.51	$ 227,999.69	$ 2,543,172.95	$ 1,526,222.82	$ 2,095,890.89	$ 845,443.72	$ 727,518.74	$ 385,529.54	$ (72,387.68)	$ 1,257,929.99	$ 1,533,699.76	$ 111,030.98	$ 11,323,236.91
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 153,978.86	$ 111,277.01	$ 117,657.19	$ 119,650.77	$ 72,414.94	$ 44,692.68	$ 85,143.26	$ 69,540.20	$ 88,711.46	$ 56,175.16	$ 89,420.26	$ 105,773.16	$ 1,114,434.95
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ (22,281.74)	$ (50,206.19)	$ (108,124.53)	$ (191,308.74)	$ (75,184.36)	$ (160,724.75)	$ (161,378.93)	$ (61,971.11)	$ (8,755.73)	$ (62,704.14)	$ (12,957.18)	$ (42,116.71)	$ (957,714.11)
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amou	$ 197,385.63	$ 226,855.29	$ 405,051.46	$ 160,931.36	$ 88,823.29	$ 69,340.38	$ 61,556.02	$ 10,117.32	$ 17,807.07	$ 173,613.59	$ 99,617.27	$ 384,950.52	$ 1,896,049.20
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (82,384.43)	$ (119,088.00)	$ (307,907.79)	$ (144,093.10)	$ 26,552.33	$ (3,854.63)	$ (30,005.93)	$ (8,821.22)	$ -	$ (33,083.25)	$ (6,317.73)	$ (126,207.94)	$ (835,211.69)
43 Real Time Price Volatility Make Whole Payment	$ (237,766.76)	$ (213,755.26)	$ (255,207.60)	$ (394,320.32)	$ (204,581.14)	$ (239,720.33)	$ (106,348.56)	$ (110,199.47)	$ (156,050.21)	$ (169,044.68)	$ (189,261.18)	$ (216,213.25)	$ (2,492,468.76)
SUBTOTAL	$ 8,931.56	$ (44,917.15)	$ (148,531.27)	$ (449,140.03)	$ (91,974.94)	$ (290,266.65)	$ (151,034.14)	$ (101,334.28)	$ (58,287.41)	$ (35,043.32)	$ (19,498.56)	$ 106,185.78	$ (1,274,910.41)
Other MISO Charges													
20 Real-Time Miscellaneous Amount	$ (47,233.47)	$ (40,469.85)	$ (63,780.52)	$ 28,587.50	$ 13,749.29	$ 1,072,002.52	$ (56,138.65)	$ (40,153.45)	$ 81,777.61	$ 59,612.31	$ 25,178.84	$ 2,271.42	$ 1,035,403.55
21 Real-time Net inadvertent Distribution	$ (43,696.74)	$ 7,060.53	$ 9,693.52	$ (41,932.81)	$ (70,807.91)	$ (40,441.71)	$ (192,702.88)	$ 177,367.44	$ 823,222.09	$ 31,431.11	$ (731,048.92)	$ 730,336.15	$ 658,478.87
23 Real-Time Revenue Neutrality Uplift Amount	$ 390,146.59	$ 498,449.63	$ 529,022.80	$ 376,490.64	$ 776,563.16	$ 478,236.54	$ 847,747.47	$ 248,209.81	$ (395,848.84)	$ 44,806.03	$ 1,521,383.01	$ (666,842.61)	$ 4,648,364.23
26 Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -							$ -
SUBTOTAL	$ 299,216.38	$ 465,040.31	$ 474,935.80	$ 363,145.33	$ 719,504.54	$ 1,509,797.35	$ 598,905.94	$ 385,423.80	$ 509,150.86	$ 135,849.45	$ 815,512.93	$ 65,763.96	$ 6,342,246.65
Auction Revenue Rights (ARR)													$ -
39 Auction Revenue Rights - FTR Auction Transactions	$ 3,516,999.68	$ 3,516,999.68	$ 2,850,841.75	$ 2,850,841.75	$ 2,850,841.75	$ 3,770,129.38	$ 3,770,129.38	$ 3,770,129.38	$ 2,985,759.86	$ 2,985,759.86	$ 2,985,759.86	$ 2,398,660.25	$ 38,252,852.58
40 Auction Revenue Rights - Monthly ARR Revenue	$ (3,588,338.38)	$ (3,588,338.38)	$ (2,859,231.18)	$ (2,859,231.18)	$ (2,859,231.18)	$ (3,771,745.17)	$ (3,771,745.17)	$ (3,771,745.17)	$ (2,988,827.34)	$ (2,988,827.34)	$ (2,988,827.34)	$ (2,416,523.31)	$ (38,452,611.14)
41 Auction Revenue Rights - ARR Stage 2 Distribution	$ (83,283.16)	$ (92,074.58)	$ (400,833.24)	$ (406,713.43)	$ (406,713.43)	$ (186,462.01)	$ (187,052.38)	$ (187,052.38)	$ (204,803.54)	$ (202,532.65)	$ (203,542.70)	$ (78,450.07)	$ (2,639,513.57)
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 67,063.94	$ 66,234.82	$ 101,528.16	$ 101,942.72	$ 101,942.72	$ 66,371.33	$ 66,371.33	$ 66,371.33	$ 31,176.35	$ 31,176.35	$ 31,176.35	$ 78,282.87	$ 809,638.27
SUBTOTAL	$ (87,557.92)	$ (97,178.46)	$ (307,694.51)	$ (313,160.14)	$ (313,160.14)	$ (121,706.47)	$ (122,296.84)	$ (122,296.84)	$ (176,694.67)	$ (174,423.78)	$ (175,433.83)	$ (18,030.26)	$ (2,029,633.86)
Grandfathered Charge Types													
6 Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 5,035.63	$ (4,770.96)	$ (17,359.37)	$ 8,231.39	$ 10,146.47	$ (4,423.75)	$ (1,928.72)	$ 1,465.68	$ 3,463.42	$ 2,538.97	$ 9,375.18	$ 10,697.44	$ 22,471.38
7 Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 70.21	$ 179.30	$ (3,269.94)	$ 380.42	$ (563.53)	$ (2,891.51)	$ (3,425.24)	$ (3,590.42)	$ (655.03)	$ (19.85)	$ 1,002.89	$ 2,221.01	$ (10,561.69)
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	$ (1.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (32.60)	$ (33.60)
18 Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (0.07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.01)	$ (6.08)
SUBTOTAL	$ 5,104.77	$ (4,591.66)	$ (20,629.31)	$ 8,611.81	$ 9,582.94	$ (7,315.26)	$ (5,353.96)	$ (2,124.74)	$ 2,808.39	$ 2,519.12	$ 10,378.07	$ 12,879.84	$ 11,870.01
TOTAL MISO DAY 2 CHARGES	$ 40,116.24	$ 3,229,491.89	$ 147,395.25	$ (4,526,546.51)	$ 3,838,907.54	$ (4,475,116.75)	$ (1,232,140.59)	$ (65,291.62)	$ (2,201,915.00)	$ (6,988,259.56)	$ (3,211,932.14)	$ 3,385,352.56	$ (12,059,938.69)

Northern States Power Company

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - INTERSYSTEM

	July 15	August 15	September 15	October 15	November 15	December 15	January 16	February 16	March 16	April 16	May 16	June 16	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	$ 3,591,831.00	$ 4,354,104.31	$ 5,544,813.92	$ 7,235,721.75	$ 2,263,598.27	$ 7,138,201.73	$ 4,942,322.68	$ 5,187,954.01	$ 5,491,329.65	$ 7,549,986.95	$ 3,660,007.06	$ 1,624,553.46	$ 58,584,424.79
5 a Day-Ahead Non-Asset Energy Amount - Energy Component													
13 a Real-Time Asset Energy Amount - Energy Component	$ 1,089,671.94	$ 1,004,003.84	$ 1,757,695.13	$ 787,375.84	$ 895,920.02	$ 790,783.22	$ 1,188,959.01	$ 1,057,763.35	$ 1,258,482.48	$ 930,664.85	$ 647,739.20	$ 799,485.93	$ 12,208,544.81
22 a Real-Time Non-Asset Energy Amount - Energy Component													
SUBTOTAL	$ 4,681,502.94	$ 5,358,108.15	$ 7,302,509.05	$ 8,023,097.59	$ 3,159,518.29	$ 7,928,984.95	$ 6,131,281.69	$ 6,245,717.36	$ 6,749,812.13	$ 8,480,651.80	$ 4,307,746.26	$ 2,424,039.39	$ 70,792,969.60
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	$ (135,463.91)	$ (146,625.09)	$ (205,172.95)	$ (267,935.07)	$ (112,112.89)	$ (245,208.78)	$ (207,478.02)	$ (207,504.27)	$ (192,421.65)	$ (318,865.27)	$ (123,240.46)	$ (56,032.81)	$ (2,218,061.18)
3 Day-Ahead Financial Bilateral Transaction Loss Amount													
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	$ (51,637.96)	$ (69,694.13)	$ (79,267.98)	$ (127,253.78)	$ (28,569.01)	$ (46,507.05)	$ (35,880.78)	$ (38,851.91)	$ (73,792.36)	$ (96,727.40)	$ (75,299.35)	$ (34,560.92)	$ (758,042.61)
13 c Real-Time Asset Energy Amount - Loss Component	$ (2,079.04)	$ (1,475.74)	$ (4,435.34)	$ 1,078.91	$ (294.54)	$ 211.16	$ 0.37	$ (25.98)	$ -	$ 75.73	$ 49.88	$ 533.74	$ (6,360.85)
22 c Real-Time Non-Asset Energy Amount - Loss Component	$ 46.97	$ 45.62	$ 48.26	$ 558.21	$ 3.09	$ (0.43)	$ (911.01)	$ 262.07	$ 2,207.23	$ 1,526.23	$ 3,036.29	$ (4,753.17)	$ 2,069.37
14 Real-Time Distribution of Losses Amount													
16 Real-Time Financial Bilateral Transaction Loss Amount													
SUBTOTAL	$ (189,133.94)	$ (217,749.34)	$ (288,828.01)	$ (393,551.73)	$ (140,973.35)	$ (291,505.09)	$ (244,269.44)	$ (246,120.08)	$ (264,006.78)	$ (413,990.70)	$ (195,453.65)	$ (94,813.15)	$ (2,980,395.27)
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	$ (10,041.65)	$ (11,766.12)	$ (15,954.74)	$ (28,312.03)	$ (9,845.09)	$ (29,955.39)	$ (17,932.66)	$ (22,682.53)	$ (28,205.53)	$ (32,739.33)	$ (17,405.30)	$ (4,137.04)	$ (228,977.41)
19 Real-Time Market Administration Amount	$ (2,812.19)	$ (2,691.51)	$ (5,571.65)	$ (3,895.07)	$ (4,135.12)	$ (3,278.41)	$ (5,387.46)	$ (5,702.00)	$ (4,909.96)	$ (4,878.26)	$ (3,205.36)	$ (2,782.57)	$ (49,249.56)
29 Financial Transmission Rights Market Administration Amount	$ -	$ -	$ -	$ -	$ -	-							$ -
33 Day-Ahead Schedule 24 Allocation Amount	$ (1,443.05)	$ (1,801.03)	$ (2,534.81)	$ (4,222.77)	$ (1,497.10)	$ (4,282.16)	$ (2,439.52)	$ (3,070.88)	$ (4,393.80)	$ (5,662.59)	$ (2,795.97)	$ (779.95)	$ (34,923.63)
34 Real -Time Schedule 24 Allocation Amount	$ 120,388.25	$ 104,868.28	$ 100,032.99	$ 100,235.76	$ 87,727.71	$ 108,803.14	$ 96,815.23	$ 113,723.29	$ 96,793.14	$ 100,492.27	$ 107,593.47	$ 103,081.02	$ 1,240,554.55
35 Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	-							$ -
SUBTOTAL	$ 106,091.36	$ 88,609.62	$ 75,971.79	$ 63,805.89	$ 72,250.40	$ 71,287.18	$ 71,055.59	$ 82,267.88	$ 59,283.85	$ 57,212.09	$ 84,186.84	$ 95,381.46	$ 927,403.95
Congestion Related Charges													
1 b Day-Ahead Asset Energy Amount - Congestion Component	$ (48,824.22)	$ (142,048.93)	$ (426,037.17)	$ (173,165.46)	$ (94,511.25)	$ (135,699.55)	$ (72,979.33)	$ (69,037.75)	$ (222,916.78)	$ (208,652.77)	$ (246,304.78)	$ (848.29)	$ (1,841,026.29)
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (13,580.73)	$ (33,790.86)	$ (78,591.25)	$ (192,058.82)	$ (75,932.76)	$ (72,837.05)	$ (23,638.42)	$ (35,598.13)	$ (103,870.56)	$ (151,662.84)	$ (135,212.97)	$ (51,639.40)	$ (968,413.77)
13 b Real-Time Asset Energy Amount - Congestion Component	$ (5,314.06)	$ (10,424.99)	$ (11,196.30)	$ (4,683.51)	$ (3,685.73)	$ (359.65)	$ 0.58	$ (38.40)	$ -	$ 147.89	$ 78.82	$ 999.61	$ (34,475.75)
22 b Real-Time Non-Asset Energy Amount - Congestion Component	$ (12.29)	$ 36.92	$ 125.84	$ 1,009.69	$ (3.12)	$ 0.02	$ (16.47)	$ 5,749.71	$ 9,237.62	$ 20,395.33	$ 6,055.14	$ (8,810.91)	$ 33,767.48
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	$ (67,731.29)	$ (186,227.87)	$ (515,698.88)	$ (368,898.09)	$ (174,132.87)	$ (208,896.23)	$ (96,633.64)	$ (98,924.56)	$ (317,549.71)	$ (339,772.41)	$ (375,383.79)	$ (60,298.99)	$ (2,810,148.34)
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ (6,353.02)	$ (5,753.98)	$ (9,129.12)	$ (14,133.31)	$ (3,517.33)	$ (4,814.90)	$ (6,123.06)	$ (6,251.44)	$ (10,256.06)	$ (7,848.47)	$ (6,737.22)	$ (2,922.24)	$ (83,840.16)
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ (1,739.35)	$ 8,687.42	$ 50,832.92	$ 16,040.55	$ 450.45	$ 19,411.64	$ 26,336.73	$ 26,470.54	$ 15,453.92	$ 17,637.38	$ (10,198.91)	$ 4,792.22	$ 174,175.51
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amou	$ (16,097.09)	$ (25,774.13)	$ (41,047.31)	$ (44,471.58)	$ (37,719.18)	$ (51,522.13)	$ (4,426.79)	$ (909.51)	$ (2,058.70)	$ (24,256.30)	$ (7,505.50)	$ (10,635.18)	$ (266,423.40)
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 35,469.81	$ 51,979.48	$ 138,699.53	$ 54,353.72	$ 782.26	$ 1,886.63	$ (14,822.44)	$ (7,012.43)	$ -	$ 9,842.50	$ 1,826.23	$ 51,099.69	$ 324,104.98
43 Real Time Price Volatility Make Whole Payment	$ 11,019.53	$ 7,821.08	$ 12,911.09	$ 23,728.10	$ 42,770.37	$ 11,633.29	$ 20,187.20	$ 8,040.28	$ 14,525.07	$ 19,777.25	$ 25,770.76	$ 17,664.67	$ 215,848.69
SUBTOTAL	$ 22,299.88	$ 36,959.87	$ 152,267.11	$ 35,517.48	$ 2,766.57	$ (23,405.47)	$ 21,151.64	$ 20,337.44	$ 17,664.22	$ 15,152.36	$ 3,155.36	$ 59,999.16	$ 363,865.63
Other MISO Charges													
20 Real-Time Miscellaneous Amount	$ 40,902.19	$ 42,258.91	$ 33,304.72	$ (8,805.23)	$ 12,121.76	$ 52,588.75	$ 17,534.72	$ 1,252.48	$ 19,100.32	$ 9,393.60	$ 9,706.72	$ 54,339.70	$ 283,698.64
21 Real-time Net inadvertent Distribution													
23 Real-Time Revenue Neutrality Uplift Amount	$ (8,143.95)	$ (11,730.37)	$ (31,428.28)	$ (19,009.43)	$ (4,314.32)	$ (7,470.29)	$ (60,965.58)	$ (22,313.26)	$ 45,764.67	$ (6,260.04)	$ (114,626.05)	$ 18,423.13	$ (222,073.75)
26 Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	-							$ -
SUBTOTAL	$ 32,758.24	$ 30,528.54	$ 1,876.44	$ (27,814.66)	$ 7,807.44	$ 45,118.46	$ (43,430.86)	$ (21,060.78)	$ 64,864.99	$ 3,133.56	$ (104,919.33)	$ 72,762.83	$ 61,624.89
Auction Revenue Rights (ARR)													
39 Auction Revenue Rights - FTR Auction Transactions													
40 Auction Revenue Rights - Monthly ARR Revenue	$ -	$ -	$ -	$ -	$ -	$ 9,706.72	$ 52,033.25	$ 50,303.72	$ 35,708.23	$ 38,172.66	$ 38,183.66	$ 44,288.40	$ 268,396.64
41 Auction Revenue Rights - ARR Stage 2 Distribution													
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue													
SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ 9,706.72	$ 52,033.25	$ 50,303.72	$ 35,708.23	$ 38,172.66	$ 38,183.66	$ 44,288.40	$ 268,396.64
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	$ 4,585,787.19	$ 5,110,228.98	$ 6,728,097.51	$ 7,332,156.48	$ 2,927,236.48	$ 7,531,290.52	$ 5,891,188.23	$ 6,032,520.98	$ 6,345,776.93	$ 7,840,559.36	$ 3,757,515.36	$ 2,541,359.09	$ 66,623,717.10

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - RETAIL

	July 15	August 15	September 15	October 15	November 15	December 15	January 16	February 16	March 16	April 16	May 16	June 16	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	$ 11,284,210.41	$ 14,632,238.20	$ 11,930,920.28	$ 8,868,538.72	$ 7,120,645.92	$ 3,976,352.03	$ 6,000,890.18	$ 8,223,310.89	$ 5,900,636.43	$ 1,442,089.31	$ 5,563,289.84	$ 8,663,977.01	$ 93,607,099.22
5 a Day-Ahead Non-Asset Energy Amount - Energy Component	$ (12,614,280.97)	$ (11,838,109.40)	$ (11,378,475.04)	$ (10,360,122.10)	$ (5,967,760.53)	$ (5,904,338.05)	$ (6,524,620.37)	$ (5,803,517.39)	$ (5,894,607.14)	$ (5,938,923.06)	$ (8,631,057.15)	$ (10,479,565.97)	$ (101,335,377.17)
13 a Real-Time Asset Energy Amount - Energy Component	$ 1,663,747.26	$ 1,978,560.59	$ 1,240,335.72	$ 612,238.18	$ 906,744.42	$ 755,209.32	$ 1,787,859.78	$ 1,128,429.78	$ 1,451,786.62	$ 1,500,859.68	$ (744,831.13)	$ 3,412,749.33	$ 15,693,689.55
22 a Real-Time Non-Asset Energy Amount - Energy Component	$ 401,830.71	$ 18,844.12	$ 8,595.58	$ 56,481.99	$ (0.73)	$ 505.06	$ 13.15	$ (716.14)	$ (11,690.73)	$ 4,284.51	$ 17,318.67	$ 244,045.95	$ 739,512.14
SUBTOTAL	$ 735,507.41	$ 4,791,533.51	$ 1,801,376.54	$ (822,863.21)	$ 2,059,629.08	$ (1,172,271.64)	$ 1,264,142.74	$ 3,547,507.14	$ 1,446,125.18	$ (2,991,689.56)	$ (3,795,279.77)	$ 1,841,206.32	$ 8,704,923.74
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	$ 3,147,787.71	$ 2,688,978.80	$ 2,439,121.08	$ 2,000,368.44	$ 2,196,069.54	$ 2,030,858.01	$ 2,677,575.69	$ 2,100,746.63	$ 1,471,960.14	$ 1,963,401.46	$ 1,512,478.06	$ 1,972,127.88	$ 26,201,473.43
3 Day-Ahead Financial Bilateral Transaction Loss Amount	$ (70.21)	$ (179.30)	$ 3,269.94	$ (380.42)	$ 563.53	$ 2,891.51	$ 3,425.24	$ 3,590.42	$ 655.03	$ 19.85	$ (1,002.89)	$ (2,221.02)	$ 10,561.68
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,199,916.16	$ 1,278,130.79	$ 942,347.42	$ 950,060.15	$ 559,610.29	$ 385,178.72	$ 463,053.87	$ 393,331.74	$ 564,486.43	$ 595,595.48	$ 924,117.08	$ 1,216,404.25	$ 9,472,232.40
13 c Real-Time Asset Energy Amount - Loss Component	$ 48,310.77	$ 27,063.84	$ 52,727.84	$ (8,054.98)	$ 5,769.46	$ (1,748.90)	$ (4,407.15)	$ 9,557.57	$ 20,822.99	$ 3,263.32	$ 54,253.05	$ (22,567.14)	$ 184,990.67
22 c Real-Time Non-Asset Energy Amount - Loss Component	$ (1,091.47)	$ (836.63)	$ (573.69)	$ (4,167.54)	$ (60.51)	$ 3.59	$ (916.10)	$ 551.06	$ 2,207.23	$ 984.18	$ 2,374.32	$ (24,072.44)	$ (25,597.99)
14 Real-Time Distribution of Losses Amount	$ (1,618,305.61)	$ (1,557,344.15)	$ (1,226,063.07)	$ (738,769.12)	$ (980,115.94)	$ (687,512.97)	$ (1,483,744.46)	$ (1,344,475.97)	$ (30,110.52)	$ (276,111.47)	$ (586,154.43)	$ (177,928.43)	$ (10,706,636.14)
16 Real-Time Financial Bilateral Transaction Loss Amount	$ 0.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.01	$ 6.08
SUBTOTAL	$ 2,776,547.42	$ 2,435,813.35	$ 2,210,829.52	$ 2,199,056.53	$ 1,781,836.37	$ 1,729,669.97	$ 1,654,987.09	$ 1,163,301.46	$ 2,030,021.30	$ 2,287,152.83	$ 1,906,065.18	$ 2,961,749.12	$ 25,137,030.13
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	$ 593,316.71	$ 530,979.56	$ 535,625.64	$ 511,072.57	$ 533,647.29	$ 564,573.12	$ 611,187.76	$ 594,267.16	$ 516,984.61	$ 498,117.93	$ 548,966.89	$ 575,825.03	$ 6,614,564.27
19 Real-Time Market Administration Amount	$ 32,328.98	$ 33,602.90	$ 32,457.78	$ 32,889.06	$ 42,160.75	$ 49,292.27	$ 40,741.38	$ 36,024.26	$ 35,599.04	$ 32,074.36	$ 35,386.65	$ 46,164.81	$ 448,722.24
29 Financial Transmission Rights Market Administration Amount	$ 26,067.44	$ 33,650.16	$ 25,266.24	$ 22,747.52	$ 19,141.60	$ 27,410.96	$ 27,851.04	$ 32,570.16	$ 27,470.08	$ 36,000.00	$ 29,130.00	$ 35,475.36	$ 342,780.56
33 Day-Ahead Schedule 24 Allocation Amount	$ 85,756.94	$ 81,381.18	$ 85,270.75	$ 76,251.41	$ 80,808.82	$ 82,223.60	$ 83,925.99	$ 80,281.62	$ 81,068.29	$ 84,252.43	$ 84,338.84	$ 89,856.50	$ 995,416.37
34 Real -Time Schedule 24 Allocation Amount	$ 22,171.40	$ 5,146.93	$ 4,967.95	$ 11,971.57	$ (7,364.32)	$ 16,799.32	$ (4,648.49)	$ 17,424.26	$ 1,316.21	$ 2,874.18	$ 11,281.15	$ (18,147.18)	$ 63,792.98
35 Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 759,641.47	$ 684,760.73	$ 683,588.36	$ 654,932.13	$ 668,394.14	$ 740,299.27	$ 759,057.68	$ 760,567.46	$ 662,438.23	$ 653,318.90	$ 709,103.53	$ 729,174.52	$ 8,465,276.42
Congestion Related Charges													
1 b Day-Ahead Asset Energy Amount - Congestion Component	$ 1,134,532.97	$ 2,605,055.99	$ 5,064,782.04	$ 1,292,830.81	$ 1,851,288.23	$ 1,123,885.23	$ 941,823.56	$ 698,929.29	$ 1,705,237.48	$ 1,284,771.99	$ 3,022,794.38	$ 29,856.55	$ 20,755,788.51
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 315,576.60	$ 619,695.55	$ 934,302.33	$ 1,433,886.19	$ 1,487,372.46	$ 603,248.00	$ 305,061.93	$ 360,390.88	$ 794,574.43	$ 933,858.53	$ 1,659,411.52	$ 1,817,497.45	$ 11,264,875.89
13 b Real-Time Asset Energy Amount - Congestion Component	$ 123,483.32	$ 191,185.42	$ 133,102.94	$ 34,966.49	$ 72,196.25	$ 2,978.64	$ (9,139.09)	$ (4,425.48)	$ 75,576.87	$ 5,042.76	$ 114,407.22	$ (153,385.84)	$ 585,989.49
22 b Real-Time Non-Asset Energy Amount - Congestion Component	$ 285.50	$ (676.99)	$ (1,495.94)	$ (7,538.25)	$ 61.20	$ (0.16)	$ (24.51)	$ 6,176.87	$ 9,237.62	$ 19,336.84	$ 5,009.03	$ (44,992.75)	$ (14,621.54)
2 Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (5,035.63)	$ 4,770.96	$ 17,359.37	$ (8,231.39)	$ (10,146.47)	$ 4,423.75	$ 1,928.72	$ (1,465.68)	$ (3,463.42)	$ (2,538.97)	$ (9,375.18)	$ (10,697.44)	$ (22,471.38)
15 Real-Time Financial Bilateral Transaction Congestion Amount	$ 1.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32.60	$ 33.60
28 Financial Transmission Rights Hourly Allocation Amount	$ (1,393,667.94)	$ (3,116,717.17)	$ (3,806,681.63)	$ (1,522,933.66)	$ (1,381,013.39)	$ (992,388.90)	$ (598,278.53)	$ (743,219.43)	$ (2,748,669.69)	$ (894,440.50)	$ (3,394,360.59)	$ (1,404,238.41)	$ (21,996,609.84)
30 Financial Transmission Rights Monthly Allocation Amount	$ (99,094.55)	$ (253,555.01)	$ (318,211.73)	$ (69,809.70)	$ (100,477.08)	$ (91,420.53)	$ (11,899.73)	$ (28,067.47)	$ (222,739.77)	$ (66,083.22)	$ (243,817.37)	$ (181,031.43)	$ (1,686,207.59)
32 Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (395,567.97)	$ -	$ -	$ (395,567.97)
31 Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	$ (58,202.42)	$ (123,309.40)	$ (68,287.15)	$ 131,266.47	$ (293,392.53)	$ (18,226.83)	$ 73,446.38	$ (5,613.72)	$ 21,499.66	$ 356,580.37	$ (20,228.52)	$ 82,809.64	$ 78,341.95
37 Financial Transmission Guarantee Uplift Amount	$ 55,575.36	$ 115,322.48	$ 72,603.84	$ (127,112.24)	$ 295,869.36	$ 4,048.29	$ (72,033.63)	$ 3,899.71	$ (21,190.58)	$ (322,802.23)	$ 24,475.48	$ (85,118.38)	$ (56,462.54)
38 Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 73,454.22	$ 41,771.82	$ 2,027,474.07	$ 1,157,324.73	$ 1,921,758.02	$ 636,547.49	$ 630,885.10	$ 286,604.98	$ (389,937.39)	$ 918,157.58	$ 1,158,315.97	$ 50,731.99	$ 8,513,088.57
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 147,625.84	$ 105,523.03	$ 108,528.07	$ 105,517.46	$ 68,897.61	$ 39,877.78	$ 79,020.20	$ 63,288.76	$ 78,455.40	$ 48,326.69	$ 82,683.04	$ 102,850.92	$ 1,030,594.79
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ (24,021.09)	$ (41,518.77)	$ (57,291.61)	$ (175,268.19)	$ (74,733.91)	$ (141,313.11)	$ (135,042.20)	$ (35,500.57)	$ 6,698.19	$ (45,066.76)	$ (23,156.09)	$ (37,324.49)	$ (783,538.60)
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amou	$ 181,288.54	$ 201,081.16	$ 364,004.15	$ 116,459.78	$ 51,104.11	$ 17,818.25	$ 57,129.23	$ 9,207.81	$ 15,748.37	$ 149,357.29	$ 92,111.77	$ 374,315.34	$ 1,629,625.80
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (46,914.62)	$ (67,108.52)	$ (169,208.26)	$ (89,739.38)	$ 27,334.59	$ (1,968.00)	$ (44,828.37)	$ (15,833.65)	$ -	$ (23,240.75)	$ (4,491.50)	$ (75,108.25)	$ (511,106.71)
43 Real Time Price Volatility Make Whole Payment	$ (226,747.23)	$ (205,934.18)	$ (242,296.51)	$ (370,592.22)	$ (161,810.77)	$ (228,087.04)	$ (86,161.36)	$ (102,159.19)	$ (141,525.14)	$ (149,267.43)	$ (163,490.42)	$ (198,548.58)	$ (2,276,620.07)
SUBTOTAL	$ 31,231.44	$ (7,957.28)	$ 3,735.84	$ (413,622.55)	$ (89,208.37)	$ (313,672.12)	$ (129,882.50)	$ (80,996.84)	$ (40,623.19)	$ (19,890.96)	$ (16,343.20)	$ 166,184.94	$ (911,044.78)
Other MISO Charges													
20 Real-Time Miscellaneous Amount	$ (6,331.28)	$ 1,789.06	$ (30,475.80)	$ 19,782.27	$ 25,871.05	$ 1,124,591.27	$ (38,603.93)	$ (38,900.97)	$ 100,877.93	$ 69,005.91	$ 34,885.56	$ 56,611.12	$ 1,319,102.19
21 Real-time Net inadvertent Distribution	$ (43,696.74)	$ 7,060.53	$ 9,693.52	$ (41,932.81)	$ (70,807.91)	$ (40,441.71)	$ (192,702.88)	$ 177,367.44	$ 823,222.09	$ 31,431.11	$ (731,048.92)	$ 730,335.15	$ 658,478.87
23 Real-Time Revenue Neutrality Uplift Amount	$ 382,002.64	$ 486,719.26	$ 497,594.52	$ 357,481.21	$ 772,248.84	$ 470,766.25	$ 786,781.89	$ 225,896.55	$ (350,084.17)	$ 38,545.99	$ 1,406,756.96	$ (648,419.48)	$ 4,426,290.48
26 Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 331,974.62	$ 495,568.85	$ 476,812.24	$ 335,330.67	$ 727,311.98	$ 1,554,915.81	$ 555,475.08	$ 364,363.02	$ 574,015.85	$ 138,983.01	$ 710,593.60	$ 138,526.79	$ 6,403,871.54
Auction Revenue Rights (ARR)													
39 Auction Revenue Rights - FTR Auction Transactions	$ 3,516,999.68	$ 3,516,999.68	$ 2,850,841.75	$ 2,850,841.75	$ 2,850,841.75	$ 3,770,129.38	$ 3,770,129.38	$ 3,770,129.38	$ 2,985,759.86	$ 2,985,759.86	$ 2,985,759.86	$ 2,398,660.25	$ 38,252,852.58
40 Auction Revenue Rights - Monthly ARR Revenue	$ (3,588,338.38)	$ (3,588,338.38)	$ (2,859,231.18)	$ (2,859,231.18)	$ (2,859,231.18)	$ (3,762,038.45)	$ (3,719,711.92)	$ (3,721,441.45)	$ (2,953,119.11)	$ (2,950,654.68)	$ (2,950,643.68)	$ (2,372,234.91)	$ (38,184,214.50)
41 Auction Revenue Rights - ARR Stage 2 Distribution	$ (83,283.16)	$ (92,074.58)	$ (400,833.24)	$ (406,713.43)	$ (406,713.43)	$ (186,462.01)	$ (187,052.38)	$ (187,052.38)	$ (204,803.54)	$ (202,532.65)	$ (203,542.70)	$ (78,450.07)	$ (2,639,513.57)
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 67,063.94	$ 66,234.82	$ 101,528.16	$ 101,942.72	$ 101,942.72	$ 66,371.33	$ 66,371.33	$ 66,371.33	$ 31,176.35	$ 31,176.35	$ 31,176.35	$ 78,282.87	$ 809,638.27
SUBTOTAL	$ (87,557.92)	$ (97,178.46)	$ (307,694.51)	$ (313,160.14)	$ (313,160.14)	$ (111,999.75)	$ (70,263.59)	$ (71,993.12)	$ (140,986.44)	$ (136,251.12)	$ (137,250.17)	$ 26,258.14	$ (1,761,237.22)
Grandfathered Charge Types													
6 Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 5,035.63	$ (4,770.96)	$ (17,359.37)	$ 8,231.39	$ 10,146.47	$ (4,423.75)	$ (1,928.72)	$ 1,465.68	$ 3,463.42	$ 2,538.97	$ 9,375.18	$ 10,697.44	$ 22,471.38
7 Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 70.21	$ 179.30	$ (3,269.94)	$ 380.42	$ (563.53)	$ (2,891.51)	$ (3,425.24)	$ (3,590.42)	$ (655.03)	$ (19.85)	$ 1,002.89	$ 2,221.01	$ (10,561.69)
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	$ (1.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (32.60)	$ (33.60)
18 Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (0.07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6.01)	$ (6.08)
SUBTOTAL	$ 5,104.77	$ (4,591.66)	$ (20,629.31)	$ 8,611.81	$ 9,582.94	$ (7,315.26)	$ (5,353.96)	$ (2,124.74)	$ 2,808.39	$ 2,519.12	$ 10,378.07	$ 12,879.84	$ 11,870.01
TOTAL MISO DAY 2 CHARGES	$ 4,625,903.43	$ 8,339,720.87	$ 6,875,492.76	$ 2,805,609.97	$ 6,766,144.02	$ 3,056,173.77	$ 4,659,047.64	$ 5,967,229.36	$ 4,143,861.93	$ 852,299.80	$ 545,583.22	$ 5,926,711.65	$ 54,563,778.41

Northern States Power Company

Docket No. E999/AA-16-523

Part J

Section 5

Schedule 6

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

	July 15	August 15	September 15	October 15	November 15	December 15	January 16	February 16	March 16	April 16	May 16	June 16	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	$ 8,411,872.15	$ 10,857,425.16	$ 8,850,736.67	$ 6,563,565.40	$ 5,181,965.72	$ 2,886,664.12	$ 4,324,100.98	$ 5,948,745.03	$ 4,277,243.09	$ 1,056,424.98	$ 4,092,462.77	$ 6,394,857.87	$ 68,846,063.94
5 a Day-Ahead Non-Asset Energy Amount - Energy Component	$ (9,403,380.02)	$ (8,784,123.46)	$ (8,440,915.19)	$ (7,667,479.51)	$ (4,342,967.03)	$ (4,286,300.79)	$ (4,701,488.69)	$ (4,198,265.84)	$ (4,272,872.59)	$ (4,350,650.56)	$ (6,349,171.28)	$ (7,734,939.15)	$ (74,532,554.12)
13 a Real-Time Asset Energy Amount - Energy Component	$ 1,240,248.87	$ 1,468,133.12	$ 920,120.54	$ 453,114.71	$ 659,872.51	$ 548,250.16	$ 1,288,289.90	$ 816,306.37	$ 1,052,368.57	$ 1,099,478.13	$ (547,912.07)	$ 2,518,941.00	$ 11,517,211.81
22 a Real-Time Non-Asset Energy Amount - Energy Component	$ 299,546.75	$ 13,982.73	$ 6,376.48	$ 41,802.07	$ (0.53)	$ 366.65	$ 9.48	$ (518.06)	$ (8,474.36)	$ 3,138.68	$ 12,739.95	$ 180,129.65	$ 549,099.49
SUBTOTAL	$ 548,287.75	$ 3,555,417.55	$ 1,336,318.49	$ (608,997.34)	$ 1,498,870.66	$ (851,019.84)	$ 910,911.66	$ 2,566,267.50	$ 1,048,264.71	$ (2,191,608.77)	$ (2,791,880.64)	$ 1,358,989.38	$ 6,379,821.11
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	$ 2,346,534.38	$ 1,995,278.22	$ 1,809,417.71	$ 1,480,463.63	$ 1,598,163.59	$ 1,474,317.39	$ 1,929,398.36	$ 1,519,680.61	$ 1,066,991.91	$ 1,438,320.31	$ 1,112,607.89	$ 1,455,622.22	$ 19,226,796.22
3 Day-Ahead Financial Bilateral Transaction Loss Amount	$ (52.34)	$ (133.04)	$ 2,425.75	$ (281.55)	$ 410.10	$ 2,099.11	$ 2,468.15	$ 2,597.31	$ 474.82	$ 14.54	$ (737.75)	$ (1,639.33)	$ 7,645.78
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	$ 894,483.61	$ 948,399.64	$ 699,063.33	$ 703,135.22	$ 407,249.76	$ 279,623.53	$ 333,665.78	$ 284,536.27	$ 409,183.94	$ 436,312.74	$ 679,798.26	$ 897,824.67	$ 6,973,276.77
13 c Real-Time Asset Energy Amount - Loss Component	$ 36,013.51	$ 20,081.93	$ 39,115.19	$ (5,961.46)	$ 4,198.66	$ (1,269.62)	$ (3,175.69)	$ 6,913.95	$ 15,094.13	$ 2,390.60	$ 39,909.58	$ (16,656.74)	$ 136,654.04
22 c Real-Time Non-Asset Energy Amount - Loss Component	$ (813.64)	$ (620.80)	$ (425.58)	$ (3,084.38)	$ (44.04)	$ 2.60	$ (660.12)	$ 398.64	$ 1,599.97	$ 720.98	$ 1,746.59	$ (17,767.80)	$ (18,947.56)
14 Real-Time Distribution of Losses Amount	$ (1,206,374.16)	$ (1,155,581.76)	$ (909,532.64)	$ (546,759.68)	$ (713,267.76)	$ (499,105.46)	$ (1,069,151.52)	$ (972,594.23)	$ (21,826.46)	$ (202,269.76)	$ (431,186.45)	$ (131,328.49)	$ (7,858,978.38)
16 Real-Time Financial Bilateral Transaction Loss Amount	$ 0.05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.44	$ 4.49
SUBTOTAL	$ 2,069,791.42	$ 1,807,424.18	$ 1,640,063.76	$ 1,627,511.79	$ 1,296,710.31	$ 1,255,667.56	$ 1,192,544.95	$ 841,532.55	$ 1,471,518.32	$ 1,675,489.42	$ 1,402,138.12	$ 2,186,058.97	$ 18,466,451.35
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	$ 442,290.96	$ 393,997.88	$ 397,344.16	$ 378,242.50	$ 388,355.49	$ 409,856.31	$ 440,407.59	$ 429,893.00	$ 374,750.91	$ 364,904.05	$ 403,830.58	$ 425,014.89	$ 4,848,888.32
19 Real-Time Market Administration Amount	$ 24,099.80	$ 24,934.05	$ 24,078.21	$ 24,341.04	$ 30,681.99	$ 35,784.11	$ 29,357.28	$ 26,059.96	$ 25,804.97	$ 23,496.57	$ 26,031.10	$ 34,074.12	$ 328,743.22
29 Financial Transmission Rights Market Administration Amount	$ 19,432.11	$ 24,969.12	$ 18,743.30	$ 16,835.34	$ 13,930.07	$ 19,899.20	$ 20,068.81	$ 23,561.26	$ 19,912.46	$ 26,372.36	$ 21,428.59	$ 26,184.27	$ 251,336.89
33 Day-Ahead Schedule 24 Allocation Amount	$ 63,927.95	$ 60,386.53	$ 63,256.56	$ 56,433.32	$ 58,807.66	$ 59,690.87	$ 60,475.10	$ 58,075.74	$ 58,764.64	$ 61,720.43	$ 62,041.27	$ 66,322.84	$ 729,902.92
34 Real -Time Schedule 24 Allocation Amount	$ 16,527.78	$ 3,819.13	$ 3,685.38	$ 8,860.10	$ (5,359.30)	$ 12,195.60	$ (3,349.59)	$ 12,604.71	$ 954.09	$ 2,105.53	$ 8,298.63	$ (13,394.38)	$ 46,947.69
35 Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 566,278.60	$ 508,106.71	$ 507,107.62	$ 484,712.31	$ 486,415.92	$ 537,426.10	$ 546,959.19	$ 550,194.68	$ 480,187.07	$ 478,598.93	$ 521,630.17	$ 538,201.73	$ 6,205,819.03
Congestion Related Charges													$ -
1 b Day-Ahead Asset Energy Amount - Congestion Component	$ 845,743.38	$ 1,933,005.74	$ 3,757,216.63	$ 956,818.24	$ 1,347,253.08	$ 815,893.35	$ 678,656.01	$ 505,605.62	$ 1,236,089.59	$ 941,179.72	$ 2,223,625.56	$ 22,037.03	$ 15,263,123.94
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 235,248.19	$ 459,826.99	$ 693,095.23	$ 1,061,212.69	$ 1,082,417.69	$ 437,932.64	$ 219,820.49	$ 260,706.85	$ 575,969.73	$ 684,112.60	$ 1,220,694.96	$ 1,341,489.93	$ 8,272,527.99
13 b Real-Time Asset Energy Amount - Congestion Component	$ 92,051.27	$ 141,863.56	$ 98,740.00	$ 25,878.54	$ 52,539.96	$ 2,162.37	$ (6,585.42)	$ (3,201.39)	$ 54,784.03	$ 3,694.15	$ 84,160.14	$ (113,213.67)	$ 432,873.55
22 b Real-Time Non-Asset Energy Amount - Congestion Component	$ 212.83	$ (502.34)	$ (1,109.74)	$ (5,579.02)	$ 44.53	$ (0.12)	$ (17.66)	$ 4,468.35	$ 6,696.15	$ 14,165.50	$ 3,684.74	$ (33,209.03)	$ (11,145.80)
2 Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (3,753.84)	$ 3,540.15	$ 12,877.73	$ (6,092.01)	$ (7,383.97)	$ 3,211.46	$ 1,389.79	$ (1,060.27)	$ (2,510.56)	$ (1,859.96)	$ (6,896.56)	$ (7,895.75)	$ (16,433.80)
15 Real-Time Financial Bilateral Transaction Congestion Amount	$ 0.75	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24.06	$ 24.81
28 Financial Transmission Rights Hourly Allocation Amount	$ (1,038,916.87)	$ (2,312,668.98)	$ (2,823,917.68)	$ (1,127,116.31)	$ (1,005,016.14)	$ (720,432.55)	$ (431,105.50)	$ (537,645.11)	$ (1,992,450.91)	$ (655,236.31)	$ (2,496,956.79)	$ (1,036,464.55)	$ (16,177,927.71)
30 Financial Transmission Rights Monthly Allocation Amount	$ (73,870.54)	$ (188,143.09)	$ (236,059.60)	$ (51,665.84)	$ (73,121.00)	$ (66,367.45)	$ (8,574.67)	$ (20,304.01)	$ (161,459.22)	$ (48,410.29)	$ (179,356.74)	$ (133,618.81)	$ (1,240,951.26)
32 Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (289,779.48)	$ -	$ -	$ (289,779.48)
31 Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	$ (43,387.29)	$ (91,498.14)	$ (50,657.58)	$ 97,149.72	$ (213,512.94)	$ (13,231.91)	$ 52,923.74	$ (4,060.97)	$ 15,584.64	$ 261,218.50	$ (14,880.49)	$ 61,121.57	$ 56,768.85
37 Financial Transmission Guarantee Uplift Amount	$ 41,428.94	$ 85,571.68	$ 53,859.84	$ (94,075.19)	$ 215,315.42	$ 2,938.89	$ (51,905.75)	$ 2,821.05	$ (15,360.59)	$ (236,473.80)	$ 18,004.63	$ (62,825.64)	$ (40,700.53)
38 Financial Transmission Rights Monthly Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 54,756.82	$ 30,995.56	$ 1,504,044.84	$ 856,530.80	$ 1,398,536.63	$ 462,106.67	$ 454,601.04	$ 207,330.11	$ (282,657.14)	$ 672,610.63	$ 852,079.46	$ 37,445.14	$ 6,248,380.56
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 110,048.43	$ 78,300.29	$ 80,509.58	$ 78,092.99	$ 50,139.42	$ 28,949.59	$ 56,940.11	$ 45,783.10	$ 56,870.61	$ 35,402.47	$ 60,823.23	$ 75,913.99	$ 757,773.80
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ (17,906.64)	$ (30,807.79)	$ (42,500.74)	$ (129,715.19)	$ (54,386.72)	$ (102,587.37)	$ (97,308.25)	$ (25,681.12)	$ 4,855.37	$ (33,014.36)	$ (17,034.06)	$ (27,549.10)	$ (573,635.98)
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amou	$ 135,142.47	$ 149,206.41	$ 270,029.87	$ 86,191.35	$ 37,190.41	$ 12,935.30	$ 41,165.99	$ 6,660.93	$ 11,415.65	$ 109,414.01	$ 67,759.19	$ 276,281.13	$ 1,203,392.71
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (34,972.74)	$ (49,795.92)	$ (125,524.08)	$ (66,415.71)	$ 19,892.42	$ (1,428.69)	$ (32,302.27)	$ (11,454.07)	$ -	$ (17,025.37)	$ (3,304.03)	$ (55,437.20)	$ (377,767.65)
43 Real Time Price Volatility Make Whole Payment	$ (169,029.88)	$ (152,807.45)	$ (179,743.27)	$ (274,273.63)	$ (117,755.87)	$ (165,581.59)	$ (62,085.86)	$ (73,901.98)	$ (102,588.50)	$ (109,348.18)	$ (120,266.69)	$ (146,548.17)	$ (1,673,931.05)
SUBTOTAL	$ 23,281.64	$ (5,904.46)	$ 2,771.36	$ (306,120.18)	$ (64,920.34)	$ (227,712.75)	$ (93,590.29)	$ (58,593.13)	$ (29,446.86)	$ (14,571.43)	$ (12,022.37)	$ 122,660.65	$ (664,168.16)
Other MISO Charges													
20 Real-Time Miscellaneous Amount	$ (4,719.68)	$ 1,327.52	$ (22,607.92)	$ 14,640.77	$ 18,827.35	$ 816,405.90	$ (27,817.09)	$ (28,140.97)	$ 73,124.22	$ 50,551.35	$ 25,662.49	$ 41,784.51	$ 959,038.45
21 Real-time Net inadvertent Distribution	$ (32,573.96)	$ 5,239.06	$ 7,190.96	$ (31,034.28)	$ (51,529.62)	$ (29,358.98)	$ (138,857.18)	$ 128,307.65	$ 596,735.80	$ 23,025.35	$ (537,773.62)	$ 539,058.39	$ 478,429.57
23 Real-Time Revenue Neutrality Uplift Amount	$ 284,765.82	$ 361,155.82	$ 369,131.47	$ 264,570.23	$ 561,994.95	$ 341,756.48	$ 566,936.61	$ 163,413.62	$ (253,768.40)	$ 28,237.46	$ 1,034,837.42	$ (478,596.66)	$ 3,244,434.81
26 Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 247,472.17	$ 367,722.40	$ 353,714.51	$ 248,176.71	$ 529,292.68	$ 1,128,803.40	$ 400,262.34	$ 263,580.30	$ 416,091.61	$ 101,814.17	$ 522,726.29	$ 102,246.25	$ 4,681,902.83
Auction Revenue Rights (ARR)													
39 Auction Revenue Rights - FTR Auction Transactions	$ 2,621,765.33	$ 2,609,686.93	$ 2,114,845.21	$ 2,109,895.09	$ 2,074,666.31	$ 2,736,955.17	$ 2,716,666.97	$ 2,727,312.48	$ 2,164,312.42	$ 2,187,264.87	$ 2,196,382.25	$ 1,770,444.61	$ 28,030,197.65
40 Auction Revenue Rights - Monthly ARR Revenue	$ (2,674,945.13)	$ (2,662,621.73)	$ (2,121,068.76)	$ (2,116,104.07)	$ (2,080,771.62)	$ (2,731,081.49)	$ (2,680,337.33)	$ (2,692,091.62)	$ (2,140,651.85)	$ (2,161,548.03)	$ (2,170,550.12)	$ (1,750,940.14)	$ (27,982,711.88)
41 Auction Revenue Rights - ARR Stage 2 Distribution	$ (62,083.86)	$ (68,321.25)	$ (297,350.86)	$ (301,006.77)	$ (295,980.88)	$ (135,363.57)	$ (134,785.57)	$ (135,313.74)	$ (148,457.63)	$ (148,368.45)	$ (149,729.92)	$ (57,903.78)	$ (1,934,666.27)
42 Auction Revenue Rights - Monthly infeasible ARR Revenue	$ 49,993.16	$ 49,147.61	$ 75,316.82	$ 75,447.35	$ 74,187.61	$ 48,182.79	$ 47,825.63	$ 48,013.04	$ 22,599.06	$ 22,838.72	$ 22,933.92	$ 57,780.37	$ 594,266.07
SUBTOTAL	$ (65,270.50)	$ (72,108.44)	$ (228,257.59)	$ (231,768.40)	$ (227,898.58)	$ (81,307.10)	$ (50,630.30)	$ (52,079.84)	$ (102,198.01)	$ (99,812.88)	$ (100,963.86)	$ 19,381.06	$ (1,292,914.43)
Grandfathered Charge Types													
6 Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 3,753.84	$ (3,540.15)	$ (12,877.73)	$ 6,092.01	$ 7,383.97	$ (3,211.46)	$ (1,389.79)	$ 1,060.27	$ 2,510.56	$ 1,859.96	$ 6,896.56	$ 7,895.75	$ 16,433.80
7 Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ 52.34	$ 133.04	$ (2,425.75)	$ 281.55	$ (410.10)	$ (2,099.11)	$ (2,468.15)	$ (2,597.31)	$ (474.82)	$ (14.54)	$ 737.75	$ 1,639.32	$ (7,645.78)
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	$ (0.75)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (24.06)	$ (24.81)
18 Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ (0.05)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (4.44)	$ (4.49)
SUBTOTAL	$ 3,805.38	$ (3,407.11)	$ (15,303.48)	$ 6,373.56	$ 6,973.87	$ (5,310.57)	$ (3,857.94)	$ (1,537.04)	$ 2,035.74	$ 1,845.42	$ 7,634.31	$ 9,506.57	$ 8,758.72
TOTAL MISO DAY 2 CHARGES	$ 3,448,403.28	$ 6,188,246.39	$ 5,100,459.52	$ 2,076,419.25	$ 4,923,981.16	$ 2,218,653.46	$ 3,357,200.66	$ 4,316,695.11	$ 3,003,795.44	$ 624,365.49	$ 401,341.49	$ 4,374,489.75	$ 40,034,051.00

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT ****NOTE 1****

July 2015					**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	217,537	$7,692,379	353,508	$ 11,284,210.41	(135,971)	($3,591,831)		
5a Day Ahead Non Asset Energy	(400,366)	($12,614,281)	(400,366)	($12,614,281)			93,530	$2,675,028
13a Real Time Asset Energy	19,284	$574,075	60,289	$1,663,747	(41,005)	($1,089,672)		
22a Real Time Non Asset Energy	1,130	$401,831	1,130	$401,831				
SUBTOTAL	(162,415)	($3,945,996)	14,561	$ 735,507.41	(176,976)	($4,681,503)	93,530	$2,675,028
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,283,251.62		$3,147,788		$ 135,463.91		
5c Day Ahead Non Asset Loss		$ 1,251,554.12		$1,199,916		$ 51,637.96		
3 Day Ahead Financial Bilateral Transaction Loss		$ (70.21)		($70)				
13c Real Time Loss		$ 50,389.81		$48,311		$ 2,079.04		
22c Real Time Non Asset Loss		$ (1,138.44)		($1,091)		$ (46.97)		
14 Real Time Distribution Losses		$ (1,618,305.61)		($1,618,306)				
16 Real Time Financial Bilateral Loss		$ 0.07		$0				
SUBTOTAL	-	$ 2,965,681.36	-	$2,776,547	-	$189,134	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 603,358.36		$593,317		$ 10,041.65		$6,406
19 Real Time Market Administration (Schedule 17)		$ 35,141.17		$32,329		$ 2,812.19		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 26,067.44		$26,067		$ -		$7,135
33 Day-Ahead Schedule 24 Allocation Amount		$ 87,199.99		$85,757		$ 1,443.05		$925
34 Real -Time Schedule 24 Allocation Amount		$ (98,216.85)		$22,171		$ (120,388.25)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 653,550.11	-	$759,641	-	$ (106,091.36)	-	$14,467
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,183,357.19		$1,134,533		$ 48,824.22		
5b Day Ahead Non Asset Congestion		$ 329,157.33		$315,577		$ 13,580.73		
13b Real Time Congestion		$ 128,797.38		$123,483		$ 5,314.06		
22b Real Time Non Asset Congestion		$ 297.79		$286		$ 12.29		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (5,035.63)		($5,036)				
15 Real Time Financial Bilateral Congestion		$ 1.00		$1				
28 Financial Transmission Rights Hourly Allocation		$ (1,393,667.94)		($1,393,668)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (99,094.55)		($99,095)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (58,202.42)		($58,202)				
37 Financial Transmission Guarantee Uplift Amount		$ 55,575.36		$55,575				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 141,185.51	-	$73,454	-	$ 67,731.29	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 153,978.86		$ 147,625.84		$ 6,353		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (22,281.74)		($24,021)		$ 1,739		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 197,385.63		$181,289		$ 16,097		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (82,384.43)		($46,915)		$ (35,470)		
43 Real Time Price Volatility Make Whole Payment		($237,767)		($226,747)		$ (11,020)		
SUBTOTAL	-	$ 8,931.56	-	$ 31,231.44	-	$ (22,300)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (47,233.47)		($6,331)		$ (40,902.19)		$0
21 Real Time Net Inadvertent Distribution		$ (43,696.74)		($43,697)				($481)
23 Real Time Revenue Neutrality Uplift Amount		$ 390,146.59		$382,003		$ 8,144		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 299,216.38	-	$331,975	-	$ (32,758)	-	($481)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,516,999.68		$3,517,000				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,588,338.38)		($3,588,338)		$ -		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (83,283.16)		($83,283)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 67,063.94		$67,064				
SUBTOTAL	-	$ (87,557.92)	-	($87,558)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 5,035.63		$5,036				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 70.21		$70				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ (1.00)		($1)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (0.07)		($0)				
SUBTOTAL	-	$ 5,104.77	-	$5,105	-	$0	-	$0
Total MISO Day 2 Charges	(162,415)	$ 40,116.24	14,561	$ 4,625,903.43	(176,976)	$ (4,585,787.19)	93,530	$ 2,689,014

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 - NEW FORMAT **NOTE 1**

August 2015					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	302,407	$10,278,134	480,772	$ 14,632,238.20	(178,365)	($4,354,104)		
5a Day Ahead Non Asset Energy	(389,793)	($11,838,109)	(389,793)	($11,838,109)			92,707	$2,367,350
13a Real Time Asset Energy	42,110	$974,557	82,793	$1,978,561	(40,683)	($1,004,004)		
22a Real Time Non Asset Energy	695	$18,844	695	$18,844				
SUBTOTAL	(44,581)	($566,575)	174,467	$ 4,791,533.51	(219,048)	($5,358,108)	92,707	$2,367,350
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,835,603.89		$2,688,979		$ 146,625.09		
5c Day Ahead Non Asset Loss		$ 1,347,824.92		$1,278,131		$ 69,694.13		
3 Day Ahead Financial Bilateral Transaction Loss		$ (179.30)		($179)				
13c Real Time Loss		$ 28,539.58		$27,064		$ 1,475.74		
22c Real Time Non Asset Loss		$ (882.25)		($837)		$ (45.62)		
14 Real Time Distribution Losses		$ (1,557,344.15)		($1,557,344)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,653,562.69	-	$2,435,813	-	$217,749	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 542,745.68		$530,980		$ 11,766.12		$5,602
19 Real Time Market Administration (Schedule 17)		$ 36,294.41		$33,603		$ 2,691.51		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 33,650.16		$33,650		$ -		$7,957
33 Day-Ahead Schedule 24 Allocation Amount		$ 83,182.21		$81,381		$ 1,801.03		$845
34 Real -Time Schedule 24 Allocation Amount		$ (99,721.35)		$5,147		$ (104,868.28)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 596,151.11	-	$684,761	-	$ (88,609.62)	-	$14,403
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,747,104.92		$2,605,056		$ 142,048.93		
5b Day Ahead Non Asset Congestion		$ 653,486.41		$619,696		$ 33,790.86		
13b Real Time Congestion		$ 201,610.41		$191,185		$ 10,424.99		
22b Real Time Non Asset Congestion		$ (713.91)		($677)		$ (36.92)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 4,770.96		$4,771				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (3,116,717.17)		($3,116,717)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (253,555.01)		($253,555)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (123,309.40)		($123,309)				
37 Financial Transmission Guarantee Uplift Amount		$ 115,322.48		$115,322				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 227,999.69	-	$41,772	-	$ 186,227.87	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 111,277.01		$ 105,523.03		$ 5,753.98		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (50,206.19)		($41,519)		$ (8,687.42)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 226,855.29		$201,081		$ 25,774.13		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (119,088.00)		($67,109)		$ (51,979.48)		
43 Real Time Price Volatility Make Whole Payment		($213,755)		($205,934)		($7,821)		
SUBTOTAL	-	$ (44,917.15)	-	$ (7,957.28)	-	($36,960)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (40,469.85)		$1,789		$ (42,258.91)		$0
21 Real Time Net Inadvertent Distribution		$ 7,060.53		$7,061				$169
23 Real Time Revenue Neutrality Uplift Amount		$ 498,449.63		$486,719		$ 11,730.37		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 465,040.31	-	$495,569	-	$ (30,528.54)	-	$169
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,516,999.68		$3,517,000				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,588,338.38)		($3,588,338)		$ -		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (92,074.58)		($92,075)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 66,234.82		$66,235				
SUBTOTAL	-	$ (97,178.46)	-	($97,178)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (4,770.96)		($4,771)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 179.30		$179				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
SUBTOTAL	-	$ (4,591.66)	-	($4,592)	-	$0	-	$0
Total MISO Day 2 Charges	(44,581)	$ 3,229,491.89	174,467	$ 8,339,720.87	(219,048)	$ (5,110,228.98)	92,707	$ 2,381,923

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 - NEW FORMAT **NOTE 1**

September 2015	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	145,376	$6,386,106	375,549	$ 11,930,920.28	(230,173)	($5,544,814)		
5a Day Ahead Non Asset Energy	(386,889)	($11,378,475)	(386,889)	($11,378,475)			89,996	$2,614,339
13a Real Time Asset Energy	(20,919)	($517,359)	59,526	$1,240,336	(80,445)	($1,757,695)		
22a Real Time Non Asset Energy	334	$8,596	334	$8,596				
SUBTOTAL	(262,098)	($5,501,133)	48,520	$ 1,801,376.54	(310,618)	($7,302,509)	89,996	$2,614,339
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,644,294.03		$2,439,121		$ 205,172.95		
5c Day Ahead Non Asset Loss		$ 1,021,615.40		$942,347		$ 79,267.98		
3 Day Ahead Financial Bilateral Transaction Loss		$ 3,269.94		$3,270				
13c Real Time Loss		$ 57,163.18		$52,728		$ 4,435.34		
22c Real Time Non Asset Loss		$ (621.95)		($574)		$ (48.26)		
14 Real Time Distribution Losses		$ (1,226,063.07)		($1,226,063)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,499,657.53	-	$2,210,830	-	$288,828	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 551,580.38		$535,626		$ 15,954.74		$6,727
19 Real Time Market Administration (Schedule 17)		$ 38,029.43		$32,458		$ 5,571.65		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 25,266.24		$25,266		$ -		$10,357
33 Day-Ahead Schedule 24 Allocation Amount		$ 87,805.56		$85,271		$ 2,534.81		$1,081
34 Real -Time Schedule 24 Allocation Amount		$ (95,065.04)		$4,968		$ (100,032.99)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 607,616.57	-	$683,588	-	$ (75,971.79)	-	$18,165
Congestion & FTRs								
1b Day Ahead Congestion		$ 5,490,819.21		$5,064,782		$ 426,037.17		
5b Day Ahead Non Asset Congestion		$ 1,012,893.58		$934,302		$ 78,591.25		
13b Real Time Congestion		$ 144,299.24		$133,103		$ 11,196.30		
22b Real Time Non Asset Congestion		$ (1,621.78)		($1,496)		$ (125.84)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 17,359.37		$17,359				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (3,806,681.63)		($3,806,682)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (318,211.73)		($318,212)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (68,287.15)		($68,287)				
37 Financial Transmission Guarantee Uplift Amount		$ 72,603.84		$72,604				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 2,543,172.95	-	$2,027,474	-	$ 515,698.88	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 117,657.19		$ 108,528.07		$ 9,129.12		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (108,124.53)		($57,292)		$ (50,832.92)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 405,051.46		$364,004		$ 41,047.31		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (307,907.79)		($169,208)		$ (138,699.53)		
43 Real Time Price Volatility Make Whole Payment		($255,208)		($242,297)		($12,911)		
SUBTOTAL	-	$ (148,531.27)	-	$ 3,735.84	-	($152,267)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (63,780.52)		($30,476)		$ (33,304.72)		$0
21 Real Time Net Inadvertent Distribution		$ 9,693.52		$9,694				$52
23 Real Time Revenue Neutrality Uplift Amount		$ 529,022.80		$497,595		$ 31,428.28		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 474,935.80	-	$476,812	-	$ (1,876.44)	-	$52
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,850,841.75		$2,850,842				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,859,231.18)		($2,859,231)		$ -		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (400,833.24)		($400,833)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 101,528.16		$101,528				
SUBTOTAL	-	$ (307,694.51)	-	($307,695)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (17,359.37)		($17,359)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,269.94)		($3,270)				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
SUBTOTAL	-	$ (20,629.31)	-	($20,629)	-	$0	-	$0
Total MISO Day 2 Charges	(262,098)	$ 147,395.25	48,520	$ 6,875,492.76	(310,618)	$ (6,728,097.51)	89,996	$ 2,632,555

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, A Minnesota Corporation Docket No. E999/AA-16-523
Electric Operations - State of Minnesota Part J, Section 5
MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT **NOTE 1** Schedule 7

October 2015	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	(27,526)	$1,632,817	353,016	$ 8,868,538.72	(380,542)	($7,235,722)		
5a Day Ahead Non Asset Energy	(386,457)	($10,360,122)	(386,457)	($10,360,122)			93,118	$2,220,025
13a Real Time Asset Energy	2,913	($175,138)	55,056	$612,238	(52,143)	($787,376)		
22a Real Time Non Asset Energy	2,253	$56,482	2,253	$56,482				
SUBTOTAL	(408,817)	($8,845,961)	23,868	$ (822,863.21)	(432,685)	($8,023,098)	93,118	$2,220,025
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,268,303.51		$2,000,368		$ 267,935.07		
5c Day Ahead Non Asset Loss		$ 1,077,313.93		$950,060		$ 127,253.78		
3 Day Ahead Financial Bilateral Transaction Loss		$ (380.42)		($380)				
13c Real Time Loss		$ (9,133.89)		($8,055)		$ (1,078.91)		
22c Real Time Non Asset Loss		$ (4,725.75)		($4,168)		$ (558.21)		
14 Real Time Distribution Losses		$ (738,769.12)		($738,769)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,592,608.26	-	$2,199,057	-	$393,552	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 539,384.60		$511,073		$ 28,312.03		$6,929
19 Real Time Market Administration (Schedule 17)		$ 36,784.13		$32,889		$ 3,895.07		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 22,747.52		$22,748		$ -		$6,936
33 Day-Ahead Schedule 24 Allocation Amount		$ 80,474.18		$76,251		$ 4,222.77		$1,032
34 Real -Time Schedule 24 Allocation Amount		$ (88,264.19)		$11,972		$ (100,235.76)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 591,126.24	-	$654,932	-	$ (63,805.89)	-	$14,897
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,465,996.27		$1,292,831		$ 173,165.46		
5b Day Ahead Non Asset Congestion		$ 1,625,945.01		$1,433,886		$ 192,058.82		
13b Real Time Congestion		$ 39,650.00		$34,966		$ 4,683.51		
22b Real Time Non Asset Congestion		$ (8,547.94)		($7,538)		$ (1,009.69)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (8,231.39)		($8,231)				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (1,522,933.66)		($1,522,934)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (69,809.70)		($69,810)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 131,266.47		$131,266				
37 Financial Transmission Guarantee Uplift Amount		$ (127,112.24)		($127,112)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 1,526,222.82	-	$1,157,325	-	$ 368,898.09	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 119,650.77		$ 105,517.46		$ 14,133.31		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (191,308.74)		($175,268)		$ (16,040.55)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 160,931.36		$116,460		$ 44,471.58		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (144,093.10)		($89,739)		$ (54,353.72)		
43 Real Time Price Volatility Make Whole Payment		($394,320)		($370,592)		($23,728)		
SUBTOTAL	-	$ (449,140.03)	-	$ (413,622.55)	-	($35,517)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ 28,587.50		$19,782		$ 8,805.23		$0
21 Real Time Net Inadvertent Distribution		$ (41,932.81)		($41,933)				($462)
23 Real Time Revenue Neutrality Uplift Amount		$ 376,490.64		$357,481		$ 19,009.43		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 363,145.33	-	$335,331	-	$ 27,814.66	-	($462)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,850,841.75		$2,850,842				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,859,231.18)		($2,859,231)		$ -		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (406,713.43)		($406,713)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 101,942.72		$101,943				
SUBTOTAL	-	$ (313,160.14)	-	($313,160)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 8,231.39		$8,231				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 380.42		$380				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
SUBTOTAL	-	$ 8,611.81	-	$8,612	-	$0	-	$0
Total MISO Day 2 Charges	(408,817)	$ (4,526,546.51)	23,868	$ 2,805,609.97	(432,685)	$ (7,332,156.48)	93,118	$ 2,234,461

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 - NEW FORMAT **NOTE 1**

November 2015	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	212,261	$4,857,048	332,818	$ 7,120,645.92	(120,557)	($2,263,598)		
5a Day Ahead Non Asset Energy	(254,669)	($5,967,761)	(254,669)	($5,967,761)			89,584	$1,678,029
13a Real Time Asset Energy	(1,884)	$10,824	49,061	$906,744	(50,945)	($895,920)		
22a Real Time Non Asset Energy	-	($1)	-	($1)				
SUBTOTAL	(44,292)	($1,099,889)	127,210	$ 2,059,629.08	(171,502)	($3,159,518)	89,584	$1,678,029
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,308,182.43		$2,196,070		$ 112,112.89		
5c Day Ahead Non Asset Loss		$ 588,179.30		$559,610		$ 28,569.01		
3 Day Ahead Financial Bilateral Transaction Loss		$ 563.53		$564				
13c Real Time Loss		$ 6,064.00		$5,769		$ 294.54		
22c Real Time Non Asset Loss		$ (63.60)		($61)		$ (3.09)		
14 Real Time Distribution Losses		$ (980,115.94)		($980,116)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 1,922,809.72	-	$1,781,836	-	$140,973	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 543,492.38		$533,647		$ 9,845.09		$7,158
19 Real Time Market Administration (Schedule 17)		$ 46,295.87		$42,161		$ 4,135.12		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 19,141.60		$19,142		$ -		$4,647
33 Day-Ahead Schedule 24 Allocation Amount		$ 82,305.92		$80,809		$ 1,497.10		$1,086
34 Real -Time Schedule 24 Allocation Amount		$ (95,092.03)		($7,364)		$ (87,727.71)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 596,143.74	-	$668,394	-	$ (72,250.40)	-	$12,890
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,945,799.48		$1,851,288		$ 94,511.25		
5b Day Ahead Non Asset Congestion		$ 1,563,305.22		$1,487,372		$ 75,932.76		
13b Real Time Congestion		$ 75,881.98		$72,196		$ 3,685.73		
22b Real Time Non Asset Congestion		$ 64.32		$61		$ 3.12		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (10,146.47)		($10,146)				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (1,381,013.39)		($1,381,013)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (100,477.08)		($100,477)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (293,392.53)		($293,393)				
37 Financial Transmission Guarantee Uplift Amount		$ 295,869.36		$295,869				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 2,095,890.89	-	$1,921,758	-	$ 174,132.87	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 72,414.94		$ 68,897.61		$ 3,517.33		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (75,184.36)		($74,734)		$ (450.45)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 88,823.29		$51,104		$ 37,719.18		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ 26,552.33		$27,335		$ (782.26)		
43 Real Time Price Volatility Make Whole Payment		($204,581)		($161,811)		($42,770)		
SUBTOTAL	-	$ (91,974.94)	-	$ (89,208.37)	-	($2,767)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ 13,749.29		$25,871		$ (12,121.76)		$0
21 Real Time Net Inadvertent Distribution		$ (70,807.91)		($70,808)				($860)
23 Real Time Revenue Neutrality Uplift Amount		$ 776,563.16		$772,249		$ 4,314.32		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 719,504.54	-	$727,312	-	$ (7,807.44)	-	($860)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,850,841.75		$2,850,842				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,859,231.18)		($2,859,231)		$ -		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (406,713.43)		($406,713)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 101,942.72		$101,943				
SUBTOTAL	-	$ (313,160.14)	-	($313,160)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 10,146.47		$10,146				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (563.53)		($564)				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
SUBTOTAL	-	$ 9,582.94	-	$9,583	-	$0	-	$0
Total MISO Day 2 Charges	(44,292)	$ 3,838,907.54	127,210	$ 6,766,144.02	(171,502)	$ (2,927,236.48)	89,584	$ 1,690,060

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 - NEW FORMAT **NOTE 1**

December 2015	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	(223,728)	($3,161,850)	181,608	$ 3,976,352.03	(405,336)	($7,138,202)		
5a Day Ahead Non Asset Energy	(266,001)	($5,904,338)	(266,001)	($5,904,338)			93,119	$1,937,726
13a Real Time Asset Energy	9,811	($35,574)	56,716	$755,209	(46,905)	($790,783)		
22a Real Time Non Asset Energy	24	$505	24	$505				
SUBTOTAL	(479,894)	($9,101,257)	(27,653)	$ (1,172,271.64)	(452,241)	($7,928,985)	93,119	$1,937,726
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,276,066.79		$2,030,858		$ 245,208.78		
5c Day Ahead Non Asset Loss		$ 431,685.77		$385,179		$ 46,507.05		
3 Day Ahead Financial Bilateral Transaction Loss		$ 2,891.51		$2,892				
13c Real Time Loss		$ (1,960.06)		($1,749)		$ (211.16)		
22c Real Time Non Asset Loss		$ 4.02		$4		$ 0.43		
14 Real Time Distribution Losses		$ (687,512.97)		($687,513)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,021,175.06	-	$1,729,670	-	$291,505	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 594,528.51		$564,573		$ 29,955.39		$7,040
19 Real Time Market Administration (Schedule 17)		$ 52,570.68		$49,292		$ 3,278.41		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 27,410.96		$27,411		$ -		$2,001
33 Day-Ahead Schedule 24 Allocation Amount		$ 86,505.76		$82,224		$ 4,282.16		$1,025
34 Real -Time Schedule 24 Allocation Amount		$ (92,003.82)		$16,799		$ (108,803.14)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 669,012.09	-	$740,299	-	$ (71,287.18)	-	$10,066
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,259,584.78		$1,123,885		$ 135,699.55		
5b Day Ahead Non Asset Congestion		$ 676,085.05		$603,248		$ 72,837.05		
13b Real Time Congestion		$ 3,338.29		$2,979		$ 359.65		
22b Real Time Non Asset Congestion		$ (0.18)		($0)		$ (0.02)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 4,423.75		$4,424				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (992,388.90)		($992,389)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (91,420.53)		($91,421)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (18,226.83)		($18,227)				
37 Financial Transmission Guarantee Uplift Amount		$ 4,048.29		$4,048				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 845,443.72	-	$636,547	-	$ 208,896.23	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 44,692.68		$ 39,877.78		$ 4,814.90		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (160,724.75)		($141,313)		$ (19,411.64)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 69,340.38		$17,818		$ 51,522.13		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (3,854.63)		($1,968)		$ (1,886.63)		
43 Real Time Price Volatility Make Whole Payment		($239,720)		($228,087)		($11,633)		
SUBTOTAL	-	$ (290,266.65)	-	$ (313,672.12)	-	$23,405	-	$0
Other Charges								
20 Real Time Miscellaneous		$ 1,072,002.52		$1,124,591		$ (52,588.75)		$0
21 Real Time Net Inadvertent Distribution		$ (40,441.71)		($40,442)				($446)
23 Real Time Revenue Neutrality Uplift Amount		$ 478,236.54		$470,766		$ 7,470.29		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 1,509,797.35	-	$1,554,916	-	$ (45,118.46)	-	($446)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,770,129.38		$3,770,129				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,771,745.17)		($3,762,038)		$ (9,706.72)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (186,462.01)		($186,462)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 66,371.33		$66,371				
SUBTOTAL	-	$ (121,706.47)	-	($112,000)	-	($9,707)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (4,423.75)		($4,424)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (2,891.51)		($2,892)				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
SUBTOTAL	-	$ (7,315.26)	-	($7,315)	-	$0	-	$0
Total MISO Day 2 Charges	(479,894)	$ (4,475,116.75)	(27,653)	$ 3,056,173.77	(452,241)	$ (7,531,290.52)	93,119	$ 1,947,346

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 - NEW FORMAT **NOTE 1**

January 2016	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	28,797	$1,058,568	252,727	$ 6,000,890.18	(223,930)	($4,942,323)		
5a Day Ahead Non Asset Energy	(268,933)	($6,524,620)	(268,933)	($6,524,620)			11,591	$255,867
13a Real Time Asset Energy	23,048	$598,901	89,766	$1,787,860	(66,718)	($1,188,959)		
22a Real Time Non Asset Energy		$13	-	$13				
SUBTOTAL	(217,087)	($4,867,139)	73,561	$ 1,264,142.74	(290,648)	($6,131,282)	11,591	$255,867
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,885,053.71		$2,677,576		$ 207,478.02		
5c Day Ahead Non Asset Loss		$ 498,934.65		$463,054		$ 35,880.78		
3 Day Ahead Financial Bilateral Transaction Loss		$ 3,425.24		$3,425		$ -		
13c Real Time Loss		$ (4,407.52)		($4,407)		$ (0.37)		
22c Real Time Non Asset Loss		$ (5.09)		($916)		$ 911.01		
14 Real Time Distribution Losses		$ (1,483,744.46)		($1,483,744)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 1,899,256.53	-	$1,654,987	-	$244,269	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 629,120.42		$611,188		$ 17,932.66		$920
19 Real Time Market Administration (Schedule 17)		$ 46,128.84		$40,741		$ 5,387.46		
29 Financial Transmission Rights Administration (Schedule 16)		$ 27,851.04		$27,851		$ -		$4,247
33 Day-Ahead Schedule 24 Allocation Amount		$ 86,365.51		$83,926		$ 2,439.52		$127
34 Real -Time Schedule 24 Allocation Amount		$ (101,463.72)		($4,648)		$ (96,815.23)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 688,002.09	-	$759,058	-	$ (71,055.59)	-	$5,294
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,014,802.89		$941,824		$ 72,979.33		
5b Day Ahead Non Asset Congestion		$ 328,700.35		$305,062		$ 23,638.42		
13b Real Time Congestion		$ (9,139.67)		($9,139)		$ (0.58)		
22b Real Time Non Asset Congestion		$ (8.04)		($25)		$ 16.47		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 1,928.72		$1,929				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (598,278.53)		($598,279)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (11,899.73)		($11,900)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 73,446.38		$73,446				
37 Financial Transmission Guarantee Uplift Amount		$ (72,033.63)		($72,034)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 727,518.74	-	$630,885	-	$ 96,633.64	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 85,143.26		$ 79,020.20		$ 6,123.06		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (161,378.93)		($135,042)		$ (26,336.73)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 61,556.02		$57,129		$ 4,426.79		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (30,005.93)		($44,828)		$ 14,822.44		
43 Real Time Price Volatility Make Whole Payment		($106,349)		($86,161)		($20,187)		
SUBTOTAL	-	$ (151,034.14)	-	$ (129,882.50)	-	($21,152)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (56,138.65)		($38,604)		$ (17,534.72)		
21 Real Time Net Inadvertent Distribution		$ (192,702.88)		($192,703)				($419)
23 Real Time Revenue Neutrality Uplift Amount		$ 847,747.47		$786,782		$ 60,965.58		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 598,905.94	-	$555,475	-	$ 43,430.86	-	($419)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,770,129.38		$3,770,129				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,771,745.17)		($3,719,712)		$ (52,033.25)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (187,052.38)		($187,052)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 66,371.33		$66,371				
SUBTOTAL	-	$ (122,296.84)	-	($70,264)	-	($52,033)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (1,928.72)		($1,929)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,425.24)		($3,425)				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
SUBTOTAL	-	$ (5,353.96)	-	($5,354)	-	$0	-	$0
Total MISO Day 2 Charges	(217,087)	$ (1,232,140.59)	73,561	$ 4,659,047.64	(290,648)	$ (5,891,188.23)	11,591	$ 260,742

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 - NEW FORMAT **NOTE 1**

February 2016	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	84,094	$ 3,035,356.88	351,377	$ 8,223,310.89	(267,283)	$ (5,187,954.01)		
5a Day Ahead Non Asset Energy	(262,389)	$ (5,803,517.39)	(262,389)	$ (5,803,517.39)			11,064	######
13a Real Time Asset Energy	7,909	$ 70,666.43	72,606	$ 1,128,429.78	(64,697)	$ (1,057,763.35)		
22a Real Time Non Asset Energy		$ (716.14)	-	$ (716.14)				
SUBTOTAL	(170,386)	$ (2,698,210.22)	161,594	$ 3,547,507.14	(331,980)	$ (6,245,717.36)	11,064	######
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,308,250.90		$ 2,100,746.63		$ 207,504.27		
5c Day Ahead Non Asset Loss		$ 432,183.65		$ 393,331.74		$ 38,851.91		
3 Day Ahead Financial Bilateral Transaction Loss		$ 3,590.42		$ 3,590.42		$ -		
13c Real Time Loss		$ 9,583.55		$ 9,557.57		$ 25.98		
22c Real Time Non Asset Loss		$ 288.99		$ 551.06		$ (262.07)		
14 Real Time Distribution Losses		$ (1,344,475.97)		$ (1,344,475.97)				
16 Real Time Financial Bilateral Loss		$ -		$ -				
SUBTOTAL	-	$ 1,409,421.54	-	$ 1,163,301.46	-	$ 246,120.08	-	$ -
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)		$ 616,949.69		$ 594,267.16		$ 22,682.53		$ 961.20
19 Real Time Market Administration (Schedule 17)		$ 41,726.26		$ 36,024.26		$ 5,702.00		
29 Financial Transmission Rights Administration (Schedule 16)		$ 32,570.16		$ 32,570.16		$ -		$ 4,851.04
33 Day-Ahead Schedule 24 Allocation Amount		$ 83,352.50		$ 80,281.62		$ 3,070.88		$ 127.92
34 Real -Time Schedule 24 Allocation Amount		$ (96,299.03)		$ 17,424.26		$ (113,723.29)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 678,299.58	-	$ 760,567.46	-	$ (82,267.88)	-	$ 5,940.16
Congestion & FTRs								
1b Day Ahead Congestion		$ 767,967.04		$ 698,929.29		$ 69,037.75		
5b Day Ahead Non Asset Congestion		$ 395,989.01		$ 360,390.88		$ 35,598.13		
13b Real Time Congestion		$ (4,387.08)		$ (4,425.48)		$ 38.40		
22b Real Time Non Asset Congestion		$ 427.16		$ 6,176.87		$ (5,749.71)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (1,465.68)		$ (1,465.68)				
15 Real Time Financial Bilateral Congestion		$ -		$ -				
28 Financial Transmission Rights Hourly Allocation		$ (743,219.43)		$ (743,219.43)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (28,067.47)		$ (28,067.47)				
32 Financial Transmission Rights Yearly Allocation		$ -		$ -				
31 Financial Transmission Rights Transaction		$ -		$ -				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (5,613.72)		$ (5,613.72)				
37 Financial Transmission Guarantee Uplift Amount		$ 3,899.71		$ 3,899.71				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$ -				
SUBTOTAL	-	$ 385,529.54	-	$ 286,604.98	-	$ 98,924.56	-	$ -
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 69,540.20		$ 63,288.76		$ 6,251.44		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (61,971.11)		$ (35,500.57)		$ (26,470.54)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 10,117.32		$ 9,207.81		$ 909.51		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (8,821.22)		$ (15,833.65)		$ 7,012.43		
43 Real Time Price Volatility Make Whole Payment		$ (110,199.47)		$ (102,159.19)		$ (8,040.28)		
SUBTOTAL	-	$ (101,334.28)	-	$ (80,996.84)	-	$ (20,337.44)	-	$ -
Other Charges								
20 Real Time Miscellaneous		$ (40,153.45)		$ (38,900.97)		$ (1,252.48)		
21 Real Time Net Inadvertent Distribution		$ 177,367.44		$ 177,367.44				$ 520.45
23 Real Time Revenue Neutrality Uplift Amount		$ 248,209.81		$ 225,896.55		$ 22,313.26		
26 Real Time Uninstructed Deviation Amount		$ -		$ -		$ -		
SUBTOTAL	-	$ 385,423.80	-	$ 364,363.02	-	$ 21,060.78	-	$ 520.45
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 3,770,129.38		$ 3,770,129.38				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (3,771,745.17)		$ (3,721,441.45)		$ (50,303.72)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (187,052.38)		$ (187,052.38)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 66,371.33		$ 66,371.33				
SUBTOTAL	-	$ (122,296.84)	-	($71,993)	-	($50,304)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 1,465.68		$ 1,465.68				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,590.42)		$ (3,590.42)				
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	-	$ (2,124.74)	-	$ (2,124.74)	-	$ -	-	$ -
Total MISO Day 2 Charges	(170,386)	$ (65,291.62)	161,594	$ 5,967,229.36	(331,980)	$ (6,032,520.98)	11,064	######

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 - NEW FORMAT **NOTE 1**

March 2016	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	(425,127)	$409,307	(59,495)	$ 5,900,636.43	(365,632)	($5,491,330)		
5a Day Ahead Non Asset Energy	33,092	($5,894,607)	33,092	($5,894,607)			11,880	$186,634
13a Real Time Asset Energy	73,569	$193,304	149,701	$1,451,787	(76,132)	($1,258,482)		
22a Real Time Non Asset Energy	(1,850)	($11,691)	(1,850)	($11,691)				
SUBTOTAL	(320,315)	($5,303,687)	121,449	$ 1,446,125.18	(441,764)	($6,749,812)	11,880	$186,634
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,664,381.79		$1,471,960		$ 192,421.65		
5c Day Ahead Non Asset Loss		$ 638,278.79		$564,486		$ 73,792.36		
3 Day Ahead Financial Bilateral Transaction Loss		$ 655.03		$655		$ -		
13c Real Time Loss		$ 20,822.99		$20,823		$ -		
22c Real Time Non Asset Loss		$ -		$2,207		$ (2,207.23)		
14 Real Time Distribution Losses		$ (30,110.52)		($30,111)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,294,028.08	-	$2,030,021	-	$264,007	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 545,190.14		$516,985		$ 28,205.53		$880
19 Real Time Market Administration (Schedule 17)		$ 40,509.00		$35,599		$ 4,909.96		
29 Financial Transmission Rights Administration (Schedule 16)		$ 27,470.08		$27,470		$ -		$1,413
33 Day-Ahead Schedule 24 Allocation Amount		$ 85,462.09		$81,068		$ 4,393.80		$137
34 Real -Time Schedule 24 Allocation Amount		$ (95,476.93)		$1,316		$ (96,793.14)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 603,154.38	-	$662,438	-	$ (59,283.85)	-	$2,430
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,928,154.26		$1,705,237		$ 222,916.78		
5b Day Ahead Non Asset Congestion		$ 898,444.99		$794,574		$ 103,870.56		
13b Real Time Congestion		$ 75,576.87		$75,577		$ -		
22b Real Time Non Asset Congestion		$ -		$9,238		$ (9,237.62)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (3,463.42)		($3,463)				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (2,748,669.69)		($2,748,670)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (222,739.77)		($222,740)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 21,499.66		$21,500				
37 Financial Transmission Guarantee Uplift Amount		$ (21,190.58)		($21,191)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ (72,387.68)	-	($389,937)	-	$ 317,549.71	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 88,711.46		$ 78,455.40		$ 10,256.06		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (8,755.73)		$6,698		$ (15,453.92)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 17,807.07		$15,748		$ 2,058.70		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ -		$0		$ -		
43 Real Time Price Volatility Make Whole Payment		($156,050)		($141,525)		($14,525)		
SUBTOTAL	-	$ (58,287.41)	-	$ (40,623.19)	-	($17,664)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ 81,777.61		$100,878		$ (19,100.32)		$166
21 Real Time Net Inadvertent Distribution		$ 823,222.09		$823,222				$1,186
23 Real Time Revenue Neutrality Uplift Amount		$ (395,848.84)		($350,084)		$ (45,764.67)		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 509,150.86	-	$574,016	-	$ (64,864.99)	-	$1,352
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,985,759.86		$2,985,760				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,988,827.34)		($2,953,119)		$ (35,708.23)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (204,803.54)		($204,804)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 31,176.35		$31,176				
SUBTOTAL	-	$ (176,694.67)	-	($140,986)	-	($35,708)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 3,463.42		$3,463				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (655.03)		($655)				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
SUBTOTAL	-	$ 2,808.39	-	$2,808	-	$0	-	$0
Total MISO Day 2 Charges	(320,315)	$ (2,201,915.00)	121,449	$ 4,143,861.93	(441,764)	$ (6,345,776.93)	11,880	$ 190,415

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 - NEW FORMAT **NOTE 1**

April 2016		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	(404,432)	($6,107,898)	40,829	$ 1,442,089.31	(445,261)	($7,549,987)		
5a	Day Ahead Non Asset Energy	(251,660)	($5,938,923)	(251,660)	($5,938,923)			11,376	$191,153
13a	Real Time Asset Energy	34,275	$570,195	100,578	$1,500,860	(66,303)	($930,665)		
22a	Real Time Non Asset Energy	108	$4,285	108	$4,285				
	SUBTOTAL	(621,709)	($11,472,341)	(110,145)	$ (2,991,689.56)	(511,564)	($8,480,652)	11,376	$191,153
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss		$ 2,282,266.73		$1,963,401		$ 318,865.27		
5c	Day Ahead Non Asset Loss		$ 692,322.88		$595,595		$ 96,727.40		
3	Day Ahead Financial Bilateral Transaction Loss		$ 19.85		$20		$ -		
13c	Real Time Loss		$ 3,187.59		$3,263		$ (75.73)		
22c	Real Time Non Asset Loss		$ (542.05)		$984		$ (1,526.23)		
14	Real Time Distribution Losses		$ (276,111.47)		($276,111)				
16	Real Time Financial Bilateral Loss		$ -		$0				
	SUBTOTAL	-	$ 2,701,143.53	-	$2,287,153	-	$413,991	-	$0
	Virtual Energy								
12	Day Ahead Virtual Energy		$ -		$0				
27	Real Time Virtual Energy		$ -		$0				
	SUBTOTAL	-	$0	-	$0	-	$0	-	$0
	Schedules 16, 17 & 24								
4	Day Ahead Market Administration (Schedule 17)		$ 530,857.26		$498,118		$ 32,739.33		$839
19	Real Time Market Administration (Schedule 17)		$ 36,952.62		$32,074		$ 4,878.26		
29	Financial Transmission Rights Administration (Schedule 16)		$ 36,000.00		$36,000		$ -		$2,499
33	Day-Ahead Schedule 24 Allocation Amount		$ 89,915.02		$84,252		$ 5,662.59		$142
34	Real -Time Schedule 24 Allocation Amount		$ (97,618.09)		$2,874		$ (100,492.27)		
35	Schedule 24 Admin Allocation		$ -				$ -		
	SUBTOTAL	-	$ 596,106.81	-	$653,319	-	$ (57,212.09)	-	$3,480
	Congestion & FTRs								
1b	Day Ahead Congestion		$ 1,493,424.76		$1,284,772		$ 208,652.77		
5b	Day Ahead Non Asset Congestion		$ 1,085,521.37		$933,859		$ 151,662.84		
13b	Real Time Congestion		$ 4,894.87		$5,043		$ (147.89)		
22b	Real Time Non Asset Congestion		$ (1,058.49)		$19,337		$ (20,395.33)		
2	Day Ahead Financial Bilateral Transaction Congestion		$ (2,538.97)		($2,539)				
15	Real Time Financial Bilateral Congestion		$ -		$0				
28	Financial Transmission Rights Hourly Allocation		$ (894,440.50)		($894,441)		$ -		
30	Financial Transmission Rights Monthly Allocation		$ (66,083.22)		($66,083)				
32	Financial Transmission Rights Yearly Allocation		$ (395,567.97)		($395,568)				
31	Financial Transmission Rights Transaction		$ -		$0				
36	Financial Transmission Rights Full Funding Guarantee Amount		$ 356,580.37		$356,580				
37	Financial Transmission Guarantee Uplift Amount		$ (322,802.23)		($322,802)				
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
	SUBTOTAL	-	$ 1,257,929.99	-	$918,158	-	$ 339,772.41	-	$0
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 56,175.16		$ 48,326.69		$ 7,848.47		
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (62,704.14)		($45,067)		$ (17,637.38)		
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 173,613.59		$149,357		$ 24,256.30		
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (33,083.25)		($23,241)		$ (9,842.50)		
43	Real Time Price Volatility Make Whole Payment		($169,045)		($149,267)		($19,777)		
	SUBTOTAL	-	$ (35,043.32)	-	$ (19,890.96)	-	($15,152)	-	$0
	Other Charges								
20	Real Time Miscellaneous		$ 59,612.31		$69,006		$ (9,393.60)		$4,097
21	Real Time Net Inadvertent Distribution		$ 31,431.11		$31,431				($198)
23	Real Time Revenue Neutrality Uplift Amount		$ 44,806.03		$38,546		$ 6,260.04		
26	Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
	SUBTOTAL	-	$ 135,849.45	-	$138,983	-	$ (3,133.56)	-	$3,899
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions		$ 2,985,759.86		$2,985,760				
40	Auction Revenue Rights - Monthly ARR Revenue		$ (2,988,827.34)		($2,950,655)		$ (38,172.66)		
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (202,532.65)		($202,533)				
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 31,176.35		$31,176				
	SUBTOTAL	-	$ (174,423.78)	-	($136,251)	-	($38,173)	-	$0
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 2,538.97		$2,539				
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (19.85)		($20)				
8	Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9	Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17	Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
	SUBTOTAL	-	$ 2,519.12	-	$2,519	-	$0	-	$0
	Total MISO Day 2 Charges	(621,709)	$ (6,988,259.56)	(110,145)	$ 852,299.80	(511,564)	$ (7,840,559.36)	11,376	$ 198,532

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 - NEW FORMAT **NOTE 1**

May 2016	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	(28,426)	$1,903,283	201,771	$ 5,563,289.84	(230,197)	($3,660,007)		
5a Day Ahead Non Asset Energy	(347,064)	($8,631,057)	(347,064)	($8,631,057)			17,640	$345,766
13a Real Time Asset Energy	(53,033)	($1,392,570)	(11,165)	($744,831)	(41,868)	($647,739)		
22a Real Time Non Asset Energy	1,083	$17,319	1,083	$17,319				
SUBTOTAL	(427,439)	($8,103,026)	(155,374)	$ (3,795,279.77)	(272,065)	($4,307,746)	17,640	$345,766
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,635,718.52		$1,512,478		$ 123,240.46		
5c Day Ahead Non Asset Loss		$ 999,416.43		$924,117		$ 75,299.35		
3 Day Ahead Financial Bilateral Transaction Loss		$ (1,002.89)		($1,003)		$ -		
13c Real Time Loss		$ 54,203.17		$54,253		$ (49.88)		
22c Real Time Non Asset Loss		$ (661.97)		$2,374		$ (3,036.29)		
14 Real Time Distribution Losses		$ (586,154.43)		($586,154)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,101,518.83	-	$1,906,065	-	$195,454	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 566,372.19		$548,967		$ 17,405.30		$899
19 Real Time Market Administration (Schedule 17)		$ 38,592.01		$35,387		$ 3,205.36		
29 Financial Transmission Rights Administration (Schedule 16)		$ 29,130.00		$29,130		$ -		$6,324
33 Day-Ahead Schedule 24 Allocation Amount		$ 87,134.81		$84,339		$ 2,795.97		$262
34 Real -Time Schedule 24 Allocation Amount		$ (96,312.32)		$11,281		$ (107,593.47)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 624,916.69	-	$709,104	-	$ (84,186.84)	-	$7,484
Congestion & FTRs								
1b Day Ahead Congestion		$ 3,269,099.16		$3,022,794		$ 246,304.78		
5b Day Ahead Non Asset Congestion		$ 1,794,624.49		$1,659,412		$ 135,212.97		
13b Real Time Congestion		$ 114,328.40		$114,407		$ (78.82)		
22b Real Time Non Asset Congestion		$ (1,046.11)		$5,009		$ (6,055.14)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (9,375.18)		($9,375)				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (3,394,360.59)		($3,394,361)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (243,817.37)		($243,817)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (20,228.52)		($20,229)				
37 Financial Transmission Guarantee Uplift Amount		$ 24,475.48		$24,475				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 1,533,699.76	-	$1,158,316	-	$ 375,383.79	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 89,420.26		$ 82,683.04		$ 6,737.22		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (12,957.18)		($23,156)		$ 10,198.91		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 99,617.27		$92,112		$ 7,505.50		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (6,317.73)		($4,492)		$ (1,826.23)		
43 Real Time Price Volatility Make Whole Payment		($189,261)		($163,490)		($25,771)		
SUBTOTAL	-	$ (19,498.56)	-	$ (16,343.20)	-	($3,155)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ 25,178.84		$34,886		$ (9,706.72)		
21 Real Time Net Inadvertent Distribution		$ (731,048.92)		($731,049)				($1,513)
23 Real Time Revenue Neutrality Uplift Amount		$ 1,521,383.01		$1,406,757		$ 114,626.05		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 815,512.93	-	$710,594	-	$ 104,919.33	-	($1,513)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,985,759.86		$2,985,760				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,988,827.34)		($2,950,644)		$ (38,183.66)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (203,542.70)		($203,543)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 31,176.35		$31,176				
SUBTOTAL	-	$ (175,433.83)	-	($137,250)	-	($38,184)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 9,375.18		$9,375				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 1,002.89		$1,003				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ -		$0				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ -		$0				
SUBTOTAL	-	$ 10,378.07	-	$10,378	-	$0	-	$0
Total MISO Day 2 Charges	(427,439)	$ (3,211,932.14)	(155,374)	$ 545,583.22	(272,065)	$ (3,757,515.36)	17,640	$ 351,738

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 - NEW FORMAT **NOTE 1**

June 2016	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	179,610	$7,039,424	248,587	$ 8,663,977.01	(68,977)	($1,624,553)		
5a Day Ahead Non Asset Energy	(345,714)	($10,479,566)	(345,714)	($10,479,566)			(129)	$2,039
13a Real Time Asset Energy	101,107	$2,613,263	140,425	$3,412,749	(39,318)	($799,486)		
22a Real Time Non Asset Energy	5,564	$244,046	5,564	$244,046			(1,725)	($39,513)
SUBTOTAL	(59,432)	($582,833)	48,863	$ 1,841,206.32	(108,295)	($2,424,039)	(1,854)	($37,474)
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,028,160.69		$1,972,128		$ 56,032.81		
5c Day Ahead Non Asset Loss		$ 1,250,965.17		$1,216,404		$ 34,560.92		
3 Day Ahead Financial Bilateral Transaction Loss		$ (2,221.02)		($2,221)		$ -		
13c Real Time Loss		$ (23,100.88)		($22,567)		$ (533.74)		
22c Real Time Non Asset Loss		$ (19,319.27)		($24,072)		$ 4,753.17		
14 Real Time Distribution Losses		$ (177,928.43)		($177,928)				
16 Real Time Financial Bilateral Loss		$ 6.01		$6				
SUBTOTAL	-	$ 3,056,562.27	-	$2,961,749	-	$94,813	-	$0
Virtual Energy								
12 Day Ahead Virtual Energy		$ -		$0				
27 Real Time Virtual Energy		$ -		$0				
SUBTOTAL	-	$0	-	$0	-	$0	-	$0
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)		$ 579,962.07		$575,825		$ 4,137.04		$1,674
19 Real Time Market Administration (Schedule 17)		$ 48,947.38		$46,165		$ 2,782.57		
29 Financial Transmission Rights Administration (Schedule 16)		$ 35,475.36		$35,475		$ -		$1
33 Day-Ahead Schedule 24 Allocation Amount		$ 90,636.45		$89,857		$ 779.95		$262
34 Real -Time Schedule 24 Allocation Amount		$ (121,228.20)		($18,147)		$ (103,081.02)		
35 Schedule 24 Admin Allocation		$ -				$ -		
SUBTOTAL	-	$ 633,793.06	-	$729,175	-	$ (95,381.46)	-	$1,937
Congestion & FTRs								
1b Day Ahead Congestion		$ 30,704.84		$29,857		$ 848.29		
5b Day Ahead Non Asset Congestion		$ 1,869,136.85		$1,817,497		$ 51,639.40		
13b Real Time Congestion		$ (154,385.45)		($153,386)		$ (999.61)		
22b Real Time Non Asset Congestion		$ (36,181.84)		($44,993)		$ 8,810.91		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (10,697.44)		($10,697)				
15 Real Time Financial Bilateral Congestion		$ 32.60		$33				
28 Financial Transmission Rights Hourly Allocation		$ (1,404,238.41)		($1,404,238)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (181,031.43)		($181,031)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 82,809.64		$82,810				
37 Financial Transmission Guarantee Uplift Amount		$ (85,118.38)		($85,118)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 111,030.98	-	$50,732	-	$ 60,298.99	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 105,773.16		$ 102,850.92		$ 2,922.24		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (42,116.71)		($37,324)		$ (4,792.22)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 384,950.52		$374,315		$ 10,635.18		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (126,207.94)		($75,108)		$ (51,099.69)		
43 Real Time Price Volatility Make Whole Payment		($216,213)		($198,549)		($17,665)		
SUBTOTAL	-	$ 106,185.78	-	$ 166,184.94	-	($59,999)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ 2,271.42		$56,611		$ (54,339.70)		$366
21 Real Time Net Inadvertent Distribution		$ 730,335.15		$730,335				$974
23 Real Time Revenue Neutrality Uplift Amount		$ (666,842.61)		($648,419)		$ (18,423.13)		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 65,763.96	-	$138,527	-	$ (72,762.83)	-	$1,340
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 2,398,660.25		$2,398,660				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (2,416,523.31)		($2,372,235)		$ (44,288.40)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (78,450.07)		($78,450)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 78,282.87		$78,283				
SUBTOTAL	-	$ (18,030.26)	-	$26,258	-	($44,288)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 10,697.44		$10,697				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ 2,221.01		$2,221				
8 Day Ahead Congestion Rebate on Option B-Grandfathered		$ -		$0				
9 Day Ahead Loss Rebate on Option B-Grandfathered		$ -		$0				
17 Real Time Loss Rebate on Carve Out Grandfathered		$ (32.60)		($33)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ (6.01)		($6)				
SUBTOTAL	-	$ 12,879.84	-	$12,880	-	$0	-	$0
Total MISO Day 2 Charges	(59,432)	$ 3,385,352.56	48,863	$ 5,926,711.65	(108,295)	$ (2,541,359.09)	(1,854)	$ (34,198)

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 - NEW FORMAT **NOTE 1**

July 2015 - June 2016					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	60,843	35,022,674	3,113,067	93,607,099	(3,052,224)	(58,584,425)	-	-
5a Day Ahead Non Asset Energy	(3,526,842)	(101,335,377)	(3,526,842)	(101,335,377)	-	-	615,475	14,687,141
13a Real Time Asset Energy	238,190	3,485,145	905,352	15,693,690	(667,162)	(12,208,545)	-	-
22a Real Time Non Asset Energy	9,341	739,512	9,341	739,512	-	-	(1,725)	(39,513)
SUBTOTAL	(3,218,468)	(62,088,046)	500,918	8,704,924	(3,719,386)	(70,792,970)	613,750	14,647,628
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	28,419,535	-	26,201,473	-	2,218,061	-	-
5c Day Ahead Non Asset Loss	-	10,230,275	-	9,472,232	-	758,043	-	-
3 Day Ahead Financial Bilateral Transaction Loss	-	10,562	-	10,562	-	-	-	-
13c Real Time Loss	-	191,352	-	184,991	-	6,361	-	-
22c Real Time Non Asset Loss	-	(27,667)	-	(25,598)	-	(2,069)	-	-
14 Real Time Distribution Losses	-	(10,706,636)	-	(10,706,636)	-	-	-	-
16 Real Time Financial Bilateral Loss	-	6	-	6	-	-	-	-
SUBTOTAL	-	28,117,425	-	25,137,030	-	2,980,395	-	-
Virtual Energy								
12 Day Ahead Virtual Energy	-	-	-	-	-	-	-	-
27 Real Time Virtual Energy	-	-	-	-	-	-	-	-
SUBTOTAL	-	-	-	-	-	-	-	-
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	6,843,542	-	6,614,564	-	228,977	-	46,034
19 Real Time Market Administration (Schedule 17)	-	497,972	-	448,722	-	49,250	-	-
29 Financial Transmission Rights Administration (Schedule 16)	-	342,781	-	342,781	-	-	-	58,368
33 Day-Ahead Schedule 24 Allocation Amount	-	1,030,340	-	995,416	-	34,924	-	7,051
34 Real -Time Schedule 24 Allocation Amount	-	(1,176,762)	-	63,793	-	(1,240,555)	-	-
35 Schedule 24 Admin Allocation	-	-	-	-	-	-	-	-
SUBTOTAL	-	7,537,872	-	8,465,276	-	(927,404)	-	111,454
Congestion & FTRs								
1b Day Ahead Congestion	-	22,596,815	-	20,755,789	-	1,841,026	-	-
5b Day Ahead Non Asset Congestion	-	12,233,290	-	11,264,876	-	968,414	-	-
13b Real Time Congestion	-	620,465	-	585,989	-	34,476	-	-
22b Real Time Non Asset Congestion	-	(48,389)	-	(14,622)	-	(33,767)	-	-
2 Day Ahead Financial Bilateral Transaction Congestion	-	(22,471)	-	(22,471)	-	-	-	-
15 Real Time Financial Bilateral Congestion	-	34	-	34	-	-	-	-
28 Financial Transmission Rights Hourly Allocation	-	(21,996,610)	-	(21,996,610)	-	-	-	-
30 Financial Transmission Rights Monthly Allocation	-	(1,686,208)	-	(1,686,208)	-	-	-	-
32 Financial Transmission Rights Yearly Allocation	-	(395,568)	-	(395,568)	-	-	-	-
31 Financial Transmission Rights Transaction	-	-	-	-	-	-	-	-
36 Financial Transmission Rights Full Funding Guarantee Amount	-	78,342	-	78,342	-	-	-	-
37 Financial Transmission Guarantee Uplift Amount	-	(56,463)	-	(56,463)	-	-	-	-
38 Financial Transmission Rights Monthly Transacton Amount	-	-	-	-	-	-	-	-
SUBTOTAL	-	11,323,237	-	8,513,089	-	2,810,148	-	-
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	1,114,435	-	1,030,595	-	83,840	-	-
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	(957,714)	-	(783,539)	-	(174,176)	-	-
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	1,896,049	-	1,629,626	-	266,423	-	-
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	(835,212)	-	(511,107)	-	(324,105)	-	-
43 Real Time Price Volatility Make Whole Payment	-	(2,492,469)	-	(2,276,620)	-	(215,849)	-	-
SUBTOTAL	-	(1,274,910)	-	(911,045)	-	(363,866)	-	-
Other Charges								
20 Real Time Miscellaneous	-	1,035,404	-	1,319,102	-	(283,699)	-	4,629
21 Real Time Net Inadvertent Distribution	-	658,479	-	658,479	-	-	-	(1,477)
23 Real Time Revenue Neutrality Uplift Amount	-	4,648,364	-	4,426,290	-	222,074	-	-
26 Real Time Uninstructed Deviation Amount	-	-	-	-	-	-	-	-
SUBTOTAL	-	6,342,247	-	6,403,872	-	(61,625)	-	3,152
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	38,252,853	-	38,252,853	-	-	-	-
40 Auction Revenue Rights - Monthly ARR Revenue	-	(38,452,611)	-	(38,184,215)	-	(268,397)	-	-
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	(2,639,514)	-	(2,639,514)	-	-	-	-
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	809,638	-	809,638	-	-	-	-
SUBTOTAL	-	(2,029,634)	-	(1,761,237)	-	(268,397)	-	-
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	22,471	-	22,471	-	-	-	-
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	(10,562)	-	(10,562)	-	-	-	-
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	-	(34)	-	(34)	-	-	-	-
18 Real Time Congestion Rebate on Carve Out Grandfathered	-	(6)	-	(6)	-	-	-	-
SUBTOTAL	-	11,870	-	11,870	-	-	-	-
Total MISO Day 2 Charges	(3,218,468)	(12,059,939)	500,918	54,563,778	(3,719,386)	(66,623,717)	613,750	14,762,234

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.

Total

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	July 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (57,199.93)	$ -	$ (57,199.93)	$ (42,639.98)
2	Day-Ahead Spinning Reserve Amount	$ (122,318.89)	$ -	$ (122,318.89)	$ (91,183.24)
3	Day-Ahead Supplemental Reserve	$ (73,586.68)	$ -	$ (73,586.68)	$ (54,855.57)
4	Real-Time Regulation Amount (See Note 1)	$ (82,014.94)	$ 43,573.90	$ (38,441.04)	$ (28,656.07)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (30,639.63)	$ 60,745.01	$ 30,105.38	$ 22,442.21
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 17,028.97	$ 9,474.72	$ 26,503.69	$ 19,757.31
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (26,561.20)		$ (26,561.20)	$ (19,800.18)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 546,921.45		$ 546,921.45	$ 407,705.38
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (160,907.88)	$ 6,638.91	$ (154,268.97)	$ (115,000.59)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (30,879.38)	$ 1,274.05	$ (29,605.33)	$ (22,069.44)
9	Real Time Net Regulation Adjustment Amount	$ 12,044.79	$ (5,239.76)	$ 6,805.03	$ 5,072.84
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 89,641.02	$ -	$ 89,641.02	$ 66,823.36
11	Real Time Spinnng Reserve Cost Distribution	$ 173,114.10	$ -	$ 173,114.10	$ 129,048.79
12	Real Time Supplemental Reserve Cost Distribution	$ 54,284.03	$ -	$ 54,284.03	$ 40,466.31
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 71,981.87	$ (14,514.42)	$ 57,467.45	$ 42,839.40
14	Real Time Contignecy Reserve Deployment Failure	$ 4,651.56	$ (3,125.44)	$ 1,526.12	$ 1,137.65
	TOTAL MISO ASM CHARGES	**$ 385,559.26**	**$ 98,826.97**	**$ 484,386.23**	**$ 361,088.19**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	August 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (42,724.29)	$ -	$ (42,724.29)	$ (31,702.31)
2	Day-Ahead Spinning Reserve Amount	$ (85,577.05)	$ -	$ (85,577.05)	$ (63,499.95)
3	Day-Ahead Supplemental Reserve	$ (59,664.77)	$ -	$ (59,664.77)	$ (44,272.50)
4	Real-Time Regulation Amount (See Note 1)	$ (62,462.19)	$ 45,405.73	$ (17,056.46)	$ (12,656.25)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (32,572.21)	$ 34,604.00	$ 2,031.79	$ 1,507.63
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 14,505.30	$ 6,131.79	$ 20,637.09	$ 15,313.15
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (19,811.61)		$ (19,811.61)	$ (14,700.63)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,082,165.56		$ 2,082,165.56	$ 1,545,010.16
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (176,642.68)	$ 9,133.94	$ (167,508.74)	$ (124,294.97)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 16,714.25	$ (864.27)	$ 15,849.98	$ 11,761.01
9	Real Time Net Regulation Adjustment Amount	$ 14,864.62	$ (2,676.52)	$ 12,188.10	$ 9,043.82
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 90,604.79	$ -	$ 90,604.79	$ 67,230.64
11	Real Time Spinnng Reserve Cost Distribution	$ 110,581.40	$ -	$ 110,581.40	$ 82,053.70
12	Real Time Supplemental Reserve Cost Distribution	$ 54,172.27	$ -	$ 54,172.27	$ 40,196.95
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 33,481.46	$ (7,473.55)	$ 26,007.91	$ 19,298.41
14	Real Time Contignecy Reserve Deployment Failure	$ 10,693.34	$ (4,250.32)	$ 6,443.02	$ 4,780.85
	TOTAL MISO ASM CHARGES	**$ 1,948,328.19**	**$ 80,010.80**	**$ 2,028,338.99**	**$ 1,505,069.73**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	September 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (83,111.35)	$ -	$ (83,111.35)	$ (61,654.65)
2	Day-Ahead Spinning Reserve Amount	$ (113,495.74)	$ -	$ (113,495.74)	$ (84,194.75)
3	Day-Ahead Supplemental Reserve	$ (77,740.15)	$ -	$ (77,740.15)	$ (57,670.12)
4	Real-Time Regulation Amount (See Note 1)	$ (83,439.17)	$ 74,644.60	$ (8,794.57)	$ (6,524.09)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (21,084.57)	$ 46,369.39	$ 25,284.82	$ 18,757.08
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 8,639.35	$ 4,644.03	$ 13,283.38	$ 9,854.03
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (7,170.29)		$ (7,170.29)	$ (5,319.15)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,303,212.45		$ 1,303,212.45	$ 966,764.50
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (383,403.66)	$ 29,748.60	$ (353,655.06)	$ (262,352.58)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (99,174.40)	$ 7,695.02	$ (91,479.38)	$ (67,862.32)
9	Real Time Net Regulation Adjustment Amount	$ 6,916.76	$ (4,245.50)	$ 2,671.26	$ 1,981.63
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 99,820.24	$ -	$ 99,820.24	$ 74,049.83
11	Real Time Spinnng Reserve Cost Distribution	$ 108,454.56	$ -	$ 108,454.56	$ 80,455.05
12	Real Time Supplemental Reserve Cost Distribution	$ 76,350.94	$ -	$ 76,350.94	$ 56,639.56
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 42,317.50	$ (13,225.65)	$ 29,091.85	$ 21,581.26
14	Real Time Contignecy Reserve Deployment Failure	$ 753.77	$ -	$ 753.77	$ 559.17
	TOTAL MISO ASM CHARGES	**$ 777,846.24**	**$ 145,630.50**	**$ 923,476.74**	**$ 685,064.46**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	October 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (59,507.33)	$ -	$ (59,507.33)	$ (44,041.11)
2	Day-Ahead Spinning Reserve Amount	$ (170,352.88)	$ -	$ (170,352.88)	$ (126,077.40)
3	Day-Ahead Supplemental Reserve	$ (73,168.99)	$ -	$ (73,168.99)	$ (54,152.04)
4	Real-Time Regulation Amount (See Note 1)	$ (17,992.42)	$ 7,493.90	$ (10,498.52)	$ (7,769.91)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (27,083.25)	$ 111,001.72	$ 83,918.47	$ 62,107.68
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 6,272.28	$ 3,305.04	$ 9,577.32	$ 7,088.13
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (13,815.95)		$ (13,815.95)	$ (10,225.12)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,446,786.69		$ 1,446,786.69	$ 1,070,760.29
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 75,241.38	$ (8,887.61)	$ 66,353.77	$ 49,108.12
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 25,413.21	$ (3,001.84)	$ 22,411.37	$ 16,586.55
9	Real Time Net Regulation Adjustment Amount	$ 1,017.17	$ (815.43)	$ 201.74	$ 149.31
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 100,610.83	$ -	$ 100,610.83	$ 74,461.62
11	Real Time Spinnng Reserve Cost Distribution	$ 118,148.11	$ -	$ 118,148.11	$ 87,440.88
12	Real Time Supplemental Reserve Cost Distribution	$ 81,416.18	$ -	$ 81,416.18	$ 60,255.75
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 27,314.91	$ (11,057.59)	$ 16,257.32	$ 12,031.97
14	Real Time Contignecy Reserve Deployment Failure	$ 1,014.72	$ (339.03)	$ 675.69	$ 500.08
	TOTAL MISO ASM CHARGES	**$ 1,521,314.66**	**$ 97,699.15**	**$ 1,619,013.81**	**$ 1,198,224.80**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	November 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (30,939.83)	$ -	$ (30,939.83)	$ (22,516.09)
2	Day-Ahead Spinning Reserve Amount	$ (126,476.00)	$ -	$ (126,476.00)	$ (92,041.41)
3	Day-Ahead Supplemental Reserve	$ (36,215.54)	$ -	$ (36,215.54)	$ (26,355.43)
4	Real-Time Regulation Amount (See Note 1)	$ (178.88)	$ 5,298.12	$ 5,119.24	$ 3,725.47
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (3,161.73)	$ 77,841.57	$ 74,679.84	$ 54,347.37
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 1,220.60	$ 1,898.26	$ 3,118.86	$ 2,269.71
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 101.44		$ 101.44	$ 73.82
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,944,156.53		$ 3,944,156.53	$ 2,870,313.19
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (157,392.19)	$ 7,644.84	$ (149,747.35)	$ (108,976.86)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (60,460.26)	$ 2,936.67	$ (57,523.59)	$ (41,862.11)
9	Real Time Net Regulation Adjustment Amount	$ (582.74)	$ (333.92)	$ (916.66)	$ (667.09)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 58,269.73	$ -	$ 58,269.73	$ 42,405.11
11	Real Time Spinnng Reserve Cost Distribution	$ 76,333.57	$ -	$ 76,333.57	$ 55,550.85
12	Real Time Supplemental Reserve Cost Distribution	$ 43,379.27	$ -	$ 43,379.27	$ 31,568.75
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 14,179.43	$ (1,420.68)	$ 12,758.75	$ 9,285.03
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 3,722,233.40**	**$ 93,864.87**	**$ 3,816,098.27**	**$ 2,777,120.31**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	December 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (32,032.61)	$ -	$ (32,032.61)	$ (23,254.33)
2	Day-Ahead Spinning Reserve Amount	$ (130,805.72)	$ -	$ (130,805.72)	$ (94,959.44)
3	Day-Ahead Supplemental Reserve	$ (39,329.37)	$ -	$ (39,329.37)	$ (28,551.47)
4	Real-Time Regulation Amount (See Note 1)	$ (24,150.03)	$ 14,298.72	$ (9,851.31)	$ (7,151.64)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (2,307.80)	$ 73,561.87	$ 71,254.07	$ 51,727.45
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 621.51	$ 1,293.78	$ 1,915.29	$ 1,390.42
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 43,903.07		$ 43,903.07	$ 31,871.78
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,840,720.06		$ 2,840,720.06	$ 2,062,243.14
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 136,105.72	$ (14,663.15)	$ 121,442.57	$ 88,162.19
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 64,750.07	$ (6,975.76)	$ 57,774.31	$ 41,941.72
9	Real Time Net Regulation Adjustment Amount	$ 2,826.77	$ (824.36)	$ 2,002.41	$ 1,453.67
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 71,173.52	$ -	$ 71,173.52	$ 51,668.98
11	Real Time Spinnng Reserve Cost Distribution	$ 78,292.63	$ -	$ 78,292.63	$ 56,837.15
12	Real Time Supplemental Reserve Cost Distribution	$ 40,390.87	$ -	$ 40,390.87	$ 29,322.07
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 24,696.52	$ (5,321.85)	$ 19,374.67	$ 14,065.19
14	Real Time Contignecy Reserve Deployment Failure	$ 208.99	$ -	$ 208.99	$ 151.72
	TOTAL MISO ASM CHARGES	**$ 3,075,064.20**	**$ 61,369.25**	**$ 3,136,433.45**	**$ 2,276,918.61**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	January 2016 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (32,831.67)		$ (32,831.67)	$ (23,657.73)
2	Day-Ahead Spinning Reserve Amount	$ (94,129.19)		$ (94,129.19)	$ (67,827.29)
3	Day-Ahead Supplemental Reserve	$ (31,737.97)		$ (31,737.97)	$ (22,869.64)
4	Real-Time Regulation Amount (See Note 1)	$ (15,850.66)	$ 4,940.43	$ (10,910.23)	$ (7,861.66)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (6,177.31)	$ 37,661.38	$ 31,484.07	$ 22,686.68
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 169.40	$ 848.55	$ 1,017.95	$ 733.51
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 15,343.41		$ 15,343.41	$ 11,056.10
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,666,036.28		$ 2,666,036.28	$ 1,921,083.33
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 228.97	$ 657.28	$ 886.25	$ 638.61
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 12,667.87	$ 316.97	$ 12,984.84	$ 9,356.57
9	Real Time Net Regulation Adjustment Amount	$ 2,868.67	$ (820.54)	$ 2,048.13	$ 1,475.83
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 65,560.31		$ 65,560.31	$ 47,241.22
11	Real Time Spinnng Reserve Cost Distribution	$ 80,474.86		$ 80,474.86	$ 57,988.30
12	Real Time Supplemental Reserve Cost Distribution	$ 34,779.64		$ 34,779.64	$ 25,061.39
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 24,050.30	$ (12,530.04)	$ 11,520.26	$ 8,301.23
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 2,721,452.91**	**$ 31,074.02**	**$ 2,752,526.93**	**$ 1,983,406.47**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	February 2016 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (14,280.12)		$ (14,280.12)	$ (10,330.24)
2	Day-Ahead Spinning Reserve Amount	$ (71,841.16)		$ (71,841.16)	$ (51,969.91)
3	Day-Ahead Supplemental Reserve	$ (28,924.50)		$ (28,924.50)	$ (20,923.99)
4	Real-Time Regulation Amount (See Note 1)	$ (44,694.86)	$ 5,163.41	$ (39,531.45)	$ (28,597.06)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (29,690.23)	$ 65,908.96	$ 36,218.73	$ 26,200.64
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 1,113.39	$ 2,850.94	$ 3,964.33	$ 2,867.80
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (802.86)		$ (802.86)	$ (580.79)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,129,118.39		$ 1,129,118.39	$ 816,804.51
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (63,959.04)	$ 394.38	$ (63,564.66)	$ (45,982.69)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (2,915.27)	$ (861.53)	$ (3,776.80)	$ (2,732.14)
9	Real Time Net Regulation Adjustment Amount	$ 1,344.59	$ (155.61)	$ 1,188.98	$ 860.11
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 61,283.18		$ 61,283.18	$ 44,332.27
11	Real Time Spinnng Reserve Cost Distribution	$ 61,139.42		$ 61,139.42	$ 44,228.27
12	Real Time Supplemental Reserve Cost Distribution	$ 25,542.41		$ 25,542.41	$ 18,477.39
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 43,018.21	$ (6,939.30)	$ 36,078.91	$ 26,099.49
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,065,451.55**	**$ 66,361.25**	**$ 1,131,812.80**	**$ 818,753.65**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
March 2016 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (110,484.65)		$ (110,484.65)	$ (80,087.92)
2	Day-Ahead Spinning Reserve Amount	$ (92,075.98)		$ (92,075.98)	$ (66,743.88)
3	Day-Ahead Supplemental Reserve	$ (28,975.97)		$ (28,975.97)	$ (21,004.05)
4	Real-Time Regulation Amount (See Note 1)	$ (55,366.85)	$ 63,464.77	$ 8,097.92	$ 5,870.01
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (26,740.76)	$ 42,092.50	$ 15,351.74	$ 11,128.14
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 4,280.36	$ 855.63	$ 5,135.99	$ 3,722.97
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (781.17)		$ (781.17)	$ (566.25)
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 829,293.35		$ 829,293.35	$ 601,136.72
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (79,902.28)	$ (8,737.55)	$ (88,639.83)	$ (64,253.09)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (19,091.78)	$ (2,407.38)	$ (21,499.16)	$ (15,584.27)
9	Real Time Net Regulation Adjustment Amount	$ 7,858.51	$ (1,801.57)	$ 6,056.94	$ 4,390.54
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 69,203.95		$ 69,203.95	$ 50,164.44
11	Real Time Spinnng Reserve Cost Distribution	$ 85,815.90		$ 85,815.90	$ 62,206.08
12	Real Time Supplemental Reserve Cost Distribution	$ 31,300.69		$ 31,300.69	$ 22,689.19
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 109,426.59	$ (31,204.57)	$ 78,222.02	$ 56,701.44
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ 339.03	$ 339.03	$ 245.76
	TOTAL MISO ASM CHARGES	**$ 723,759.91**	**$ 62,600.86**	**$ 786,360.77**	**$ 570,015.83**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	April 2016 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (141,162.16)		$ (141,162.16)	$ (103,410.54)
2	Day-Ahead Spinning Reserve Amount	$ (122,627.01)		$ (122,627.01)	$ (89,832.33)
3	Day-Ahead Supplemental Reserve	$ (29,752.02)		$ (29,752.02)	$ (21,795.31)
4	Real-Time Regulation Amount (See Note 1)	$ (87,555.60)	$ 111,207.73	$ 23,652.13	$ 17,326.74
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (17,828.20)	$ 72,585.08	$ 54,756.88	$ 40,113.01
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 1,511.51	$ 139.98	$ 1,651.49	$ 1,209.82
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 20,399.46		$ 20,399.46	$ 14,943.94
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,903,327.60		$ 1,903,327.60	$ 1,394,312.27
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (145,978.81)	$ (683.88)	$ (146,662.69)	$ (107,440.04)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (10,923.96)	$ (445.35)	$ (11,369.31)	$ (8,328.77)
9	Real Time Net Regulation Adjustment Amount	$ 20,357.45	$ (6,606.51)	$ 13,750.94	$ 10,073.47
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 82,757.89		$ 82,757.89	$ 60,625.58
11	Real Time Spinnng Reserve Cost Distribution	$ 114,522.54		$ 114,522.54	$ 83,895.27
12	Real Time Supplemental Reserve Cost Distribution	$ 35,121.00		$ 35,121.00	$ 25,728.44
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 89,089.13	$ (27,667.13)	$ 61,422.00	$ 44,995.64
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,711,258.82**	**$ 148,529.91**	**$ 1,859,788.73**	**$ 1,362,417.19**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	May 2016 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (171,726.95)		$ (171,726.95)	$ (126,325.64)
2	Day-Ahead Spinning Reserve Amount	$ (136,807.45)		$ (136,807.45)	$ (100,638.19)
3	Day-Ahead Supplemental Reserve	$ (42,584.90)		$ (42,584.90)	$ (31,326.27)
4	Real-Time Regulation Amount (See Note 1)	$ 1,907.74	$ 70,444.23	$ 72,351.97	$ 53,223.50
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (26,902.10)	$ 66,038.98	$ 39,136.88	$ 28,789.84
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 3,610.01	$ 699.97	$ 4,309.98	$ 3,170.50
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 16,027.06		$ 16,027.06	$ 11,789.81
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,849,014.63		$ 1,849,014.63	$ 1,360,170.65
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (80,367.36)	$ (8,613.88)	$ (88,981.24)	$ (65,456.31)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (40,299.36)	$ (4,083.85)	$ (44,383.21)	$ (32,649.14)
9	Real Time Net Regulation Adjustment Amount	$ 25,073.53	$ (10,095.65)	$ 14,977.88	$ 11,018.02
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 106,607.12		$ 106,607.12	$ 78,422.24
11	Real Time Spinnng Reserve Cost Distribution	$ 127,400.96		$ 127,400.96	$ 93,718.59
12	Real Time Supplemental Reserve Cost Distribution	$ 40,130.01		$ 40,130.01	$ 29,520.41
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 75,084.14	$ (15,568.78)	$ 59,515.36	$ 43,780.64
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,746,167.08**	**$ 98,821.02**	**$ 1,844,988.10**	**$ 1,357,208.66**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES

		System	Intersystem	Retail	Minnesota Retail
	June 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (112,914.37)		$ (112,914.37)	$ (83,341.79)
2	Day-Ahead Spinning Reserve Amount	$ (86,733.37)		$ (86,733.37)	$ (64,017.66)
3	Day-Ahead Supplemental Reserve	$ (43,329.56)		$ (43,329.56)	$ (31,981.43)
4	Real-Time Regulation Amount (See Note 1)	$ (61,187.64)	$ 93,216.07	$ 32,028.43	$ 23,640.10
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 29,078.93	$ 17,696.44	$ 46,775.37	$ 34,524.77
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 26,699.14	$ 1,090.63	$ 27,789.77	$ 20,511.55
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 15,895.07		$ 15,895.07	$ 11,732.11
7b	Real Time Excessive Energy Congestion			$ -	$ -
7c	Real Time Excessive Energy Loss			$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,888,043.33		$ 1,888,043.33	$ 1,393,559.65
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 318,919.27	$ 4,265.27	$ 323,184.54	$ 238,541.63
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 172,045.36	$ 638.22	$ 172,683.58	$ 127,457.28
9	Real Time Net Regulation Adjustment Amount	$ 25,272.22	$ (5,925.28)	$ 19,346.94	$ 14,279.92
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 72,929.08		$ 72,929.08	$ 53,828.76
11	Real Time Spinnng Reserve Cost Distribution	$ 143,210.28		$ 143,210.28	$ 105,703.12
12	Real Time Supplemental Reserve Cost Distribution	$ 31,102.86		$ 31,102.86	$ 22,956.94
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 108,584.23	$ (23,354.89)	$ 85,229.34	$ 62,907.54
14	Real Time Contignecy Reserve Deployment Failure	$ 5,029.43	$ (408.74)	$ 4,620.69	$ 3,410.52
	TOTAL MISO ASM CHARGES	**$ 2,532,644.26**	**$ 87,217.72**	**$ 2,619,861.98**	**$ 1,933,713.00**

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

Northern States Power Company

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

		July 15	August 15	September 15	3rd Qt	October 15	November 15	December 15	4th Qt	January 16	February 16	March 16	1st Qt	April 16	May 16	June 16	2nd Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (57,199.93)	$ (42,724.29)	$ (83,111.35)	$ (183,035.57)	$ (59,507.33)	$ (30,939.83)	$ (32,032.61)	$ (122,479.77)	$ (32,831.67)	$ (14,280.12)	$ (110,484.65)	$ (157,596.44)	$ (141,162.16)	$ (171,726.95)	$ (112,914.37)	$ (425,803.48)	$ (888,915.26)
4	Real-Time Regulation Amount	$ (82,014.94)	$ (62,462.19)	$ (83,439.17)	$ (227,916.30)	$ (17,992.42)	$ (178.88)	$ (24,150.03)	$ (42,321.33)	$ (15,850.66)	$ (44,694.86)	$ (55,366.85)	$ (115,912.37)	$ (87,555.60)	$ 1,907.74	$ (61,187.64)	$ (146,835.50)	$ (532,985.50)
10	Real Time Regulation Reserve Cost Distribution Amou	$ 89,641.02	$ 90,604.79	$ 99,820.24	$ 280,066.05	$ 100,610.83	$ 58,269.73	$ 71,173.52	$ 230,054.08	$ 65,560.31	$ 61,283.18	$ 69,203.95	$ 196,047.44	$ 82,757.89	$ 106,607.12	$ 72,929.08	$ 262,294.09	$ 968,461.66
	SUBTOTAL	$ (49,573.85)	$ (14,581.69)	$ (66,730.28)	$ (130,885.82)	$ 23,111.08	$ 27,151.02	$ 14,990.88	$ 65,252.98	$ 16,877.98	$ 2,308.20	$ (96,647.55)	$ (77,461.37)	$ (145,959.87)	$ (63,212.09)	$ (101,172.93)	$ (310,344.89)	$ (453,439.10)
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (122,318.89)	$ (85,577.05)	$ (113,495.74)	$ (321,391.68)	$ (170,352.88)	$ (126,476.00)	$ (130,805.72)	$ (427,634.60)	$ (94,129.19)	$ (71,841.16)	$ (92,075.98)	$ (258,046.33)	$ (122,627.01)	$ (136,807.45)	$ (86,733.37)	$ (346,167.83)	$ (1,353,240.44)
5	Real-Time Spinning Reserve Amount	$ (30,639.63)	$ (32,572.21)	$ (21,084.57)	$ (84,296.41)	$ (27,083.25)	$ (3,161.73)	$ (2,307.80)	$ (32,552.78)	$ (6,177.31)	$ (29,690.23)	$ (26,740.76)	$ (62,608.30)	$ (17,828.20)	$ (26,902.10)	$ 29,078.93	$ (15,651.37)	$ (195,108.86)
11	Real Time Spinnng Reserve Cost Distribution	$ 173,114.10	$ 110,581.40	$ 108,454.56	$ 392,150.06	$ 118,148.11	$ 76,333.57	$ 78,292.63	$ 272,774.31	$ 80,474.86	$ 61,139.42	$ 85,815.90	$ 227,430.18	$ 114,522.54	$ 127,400.96	$ 143,210.28	$ 385,133.78	$ 1,277,488.33
	SUBTOTAL	$ 20,155.58	$ (7,567.86)	$ (26,125.75)	$ (13,538.03)	$ (79,288.02)	$ (53,304.16)	$ (54,820.89)	$ (187,413.07)	$ (19,831.64)	$ (40,391.97)	$ (33,000.84)	$ (93,224.45)	$ (25,932.67)	$ (36,308.59)	$ 85,555.84	$ 23,314.58	$ (270,860.97)
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (73,586.68)	$ (59,664.77)	$ (77,740.15)	$ (210,991.60)	$ (73,168.99)	$ (36,215.54)	$ (39,329.37)	$ (148,713.90)	$ (31,737.97)	$ (28,924.50)	$ (28,975.97)	$ (89,638.44)	$ (29,752.02)	$ (42,584.90)	$ (43,329.56)	$ (115,666.48)	$ (565,010.42)
6	Real-Time Supplemental Reserve Amount.	$ 17,028.97	$ 14,505.30	$ 8,639.35	$ 40,173.62	$ 6,272.28	$ 1,220.60	$ 621.51	$ 8,114.39	$ 169.40	$ 1,113.39	$ 4,280.36	$ 5,563.15	$ 1,511.51	$ 3,610.01	$ 26,699.14	$ 31,820.66	$ 85,671.82
12	Real Time Supplemental Reserve Cost Distribution	$ 54,284.03	$ 54,172.27	$ 76,350.94	$ 184,807.24	$ 81,416.18	$ 43,379.27	$ 40,390.87	$ 165,186.32	$ 34,779.64	$ 25,542.41	$ 31,300.69	$ 91,622.74	$ 35,121.00	$ 40,130.01	$ 31,102.86	$ 106,353.87	$ 547,970.17
	SUBTOTAL	$ (2,273.68)	$ 9,012.80	$ 7,250.14	$ 13,989.26	$ 14,519.47	$ 8,384.33	$ 1,683.01	$ 24,586.81	$ 3,211.07	$ (2,268.70)	$ 6,605.08	$ 7,547.45	$ 6,880.49	$ 1,155.12	$ 14,472.44	$ 22,508.05	$ 68,631.57
Other Charges																		
14	Real Time Contignecy Reserve Deployment Failure	$ 4,651.56	$ 10,693.34	$ 753.77	$ 16,098.67	$ 1,014.72	$ -	$ 208.99	$ 1,223.71	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,029.43	$ 5,029.43	$ 22,351.81
13	Real Time Excessive/Dificient Energy Deployment	$ 71,981.87	$ 33,481.46	$ 42,317.50	$ 147,780.83	$ 27,314.91	$ 14,179.43	$ 24,696.52	$ 66,190.86	$ 24,050.30	$ 43,018.21	$ 109,426.59	$ 176,495.10	$ 89,089.13	$ 75,084.14	$ 108,584.23	$ 272,757.50	$ 663,224.29
9	Real Time Net Regulation Adjustment Amount	$ 12,044.79	$ 14,864.62	$ 6,916.76	$ 33,826.17	$ 1,017.17	$ (582.74)	$ 2,826.77	$ 3,261.20	$ 2,868.67	$ 1,344.59	$ 7,858.51	$ 12,071.77	$ 20,357.45	$ 25,073.53	$ 25,272.22	$ 70,703.20	$ 119,862.34
	SUBTOTAL	$ 88,678.22	$ 59,039.42	$ 49,988.03	$ 197,705.67	$ 29,346.80	$ 13,596.69	$ 27,732.28	$ 70,675.77	$ 26,918.97	$ 44,362.80	$ 117,285.10	$ 188,566.87	$ 109,446.58	$ 100,157.67	$ 138,885.88	$ 348,490.13	$ 805,438.44
	TOTAL MISO ASM CHARGES	$ 56,986.27	$ 45,902.67	$ (35,617.86)	$ 67,271.08	$ (12,310.67)	$ (4,172.12)	$ (10,414.72)	$ (26,897.51)	$ 27,176.38	$ 4,010.33	$ (5,758.21)	$ 25,428.50	$ (55,565.47)	$ 1,792.11	$ 137,741.23	$ 83,967.87	$ 149,769.94
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (26,561.20)	$ (19,811.61)	$ (7,170.29)	$ (53,543.10)	$ (13,815.95)	$ 101.44	$ 43,903.07	$ 30,188.56	$ 15,343.41	$ (802.86)	$ (781.17)	$ 13,759.38	$ 20,399.46	$ 16,027.06	$ 15,895.07	$ 52,321.59	$ 42,726.43
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -				$ -				$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -				$ -				$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 546,921.45	$ 2,082,165.56	$ 1,303,212.45	$ 3,932,299.46	$ 1,446,786.69	$ 3,944,156.53	$ 2,840,720.06	$ 8,231,663.28	$ 2,666,036.28	$ 1,129,118.39	$ 829,293.35	$ 4,624,448.02	$ 1,903,327.60	$ 1,849,014.63	$ 1,888,043.33	$ 5,640,385.56	$ 22,428,796.32
8b	Real Time Non Excessive Energy Congestion	$ (160,907.88)	$ (176,642.68)	$ (383,403.66)	$ (720,954.22)	$ 75,241.38	$ (157,392.19)	$ 136,105.72	$ 53,954.91	$ 228.97	$ (63,959.04)	$ (79,902.28)	$ (143,632.35)	$ (145,978.81)	$ (80,367.36)	$ 318,919.27	$ 92,573.10	$ (718,058.56)
8c	Real Time Non Excessive Energy Loss	$ (30,879.38)	$ 16,714.25	$ (99,174.40)	$ (113,339.53)	$ 25,413.21	$ (60,460.26)	$ 64,750.07	$ 29,703.02	$ 12,667.87	$ (2,915.27)	$ (19,091.78)	$ (9,339.18)	$ (10,923.96)	$ (40,299.36)	$ 172,045.36	$ 120,822.04	$ 27,846.35
	SUBTOTAL	$ 328,572.99	$ 1,902,425.52	$ 813,464.10	$ 3,044,462.61	$ 1,533,625.33	$ 3,726,405.52	$ 3,085,478.92	$ 8,345,509.77	$ 2,694,276.53	$ 1,061,441.22	$ 729,518.12	$ 4,485,235.87	$ 1,766,824.29	$ 1,744,374.97	$ 2,394,903.03	$ 5,906,102.29	$ 21,781,310.54
	GRAND TOTAL MISO ASM CHARGES	$ 385,559.26	$ 1,948,328.19	$ 777,846.24	$ 3,111,733.69	$ 1,521,314.66	$ 3,722,233.40	$ 3,075,064.20	$ 8,318,612.26	$ 2,721,452.91	$ 1,065,451.55	$ 723,759.91	$ 4,510,664.37	$ 1,711,258.82	$ 1,746,167.08	$ 2,532,644.26	$ 5,990,070.16	$ 21,931,080.48

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

		July 15	August 15	September 15	3rd Qt	October 15	November 15	December 15	4th Qt	January 16	February 16	March 16	1st Qt	April 16	May 16	June 16	2nd Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	-	-	-	-	-	-	-	-				-				-	-
4	Real-Time Regulation Amount	43,573.90	45,405.73	74,644.60	163,624.23	7,493.90	5,298.12	14,298.72	27,090.74	4,940.43	5,163.41	63,464.77	73,568.61	111,207.73	70,444.23	93,216.07	274,868.03	539,151.61
10	Real Time Regulation Reserve Cost Distribution Amou	-	-	-	-	-	-	-	-				-				-	-
	SUBTOTAL	43,573.90	45,405.73	74,644.60	163,624.23	7,493.90	5,298.12	14,298.72	27,090.74	4,940.43	5,163.41	63,464.77	73,568.61	111,207.73	70,444.23	93,216.07	274,868.03	539,151.61
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	-	-	-	-	-	-	-	-				-				-	-
5	Real-Time Spinning Reserve Amount	60,745.01	34,604.00	46,369.39	141,718.40	111,001.72	77,841.57	73,561.87	262,405.16	37,661.38	65,908.96	42,092.50	145,662.84	72,585.08	66,038.98	17,696.44	156,320.50	706,106.90
11	Real Time Spinnng Reserve Cost Distribution	-	-	-	-	-	-	-	-				-				-	-
	SUBTOTAL	60,745.01	34,604.00	46,369.39	141,718.40	111,001.72	77,841.57	73,561.87	262,405.16	37,661.38	65,908.96	42,092.50	145,662.84	72,585.08	66,038.98	17,696.44	156,320.50	706,106.90
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	-	-	-	-	-	-	-	-				-				-	-
6	Real-Time Supplemental Reserve Amount.	9,474.72	6,131.79	4,644.03	20,250.54	3,305.04	1,898.26	1,293.78	6,497.08	848.55	2,850.94	855.63	4,555.12	139.98	699.97	1,090.63	1,930.58	33,233.32
12	Real Time Supplemental Reserve Cost Distribution	-	-	-	-	-	-	-	-				-				-	-
	SUBTOTAL	9,474.72	6,131.79	4,644.03	20,250.54	3,305.04	1,898.26	1,293.78	6,497.08	848.55	2,850.94	855.63	4,555.12	139.98	699.97	1,090.63	1,930.58	33,233.32
Other Charges																		
14	Real Time Contignecy Reserve Deployment Failure	(3,125.44)	(4,250.32)	-	(7,375.76)	(339.03)	-	-	(339.03)	-	(339.03)	-	(339.03)	-	-	(408.74)	(408.74)	(8,462.56)
13	Real Time Excessive/Dificient Energy Deployment	(14,514.42)	(7,473.55)	(13,225.65)	(35,213.62)	(11,057.59)	(1,420.68)	(5,321.85)	(17,800.12)	(12,530.04)	(6,939.30)	(31,204.57)	(50,673.91)	(27,667.13)	(15,568.78)	(23,354.89)	(66,590.80)	(170,278.45)
9	Real Time Net Regulation Adjustment Amount	(5,239.76)	(2,676.52)	(4,245.50)	(12,161.78)	(815.43)	(333.92)	(824.36)	(1,973.71)	(820.54)	(155.61)	(1,801.57)	(2,777.72)	(6,606.51)	(10,095.65)	(5,925.28)	(22,627.44)	(39,540.65)
	SUBTOTAL	(22,879.62)	(14,400.39)	(17,471.15)	(54,751.16)	(12,212.05)	(1,754.60)	(6,146.21)	(20,112.86)	(13,350.58)	(7,433.94)	(33,006.14)	(53,790.66)	(34,273.64)	(25,664.43)	(29,688.91)	(89,626.98)	(218,281.66)
	TOTAL MISO ASM CHARGES	90,914.01	71,741.13	108,186.87	270,842.01	109,588.61	83,283.35	83,008.16	275,880.12	30,099.78	66,489.37	73,406.76	169,995.91	149,659.15	111,518.75	82,314.23	343,492.13	1,060,210.17
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	6,638.91	9,133.94	29,748.60	45,521.46	(8,887.61)	7,644.84	(14,663.15)	(15,905.92)	657.28	394.38	(8,737.55)	(7,685.89)	(683.88)	(8,613.88)	4,265.27	(5,032.50)	16,897.15
8c	Real Time Non Excessive Energy Loss	1,274.05	(864.27)	7,695.02	8,104.81	(3,001.84)	2,936.67	(6,975.76)	(7,040.93)	316.97	(861.53)	(2,407.38)	(2,951.94)	(445.35)	(4,083.85)	638.22	(3,890.98)	(5,779.04)
	SUBTOTAL	7,912.96	8,269.67	37,443.63	53,626.27	(11,889.46)	10,581.52	(21,638.91)	(22,946.85)	974.24	(467.15)	(11,144.93)	(10,637.83)	(1,129.24)	(12,697.73)	4,903.49	(8,923.48)	11,118.11
	GRAND TOTAL MISO ASM CHARGES	98,826.97	80,010.80	145,630.50	324,468.28	97,699.15	93,864.87	61,369.25	252,933.27	31,074.02	66,022.22	62,261.83	159,358.08	148,529.91	98,821.02	87,217.72	334,568.65	1,071,328.28

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

		July 15	August 15	September 15	3rd Qt	October 15	November 15	December 15	4th Qt	January 16	February 16	March 16	1st Qt	April 16	May 16	June 16	2nd Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (57,199.93)	$ (42,724.29)	$ (83,111.35)	$ (183,035.57)	$ (59,507.33)	$ (30,939.83)	$ (32,032.61)	$ (122,479.77)	$ (32,831.67)	$ (14,280.12)	$ (110,484.65)	$ (157,596.44)	$ (141,162.16)	$ (171,726.95)	$ (112,914.37)	$ (425,803.48)	$ (888,915.26)
4	Real-Time Regulation Amount	$ (38,441.04)	$ (17,056.46)	$ (8,794.57)	$ (64,292.07)	$ (10,498.52)	$ 5,119.24	$ (9,851.31)	$ (15,230.59)	$ (10,910.23)	$ (39,531.45)	$ 8,097.92	$ (42,343.76)	$ 23,652.13	$ 72,351.97	$ 32,028.43	$ 128,032.53	$ 6,166.11
10	Real Time Regulation Reserve Cost Distribution Amou	$ 89,641.02	$ 90,604.79	$ 99,820.24	$ 280,066.05	$ 100,610.83	$ 58,269.73	$ 71,173.52	$ 230,054.08	$ 65,560.31	$ 61,283.18	$ 69,203.95	$ 196,047.44	$ 82,757.89	$ 106,607.12	$ 72,929.08	$ 262,294.09	$ 968,461.66
	SUBTOTAL	$ (5,999.95)	$ 30,824.04	$ 7,914.32	$ 32,738.41	$ 30,604.98	$ 32,449.14	$ 29,289.60	$ 92,343.72	$ 21,818.41	$ 7,471.61	$ (33,182.78)	$ (3,892.76)	$ (34,752.14)	$ 7,232.14	$ (7,956.86)	$ (35,476.86)	$ 85,712.51
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (122,318.89)	$ (85,577.05)	$ (113,495.74)	$ (321,391.68)	$ (170,352.88)	$ (126,476.00)	$ (130,805.72)	$ (427,634.60)	$ (94,129.19)	$ (71,841.16)	$ (92,075.98)	$ (258,046.33)	$ (122,627.01)	$ (136,807.45)	$ (86,733.37)	$ (346,167.83)	$ (1,353,240.44)
5	Real-Time Spinning Reserve Amount	$ 30,105.38	$ 2,031.79	$ 25,284.82	$ 57,421.99	$ 83,918.47	$ 74,679.84	$ 71,254.07	$ 229,852.38	$ 31,484.07	$ 36,218.73	$ 15,351.74	$ 83,054.54	$ 54,756.88	$ 39,136.88	$ 46,775.37	$ 140,669.13	$ 510,998.04
11	Real Time Spinnng Reserve Cost Distribution	$ 173,114.10	$ 110,581.40	$ 108,454.56	$ 392,150.06	$ 118,148.11	$ 76,333.57	$ 78,292.63	$ 272,774.31	$ 80,474.86	$ 61,139.42	$ 85,815.90	$ 227,430.18	$ 114,522.54	$ 127,400.96	$ 143,210.28	$ 385,133.78	$ 1,277,488.33
	SUBTOTAL	$ 80,900.59	$ 27,036.14	$ 20,243.64	$ 128,180.37	$ 31,713.70	$ 24,537.41	$ 18,740.98	$ 74,992.09	$ 17,829.74	$ 25,516.99	$ 9,091.66	$ 52,438.39	$ 46,652.41	$ 29,730.39	$ 103,252.28	$ 179,635.08	$ 435,245.93
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (73,586.68)	$ (59,664.77)	$ (77,740.15)	$ (210,991.60)	$ (73,168.99)	$ (36,215.54)	$ (39,329.37)	$ (148,713.90)	$ (31,737.97)	$ (28,924.50)	$ (28,975.97)	$ (89,638.44)	$ (29,752.02)	$ (42,584.90)	$ (43,329.56)	$ (115,666.48)	$ (565,010.42)
6	Real-Time Supplemental Reserve Amount.	$ 26,503.69	$ 20,637.09	$ 13,283.38	$ 60,424.16	$ 9,577.32	$ 3,118.86	$ 1,915.29	$ 14,611.47	$ 1,017.95	$ 3,964.33	$ 5,135.99	$ 10,118.27	$ 1,651.49	$ 4,309.98	$ 27,789.77	$ 33,751.24	$ 118,905.14
12	Real Time Supplemental Reserve Cost Distribution	$ 54,284.03	$ 54,172.27	$ 76,350.94	$ 184,807.24	$ 81,416.18	$ 43,379.27	$ 40,390.87	$ 165,186.32	$ 34,779.64	$ 25,542.41	$ 31,300.69	$ 91,622.74	$ 35,121.00	$ 40,130.01	$ 31,102.86	$ 106,353.87	$ 547,970.17
	SUBTOTAL	$ 7,201.04	$ 15,144.59	$ 11,894.17	$ 34,239.80	$ 17,824.51	$ 10,282.59	$ 2,976.79	$ 31,083.89	$ 4,059.62	$ 582.24	$ 7,460.71	$ 12,102.57	$ 7,020.47	$ 1,855.09	$ 15,563.07	$ 24,438.63	$ 101,864.89
Other Charges																		
13	Real Time Excessive/Dificient Energy Deployment	$ 1,526.12	$ 6,443.02	$ 753.77	$ 8,722.91	$ 675.69	$ -	$ 208.99	$ 884.68	$ -	$ (339.03)	$ -	$ (339.03)	$ -	$ -	$ 4,620.69	$ 4,620.69	$ 13,889.25
14	Real Time Contignecy Reserve Deployment Failure	$ 57,467.45	$ 26,007.91	$ 29,091.85	$ 112,567.21	$ 16,257.32	$ 12,758.75	$ 19,374.67	$ 48,390.74	$ 11,520.26	$ 36,078.91	$ 78,222.02	$ 125,821.19	$ 61,422.00	$ 59,515.36	$ 85,229.34	$ 206,166.70	$ 492,945.84
9	Real Time Net Regulation Adjustment Amount	$ 6,805.03	$ 12,188.10	$ 2,671.26	$ 21,664.39	$ 201.74	$ (916.66)	$ 2,002.41	$ 1,287.49	$ 2,048.13	$ 1,188.98	$ 6,056.94	$ 9,294.05	$ 13,750.94	$ 14,977.88	$ 19,346.94	$ 48,075.76	$ 80,321.69
	SUBTOTAL	$ 65,798.60	$ 44,639.03	$ 32,516.88	$ 142,954.51	$ 17,134.75	$ 11,842.09	$ 21,586.07	$ 50,562.91	$ 13,568.39	$ 36,928.86	$ 84,278.96	$ 134,776.21	$ 75,172.94	$ 74,493.24	$ 109,196.97	$ 258,863.15	$ 587,156.78
	TOTAL MISO ASM CHARGES	$ 147,900.28	$ 117,643.80	$ 72,569.01	$ 338,113.09	$ 97,277.94	$ 79,111.23	$ 72,593.44	$ 248,982.61	$ 57,276.16	$ 70,499.70	$ 67,648.55	$ 195,424.41	$ 94,093.68	$ 113,310.86	$ 220,055.46	$ 427,460.00	$ 1,209,980.11
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (26,561.20)	$ (19,811.61)	$ (7,170.29)	$ (53,543.10)	$ (13,815.95)	$ 101.44	$ 43,903.07	$ 30,188.56	$ 15,343.41	$ (802.86)	$ (781.17)	$ 13,759.38	$ 20,399.46	$ 16,027.06	$ 15,895.07	$ 52,321.59	$ 42,726.43
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 546,921.45	$ 2,082,165.56	$ 1,303,212.45	$ 3,932,299.46	$ 1,446,786.69	$ 3,944,156.53	$ 2,840,720.06	$ 8,231,663.28	$ 2,666,036.28	$ 1,129,118.39	$ 829,293.35	$ 4,624,448.02	$ 1,903,327.60	$ 1,849,014.63	$ 1,888,043.33	$ 5,640,385.56	$ 22,428,796.32
8b	Real Time Non Excessive Energy Congestion	$ (154,268.97)	$ (167,508.74)	$ (353,655.06)	$ (675,432.76)	$ 66,353.77	$ (149,747.35)	$ 121,442.57	$ 38,048.99	$ 886.25	$ (63,564.66)	$ (88,639.83)	$ (151,318.24)	$ (146,662.69)	$ (88,981.24)	$ 323,184.54	$ 87,540.60	$ (701,161.41)
8c	Real Time Non Excessive Energy Loss	$ (29,605.33)	$ 15,849.98	$ (91,479.38)	$ (105,234.72)	$ 22,411.37	$ (57,523.59)	$ 57,774.31	$ 22,662.09	$ 12,984.84	$ (3,776.80)	$ (21,499.16)	$ (12,291.12)	$ (11,369.31)	$ (44,383.21)	$ 172,683.58	$ 116,931.06	$ 22,067.31
	SUBTOTAL	$ 336,485.95	$ 1,910,695.19	$ 850,907.73	$ 3,098,088.88	$ 1,521,735.87	$ 3,736,987.04	$ 3,063,840.01	$ 8,322,562.92	$ 2,695,250.77	$ 1,060,974.07	$ 718,373.19	$ 4,474,598.04	$ 1,765,695.05	$ 1,731,677.24	$ 2,399,806.52	$ 5,897,178.81	$ 21,792,428.65
	GRAND TOTAL MISO ASM CHARGES	$ 484,386.23	$ 2,028,338.99	$ 923,476.74	$ 3,436,201.97	$ 1,619,013.81	$ 3,816,098.27	$ 3,136,433.45	$ 8,571,545.53	$ 2,752,526.93	$ 1,131,473.77	$ 786,021.74	$ 4,670,022.45	$ 1,859,788.73	$ 1,844,988.10	$ 2,619,861.98	$ 6,324,638.81	$ 23,002,408.76

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

		July 15	August 15	September 15	3rd Qt	October 15	November 15	December 15	4th Qt	January 16	February 16	March 16	1st Qt	April 16	May 16	June 16	2nd Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (42,639.98)	$ (31,702.31)	$ (61,654.65)	$ (135,996.94)	$ (44,041.11)	$ (22,516.09)	$ (23,254.33)	$ (89,811.53)	$ (23,657.73)	$ (10,330.24)	$ (80,087.92)	$ (114,075.90)	$ (103,410.54)	$ (126,325.64)	$ (83,341.79)	$ (313,077.97)	$ (652,962.33)
4	Real-Time Regulation Amount	$ (28,656.07)	$ (12,656.25)	$ (6,524.09)	$ (47,836.41)	$ (7,769.91)	$ 3,725.47	$ (7,151.64)	$ (11,196.08)	$ (7,861.66)	$ (28,597.06)	$ 5,870.01	$ (30,588.71)	$ 17,326.74	$ 53,223.50	$ 23,640.10	$ 94,190.33	$ 4,569.13
10	Real Time Regulation Reserve Cost Distribution Amou	$ 66,823.36	$ 67,230.64	$ 74,049.83	$ 208,103.83	$ 74,461.62	$ 42,405.11	$ 51,668.98	$ 168,535.70	$ 47,241.22	$ 44,332.27	$ 50,164.44	$ 141,737.93	$ 60,625.58	$ 78,422.24	$ 53,828.76	$ 192,876.58	$ 711,254.04
	SUBTOTAL	$ (4,472.69)	$ 22,872.08	$ 5,871.09	$ 24,270.48	$ 22,650.61	$ 23,614.48	$ 21,263.02	$ 67,528.10	$ 15,721.84	$ 5,404.96	$ (24,053.48)	$ (2,926.68)	$ (25,458.22)	$ 5,320.10	$ (5,872.94)	$ (26,011.06)	$ 62,860.85
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (91,183.24)	$ (63,499.95)	$ (84,194.75)	$ (238,877.95)	$ (126,077.40)	$ (92,041.41)	$ (94,959.44)	$ (313,078.25)	$ (67,827.29)	$ (51,969.91)	$ (66,743.88)	$ (186,541.08)	$ (89,832.33)	$ (100,638.19)	$ (64,017.66)	$ (254,488.18)	$ (992,985.45)
5	Real-Time Spinning Reserve Amount	$ 22,442.21	$ 1,507.63	$ 18,757.08	$ 42,706.92	$ 62,107.68	$ 54,347.37	$ 51,727.45	$ 168,182.50	$ 22,686.68	$ 26,200.64	$ 11,128.14	$ 60,015.46	$ 40,113.01	$ 28,789.84	$ 34,524.77	$ 103,427.62	$ 374,332.51
11	Real Time Spinnng Reserve Cost Distribution	$ 129,048.79	$ 82,053.70	$ 80,455.05	$ 291,557.53	$ 87,440.88	$ 55,550.85	$ 56,837.15	$ 199,828.89	$ 57,988.30	$ 44,228.27	$ 62,206.08	$ 164,422.65	$ 83,895.27	$ 93,718.59	$ 105,703.12	$ 283,316.98	$ 939,126.05
	SUBTOTAL	$ 60,307.76	$ 20,061.38	$ 15,017.38	$ 95,386.51	$ 23,471.17	$ 17,856.81	$ 13,605.16	$ 54,933.14	$ 12,847.69	$ 18,459.00	$ 6,590.35	$ 37,897.04	$ 34,175.95	$ 21,870.25	$ 76,210.23	$ 132,256.42	$ 320,473.11
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (54,855.57)	$ (44,272.50)	$ (57,670.12)	$ (156,798.19)	$ (54,152.04)	$ (26,355.43)	$ (28,551.47)	$ (109,058.94)	$ (22,869.64)	$ (20,923.99)	$ (21,004.05)	$ (64,797.68)	$ (21,795.31)	$ (31,326.27)	$ (31,981.43)	$ (85,103.01)	$ (415,757.81)
6	Real-Time Supplemental Reserve Amount.	$ 19,757.31	$ 15,313.15	$ 9,854.03	$ 44,924.50	$ 7,088.13	$ 2,269.71	$ 1,390.42	$ 10,748.26	$ 733.51	$ 2,867.80	$ 3,722.97	$ 7,324.28	$ 1,209.82	$ 3,170.50	$ 20,511.55	$ 24,891.88	$ 87,888.92
12	Real Time Supplemental Reserve Cost Distribution	$ 40,466.31	$ 40,196.95	$ 56,639.56	$ 137,302.82	$ 60,255.75	$ 31,568.75	$ 29,322.07	$ 121,146.57	$ 25,061.39	$ 18,477.39	$ 22,689.19	$ 66,227.97	$ 25,728.44	$ 29,520.41	$ 22,956.94	$ 78,205.78	$ 402,883.13
	SUBTOTAL	$ 5,368.05	$ 11,237.60	$ 8,823.47	$ 25,429.13	$ 13,191.84	$ 7,483.03	$ 2,161.02	$ 22,835.90	$ 2,925.27	$ 421.19	$ 5,408.11	$ 8,754.57	$ 5,142.95	$ 1,364.64	$ 11,487.06	$ 17,994.65	$ 75,014.24
Other Charges																		
14	Real Time Contignecy Reserve Deployment Failure	$ 1,137.65	$ 4,780.85	$ 559.17	$ 6,477.68	$ 500.08	$ -	$ 151.72	$ 651.79	$ -	$ (245.25)	$ -	$ (245.25)	$ -	$ -	$ 3,410.52	$ 3,410.52	$ 10,294.74
13	Real Time Excessive/Dificient Energy Deployment	$ 42,839.40	$ 19,298.41	$ 21,581.26	$ 83,719.07	$ 12,031.97	$ 9,285.03	$ 14,065.19	$ 35,382.19	$ 8,301.23	$ 26,099.49	$ 56,701.44	$ 91,102.16	$ 44,995.64	$ 43,780.64	$ 62,907.54	$ 151,683.83	$ 361,887.26
9	Real Time Net Regulation Adjustment Amount	$ 5,072.84	$ 9,043.82	$ 1,981.63	$ 16,098.29	$ 149.31	$ (667.09)	$ 1,453.67	$ 935.88	$ 1,475.83	$ 860.11	$ 4,390.54	$ 6,726.49	$ 10,073.47	$ 11,018.02	$ 14,279.92	$ 35,371.40	$ 59,132.07
	SUBTOTAL	$ 49,049.90	$ 33,123.09	$ 24,122.06	$ 106,295.05	$ 12,681.35	$ 8,617.94	$ 15,670.58	$ 36,969.87	$ 9,777.06	$ 26,714.35	$ 61,091.99	$ 97,583.40	$ 55,069.11	$ 54,798.66	$ 80,597.99	$ 190,465.75	$ 431,314.06
	TOTAL MISO ASM CHARGES	$ 110,253.02	$ 87,294.15	$ 53,834.00	$ 251,381.17	$ 71,994.96	$ 57,572.26	$ 52,699.78	$ 182,267.00	$ 41,271.86	$ 50,999.50	$ 49,036.96	$ 141,308.32	$ 68,929.79	$ 83,353.64	$ 162,422.34	$ 314,705.77	$ 889,662.26
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ (19,800.18)	$ (14,700.63)	$ (5,319.15)	$ (39,819.96)	$ (10,225.12)	$ 73.82	$ 31,871.78	$ 21,720.48	$ 11,056.10	$ (580.79)	$ (566.25)	$ 9,909.06	$ 14,943.94	$ 11,789.81	$ 11,732.11	$ 38,465.86	$ 30,275.44
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 407,705.38	$ 1,545,010.16	$ 966,764.50	$ 2,919,480.05	$ 1,070,760.29	$ 2,870,313.19	$ 2,062,243.14	$ 6,003,316.62	$ 1,921,083.33	$ 816,804.51	$ 601,136.72	$ 3,339,024.56	$ 1,394,312.27	$ 1,360,170.65	$ 1,393,559.65	$ 4,148,042.56	$ 16,409,863.79
8b	Real Time Non Excessive Energy Congestion	$ (115,000.59)	$ (124,294.97)	$ (262,352.58)	$ (501,648.14)	$ 49,108.12	$ (108,976.86)	$ 88,162.19	$ 28,293.45	$ 638.61	$ (45,982.69)	$ (64,253.09)	$ (109,597.17)	$ (107,440.04)	$ (65,456.31)	$ 238,541.63	$ 65,645.28	$ (517,306.57)
8c	Real Time Non Excessive Energy Loss	$ (22,069.44)	$ 11,761.01	$ (67,862.32)	$ (78,170.74)	$ 16,586.55	$ (41,862.11)	$ 41,941.72	$ 16,666.16	$ 9,356.57	$ (2,732.14)	$ (15,584.27)	$ (8,959.84)	$ (8,328.77)	$ (32,649.14)	$ 127,457.28	$ 86,479.37	$ 16,014.95
	SUBTOTAL	$ 250,835.17	$ 1,417,775.58	$ 631,230.45	$ 2,299,841.21	$ 1,126,229.84	$ 2,719,548.05	$ 2,224,218.83	$ 6,069,996.71	$ 1,942,134.61	$ 767,508.89	$ 520,733.11	$ 3,230,376.61	$ 1,293,487.40	$ 1,273,855.01	$ 1,771,290.66	$ 4,338,633.08	$ 15,938,847.61
	GRAND TOTAL MISO ASM CHARGES	$ 361,088.19	$ 1,505,069.73	$ 685,064.46	$ 2,551,222.38	$ 1,198,224.80	$ 2,777,120.31	$ 2,276,918.61	$ 6,252,263.72	$ 1,983,406.47	$ 818,508.39	$ 569,770.07	$ 3,371,684.94	$ 1,362,417.19	$ 1,357,208.66	$ 1,933,713.00	$ 4,653,338.85	$ 16,828,509.88

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

July 2015	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		$ (57,199.93)		$ (57,199.93)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (122,318.89)		$ (122,318.89)		$ -		
3 Day-Ahead Supplemental Reserve		$ (73,586.68)		$ (73,586.68)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (82,014.94)		$ (38,441.04)		$ (43,573.90)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (30,639.63)		$ 30,105.38		$ (60,745.01)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 17,028.97		$ 26,503.69		$ (9,474.72)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,571)	$ (26,561.20)	(2,571)	$ (26,561.20)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	28,878	$ 546,921.45	28,878	$ 546,921.45				
8b Real Time Non Excessive Energy Congestion		$ (160,907.88)		$ (154,268.97)		$ (6,638.91)		
8c Real Time Non Excessive Energy Loss		$ (30,879.38)		$ (29,605.33)		$ (1,274.05)		
9 Real Time Net Regulation Adjustment Amount		$ 12,044.79		$ 6,805.03		$ 5,239.76		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 89,641.02		$ 89,641.02		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 173,114.10		$ 173,114.10		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 54,284.03		$ 54,284.03		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 71,981.87		$ 57,467.45		$ 14,514.42		
14 Real Time Contignecy Reserve Deployment Failure		$ 4,651.56		$ 1,526.12		$ 3,125.44		
TOTAL MISO ASM CHARGES	**26,307**	**$ 385,559.26**	**26,307**	**$ 484,386.23**		**$ (98,826.97)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

August 2015	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		$ (42,724.29)		$ (42,724.29)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (85,577.05)		$ (85,577.05)		$ -		
3 Day-Ahead Supplemental Reserve		$ (59,664.77)		$ (59,664.77)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (62,462.19)		$ (17,056.46)		$ (45,405.73)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (32,572.21)		$ 2,031.79		$ (34,604.00)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 14,505.30		$ 20,637.09		$ (6,131.79)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,037)	$ (19,811.61)	(2,037)	$ (19,811.61)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	101,137	$ 2,082,165.56	101,137	$ 2,082,165.56				
8b Real Time Non Excessive Energy Congestion		$ (176,642.68)		$ (167,508.74)		$ (9,133.94)		
8c Real Time Non Excessive Energy Loss		$ 16,714.25		$ 15,849.98		$ 864.27		
9 Real Time Net Regulation Adjustment Amount		$ 14,864.62		$ 12,188.10		$ 2,676.52		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 90,604.79		$ 90,604.79		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 110,581.40		$ 110,581.40		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 54,172.27		$ 54,172.27		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 33,481.46		$ 26,007.91		$ 7,473.55		
14 Real Time Contignecy Reserve Deployment Failure		$ 10,693.34		$ 6,443.02		$ 4,250.32		
TOTAL MISO ASM CHARGES	**99,100**	**$ 1,948,328.19**	**99,100**	**$ 2,028,338.99**		**$ (80,010.80)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

September 2015	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		$ (83,111.35)		$ (83,111.35)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (113,495.74)		$ (113,495.74)		$ -		
3 Day-Ahead Supplemental Reserve		$ (77,740.15)		$ (77,740.15)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (83,439.17)		$ (8,794.57)		$ (74,644.60)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (21,084.57)		$ 25,284.82		$ (46,369.39)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 8,639.35		$ 13,283.38		$ (4,644.03)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	3,886	$ (7,170.29)	3,886	$ (7,170.29)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	43,162	$ 1,303,212.45	43,162	$ 1,303,212.45				
8b Real Time Non Excessive Energy Congestion		$ (383,403.66)		$ (353,655.06)		$ (29,748.60)		
8c Real Time Non Excessive Energy Loss		$ (99,174.40)		$ (91,479.38)		$ (7,695.02)		
9 Real Time Net Regulation Adjustment Amount		$ 6,916.76		$ 2,671.26		$ 4,245.50		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 99,820.24		$ 99,820.24		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 108,454.56		$ 108,454.56		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 76,350.94		$ 76,350.94		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 42,317.50		$ 29,091.85		$ 13,225.65		
14 Real Time Contignecy Reserve Deployment Failure		$ 753.77		$ 753.77		$ -		
TOTAL MISO ASM CHARGES	**47,048**	**$ 777,846.24**	**47,048**	**$ 923,476.74**		**$ (145,630.50)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

October 2015	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		$ (59,507.33)		$ (59,507.33)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (170,352.88)		$ (170,352.88)		$ -		
3 Day-Ahead Supplemental Reserve		$ (73,168.99)		$ (73,168.99)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (17,992.42)		$ (10,498.52)		$ (7,493.90)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (27,083.25)		$ 83,918.47		$ (111,001.72)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 6,272.28		$ 9,577.32		$ (3,305.04)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(6,551)	$ (13,815.95)	(6,551)	$ (13,815.95)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	86,742	$ 1,446,786.69	86,742	$ 1,446,786.69				
8b Real Time Non Excessive Energy Congestion		$ 75,241.38		$ 66,353.77		$ 8,887.61		
8c Real Time Non Excessive Energy Loss		$ 25,413.21		$ 22,411.37		$ 3,001.84		
9 Real Time Net Regulation Adjustment Amount		$ 1,017.17		$ 201.74		$ 815.43		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 100,610.83		$ 100,610.83		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 118,148.11		$ 118,148.11		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 81,416.18		$ 81,416.18		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 27,314.91		$ 16,257.32		$ 11,057.59		
14 Real Time Contignecy Reserve Deployment Failure		$ 1,014.72		$ 675.69		$ 339.03		
TOTAL MISO ASM CHARGES	**80,191**	**$ 1,521,314.66**	**80,191**	**$ 1,619,013.81**		**$ (97,699.15)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

November 2015	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		$ (30,939.83)		$ (30,939.83)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (126,476.00)		$ (126,476.00)		$ -		
3 Day-Ahead Supplemental Reserve		$ (36,215.54)		$ (36,215.54)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (178.88)		$ 5,119.24		$ (5,298.12)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (3,161.73)		$ 74,679.84		$ (77,841.57)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,220.60		$ 3,118.86		$ (1,898.26)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,683)	$ 101.44	(1,683)	$ 101.44				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	179,931	$ 3,944,156.53	179,931	$ 3,944,156.53				
8b Real Time Non Excessive Energy Congestion		$ (157,392.19)		$ (149,747.35)		$ (7,644.84)		
8c Real Time Non Excessive Energy Loss		$ (60,460.26)		$ (57,523.59)		$ (2,936.67)		
9 Real Time Net Regulation Adjustment Amount		$ (582.74)		$ (916.66)		$ 333.92		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 58,269.73		$ 58,269.73		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 76,333.57		$ 76,333.57		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 43,379.27		$ 43,379.27		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 14,179.43		$ 12,758.75		$ 1,420.68		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**178,248**	**$ 3,722,233.40**	**178,248**	**$ 3,816,098.27**		**$ (93,864.87)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

December 2015	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		$ (32,032.61)		$ (32,032.61)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (130,805.72)		$ (130,805.72)		$ -		
3 Day-Ahead Supplemental Reserve		$ (39,329.37)		$ (39,329.37)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (24,150.03)		$ (9,851.31)		$ (14,298.72)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (2,307.80)		$ 71,254.07		$ (73,561.87)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 621.51		$ 1,915.29		$ (1,293.78)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,114)	$ 43,903.07	(2,114)	$ 43,903.07				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	180,362	$ 2,840,720.06	180,362	$ 2,840,720.06				
8b Real Time Non Excessive Energy Congestion		$ 136,105.72		$ 121,442.57		$ 14,663.15		
8c Real Time Non Excessive Energy Loss		$ 64,750.07		$ 57,774.31		$ 6,975.76		
9 Real Time Net Regulation Adjustment Amount		$ 2,826.77		$ 2,002.41		$ 824.36		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 71,173.52		$ 71,173.52		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 78,292.63		$ 78,292.63		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 40,390.87		$ 40,390.87		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 24,696.52		$ 19,374.67		$ 5,321.85		
14 Real Time Contignecy Reserve Deployment Failure		$ 208.99		$ 208.99		$ -		
TOTAL MISO ASM CHARGES	**178,248**	**$ 3,075,064.20**	**178,248**	**$ 3,136,433.45**		**$ (61,369.25)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

January 2016	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		$ (32,831.67)		$ (32,831.67)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (94,129.19)		$ (94,129.19)		$ -		
3 Day-Ahead Supplemental Reserve		$ (31,737.97)		$ (31,737.97)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (15,850.66)		$ (10,910.23)		$ (4,940.43)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (6,177.31)		$ 31,484.07		$ (37,661.38)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 169.40		$ 1,017.95		$ (848.55)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,031)	$ 15,343.41	(3,031)	$ 15,343.41		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	144,216	$ 2,666,036.28	144,216	$ 2,666,036.28		$ -		
8b Real Time Non Excessive Energy Congestion		$ 228.97		$ 886.25		$ (657.28)		
8c Real Time Non Excessive Energy Loss		$ 12,667.87		$ 12,984.84		$ (316.97)		
9 Real Time Net Regulation Adjustment Amount		$ 2,868.67		$ 2,048.13		$ 820.54		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 65,560.31		$ 65,560.31		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 80,474.86		$ 80,474.86		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 34,779.64		$ 34,779.64		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 24,050.30		$ 11,520.26		$ 12,530.04		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**141,185**	**$ 2,721,452.91**	**141,185**	**$ 2,752,526.93**		**$ (31,074.02)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

February 2016	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		$ (14,280.12)		$ (14,280.12)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (71,841.16)		$ (71,841.16)		$ -		
3 Day-Ahead Supplemental Reserve		$ (28,924.50)		$ (28,924.50)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (44,694.86)		$ (39,531.45)		$ (5,163.41)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (29,690.23)		$ 36,218.73		$ (65,908.96)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,113.39		$ 3,964.33		$ (2,850.94)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,310)	$ (802.86)	(3,310)	$ (802.86)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	71,110	$ 1,129,118.39	71,110	$ 1,129,118.39		$ -		
8b Real Time Non Excessive Energy Congestion		$ (63,959.04)		$ (63,564.66)		$ (394.38)		
8c Real Time Non Excessive Energy Loss		$ (2,915.27)		$ (3,776.80)		$ 861.53		
9 Real Time Net Regulation Adjustment Amount		$ 1,344.59		$ 1,188.98		$ 155.61		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 61,283.18		$ 61,283.18		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 61,139.42		$ 61,139.42		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 25,542.41		$ 25,542.41		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 43,018.21		$ 36,078.91		$ 6,939.30		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**67,800**	**$ 1,065,451.55**	**67,800**	**$ 1,131,812.80**		**$ (66,361.25)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

March 2016	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		$ (110,484.65)		$ (110,484.65)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (92,075.98)		$ (92,075.98)		$ -		
3 Day-Ahead Supplemental Reserve		$ (28,975.97)		$ (28,975.97)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (55,366.85)		$ 8,097.92		$ (63,464.77)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (26,740.76)		$ 15,351.74		$ (42,092.50)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 4,280.36		$ 5,135.99		$ (855.63)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	34,550	$ (781.17)	34,550	$ (781.17)		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	(4,191)	$ 829,293.35	(4,191)	$ 829,293.35		$ -		
8b Real Time Non Excessive Energy Congestion		$ (79,902.28)		$ (88,639.83)		$ 8,737.55		
8c Real Time Non Excessive Energy Loss		$ (19,091.78)		$ (21,499.16)		$ 2,407.38		
9 Real Time Net Regulation Adjustment Amount		$ 7,858.51		$ 6,056.94		$ 1,801.57		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 69,203.95		$ 69,203.95		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 85,815.90		$ 85,815.90		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 31,300.69		$ 31,300.69		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 109,426.59		$ 78,222.02		$ 31,204.57		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ 339.03		$ (339.03)		
TOTAL MISO ASM CHARGES	**30,359**	**$ 723,759.91**	**30,359**	**$ 786,360.77**		**$ (62,600.86)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

April 2016	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		$ (141,162.16)		$ (141,162.16)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (122,627.01)		$ (122,627.01)		$ -		
3 Day-Ahead Supplemental Reserve		$ (29,752.02)		$ (29,752.02)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (87,555.60)		$ 23,652.13		$ (111,207.73)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (17,828.20)		$ 54,756.88		$ (72,585.08)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,511.51		$ 1,651.49		$ (139.98)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,517)	$ 20,399.46	(2,517)	$ 20,399.46		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	110,741	$ 1,903,327.60	110,741	$ 1,903,327.60		$ -		
8b Real Time Non Excessive Energy Congestion		$ (145,978.81)		$ (146,662.69)		$ 683.88		
8c Real Time Non Excessive Energy Loss		$ (10,923.96)		$ (11,369.31)		$ 445.35		
9 Real Time Net Regulation Adjustment Amount		$ 20,357.45		$ 13,750.94		$ 6,606.51		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 82,757.89		$ 82,757.89		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 114,522.54		$ 114,522.54		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 35,121.00		$ 35,121.00		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 89,089.13		$ 61,422.00		$ 27,667.13		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**108,223**	**$ 1,711,258.82**	**108,223**	**$ 1,859,788.73**		**$ (148,529.91)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

May 2016	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		$ (171,726.95)		$ (171,726.95)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (136,807.45)		$ (136,807.45)		$ -		
3 Day-Ahead Supplemental Reserve		$ (42,584.90)		$ (42,584.90)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 1,907.74		$ 72,351.97		$ (70,444.23)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (26,902.10)		$ 39,136.88		$ (66,038.98)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 3,610.01		$ 4,309.98		$ (699.97)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	65	$ 16,027.06	65	$ 16,027.06		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	120,203	$ 1,849,014.63	120,203	$ 1,849,014.63		$ -		
8b Real Time Non Excessive Energy Congestion		$ (80,367.36)		$ (88,981.24)		$ 8,613.88		
8c Real Time Non Excessive Energy Loss		$ (40,299.36)		$ (44,383.21)		$ 4,083.85		
9 Real Time Net Regulation Adjustment Amount		$ 25,073.53		$ 14,977.88		$ 10,095.65		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 106,607.12		$ 106,607.12		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 127,400.96		$ 127,400.96		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 40,130.01		$ 40,130.01		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 75,084.14		$ 59,515.36		$ 15,568.78		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**120,268**	**$ 1,746,167.08**	**120,268**	**$ 1,844,988.10**		**$ (98,821.02)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

June 2016	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		$ (112,914.37)		$ (112,914.37)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (86,733.37)		$ (86,733.37)		$ -		
3 Day-Ahead Supplemental Reserve		$ (43,329.56)		$ (43,329.56)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (61,187.64)		$ 32,028.43		$ (93,216.07)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 29,078.93		$ 46,775.37		$ (17,696.44)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 26,699.14		$ 27,789.77		$ (1,090.63)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,245)	$ 15,895.07	(2,245)	$ 15,895.07		$ -		
7b Real Time Excessive Energy Congestion		$ -		$ -		$ -		
7c Real Time Excessive Energy Loss		$ -		$ -		$ -		
8a Real Time Non Excessive Energy Amount	81,235	$ 1,888,043.33	81,235	$ 1,888,043.33		$ -		
8b Real Time Non Excessive Energy Congestion		$ 318,919.27		$ 323,184.54		$ (4,265.27)		
8c Real Time Non Excessive Energy Loss		$ 172,045.36		$ 172,683.58		$ (638.22)		
9 Real Time Net Regulation Adjustment Amount		$ 25,272.22		$ 19,346.94		$ 5,925.28		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 72,929.08		$ 72,929.08		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 143,210.28		$ 143,210.28		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 31,102.86		$ 31,102.86		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 108,584.23		$ 85,229.34		$ 23,354.89		
14 Real Time Contignecy Reserve Deployment Failure		$ 5,029.43		$ 4,620.69		$ 408.74		
TOTAL MISO ASM CHARGES	**78,990**	**$ 2,532,644.26**	**78,990**	**$ 2,619,861.98**		**$ (87,217.72)**		**$ -**

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

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

July 2015 - June 2016	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	-	$ (888,915.26)	-	$ (888,915.26)	-	$ -	-	$ -
2 Day-Ahead Spinning Reserve Amount	-	$ (1,353,240.44)	-	$ (1,353,240.44)	-	$ -	-	$ -
3 Day-Ahead Supplemental Reserve	-	$ (565,010.42)	-	$ (565,010.42)	-	$ -	-	$ -
4 Real-Time Regulation Amount	-	$ (532,985.50)	-	$ 6,166.11	-	$ (539,151.61)	-	$ -
5 Real-Time Spinning Reserve Amount	-	$ (195,108.86)	-	$ 510,998.04	-	$ (706,106.90)	-	$ -
6 Real-Time Supplemental Reserve Amount.	-	$ 85,671.82	-	$ 118,905.14	-	$ (33,233.32)	-	$ -
Resource Energy Charges								
7a Real Time Excessive Energy Amount	12,442	$ 42,726.43	12,442	$ 42,726.43	-	$ -	-	$ -
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -	-	$ -
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -	-	$ -
8a Real Time Non Excessive Energy Amount	1,143,525	$ 22,428,796.32	1,143,525	$ 22,428,796.32	-	$ -	-	$ -
8b Real Time Non Excessive Energy Congestion	-	$ (718,058.56)	-	$ (701,161.41)	-	$ (16,897.15)	-	$ -
8c Real Time Non Excessive Energy Loss	-	$ 27,846.35	-	$ 22,067.31	-	$ 5,779.04	-	$ -
9 Real Time Net Regulation Adjustment Amount	-	$ 119,862.34	-	$ 80,321.69	-	$ 39,540.65	-	$ -
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 968,461.66	-	$ 968,461.66	-	$ -	-	$ -
11 Real Time Spinnng Reserve Cost Distribution	-	$ 1,277,488.33	-	$ 1,277,488.33	-	$ -	-	$ -
12 Real Time Supplemental Reserve Cost Distribution	-	$ 547,970.17	-	$ 547,970.17	-	$ -	-	$ -
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment	-	$ 663,224.29	-	$ 492,945.84	-	$ 170,278.45	-	$ -
14 Real Time Contignecy Reserve Deployment Failure	-	$ 22,351.81	-	$ 14,567.31	-	$ 7,784.50	-	$ -
	-	$ -	-	$ -	-	$ -	-	$ -
TOTAL MISO ASM CHARGES	**1,155,967**	**$ 21,931,080.48**	**1,155,967**	**$ 23,003,086.82**	**-**	**$ (1,072,006.34)**	**-**	**$ -**

Total

MISO ASM

A. Overall Market Performance to Date

During the 2015-2016 AAA Period, MISO continued to operate the electric system reliably and has exceeded compliance thresholds for all North American Electric Reliability Corporation (NERC) reliability standards to which they are subject. The MISO Independent Market Monitor, which is tasked with monitoring both the behavior of Market Participants and the operation of the market, noted in its monthly reports that temperatures for the 2015-2016 AAA period were generally mild and summer 2015 loads were consistent with recent summers of 2014 and 2013, except for extreme heat in the South Region that led to several Hot Weather Alerts and a new all-time South Region peak load. Winter 2016 was characterized by above normal temperatures causing average load for winter 2016 to decrease 6.0% relative to winter 2015. Energy prices for the 2015 summer months were relatively low as natural gas prices declined 33% relative to 2014 summer prices. The 3-month average Day-Ahead LMP for summer 2015 was $26.63/MWh and the 3-month average Real-Time LMP was $26.06/MWh. The average Day-Ahead and Real-Time system-wide LMPs for the 2016 winter season were $21.60/MWh and $21.12/MWh respectively, a decrease of approximately 28% from the 2015 winter averages. Energy prices were at relatively low levels, mainly driven by low gas prices with Henry hub gas prices averaging $2.09/MMBtu; a decline of 39.0% compared to last winter and Power River Basin coal prices averaged $0.97/MMBtu; a decline of 22.8%compared to winter 2015. Also, MISO set a new wind generation record of 13.1 GW in February compared to a winter 2015 peak wind output of 11.9 GW[1].

B. Estimated Market Benefits Calculation

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 2015-2016 AAA reporting period, and are provided in the table on the following page.

[1] https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2015%20Summer%20Assessment%20Report.pdf
https://www.misoenergy.org/Library/Repository/Report/Seasonal%20Market%20Assessments/2016%20Winter%20Assessment%20Report.pdf

ASM Benefit Analysis - NSP System						
	ASM Market Run Cost (Case A)	**Self Schedule Run Cost (Case B)**	**ASM Market Savings**	**Other Market Charge Types**	**ASM Admin Fees**	**Net Savings**
Jul '15	(69,989,926)	(71,159,046)	1,169,120	80,425	63,851	1,024,844
Aug '15	(62,547,131)	(62,755,941)	208,810	56,668	58,006	94,137
Sep '15	(58,890,026)	(59,491,600)	601,574	56,583	59,297	485,694
Total Q3 2015	(191,427,083)	(193,406,587)	1,979,504	193,676	181,153	1,604,675
Oct '15	(51,047,599)	(51,561,908)	514,309	31,543	58,214	424,552
Nov '15	(40,569,828)	(40,874,636)	304,808	14,346	59,641	230,821
Dec '15	(49,551,817)	(50,729,637)	1,177,820	26,152	64,681	1,086,988
Total Q4 2015	(141,169,244)	(143,166,181)	1,996,937	72,041	182,536	1,742,360
Jan '16	(53,485,646)	(53,617,274)	131,629	24,255	67,480	39,894
Feb '16	(41,203,305)	(41,538,098)	351,443	43,878	65,927	241,638
Mar '16	(38,814,082)	(39,107,347)	293,265	119,009	58,355	115,901
Total Q1 2016	(133,503,033)	(134,262,719)	776,336	187,141	191,761	397,434
Apr '16	(37,166,018)	(38,045,409)	879,391	128,437	56,810	694,144
May '16	(42,148,596)	(44,004,643)	1,856,048	123,906	60,410	1,671,732
Jun '16	(49,107,207)	(49,877,994)	770,787	113,705	63,297	593,785
Total Q2 2016	(128,421,820)	(131,928,046)	3,506,226	366,048	180,517	2,959,661
Total	(594,521,181)	(602,763,534)	8,259,003	818,906	735,967	6,704,129

The Company estimates the ASM resulted in total NSP System savings of approximately $6.7 million for the 2015-16 reporting period. The Minnesota jurisdictional allocation of the savings is approximately 75 percent, or $5.0 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.

NSP believes that a certain level of EDEDCs is unavoidable given the current design of the ASM market as the benefits of offering resource flexibility and the potential costs of missing targets are appropriately weighed against procuring reserves elsewhere in the market or other NSP resources. NSP seeks a balance to maximize the value of an asset to the portfolio.

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 2015-2016 AAA reporting period, the net benefit for the Company was approximately $6.7 million[2] while the amount incurred in EDEDCs was $679,156. The $6.7 million in gross benefits would not have been achievable if the Company had been offering ramp rates for its units that would have all but eliminated the chance of incurring an Excessive Deficient Energy Deployment Charge.

In December 2012, MISO implemented changes in accordance with FERC Order 755 by adding a regulation mileage product to financially compensate for actual generator movement. An increase in EDEDC charged to the Company began in January 2013, which is attributed to the overall rate increase associated with the addition of the mileage component and higher LMPs. This increase was offset by an increase in the revenues received by the Company for Regulation. During the period of July 2015 through June 2016, EDEDC charges declined by $17,791 as compared to the 12 month period ending on June 30, 2015.

[2] The $6.7 million in ASM benefits calculated by the Company for 2015-2016 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.

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 $22,352 in CRDFC during the 2015-2016 AAA reporting period. NSP carries reserves on units with Automatic Generation Control (AGC) and units without AGC. For units without AGC, a phone call to the facility is required to deploy the reserves, adding to the time from receiving the signal and deployment. When deploying a large amount of reserves on many facilities, that action requires many more steps and time becomes critical. Additionally, MISO must meet Disturbance Control Standards within 15 minutes but does not always provide market participants the remaining time between the deployment signal and the end of the 15-minute timeframe to deploy reserves. Instead, MISO holds participants to a 10-minute response regardless if MISO has 15 minutes to meet the standard or less than 10 minutes.

In short, CRDFCs are prudently incurred as NSP strives for the benefit 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

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
7/1/2015	(2,279,297)	(2,353,795)	74,498	3.17%	0	732	571	18,427	939	1,937	71,259
7/2/2015	(2,191,462)	(2,239,724)	48,262	2.15%	0	837	-23	18,477	779	1,926	45,522
7/3/2015	(1,891,723)	(1,943,508)	51,785	2.66%	0	3,320	182	16,915	749	1,766	46,516
7/4/2015	(1,726,454)	(1,777,633)	51,179	2.88%	0	1,385	-270	16,091	438	1,653	48,411
7/5/2015	(1,693,818)	(1,752,262)	58,444	3.34%	0	437	71	17,922	1,173	1,910	56,027
7/6/2015	(1,950,098)	(2,018,612)	68,514	3.39%	0	1,679	320	19,424	1,708	2,113	64,402
7/7/2015	(1,883,109)	(1,927,961)	44,852	2.33%	0	122	-4	17,354	816	1,817	42,917
7/8/2015	(2,011,898)	(2,067,636)	55,738	2.70%	0	1,288	220	17,118	854	1,797	52,432
7/9/2015	(2,072,228)	(2,100,325)	28,097	1.34%	0	765	39	18,287	987	1,927	25,365
7/10/2015	(2,065,020)	(2,124,996)	59,976	2.82%	0	288	3	18,916	1,365	2,028	57,656
7/11/2015	(1,993,551)	(2,053,592)	60,041	2.92%	0	856	49	17,207	1,540	1,875	57,261
7/12/2015	(2,195,017)	(2,206,065)	11,048	0.50%	4,652	2,808	4,317	19,010	952	1,996	-2,725
7/13/2015	(2,504,507)	(2,518,238)	13,731	0.55%	0	1,290	861	21,541	1,085	2,263	9,318
7/14/2015	(2,998,437)	(3,010,318)	11,881	0.39%	0	1,224	483	21,781	1,275	2,306	7,868
7/15/2015	(2,477,282)	(2,498,188)	20,906	0.84%	0	1,454	53	20,408	996	2,140	17,258
7/16/2015	(2,136,329)	(2,186,727)	50,398	2.30%	0	3,115	242	19,138	1,183	2,032	45,009
7/17/2015	(2,704,782)	(2,715,566)	10,784	0.40%	0	4,021	800	21,312	838	2,215	3,747
7/18/2015	(2,594,283)	(2,591,968)	-2,315	-0.09%	0	5,057	-336	20,378	1,830	2,221	-9,257
7/19/2015	(2,386,131)	(2,417,139)	31,008	1.28%	0	4,716	134	18,980	1,333	2,031	24,127
7/20/2015	(2,430,168)	(2,462,035)	31,867	1.29%	0	4,078	226	20,987	1,250	2,224	25,339
7/21/2015	(2,189,658)	(2,227,360)	37,702	1.69%	0	2,238	25	19,101	523	1,962	33,477
7/22/2015	(2,220,570)	(2,266,058)	45,488	2.01%	0	1,726	4	19,573	1,014	2,059	41,700
7/23/2015	(2,193,983)	(2,240,748)	46,765	2.09%	0	2,177	554	20,176	1,530	2,171	41,863
7/24/2015	(2,375,789)	(2,426,795)	51,006	2.10%	0	4,627	573	21,117	1,424	2,254	43,553
7/25/2015	(2,281,478)	(2,317,103)	35,625	1.54%	0	1,915	200	18,771	1,226	2,000	31,510
7/26/2015	(2,453,441)	(2,487,435)	33,994	1.37%	0	2,643	501	18,911	1,048	1,996	28,855
7/27/2015	(2,955,532)	(2,975,180)	19,648	0.66%	0	4,399	245	23,184	979	2,416	12,588
7/28/2015	(2,332,208)	(2,371,705)	39,497	1.67%	0	897	401	22,143	1,601	2,374	35,825
7/29/2015	(2,079,569)	(2,123,319)	43,750	2.06%	0	1,734	-62	20,762	1,635	2,240	39,838
7/30/2015	(2,412,658)	(2,426,449)	13,791	0.57%	0	1,435	829	20,045	1,155	2,120	9,406
7/31/2015	(2,309,446)	(2,330,606)	21,160	0.91%	0	726	575	19,779	1,049	2,083	17,777
8/1/2015	(2,036,613)	(2,057,319)	20,706	1.01%	0	678	36	16,742	1,981	1,872	18,120
8/2/2015	(1,748,193)	(1,769,644)	21,451	1.21%	0	2,293	864	16,434	1,250	1,768	16,525
8/3/2015	(2,138,403)	(2,156,672)	18,269	0.85%	0	1,443	814	17,796	563	1,836	14,177
8/4/2015	(2,148,838)	(2,168,055)	19,217	0.89%	281	2,208	498	17,395	823	1,822	14,408
8/5/2015	(2,076,087)	(2,092,990)	16,903	0.81%	0	3,945	26	17,865	828	1,869	11,063
8/6/2015	(1,696,557)	(1,737,359)	40,802	2.35%	0	183	334	17,753	969	1,872	38,414

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
8/7/2015	(2,032,300)	(2,042,271)	9,971	0.49%	0	285	361	17,898	1,634	1,953	7,371
8/8/2015	(1,891,123)	(1,907,525)	16,402	0.86%	0	191	132	16,087	1,355	1,744	14,335
8/9/2015	(1,842,608)	(1,854,986)	12,378	0.67%	0	1,268	846	15,671	666	1,634	8,631
8/10/2015	(2,054,242)	(2,035,476)	-18,766	-0.92%	0	1,559	82	18,053	493	1,855	-22,262
8/11/2015	(2,237,599)	(2,234,460)	-3,139	-0.14%	2,054	597	213	18,104	644	1,875	-7,877
8/12/2015	(2,414,340)	(2,404,621)	-9,719	-0.40%	8,358	955	2,254	19,187	999	2,019	-23,305
8/13/2015	(2,531,017)	(2,536,336)	5,319	0.21%	0	1,982	4,005	20,544	1,408	2,195	-2,863
8/14/2015	(2,824,723)	(2,807,198)	-17,525	-0.62%	0	1,020	1,080	21,073	947	2,202	-21,827
8/15/2015	(2,469,375)	(2,471,545)	2,170	0.09%	0	1,852	669	20,185	1,056	2,124	-2,474
8/16/2015	(2,223,331)	(2,229,182)	5,851	0.26%	0	595	-71	18,122	1,123	1,925	3,402
8/17/2015	(2,770,554)	(2,785,353)	14,799	0.53%	0	842	-261	19,489	1,268	2,076	12,142
8/18/2015	(2,267,858)	(2,274,434)	6,576	0.29%	0	1,150	67	18,741	2,043	2,078	3,281
8/19/2015	(2,048,456)	(2,060,922)	12,466	0.60%	0	1,587	86	18,250	2,362	2,061	8,731
8/20/2015	(2,009,769)	(2,006,153)	-3,616	-0.18%	0	1,569	-3	16,435	840	1,728	-6,910
8/21/2015	(1,905,787)	(1,892,062)	-13,725	-0.73%	0	2,831	-128	17,647	2,035	1,968	-18,396
8/22/2015	(1,165,895)	(1,165,527)	-368	-0.03%	0	895	-10	15,540	1,238	1,678	-2,931
8/23/2015	(1,218,974)	(1,218,335)	-639	-0.05%	0	64	-20	14,391	1,199	1,559	-2,242
8/24/2015	(1,523,268)	(1,523,997)	729	0.05%	0	141	-37	15,748	715	1,646	-1,021
8/25/2015	(1,765,881)	(1,782,185)	16,304	0.91%	0	59	-17	15,709	926	1,663	14,599
8/26/2015	(1,917,243)	(1,918,799)	1,556	0.08%	0	34	0	16,152	1,521	1,767	-245
8/27/2015	(1,865,523)	(1,875,859)	10,336	0.55%	0	131	1	17,112	1,342	1,845	8,359
8/28/2015	(1,382,570)	(1,380,377)	-2,193	-0.16%	0	103	-1	15,983	2,190	1,817	-4,113
8/29/2015	(1,906,630)	(1,915,009)	8,379	0.44%	0	80	-7	15,131	731	1,586	6,720
8/30/2015	(2,003,497)	(2,029,625)	26,128	1.29%	0	1,884	199	16,860	1,044	1,790	22,255
8/31/2015	(2,429,877)	(2,421,665)	-8,212	-0.34%	0	1,446	96	20,666	1,100	2,177	-11,930
9/1/2015	(2,876,107)	(2,923,095)	46,988	1.61%	0	2,008	217	22,264	1,418	2,368	42,394
9/2/2015	(2,741,831)	(2,796,457)	54,626	1.95%	0	1,939	-305	22,952	2,372	2,532	50,460
9/3/2015	(2,870,638)	(2,896,245)	25,607	0.88%	0	1,859	276	23,163	1,629	2,479	20,992
9/4/2015	(2,717,014)	(2,750,266)	33,252	1.21%	677	1,982	430	23,030	1,326	2,436	27,727
9/5/2015	(2,369,611)	(2,395,863)	26,252	1.10%	0	1,786	207	21,799	1,479	2,328	21,931
9/6/2015	(2,134,459)	(2,150,379)	15,920	0.74%	77	2,421	-223	20,297	1,860	2,216	11,430
9/7/2015	(2,081,145)	(2,109,925)	28,780	1.36%	0	1,013	296	18,330	1,019	1,935	25,536
9/8/2015	(2,293,382)	(2,284,784)	-8,598	-0.38%	0	3,703	602	19,458	1,992	2,145	-15,048
9/9/2015	(2,144,757)	(2,113,757)	-31,000	-1.47%	0	1,023	-75	18,477	1,886	2,036	-33,983
9/10/2015	(1,799,471)	(1,777,347)	-22,124	-1.24%	0	1,037	17	17,201	1,126	1,833	-25,010
9/11/2015	(1,700,754)	(1,693,836)	-6,918	-0.41%	0	1,000	-40	16,428	1,052	1,748	-9,627
9/12/2015	(1,421,069)	(1,466,406)	45,337	3.09%	0	491	-4	13,549	663	1,421	43,429

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
9/13/2015	(1,447,449)	(1,419,784)	-27,665	-1.95%	0	510	74	16,049	1,762	1,781	-30,030
9/14/2015	(1,730,017)	(1,723,681)	-6,336	-0.37%	0	864	91	17,171	2,409	1,958	-9,249
9/15/2015	(2,082,329)	(2,053,271)	-29,058	-1.42%	0	1,417	903	20,750	1,929	2,268	-33,645
9/16/2015	(2,239,055)	(2,209,757)	-29,298	-1.33%	0	1,790	42	21,306	1,626	2,293	-33,424
9/17/2015	(2,465,225)	(2,470,582)	5,357	0.22%	0	3,710	3,885	21,025	1,645	2,267	-4,505
9/18/2015	(1,894,164)	(1,914,237)	20,073	1.05%	0	1,120	-131	17,560	1,535	1,910	17,174
9/19/2015	(1,636,938)	(1,668,290)	31,352	1.88%	0	1,407	-15	14,673	807	1,548	28,413
9/20/2015	(1,268,058)	(1,269,950)	1,892	0.15%	0	660	29	14,809	986	1,579	-377
9/21/2015	(1,615,406)	(1,648,089)	32,683	1.98%	0	1,094	-136	17,703	1,207	1,891	29,833
9/22/2015	(1,813,706)	(1,862,430)	48,724	2.62%	0	425	396	17,921	1,038	1,896	46,008
9/23/2015	(1,712,870)	(1,745,538)	32,668	1.87%	0	2,327	955	17,845	1,271	1,912	27,474
9/24/2015	(1,760,875)	(1,805,173)	44,298	2.45%	0	2,107	-12	17,898	753	1,865	40,338
9/25/2015	(1,613,905)	(1,724,237)	110,332	6.40%	0	1,495	-31	16,790	663	1,745	107,122
9/26/2015	(1,263,409)	(1,288,975)	25,566	1.98%	0	4,689	-135	14,579	881	1,546	19,466
9/27/2015	(1,372,714)	(1,407,893)	35,179	2.50%	0	471	12	15,838	1,317	1,715	32,980
9/28/2015	(2,110,774)	(2,130,590)	19,816	0.93%	0	1,671	141	18,674	1,734	2,041	15,963
9/29/2015	(1,913,243)	(1,957,112)	43,869	2.24%	0	1,617	-20	17,451	839	1,829	40,443
9/30/2015	(1,799,651)	(1,833,651)	34,000	1.85%	0	729	19	16,695	1,060	1,775	31,476
10/1/2015	(1,727,632)	(1,748,746)	21,114	1.21%	0	342	-1	18,083	1,424	1,951	18,822
10/2/2015	(1,557,574)	(1,563,480)	5,906	0.38%	0	352	-73	17,571	1,010	1,858	3,769
10/3/2015	(1,323,502)	(1,323,314)	-188	-0.01%	0	163	0	15,438	1,174	1,661	-2,012
10/4/2015	(1,626,848)	(1,633,828)	6,980	0.43%	0	655	-90	15,480	648	1,613	4,802
10/5/2015	(2,010,783)	(2,032,365)	21,582	1.06%	0	372	364	18,427	853	1,928	18,918
10/6/2015	(2,134,157)	(2,135,936)	1,779	0.08%	0	1,140	313	18,880	915	1,979	-1,654
10/7/2015	(1,901,398)	(1,921,260)	19,862	1.03%	0	806	296	18,638	1,274	1,991	16,768
10/8/2015	(1,733,101)	(1,767,787)	34,686	1.96%	0	1,533	161	18,992	1,520	2,051	30,940
10/9/2015	(1,929,258)	(1,946,346)	17,088	0.88%	0	1,673	-13	17,854	1,431	1,929	13,499
10/10/2015	(1,175,116)	(1,176,718)	1,602	0.14%	0	17	1	15,995	1,211	1,721	-137
10/11/2015	(1,217,202)	(1,217,111)	-91	-0.01%	0	195	-2	15,956	1,414	1,737	-2,021
10/12/2015	(1,332,466)	(1,370,148)	37,682	2.75%	0	969	-192	18,256	1,254	1,951	34,955
10/13/2015	(1,842,892)	(1,873,746)	30,854	1.65%	0	3,417	123	18,346	1,025	1,937	25,377
10/14/2015	(1,814,694)	(1,890,344)	75,650	4.00%	0	1,156	60	18,223	1,341	1,956	72,477
10/15/2015	(1,513,815)	(1,543,948)	30,133	1.95%	0	436	53	17,992	2,071	2,006	27,637
10/16/2015	(1,741,136)	(1,727,729)	-13,407	-0.78%	0	634	16	17,316	1,010	1,833	-15,890
10/17/2015	(2,019,096)	(2,023,608)	4,512	0.22%	0	1,052	283	16,975	1,193	1,817	1,360
10/18/2015	(1,256,000)	(1,253,958)	-2,042	-0.16%	0	1,840	297	15,573	1,645	1,722	-5,901
10/19/2015	(1,726,942)	(1,759,423)	32,481	1.85%	0	1,493	124	17,863	1,349	1,921	28,942

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10/20/2015	(1,938,365)	(1,968,264)	29,899	1.52%	0	660	78	17,787	1,121	1,891	27,270
10/21/2015	(1,891,878)	(1,904,211)	12,333	0.65%	0	1,318	61	18,149	1,191	1,934	9,021
10/22/2015	(2,053,001)	(2,064,179)	11,178	0.54%	412	853	68	18,287	1,121	1,941	7,904
10/23/2015	(1,606,989)	(1,618,260)	11,271	0.70%	0	159	24	18,287	1,601	1,989	9,099
10/24/2015	(1,571,313)	(1,583,235)	11,922	0.75%	0	132	0	15,948	2,597	1,855	9,936
10/25/2015	(1,556,527)	(1,546,802)	-9,725	-0.63%	603	64	139	15,274	1,163	1,644	-12,174
10/26/2015	(1,675,505)	(1,713,243)	37,738	2.20%	0	1,409	234	17,243	1,711	1,895	34,200
10/27/2015	(1,526,676)	(1,558,336)	31,660	2.03%	0	829	360	17,503	1,506	1,901	28,570
10/28/2015	(1,379,596)	(1,396,676)	17,080	1.22%	0	1,582	-147	18,240	2,134	2,037	13,607
10/29/2015	(1,613,461)	(1,631,011)	17,550	1.08%	0	1,005	169	18,096	2,076	2,017	14,359
10/30/2015	(1,582,872)	(1,598,138)	15,266	0.96%	0	1,694	-282	17,780	1,606	1,939	11,916
10/31/2015	(1,067,804)	(1,069,758)	1,954	0.18%	0	154	0	14,824	1,270	1,609	191
11/1/2015	(1,230,793)	(1,226,245)	-4,548	-0.37%	0	202	22	15,303	1,600	1,690	-6,462
11/2/2015	(1,754,195)	(1,776,334)	22,139	1.25%	0	731	571	18,173	1,663	1,984	18,854
11/3/2015	(1,412,826)	(1,416,341)	3,515	0.25%	0	2,418	88	18,751	1,751	2,050	-1,041
11/4/2015	(1,338,236)	(1,344,936)	6,700	0.50%	0	764	-22	19,567	2,451	2,202	3,756
11/5/2015	(1,312,203)	(1,307,215)	-4,988	-0.38%	0	1,368	-71	19,062	2,167	2,123	-8,408
11/6/2015	(1,689,054)	(1,735,673)	46,619	2.69%	0	1,793	88	19,076	2,016	2,109	42,628
11/7/2015	(1,508,151)	(1,494,777)	-13,374	-0.89%	0	433	25	16,923	1,727	1,865	-15,697
11/8/2015	(860,491)	(863,579)	3,088	0.36%	0	54	1	16,203	1,557	1,776	1,257
11/9/2015	(1,220,224)	(1,255,805)	35,581	2.83%	0	99	19	18,723	1,529	2,025	33,438
11/10/2015	(1,253,490)	(1,243,744)	-9,746	-0.78%	0	58	61	18,509	1,695	2,020	-11,886
11/11/2015	(1,203,962)	(1,225,523)	21,561	1.76%	0	64	4	17,901	1,850	1,975	19,518
11/12/2015	(1,197,408)	(1,211,293)	13,885	1.15%	0	37	0	19,055	1,970	2,102	11,746
11/13/2015	(1,518,705)	(1,526,869)	8,164	0.53%	0	328	2	18,783	2,123	2,091	5,743
11/14/2015	(865,638)	(870,857)	5,219	0.60%	0	17	1	15,600	1,491	1,709	3,492
11/15/2015	(776,294)	(778,939)	2,645	0.34%	0	21	-1	15,146	1,322	1,647	978
11/16/2015	(872,746)	(884,208)	11,462	1.30%	0	152	-98	17,666	1,969	1,964	9,445
11/17/2015	(1,095,779)	(1,104,727)	8,948	0.81%	0	51	1	17,767	1,917	1,968	6,927
11/18/2015	(944,872)	(961,547)	16,675	1.73%	0	80	-44	17,442	1,741	1,918	14,721
11/19/2015	(930,522)	(975,868)	45,346	4.65%	0	265	-13	18,670	1,423	2,009	43,085
11/20/2015	(1,835,890)	(1,840,381)	4,491	0.24%	0	215	59	19,554	1,120	2,067	2,149
11/21/2015	(1,729,098)	(1,734,499)	5,401	0.31%	0	173	70	19,170	1,109	2,028	3,129
11/22/2015	(1,409,649)	(1,416,545)	6,896	0.49%	0	104	89	18,469	1,847	2,032	4,671
11/23/2015	(1,852,248)	(1,866,175)	13,927	0.75%	0	474	117	20,856	2,519	2,338	10,999
11/24/2015	(1,595,229)	(1,606,639)	11,410	0.71%	0	1,027	-25	20,465	3,038	2,350	8,058
11/25/2015	(1,523,506)	(1,520,290)	-3,216	-0.21%	0	1,005	144	19,418	1,534	2,095	-6,460

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11/26/2015	(873,568)	(871,821)	-1,747	-0.20%	0	22	0	15,888	1,505	1,739	-3,508
11/27/2015	(1,408,482)	(1,423,823)	15,341	1.08%	209	15	0	16,862	1,638	1,850	13,268
11/28/2015	(1,666,748)	(1,670,480)	3,732	0.22%	0	44	-1	16,854	1,165	1,802	1,887
11/29/2015	(1,687,781)	(1,703,784)	16,003	0.94%	0	1	0	16,909	1,301	1,821	14,181
11/30/2015	(2,002,041)	(2,015,720)	13,679	0.68%	0	143	893	20,731	2,179	2,291	10,352
12/1/2015	(2,053,350)	(2,077,918)	24,568	1.18%	0	529	809	19,050	1,194	2,024	21,206
12/2/2015	(2,054,634)	(2,058,088)	3,454	0.17%	0	2,002	-97	19,845	2,045	2,189	-639
12/3/2015	(2,152,534)	(2,164,890)	12,356	0.57%	0	864	-69	20,418	1,630	2,205	9,357
12/4/2015	(1,466,994)	(1,467,167)	173	0.01%	0	1,125	460	19,534	1,937	2,147	-3,559
12/5/2015	(1,152,623)	(1,192,580)	39,957	3.35%	0	398	96	16,628	905	1,753	37,710
12/6/2015	(1,792,344)	(1,790,714)	-1,630	-0.09%	0	163	-4	17,487	1,302	1,879	-3,668
12/7/2015	(1,380,229)	(1,412,967)	32,738	2.32%	0	1,118	100	18,840	1,272	2,011	29,508
12/8/2015	(1,582,215)	(1,617,925)	35,710	2.21%	0	328	77	18,952	1,403	2,035	33,269
12/9/2015	(1,516,390)	(1,572,154)	55,764	3.55%	0	287	-36	19,145	1,336	2,048	53,466
12/10/2015	(1,100,807)	(1,133,360)	32,553	2.87%	0	52	0	18,782	1,325	2,011	30,491
12/11/2015	(1,762,448)	(1,791,522)	29,074	1.62%	0	409	81	19,261	1,173	2,043	26,541
12/12/2015	(1,675,525)	(1,696,797)	21,272	1.25%	0	607	391	18,366	1,079	1,944	18,330
12/13/2015	(1,138,646)	(1,149,749)	11,103	0.97%	0	1,046	5	17,484	1,415	1,890	8,162
12/14/2015	(1,237,521)	(1,305,240)	67,719	5.19%	0	293	75	19,659	2,354	2,201	65,150
12/15/2015	(1,555,861)	(1,964,117)	408,256	20.79%	0	502	26	19,915	2,094	2,201	405,526
12/16/2015	(1,408,742)	(1,470,280)	61,538	4.19%	0	1,074	48	19,989	1,675	2,166	58,249
12/17/2015	(1,606,260)	(1,714,258)	107,998	6.30%	0	373	41	21,582	2,657	2,424	105,160
12/18/2015	(1,606,629)	(1,787,636)	181,007	10.13%	0	74	2	20,600	2,340	2,294	178,637
12/19/2015	(1,453,752)	(1,436,337)	-17,415	-1.21%	0	102	0	18,461	1,646	2,011	-19,528
12/20/2015	(1,347,102)	(1,360,035)	12,933	0.95%	0	495	108	17,647	2,033	1,968	10,362
12/21/2015	(1,886,143)	(1,889,855)	3,712	0.20%	0	1,591	210	19,906	2,205	2,211	-300
12/22/2015	(1,475,044)	(1,497,511)	22,467	1.50%	0	372	45	19,874	2,500	2,237	19,813
12/23/2015	(1,719,977)	(1,737,201)	17,224	0.99%	0	1,483	-46	19,688	1,949	2,164	13,623
12/24/2015	(1,665,211)	(1,687,116)	21,905	1.30%	0	1,099	-100	18,339	1,235	1,957	18,949
12/25/2015	(1,395,785)	(1,395,736)	-49	0.00%	0	1,377	-32	16,723	1,189	1,791	-3,186
12/26/2015	(1,330,750)	(1,329,914)	-836	-0.06%	0	1,262	28	18,249	1,331	1,958	-4,084
12/27/2015	(1,559,728)	(1,569,629)	9,901	0.63%	0	1,746	-77	18,160	1,340	1,950	6,283
12/28/2015	(1,585,989)	(1,567,491)	-18,498	-1.18%	0	2,429	81	21,627	1,860	2,349	-23,357
12/29/2015	(1,852,053)	(1,855,012)	2,959	0.16%	0	184	112	19,788	1,215	2,100	563
12/30/2015	(2,140,617)	(2,129,369)	-11,248	-0.53%	0	484	-67	19,844	1,077	2,092	-13,757
12/31/2015	(1,895,914)	(1,907,069)	11,155	0.58%	0	27	-9	20,663	3,587	2,425	8,713
1/1/2016	(1,053,263)	(1,024,548)	-28,715	-2.80%	0	20	0	18,490	1,688	2,018	-30,753

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1/2/2016	(988,374)	(1,006,273)	17,899	1.78%	0	34	0	17,264	1,633	1,890	15,975
1/3/2016	(1,311,121)	(1,329,445)	18,324	1.38%	0	23	0	17,400	1,312	1,871	16,430
1/4/2016	(1,769,622)	(1,785,560)	15,938	0.89%	0	486	269	20,223	1,851	2,207	12,976
1/5/2016	(892,866)	(910,758)	17,892	1.96%	0	367	590	19,501	2,074	2,158	14,777
1/6/2016	(1,839,096)	(1,858,332)	19,236	1.04%	0	314	221	20,291	1,009	2,130	16,571
1/7/2016	(2,097,476)	(2,097,364)	-112	-0.01%	0	955	166	20,286	845	2,113	-3,346
1/8/2016	(1,818,621)	(1,819,756)	1,135	0.06%	0	2,040	-123	20,364	1,941	2,230	-3,013
1/9/2016	(1,479,722)	(1,481,459)	1,737	0.12%	0	405	-4	19,486	1,195	2,068	-732
1/10/2016	(2,028,464)	(2,041,549)	13,085	0.64%	0	871	20	19,836	1,388	2,122	10,073
1/11/2016	(2,400,390)	(2,423,425)	23,035	0.95%	0	687	-212	23,358	1,536	2,489	20,070
1/12/2016	(2,197,604)	(2,220,370)	22,766	1.03%	0	47	-54	23,281	1,600	2,488	20,285
1/13/2016	(2,249,985)	(2,266,016)	16,031	0.71%	0	595	-108	22,806	1,632	2,444	13,100
1/14/2016	(1,977,180)	(1,974,311)	-2,869	-0.15%	0	153	-67	21,207	1,726	2,293	-5,248
1/15/2016	(1,519,538)	(1,518,157)	-1,381	-0.09%	0	773	-37	20,813	1,162	2,197	-4,315
1/16/2016	(1,700,441)	(1,680,905)	-19,536	-1.16%	0	26	-8	19,679	2,025	2,170	-21,724
1/17/2016	(1,966,587)	(1,956,843)	-9,744	-0.50%	0	30	-3	20,837	1,231	2,207	-11,977
1/18/2016	(2,285,549)	(2,241,333)	-44,216	-1.97%	0	103	-58	22,175	895	2,307	-46,568
1/19/2016	(2,292,715)	(2,286,655)	-6,060	-0.27%	0	88	-93	22,799	1,119	2,392	-8,447
1/20/2016	(2,095,640)	(2,096,453)	813	0.04%	0	4,360	515	22,396	1,220	2,362	-6,424
1/21/2016	(2,083,510)	(2,099,280)	15,770	0.75%	0	1,426	187	20,985	470	2,146	12,012
1/22/2016	(2,170,024)	(2,197,024)	27,000	1.23%	0	3,579	249	21,603	773	2,238	20,934
1/23/2016	(1,523,087)	(1,546,889)	23,802	1.54%	0	1,086	151	20,103	1,411	2,151	20,413
1/24/2016	(1,866,108)	(1,919,100)	52,992	2.76%	0	1,055	-206	18,856	1,521	2,038	50,105
1/25/2016	(1,725,166)	(1,746,821)	21,655	1.24%	0	1,294	39	21,625	2,974	2,460	17,862
1/26/2016	(1,704,020)	(1,734,266)	30,246	1.74%	0	469	-36	20,910	1,306	2,222	27,591
1/27/2016	(1,306,698)	(1,284,127)	-22,571	-1.76%	0	659	-38	20,339	1,342	2,168	-25,360
1/28/2016	(1,630,863)	(1,656,242)	25,379	1.53%	0	371	11	20,299	1,716	2,201	22,796
1/29/2016	(1,020,966)	(974,512)	-46,454	-4.77%	0	517	-16	17,780	1,487	1,927	-48,881
1/30/2016	(1,100,221)	(1,063,807)	-36,414	-3.42%	0	32	0	16,764	1,664	1,843	-38,289
1/31/2016	(1,390,728)	(1,375,694)	-15,034	-1.09%	0	35	0	17,390	1,909	1,930	-16,999
2/1/2016	(2,065,035)	(2,075,686)	10,651	0.51%	0	1,984	55	22,382	1,060	2,344	6,268
2/2/2016	(1,173,636)	(1,160,159)	-13,477	-1.16%	0	50	0	20,268	2,441	2,271	-15,798
2/3/2016	(1,527,552)	(1,484,867)	-42,685	-2.87%	0	115	-95	22,108	2,147	2,425	-45,130
2/4/2016	(1,903,780)	(1,945,457)	41,677	2.14%	0	2,192	-231	23,286	1,014	2,430	37,285
2/5/2016	(1,819,971)	(1,845,707)	25,736	1.39%	0	5,931	197	23,278	1,825	2,510	17,098
2/6/2016	(1,163,096)	(1,110,404)	-52,692	-4.75%	0	1,106	48	19,623	1,344	2,097	-55,942
2/7/2016	(890,335)	(825,906)	-64,429	-7.80%	0	27	0	19,438	1,222	2,066	-66,522

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2/8/2016	(1,030,044)	(961,059)	-68,985	-7.18%	0	193	43	21,907	1,969	2,388	-71,608
2/9/2016	(1,634,703)	(1,673,101)	38,398	2.30%	0	130	3	24,131	1,445	2,558	35,707
2/10/2016	(2,100,743)	(2,153,003)	52,260	2.43%	0	784	6	23,839	1,548	2,539	48,931
2/11/2016	(1,810,318)	(1,840,928)	30,610	1.66%	0	106	-4	22,255	774	2,303	28,205
2/12/2016	(1,618,538)	(1,687,817)	69,279	4.10%	0	2,188	16	23,460	2,194	2,565	64,510
2/13/2016	(1,670,735)	(1,684,898)	14,163	0.84%	0	1,026	37	21,821	1,500	2,332	10,767
2/14/2016	(1,284,093)	(1,307,254)	23,161	1.77%	0	321	18	20,385	1,295	2,168	20,655
2/15/2016	(1,585,660)	(1,606,113)	20,453	1.27%	0	1,942	264	21,927	1,542	2,347	15,901
2/16/2016	(1,566,182)	(1,623,045)	56,863	3.50%	0	2,999	159	22,093	1,249	2,334	51,371
2/17/2016	(1,530,191)	(1,569,521)	39,330	2.51%	0	3,586	-185	21,575	1,223	2,280	33,649
2/18/2016	(871,801)	(878,407)	6,606	0.75%	0	574	39	21,123	1,408	2,253	3,740
2/19/2016	(740,313)	(743,528)	3,215	0.43%	0	344	-13	20,002	1,770	2,177	707
2/20/2016	(1,216,695)	(1,248,544)	31,849	2.55%	0	2,460	368	18,086	1,503	1,959	27,062
2/21/2016	(1,327,109)	(1,381,821)	54,712	3.96%	0	2,912	302	18,012	1,230	1,924	49,574
2/22/2016	(1,594,785)	(1,586,766)	-8,019	-0.51%	0	2,339	-154	20,786	1,646	2,243	-12,447
2/23/2016	(1,487,942)	(1,532,306)	44,364	2.90%	0	3,408	164	21,407	1,306	2,271	38,520
2/24/2016	(1,347,394)	(1,330,744)		0.00%	0	441	74	20,418	1,205	2,162	-2,678
2/25/2016	(1,407,412)	(1,414,412)	7,000	0.49%	0	1,743	20	22,158	1,264	2,342	2,895
2/26/2016	(1,429,816)	(1,415,630)	-14,186	-1.00%	0	823	44	21,162	1,178	2,234	-17,287
2/27/2016	(1,118,666)	(1,128,846)	10,180	0.90%	0	1,125	-28	19,465	1,239	2,070	7,013
2/28/2016	(941,657)	(953,060)	11,403	1.20%	0	64	7	18,296	977	1,927	9,405
2/29/2016	(1,345,103)	(1,369,109)	24,006	1.75%	0	1,480	332	22,209	1,847	2,406	19,788
3/1/2016	(1,702,525)	(1,737,252)	34,727	2.00%	0	4,973	1,495	19,332	1,011	2,034	26,225
3/2/2016	(1,733,073)	(1,765,177)	32,104	1.82%	0	3,798	96	19,578	1,089	2,067	26,144
3/3/2016	(1,734,382)	(1,769,168)	34,786	1.97%	0	5,124	679	18,734	540	1,927	27,055
3/4/2016	(1,333,633)	(1,333,639)	6	0.00%	0	4,298	87	18,923	1,299	2,022	-6,402
3/5/2016	(1,229,399)	(1,246,035)	16,636	1.34%	0	5,705	164	16,562	1,166	1,773	8,994
3/6/2016	(838,816)	(838,816)	0	0.00%	0	474	8	16,284	1,061	1,734	-2,217
3/7/2016	(1,073,458)	(1,056,785)	-16,673	-1.58%	0	1,073	-7	18,285	1,896	2,018	-19,758
3/8/2016	(1,021,879)	(1,027,853)	5,974	0.58%	0	196	1	17,447	1,068	1,852	3,925
3/9/2016	(1,435,590)	(1,461,643)	26,053	1.78%	0	3,767	835	17,294	827	1,812	19,639
3/10/2016	(1,351,646)	(1,367,356)	15,710	1.15%	0	4,149	210	17,024	774	1,780	9,572
3/11/2016	(912,053)	(912,053)	0	0.00%	0	262	31	17,271	1,082	1,835	-2,128
3/12/2016	(885,532)	(885,532)	0	0.00%	0	285	-21	15,321	785	1,611	-1,875
3/13/2016	(1,169,090)	(1,174,338)	5,248	0.45%	0	3,924	30	15,024	777	1,580	-286
3/14/2016	(1,378,408)	(1,387,803)	9,395	0.68%	0	7,701	1,128	17,534	1,709	1,924	-1,358
3/15/2016	(984,700)	(987,411)	2,711	0.27%	0	574	30	17,388	2,198	1,959	148

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3/16/2016	(980,914)	(978,389)	-2,525	-0.26%	0	646	7	18,142	1,822	1,996	-5,175
3/17/2016	(1,019,059)	(1,019,059)	0	0.00%	0	504	16	17,979	1,338	1,932	-2,452
3/18/2016	(1,675,309)	(1,682,929)	7,620	0.45%	0	9,663	-312	18,484	598	1,908	-3,639
3/19/2016	(1,456,503)	(1,466,614)	10,111	0.69%	0	5,541	27	17,178	1,310	1,849	2,695
3/20/2016	(1,563,550)	(1,578,921)	15,371	0.97%	0	7,207	143	17,016	915	1,793	6,227
3/21/2016	(1,408,080)	(1,426,165)	18,085	1.27%	0	5,802	31	18,580	1,704	2,028	10,223
3/22/2016	(1,352,431)	(1,357,928)	5,497	0.40%	0	5,012	852	18,356	1,357	1,971	-2,338
3/23/2016	(936,048)	(936,349)	301	0.03%	0	7,897	887	18,530	1,049	1,958	-10,441
3/24/2016	(1,166,011)	(1,163,523)	-2,488	-0.21%	0	1,303	158	17,182	1,619	1,880	-5,829
3/25/2016	(988,751)	(988,927)	176	0.02%	0	1,750	107	17,723	1,510	1,923	-3,605
3/26/2016	(1,343,295)	(1,361,216)	17,921	1.32%	0	4,369	-147	16,725	1,103	1,783	11,917
3/27/2016	(1,249,506)	(1,269,137)	19,631	1.55%	0	2,535	119	15,807	1,002	1,681	15,297
3/28/2016	(1,355,466)	(1,362,684)	7,218	0.53%	0	578	49	17,848	1,332	1,918	4,673
3/29/2016	(954,817)	(959,363)	4,547	0.47%	0	9,542	415	17,811	1,167	1,898	-7,308
3/30/2016	(1,182,356)	(1,193,857)	11,501	0.96%	0	632	208	17,558	1,771	1,933	8,728
3/31/2016	(1,397,802)	(1,411,425)	13,623	0.97%	0	1,426	973	18,292	1,456	1,975	9,249
4/1/2016	(1,301,709)	(1,258,197)	-43,512	-3.46%	0	1,656	64	18,903	1,193	2,010	-47,242
4/2/2016	(1,204,779)	(1,155,781)	-48,998	-4.24%	0	3,452	1,963	17,030	1,024	1,805	-56,218
4/3/2016	(951,914)	(964,815)	12,901	1.34%	0	557	-33	15,673	1,041	1,671	10,706
4/4/2016	(1,896,612)	(1,857,733)	-38,879	-2.09%	0	4,111	3,775	19,237	812	2,005	-48,770
4/5/2016	(1,205,734)	(1,247,574)	41,840	3.35%	0	8,130	571	18,876	1,679	2,055	31,084
4/6/2016	(1,104,037)	(1,150,698)	46,661	4.06%	0	1,439	369	18,404	1,576	1,998	42,854
4/7/2016	(1,084,691)	(1,111,418)	26,727	2.40%	0	1,286	550	18,517	1,262	1,978	22,912
4/8/2016	(1,402,909)	(1,396,995)	-5,914	-0.42%	0	8,422	-104	19,022	1,049	2,007	-16,240
4/9/2016	(1,192,331)	(1,211,735)	19,404	1.60%	0	5,642	1,463	17,053	775	1,783	10,516
4/10/2016	(1,106,498)	(1,137,547)	31,049	2.73%	0	1,782	224	16,486	1,270	1,776	27,268
4/11/2016	(1,497,043)	(1,448,838)	-48,205	-3.33%	0	4,661	1,200	18,720	1,124	1,984	-56,051
4/12/2016	(1,460,640)	(1,445,222)	-15,418	-1.07%	0	6,005	-417	19,094	929	2,002	-23,008
4/13/2016	(1,453,681)	(1,445,042)	-8,639	-0.60%	0	4,695	915	18,925	1,069	1,999	-16,248
4/14/2016	(1,098,877)	(1,141,188)	42,311	3.71%	0	1,749	199	18,797	964	1,976	38,386
4/15/2016	(610,195)	(872,289)	262,094	30.05%	0	3,428	81	17,282	2,009	1,929	256,655
4/16/2016	(875,481)	(1,013,253)	137,772	13.60%	0	846	97	16,130	1,188	1,732	135,097
4/17/2016	(1,130,920)	(1,219,485)	88,565	7.26%	0	3,157	354	15,563	1,717	1,728	83,326
4/18/2016	(1,429,758)	(1,455,479)	25,721	1.77%	0	2,988	881	18,176	2,105	2,028	19,824
4/19/2016	(1,727,286)	(1,646,002)	-81,284	-4.94%	0	2,186	3,555	18,847	1,180	2,003	-89,028
4/20/2016	(1,911,076)	(1,876,005)	-35,071	-1.87%	0	2,498	-1,444	18,857	1,932	2,079	-38,204
4/21/2016	(1,446,609)	(1,473,632)	27,023	1.83%	0	726	-114	18,725	1,768	2,049	24,362

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4/22/2016	(1,369,209)	(1,400,999)	31,790	2.27%	0	3,615	536	16,966	800	1,777	25,862
4/23/2016	(575,913)	(709,900)	133,987	18.87%	0	353	-85	14,898	962	1,586	132,132
4/24/2016	(920,678)	(1,016,439)	95,761	9.42%	0	2,583	117	15,049	1,250	1,630	91,431
4/25/2016	(1,471,487)	(1,494,377)	22,890	1.53%	0	3,899	1,754	17,907	1,468	1,938	15,299
4/26/2016	(1,342,174)	(1,356,292)	14,118	1.04%	0	4,468	809	18,110	967	1,908	6,932
4/27/2016	(610,087)	(715,323)	105,236	14.71%	0	1,686	-71	17,191	849	1,804	101,817
4/28/2016	(1,580,181)	(1,597,597)	17,416	1.09%	0	9,370	4,282	19,052	1,329	2,038	1,726
4/29/2016	(1,569,008)	(1,516,257)	-52,751	-3.48%	0	10,440	1,118	17,902	1,105	1,901	-66,209
4/30/2016	(634,501)	(709,298)	74,797	10.55%	0	44	-50	15,479	835	1,631	73,171
5/1/2016	(1,136,760)	(1,156,973)	20,213	1.75%	0	3,366	2,082	16,038	919	1,696	13,069
5/2/2016	(1,565,441)	(1,580,958)	15,517	0.98%	0	1,810	1,788	18,215	755	1,897	10,021
5/3/2016	(1,212,665)	(1,328,915)	116,250	8.75%	0	4,189	515	18,801	1,153	1,995	109,551
5/4/2016	(1,219,769)	(1,299,091)	79,322	6.11%	0	4,464	464	18,382	1,021	1,940	72,454
5/5/2016	(1,460,465)	(1,522,336)	61,871	4.06%	0	5,551	858	18,438	709	1,915	53,547
5/6/2016	(1,271,528)	(1,441,127)	169,599	11.77%	0	6,732	34	19,938	2,042	2,198	160,634
5/7/2016	(1,201,077)	(1,214,223)	13,146	1.08%	0	3,201	1,197	16,644	821	1,747	7,001
5/8/2016	(1,110,239)	(1,156,996)	46,757	4.04%	0	7,076	862	15,661	746	1,641	37,179
5/9/2016	(964,211)	(954,021)	-10,190	-1.07%	0	1,179	41	17,772	1,412	1,918	-13,329
5/10/2016	(1,446,644)	(1,489,450)	42,806	2.87%	0	7,699	3,472	18,363	812	1,917	29,718
5/11/2016	(1,379,384)	(1,520,170)	140,786	9.26%	0	1,344	132	18,081	1,148	1,923	137,387
5/12/2016	(1,186,494)	(1,187,463)	969	0.08%	0	1,758	425	18,601	1,375	1,998	-3,212
5/13/2016	(995,578)	(1,003,417)	7,839	0.78%	0	1,095	268	17,176	915	1,809	4,667
5/14/2016	(734,837)	(772,516)	37,679	4.88%	0	239	-6	15,210	640	1,585	35,861
5/15/2016	(1,174,882)	(1,171,092)	-3,790	-0.32%	0	2,017	161	15,309	914	1,622	-7,590
5/16/2016	(1,431,351)	(1,477,754)	46,403	3.14%	0	3,162	408	18,366	1,150	1,952	40,881
5/17/2016	(1,623,578)	(1,688,280)	64,702	3.83%	0	5,094	1,367	18,664	1,120	1,978	56,263
5/18/2016	(1,579,269)	(1,653,289)	74,020	4.48%	0	21	23	18,305	763	1,907	72,068
5/19/2016	(1,383,719)	(1,423,028)	39,309	2.76%	0	2,516	171	18,874	1,262	2,014	34,609
5/20/2016	(1,393,685)	(1,426,599)	32,914	2.31%	0	1,562	-58	18,606	1,336	1,994	29,416
5/21/2016	(1,012,097)	(1,011,605)	-492	-0.05%	0	978	0	15,251	1,029	1,628	-3,098
5/22/2016	(865,351)	(880,609)	15,258	1.73%	0	1,648	1	16,725	1,087	1,781	11,828
5/23/2016	(1,402,271)	(1,467,257)	64,986	4.43%	0	1,275	24	19,892	1,749	2,164	61,522
5/24/2016	(1,804,558)	(1,836,567)	32,009	1.74%	0	6,501	3,245	20,875	983	2,186	20,076
5/25/2016	(1,504,352)	(1,535,290)	30,938	2.02%	0	3,205	872	20,521	1,434	2,195	24,666
5/26/2016	(2,020,462)	(2,321,870)	301,408	12.98%	0	4,796	3,085	22,079	1,630	2,371	291,156
5/27/2016	(1,848,182)	(1,919,058)	70,876	3.69%	0	2,545	-794	21,315	1,910	2,322	66,802
5/28/2016	(1,519,458)	(1,532,866)	13,408	0.87%	0	375	22	17,804	1,036	1,884	11,128

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Cont Reserve Depl Failure Charge	Excessive/Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
5/29/2016	(1,507,679)	(1,583,853)	76,174	4.81%	0	4,603	934	17,602	1,320	1,892	68,745
5/30/2016	(1,499,905)	(1,572,159)	72,254	4.60%	0	5,939	573	17,945	2,140	2,009	63,734
5/31/2016	(1,692,704)	(1,875,811)	183,107	9.76%	0	4,143	1,658	20,980	2,335	2,332	174,974
6/1/2016	(1,421,034)	(1,429,360)	8,326	0.58%	0	922	305	18,656	2,166	2,082	5,017
6/2/2016	(1,604,736)	(1,598,860)	-5,876	-0.37%	0	8,253	739	17,932	879	1,881	-16,748
6/3/2016	(977,313)	(996,163)	18,850	1.89%	0	1,084	-154	17,342	1,830	1,917	16,002
6/4/2016	(872,450)	(873,247)	797	0.09%	0	189	18	15,274	1,483	1,676	-1,085
6/5/2016	(898,465)	(902,136)	3,671	0.41%	0	112	7	15,657	1,659	1,732	1,819
6/6/2016	(899,700)	(906,085)	6,385	0.70%	0	1,341	-103	17,013	1,790	1,880	3,266
6/7/2016	(1,420,553)	(1,436,763)	16,210	1.13%	0	2,984	598	17,017	1,037	1,805	10,822
6/8/2016	(1,351,490)	(1,364,353)	12,863	0.94%	0	3,061	161	17,455	1,292	1,875	7,766
6/9/2016	(1,759,090)	(1,777,508)	18,418	1.04%	0	6,628	1,498	20,234	1,814	2,205	8,087
6/10/2016	(1,920,044)	(1,937,578)	17,534	0.90%	0	2,970	134	23,626	2,243	2,587	11,843
6/11/2016	(1,889,893)	(1,905,345)	15,452	0.81%	0	2,171	1,119	21,060	2,106	2,317	9,845
6/12/2016	(1,335,170)	(1,336,586)	1,416	0.11%	0	1,216	-161	17,962	1,239	1,920	-1,560
6/13/2016	(2,020,659)	(2,041,510)	20,851	1.02%	0	2,696	737	21,152	938	2,209	15,209
6/14/2016	(1,670,868)	(1,686,894)	16,026	0.95%	0	2,341	743	20,245	1,282	2,153	10,789
6/15/2016	(1,959,574)	(1,964,592)	5,018	0.26%	0	3,201	7,523	20,530	1,228	2,176	-7,882
6/16/2016	(1,818,497)	(1,878,419)	59,922	3.19%	0	3,436	834	19,886	1,875	2,176	53,476
6/17/2016	(1,927,043)	(1,940,736)	13,693	0.71%	0	1,048	-17	20,516	1,904	2,242	10,420
6/18/2016	(1,785,538)	(1,811,293)	25,755	1.42%	0	1,947	128	19,870	1,837	2,171	21,509
6/19/2016	(1,316,497)	(1,341,350)	24,853	1.85%	0	287	-83	20,530	1,596	2,213	22,436
6/20/2016	(1,909,138)	(1,950,856)	41,718	2.14%	0	2,484	1,100	21,171	1,523	2,269	35,864
6/21/2016	(1,951,328)	(1,960,144)	8,816	0.45%	0	4,202	0	20,134	894	2,103	2,512
6/22/2016	(1,705,980)	(1,735,329)	29,349	1.69%	0	847	394	20,156	2,702	2,286	25,822
6/23/2016	(1,998,112)	(2,072,141)	74,029	3.57%	0	5,710	4,367	19,670	1,624	2,129	61,822
6/24/2016	(1,723,814)	(1,774,861)	51,047	2.88%	0	3,346	323	20,418	1,203	2,162	45,216
6/25/2016	(1,304,341)	(1,281,028)	-23,313	-1.82%	5,029	1,696	1,029	19,050	3,173	2,222	-33,289
6/26/2016	(1,570,099)	(1,576,436)	6,337	0.40%	0	2,008	1,051	19,115	2,462	2,158	1,121
6/27/2016	(2,121,654)	(2,240,157)	118,503	5.29%	0	1,945	-553	20,768	2,974	2,374	114,737
6/28/2016	(1,963,080)	(1,956,065)	-7,015	-0.36%	0	3,976	-403	19,207	873	2,008	-12,597
6/29/2016	(2,123,914)	(2,203,548)	79,634	3.61%	0	6,445	-423	20,371	1,336	2,171	71,441
6/30/2016	(1,887,133)	(1,998,652)	111,519	5.58%	0	8,205	1,008	20,001	1,992	2,199	100,106
Total	**(594,521,181)**	**(602,763,534)**	**8,259,003**	**1.43%**	**22,352**	**679,092**	**117,462**	**6,845,543**	**514,132**	**735,967**	**6,704,129**

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ 37	$ 38	$ 29	$ 46	$ 51	$ 79	$ 19	$ 28	$ 67	$ 83	$ 70	$ 28
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ 841	$ 2,472	$ 435	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3
Anson_G3	$ -	$ 69	$ -	$ -	$ 0	$ -	$ -	$ -	$ -	$ 289	$ 953	$ -
Anson_G4	$ 2,174	$ 472	$ 509	$ 541	$ 175	$ -	$ -	$ -	$ -	$ 1,263	$ 1,664	$ -
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_ A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G52	$ 15,010	$ 8,453	$ 11,087	$ 12,865	$ 4,372	$ 7,430	$ 4,648	$ 7,673	$ 19,417	$ 16,953	$ 21,265	$ 20,539
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ 14	$ -	$ 236	$ -	$ -	$ -	$ -	$ -	$ -	$ 20	$ 1,999	$ 363
Blue_Lk_G8	$ -	$ -	$ 393	$ -	$ -	$ -	$ -	$ 1	$ -	$ 26	$ 668	$ 655
BuffR_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BuffR_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Canon_Falls1	$ 397	$ 24	$ 236	$ -	$ -	$ -	$ -	$ -	$ 1	$ 282	$ 2,982	$ 1,809
Canon_Falls2	$ 1,006	$ 472	$ 547	$ -	$ -	$ -	$ -	$ -	$ 4	$ 501	$ 3,007	$ 1,261
CC Highbridge1	$ 5,457	$ 685	$ 3,785	$ 963	$ 1,451	$ 1,897	$ 1,513	$ 2,171	$ 13,101	$ 11,056	$ 1,144	$ 4,334
CC Highbridge2	$ 1,792	$ 102	$ 247	$ 298	$ 446	$ 15	$ 28	$ -	$ 2,339	$ 2,312	$ 284	$ 744
CC Mankato	$ 8,138	$ 7,885	$ 11,653	$ -	$ 101	$ 2,029	$ 10,859	$ 27,276	$ 41,279	$ 37,035	$ 47,357	$ 15,347
CCRiverside1	$ 5,279	$ 214	$ 1,225	$ 1,410	$ 838	$ 2,126	$ 117	$ 99	$ 4,160	$ 9,816	$ 3,509	$ 8,467
CCRiverside2	$ 4,733	$ 903	$ 2,947	$ 4,391	$ 71	$ 5,941	$ 2,090	$ 1,159	$ 7,774	$ 10,185	$ 3,927	$ 6,431
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ -	$ 1	$ -	$ 1	$ -
CHPFALTR2	$ 0	$ 1	$ 0	$ -	$ 0	$ 0	$ -	$ -	$ 0	$ -	$ -	$ -
CORNEL	$ 16	$ 8	$ 8	$ 11	$ 34	$ 21	$ 25	$ 21	$ 33	$ 25	$ 24	$ 17
DPC.FLAMBEAU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flambe_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Garwin_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ 16	$ 6	$ 2	$ 8	$ 39	$ 12	$ 25	$ 14	$ 20	$ 25	$ 23	$ 20
InvrHils_1	$ 9	$ 235	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -
InvrHils_2	$ 7	$ 3	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 886
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225
InvrHils_4	$ -	$ 4	$ 17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5
InvrHils_5	$ 1	$ 128	$ 24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4
InvrHils_6	$ 31	$ 204	$ 697	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
JIMFL	$ 40	$ 9	$ 2	$ 11	$ 56	$ 26	$ 35	$ 20	$ 80	$ 55	$ 38	$ 41
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ 1,170	$ 51	$ 288	$ 881	$ 852	$ 332	$ 13	$ 196	$ 2,140	$ -	$ 632	$ 2,204
LSPower_1	$ 8,228	$ 7,190	$ 3,909	$ 877	$ 17	$ 521	$ 1,172	$ 1,817	$ 3,865	$ 3,242	$ 2,130	$ 18,163
Menomone_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MHEB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ 25	$ -	$ -	$ -	$ -	$ 50	$ -
MP.LASKIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MP.NSP1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP ROCK_CO BAT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ADAMSWD1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.GEN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.BAT.SER	$ -	$ -	$ -	$ -	$ -	$ -	$ 326	$ 63	$ 336	$ 360	$ 189	$ -
NSP.BIGBLUE	$ 4	$ 6	$ 7	$ 2	$ 0	$ 4	$ 2	$ 0	$ 10	$ 10	$ 10	$ 4
NSP.CWN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.CWN2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.DANIELSN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.GRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.KEYCITYTWO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MANKATECG3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MARSHSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.MNDAK1	$ 44	$ 37	$ 48	$ 55	$ 90	$ 31	$ 21	$ 23	$ 91	$ 78	$ 72	$ 49
NSP.MNDAK2	$ 5	$ 6	$ 9	$ 17	$ 19	$ 2	$ 2	$ 1	$ 11	$ 12	$ 9	$ 6
NSP.MORAINE2	$ 6	$ 3	$ 7	$ 5	$ 2	$ 3	$ 3	$ 2	$ 30	$ 10	$ 11	$ 3
NSP.NOBLE.CWS1	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 1	$ -	$ 1	$ -	$ 0
NSP.NOBLE.CWS2	$ -	$ -	$ -	$ -	$ 0	$ -	$ -	$ 1	$ -	$ 1	$ -	$ -
NSP.NOBLES_TR	$ 25	$ 69	$ 73	$ 48	$ 37	$ 46	$ 20	$ 28	$ 44	$ 59	$ 70	$ 44
NSP.NOBLES_TR2	$ 31	$ 65	$ 89	$ 47	$ 34	$ 43	$ 19	$ 39	$ 59	$ 43	$ 77	$ 41
NSP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.NSTARSOLAR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.ODELL1.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3
NSP.ODELL2.WND	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL1_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PRISL2_LD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE	$ 162	$ 169	$ 207	$ 186	$ 161	$ 139	$ 86	$ 121	$ 285	$ 241	$ 302	$ 189
NSP.PROSE_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PROSE_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.PVALEY.WND	$ -	$ 92	$ 907	$ 510	$ 14	$ 88	$ 69	$ 57	$ 213	$ 211	$ 236	$ 152
NSP.RIVRSD10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSP.SHAKOBIO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NSPHATFIHAT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.BRDRS1.WND	$ -	$ 12	$ 635	$ 65	$ -	$ 113	$ 94	$ 195	$ 245	$ 166	$ 226	$ 149
OTP.COURTNY.WF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.FIBROMIN1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.GRANTCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTP.MPC.COYT1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

OTP.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OTPGRANTCO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PR_ISLD_1	$ -	$ -	$ -	$ 27	$ -	$ -	$ -	$ -	$ 55	$ -	$ -	$ -
PR_ISLD_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5	$ -	$ -	$ 12	$ -
Rapidan_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Redwing_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIV9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD71	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD72	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RIVRSD9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rock_County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERC3	$ 5,738	$ 2,307	$ 6,014	$ 3,191	$ 1,438	$ 1,288	$ 946	$ 570	$ 9,271	$ 8,400	$ 4,338	$ 1,618
SHERCO_G1	$ 1,947	$ 316	$ 882	$ 834	$ 627	$ 1,391	$ 588	$ 549	$ 5,553	$ 3,015	$ 2,529	$ 2,367
SHERCO_G2	$ 552	$ 313	$ 405	$ 325	$ 621	$ 189	$ 129	$ 209	$ -	$ -	$ -	$ 470
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ 17	$ 6	$ 29	$ 1	$ -	$ 2	$ -	$ -	$ -	$ -	$ 0	$ -
Wheaton_2	$ 210	$ 447	$ 168	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_3	$ 347	$ 279	$ 353	$ 1	$ -	$ 3	$ -	$ -	$ -	$ -	$ 2	$ -
Wheaton_4	$ 374	$ 18	$ 117	$ 266	$ 144	$ 3	$ -	$ -	$ -	$ -	$ 0	$ 11
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ 0	$ 0	$ -	$ -	$ -	$ -	$ 3	$ 0	$ 1	$ -
Wi Fenton 1	$ 34	$ 31	$ 30	$ 22	$ 21	$ 25	$ 8	$ 12	$ 70	$ 45	$ 79	$ 31
Wi Fenton 2	$ 38	$ 25	$ 44	$ 18	$ 29	$ 32	$ 16	$ 12	$ 59	$ 42	$ 96	$ 41
Wi Grand Meadow	$ 52	$ 34	$ 40	$ 182	$ 409	$ 27	$ 25	$ 26	$ 81	$ 66	$ 85	$ 27
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi UILK_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ 7	$ 11	$ 7	$ 2
Wi Velva	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Windvest_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ 7	$ 3	$ 4	$ 2	$ 3	$ 6	$ 2	$ 0	$ 1	$ 2	$ 4	$ -
WISSOTATR4	$ 1	$ 2	$ 3	$ -	$ 3	$ 5	$ 1	$ 1	$ 4	$ 0	$ 3	$ -
Woodstk_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ 63,989**	**$ 33,868**	**$ 48,364**	**$ 28,105**	**$ 12,157**	**$ 23,895**	**$ 22,898**	**$ 42,392**	**$ 110,709**	**$ 105,941**	**$ 100,082**	**$ 86,753**

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
Agassiz Beach1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.MOWERCO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ALTW.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anson_G4	$ -	$ 552	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BayFrnt_G6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BigFalls_ A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_dog_G5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCRiverside2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CedarFalls_A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Chara_TR4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHPFALTR2	$ -	$ 692	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CORNEL	$ -	$ -	$ 161	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DPC.FLAMBEAU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elliot_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Flambe_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Garwin_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GranCty_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.ELKRI1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.NSP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GRE.STANTO1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HBC8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hennipin1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Herc_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HiBridge9_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
HOLCOM	$ 618	$ 1,666	$ 267	$ 183	$ 89	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ 510	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 699

InvrHils_2	$ 510	$ 1,507	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 699
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 699
InvrHils_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 699
InvrHils_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 699
InvrHils_6	$ 510	$ 1,507	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 700
JIMFL	$ -	$ 597	$ 326	$ 389	$ 120	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
KeyCity_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
King_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LSPower_1	$ -	$ -	$ -	$ 339	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	$ -	$ 932	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SHERCO_G2	$ -	$ 963	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
South Ridge_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St Paul Cogen	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
St_Croix_7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
StCloud_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STCRO	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SWPP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UofMGen1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
W_Triw_TR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WAUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West_Pipestone	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_1	$ 526	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_2	$ 526	$ 1,236	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_3	$ 526	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 101
Wheaton_4	$ 526	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 733
Wheaton_5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Eastridge	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Ewngton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Fenton 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WI Jeffers 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi UILK_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Valley View	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Velva	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Yankee 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wilmart_2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Windvest_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WISSOTATR4	$ 398	$ 1,042	$ -	$ 103	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Woodstk_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	**$ 4,652**	**$ 10,693**	**$ 754**	**$ 1,015**	**$ 209**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 5,029**

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-523

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:

Order Item 11

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 Company has been in compliance with this reporting format since the 2006-2007 AAA Report. A Wind Curtailment Summary Report Table for January 2014 to May 2016 is included in Part H, Section 5, Schedule 1.

Order Item 12

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.

			NSP Minnesota Company Totals		Minnesota Jurisdictional Totals *	
			Energy Allocation Ratios		87.5707%	87.4990%
			Demand Allocation Ratios		87.6729%	87.2593%
FERC Account	Description	Allocation Method	2015 Test Year Step - Based on 2014 Test Year	2015 Actuals	2015 Test Year Step - Based on 2014 Test Year	2015 Actuals
510	Stm Maint Super&Eng	Energy	$ 1,937,824	2,539,883	$ 1,696,966	$ 2,222,373
511	Stm Maint of Structures	Demand	$ 3,529,078	7,119,441	$ 3,094,045	$ 6,212,375
512	Stm Maint of Boiler Plt	Energy	$ 43,843,815	35,287,182	$ 38,394,335	$ 30,875,931
513	Stm Maint of Elec Plant	Energy	$ 5,526,058	12,890,806	$ 4,839,208	$ 11,279,327
514	Stm Maint of Misc Stm Plt	Demand	$ 15,973,376	14,718,436	$ 14,004,322	$ 12,843,204
528	Nuc Maint Super & Eng	Energy	$ 12,650,239	8,331,495	$ 11,077,903	$ 7,289,975
529	Nuc Maint of Structures	Demand	$ 54,945	685,835	$ 48,172	$ 598,455
530	Nuc Mtc of React Plt Equip	Energy	$ 46,683,386	38,944,100	$ 40,880,968	$ 34,075,698
531	Nuc Maint of Elect Plant	Energy	$ 11,578,433	19,566,892	$ 10,139,314	$ 17,120,835
532	Nuc Mtc of Misc Nuc Plant	Demand	$ 35,343,585	44,404,013	$ 30,986,746	$ 38,746,631
541	Hydro Mtc Super& Eng	Energy	$ 5,319	3,899	$ 4,658	$ 3,411
542	Hyd Maint of Structures	Demand	$ -	64,335	$ -	$ 56,138
543	Hydro Mtc Resv, Dams	Demand	$ 60,000	106,180	$ 52,604	$ 92,652
544	Hyd Maint of Elec Plant	Energy	$ 92,839	33,673	$ 81,300	$ 29,463
545	Hyd Mt Misc Hyd Plnt Mjr	Demand	$ 52,280	19,460	$ 45,835	$ 16,981
551	Oth Maint Super & Eng	Demand	$ 458,691	737,897	$ 402,148	$ 643,884
552	Oth Maint of Structures	Demand	$ 2,083,508	3,147,071	$ 1,826,672	$ 2,746,112
553	Oth Mtc of Gen & Ele Plant	Demand	$ 10,608,955	9,128,899	$ 9,301,179	$ 7,965,814
554	Oth Mtc Misc Gen Plt Mjr	Demand	$ 3,203,235	2,163,839	$ 2,808,369	$ 1,888,151
Production Maintenance Expense Totals			**$ 193,685,565**	**$ 199,893,337**	**$ 169,684,742**	**$ 174,707,409**

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

	Generation Maintenance O&M Costs
2014 Test Year	$ 193,685,565
2015 Actual	$ 199,893,337

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 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.*

Company Report

Contractor and Supplier performance has improved over the last several years. Xcel Energy attributes this quality improvement to three areas of focus.

First, Xcel Energy has put into practice the use of 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. Scope of Work 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 details and expectations, Xcel Energy gets a better quality project in the end.

In the event problems arise with services, equipment, and/or materials provided by the vendor/supplier, the remedy is found in the Terms and Conditions of the Purchase Order and/or contract. Remedies for problems that adversely affect generating plant performance (such as de-rates or unplanned outages) include the direct costs of re-work, including labor and/or materials, depending on the nature of the problem.

The Company strives to always contract for generation plant repair and maintenance services with parties who have a history of performing work safely, reliably, and in a timely manner. Therefore, we will continue to identify and work with these types of contractor issues on a going forward basis.

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

The Generation Operating Model Playbook outlines the principles we follow to manage, operate and maintain Xcel Energy's generating assets. It ensures alignment of resources and the standardization of the key elements in our operation to help us identify best practices, capture synergies, reduce costs and promote excellence.

One of the changes implemented with our Generation Operating Model Playbook was the addition of an overhaul management group. This centralized group helps to plan and coordinate the major overhauls at our base and intermediate generating facilities. The ability of this group to move from plant to plant helps to ensure standardization of the best practices of the company and promote lessons learned at other facilities. An example of one of our best practices is that we have partnered with a boiler inspection contractor to thoroughly identify a prioritized repair scope of work for our boilers at the beginning of each overhaul. Identifying the critical path for boiler repair generally drives overhaul duration, so the quicker we can identify any work during inspections, the quicker we can manage it.

Another shared best practice is the use of critical path scheduling with activity trending and projection. This allows us to see where the critical path is moving during the planned outage and ensures that we are allocating resources to where they are needed most. For example, if we are replacing boiler waterwall panels at the King

[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.

plant, we monitor boiler weld completion rates in order to project a finish date and subsequent unit startup.

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 Metso 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 – more than 10,000 guides in all.

The help guides cover an array of operational parameters, such as temperatures, pressures, vibrations and environmental permit limits. They also address various alarm points. For example: high steam flows, high opacity levels and auxiliary transformer limits. The guides are embedded on the screen next to the equipment that has alarmed. There are also help guides for equipment startups, shutdowns, trouble shooting and trips. The guides provide assistance and considerable assurance that an operator is taking the right actions at the controls. And the guides are available at the touch of a button, which avoids the need and time to search for counsel through an operating manual, another procedural document or another technical expert.

Contractor Control - Quality Assurance / Quality Control

Improvements in contractor and vendor/supplier performance continue through the implementation of the Energy Supply Quality Management Program. In the first half of 2016, there were zero (0) 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 2016 QA/QC program oversight efforts continue to focus on contractor/supplier performance during plant overhauls and major capital projects. A significant increase in the number of in-house plant personnel in multiple disciplines are using the quality program tools and practices to conduct oversight and monitoring of contractors and suppliers that are 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.

The results of contractor/supplier performance for plant overhauls in the NSP region for the first half of 2016 have improved significantly. Continued refinement of plant overhaul quality plans have allowed plant personnel to focus on specific oversight requirements for supplier repairs of plant equipment as well as independent inspection of the contractors performing the plant equipment/component installation activities. The NSP region 2016 spring plant overhauls for the King and Sherco facilities were successful as plant overhaul schedules were met, and plant startups commencing on or before the scheduled startup/return to service dates. Post overhaul equipment failures and rework has been significantly reduced, and in most cases eliminated. There were no contractor/supplier performance issues that negatively impacted the Minnesota Region Equivalent Availability Factor (EAF) performance.

Work Management Process Improvements

As part of the Generation Operating Model, 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 2015-16 we continued the best practice of more frequent thermography scans and vibration monitoring during operator rounds. Just prior to a planned outage we will also scan critical equipment like large motors, pumps and fans to identify any recent emergent repairs that could be needed to further avoid un-needed derates or outages and to ensure no surprises during startup.

We have also identified a metric called maintenance productivity. Productivity is the ratio of preventive maintenance (PM) work orders over breakdown (BD) or corrective maintenance (CM) work orders. Our KPI target for this year is 60 percent, meaning we are working towards being more proactive than reactive when it comes to equipment maintenance. We are on track to meet this KPI this year.

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 2014/15 planning year. These most closely match the AAA reporting period of July 2014 to June 2015. 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 beginning with 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 year.

PUBLIC DOCUMENT: TRADE SECRET DATA EXCISED

Summary of Power Purchase Agreement Off-Setting Revenues (July 1, 2015 - June 30, 2016)

Project	Docket No.	Amount Received	Date Booked	Credited to FCA (Yes/No)	Month/Year Credited to FCA	FCA Docket No.	Reason for Payment
		[TRADE SECRET BEGINS					
Viking Group	E002/M-10-820		July 2015	Yes	September 2015	E002/AA-15-0788	Energy Production Credit
			October 2015	Yes	December 2015	E002/AA-15-1012	Energy Production Credit
			January 2016	Yes	March 2016	E002/AA-16-0205	Energy Production Credit
			April 2016	Yes	June 2016	E002/AA-16-0492	Energy Production Credit
MN Power Laurentian	E002/M-09-913		September 2015	Yes	November 2015	E002/AA-15-0961	Estoppel Agreement
			December 2015	Yes	February 2016	E002/AA-16-0106	Estoppel Agreement
			January 2016	Yes	March 2016	E002/AA-16-0205	Estoppel Agreement
			February 2016	Yes	April 2016	E002/AA-16-0274	Estoppel Agreement
			May 2016	Yes	July 2016	E002/AA-16-0563	Estoppel Agreement
			June 2016	Yes	August 2016	E002/AA-16-0645	Estoppel Agreement
		TRADE SECRET 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).

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TRADE SECRET DATA EXCISED

Northern States Power Company - Minnesota									
Unit Outage Information									
2016 AAA Reporting Period: July 1, 2015 - June 30, 2016									
	Updated since originally filed in monthly FCAs due to further analysis.						**[TRADE SECRET BEGINS**		
Unit	**Outage Category**	**Primary Reason for outage**	**Outage Dates Start**	**End**	**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 2015									
Allen S. King 1	Derate	Feedwater Pump	07/14/2015	07/31/2015	12 Boiler Feed Pump	12 Boiler Feed Pump removed from service due to high vibrations and temperatures of outboard bearing. Electric driven 11 boiler feed water pump has a smaller capacity resulting in derate. The inlet volute is internal to the pump, guiding the inlet water source through the first of 5 stages of impellers within the pump.		No similar failures were reported during this reporting period	Pump was removed from service, and replaced with rebuilt element that had been redesigned to reduce/remove the cyclic fatigue issues and stress risers throughout the pump element. Rebuilt element not available until October 2015.
AUGUST 2015									
Allen.S.King.1	Derate	Feedwater Pump Drive - Gear	08/27/2015	08/31/2015	12 Boiler Feed Pump	Continuation of the 7/14 event. 12 Boiler Feed Pump removed from service due to high vibrations and temperatures of outboard bearing. Electric driven 11 boiler feed water pump has a smaller capacity resulting in derate. The inlet volute is internal to the pump, guiding the inlet water source through the first of 5 stages of impellers within the pump.		No similar failures were reported during this reporting period continuation of 7/14 event	Pump was removed from service, and replaced with rebuilt element that had been redesigned to reduce/remove the cyclic fatigue issues and stress risers throughout the pump element. Rebuilt element not available until October 2015.
Angus.Anson.3G	Forced	Gas Turbine Vibration	08/12/2015	08/31/2015	Combustion Turbine Rotor	Vibration over OEM Specs		Three similar failures during reporting period	Balancing and OEM recommended inpections.

Northern States Power Company - Minnesota
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2016 AAA Reporting Period: July 1, 2015 - June 30, 2016

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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	[TRADE SECRET BEGINS Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
Allen.S.King.1	Forced	Feedwater Pump Drive - Gear	08/01/2015	08/19/2015	11 boiler feed pump	11 BFP removed from service due to high vibrations on the pump. 11 BFP is a startup pump that was used as a normal operating pump to avoid a forced outage while the 12 BFP was removed from service. By operating 11 BFP, we were able to run the plant at a capacity of approximately 450 MW and avoid a forced outage from 7/14/15-7/31/15 and 8/27/15 - 10/26/15. This resulted in additional wear to the 11 BFP but also substantial savings compared to the forced outage alternative. Upon inspection gearbox wear discrepancies between the pinion gear teeth and the large bull gear (double helical design) were found. Further disassembly revealed significant wear on the babbitted bearing of the outboard end of the bull gear shaft, and minor wear on the bearing located on the input side of the bull gear shaft.		No similar failures were reported during this reporting period	Pump is scheduled for rebuild in the spring of 2016. Alignment of whole drive train was completed.
Allen.S.King.1	Forced	Slag-tap (cyclone Furnace)	08/21/2015	08/23/2015	Slag tank	Slag tank plugged with hardened slag (molten ash).		One similar event for this unit occurred during this reporting period.	Slag tank inspected and nozzles replaced/cleaned. Operational practices changed to run until at higher load for 48 hours following a unit start up to improve tapping of boiler. Working with OEM on study to improve slag tank performance.
Allen.S.King.1	Forced	Slag-tap (cyclone Furnace)	08/25/2015	08/27/2015	Slag Tank	Slag tank plugged with hardened slag (molten ash).		One similar event for this unit occurred during this reporting period.	Slag tank inspected and nozzles replaced/cleaned. Operational practices changed to run until at higher load for 48 hours following a unit start up to improve tapping of boiler. Working with OEM on study to improve slag tank performance.
HBR CC 1x1	Forced	Other hot reheat steam valves (not incl. turbine stop...)	08/08/2015	08/09/2015	Unit 7 Hot Reheat Bypass Valve	Valve was stuck closed due to magnetite in the plug/disk. Valve must open in order for steam to be routed to the condenser during start up.		None.	Magnetite is developed in the steam piping as a result of temperature cycling during start-up and shut-dwon. During this time period, High Bridge was cycling on/off line more often than in the past. As a result our previous PM frequency was not adequate to prevent the buildup of magnetite. The PM frequency has been shortened to ensure the valve will not stick in the future.
Wheaton.2G	Forced	Other Gas Turbine Exhaust Problems	08/14/2015	08/20/2015	Unit 2 had high temp exhaust spreads	Ovation card failed		No similar events	Card under warranty from Ovation. Sent in for analysis
SEPTEMBER 2015									

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Unit Outage Information									
2016 AAA Reporting Period: July 1, 2015 - June 30, 2016									
	Updated since originally filed in monthly FCAs due to further analysis.						**[TRADE SECRET BEGINS**		
Unit	**Outage Category**	**Primary Reason for outage**	**Outage Dates Start**	**End**	**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**
Allen.S.King.1	Derate	Feedwater Pump Drive - Gear	09/01/2015	09/30/2015	12 boiler feed pump	Continuation of the 7/14 event. 12 Boiler Feed Pump removed from service due to high vibrations and temperatures of outboard bearing. Electric driven 11 boiler feed water pump has a smaller capacity resulting in derate. The inlet volute is internal to the pump, guiding the inlet water source through the first of 5 stages of impellers within the pump.		No similar failures were reported during this reporting period continuation of 7/14 event	Pump was removed from service, and replaced with rebuilt element that had been redesigned to reduce/remove the cyclic fatigue issues and stress risers throughout the pump element. Rebuilt element not available until October 2015.
Angus.Anson.3G	Forced	Gas Turbine Vibration	09/01/2015	09/30/2015	Combustion Turbine Rotor	Vibration over OEM Specs		Three similar failures during reporting period	Balencing and OEM recommended inpections
Blue.Lake.8	Maintenance	Gas Turbine - Battery And Charger System	09/17/2015	09/18/2015	This was not a forced outage. Battery Capacity Test NERC Requirement	No Failure		None	Regulatory required compliance testing requires unit outage.
Wheaton.1G	Maintenance	General Gas Turbine Unit Inspection	09/21/2015	09/30/2015	This was not a forced outage. Unit 1 Fall PM outage.	This was a maintenance outage not a forced outage.		Not applicable	Not applicable
Wheaton.2G	Maintenance	General Gas Turbine Unit Inspection	09/21/2015	09/30/2015	This was not a forced outage. Unit 2 Fall PM outage.	This was a maintenance outage not a forced outage.		Not applicable	Not applicable
OCTOBER 2015									
Allen.S.King.1	Maintenance	Feedwater Pump Drive - Gear	10/01/2015	10/24/2015	12 boiler feed pump	Continuation of the 7/14 event. 12 Boiler Feed Pump removed from service due to high vibrations and temperatures of outboard bearing. Electric driven 11 boiler feed water pump has a smaller capacity resulting in derate. The inlet volute is internal to the pump, guiding the inlet water source through the first of 5 stages of impellers within the pump.		No similar failures were reported during this reporting period continuation of 7/14 event	Pump was removed from service, and replaced with rebuilt element that had been redesigned to reduce/remove the cyclic fatigue issues and stress risers throughout the pump element. Rebuilt element installed during October outage.
Allen.S.King.1	Forced	Feedwater Pump Drive - Gear	10/24/2015	10/26/2015	12 boiler feed pump	12 Boiler Feed Pump removed from service due to high vibrations.		No similar failures were reported during this reporting period continuation of 7/14 event	12 Boiler Feed Pump removed from service due to high vibrations and weight added to balance pump.

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[TRADE SECRET BEGINS

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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
Sherburne.1	Forced	Boiler Recirculation Pumps	10/08/2015	10/12/2015	13 Boiler Circ Pump	Thrust pad wear caused increased vibration which forced removal of the pump from service. The thrust pads were changed on this pump from an asbestos pad to a non-asbestos grade material when the vendor stopped supplying the asbestos grade in 2006. The vendor stands behind the new "T2" non-asbestos grade material and they have not seen any failures like this in similar applications, so the same grade pads were used as replacement. Unit was de-rated until 10/12/15 at which time it was taken off line to repair the pump .		Similar event on Unit 2 for this reporting period from 11/23/15 to 12/19/15.	The vendor has since gone to a third generation of pad, which was installed in 13 Boiler Circ Pump. All other Unit 1 Boiler Circ Pumps will be gone through during the next overhaul to replace with this new generation of pad.
Sherburne.1	Forced	Heater Drain Pumps	10/22/2015	10/24/2015	11 Heater Drain Pump	11 Heater Drain Pump Motor tripped causing high pressure heater level to rise faster than the emergency drains could open up, eventually causing a bypass of the heaters. When an attempt was made to restore the heaters, it was found that a heater block valve had failed preventing reestablishment of flow through the heater. During repair of the valve it was found to be missing a gear retaining pin.		No similar events during this reporting period (July 1, 2015 to June 30, 2016)	11 Heater Drain Pump Motor was replaced. Tuning options on the emergency drains will be studied. Discussion with the vendor who rebuilt the limitorque on quality control.
Angus.Anson.3G	Forced	Gas Turbine Vibration	10/01/2015	10/31/2015	Combustion Turbine Rotor	Vibration over OEM Specs		Three similar failures during reporting period	Balencing and OEM recommended inpections
French.Is.2	Maintenance	Turbine - Other Lube Oil System Problems	10/16/2015	10/26/2015	This was not a forced outage. Plant staff took advantage of an opportunity to fix a number of items related to the tubine including a number of oil leaks.	Joint failures of the piping system due to vibration.		None	The maintenance and operations staff will continue to monitor system conditions. Anything that can be addressed on line will be addressed on line. Other items that require the unit to be off line will be addressed at convenient times based on operations and system needs.
HBR CC 1x1	OMC	Other Fuel Quality Problems	10/26/2015	10/28/2015	This was an OMC (Out of Management Control) event, not a forced outage. No plant equipment was involved in this outage. The gas line supplying High Bridge required a valve replacement and therefore had to be taken out of service. High Bridge could not run during the gas line outage.	N/A		There was one similar event during this reporting period.	N/A

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HBR CC 1x1	Maintenance	Other Gas Turbine Fuel System Problems	10/28/2015	10/30/2015	This is not a forced outage. Unit 7 Gas Fuel Heat Exchanger.	Gas side heat exchanger tubes were experiencing internal corrosion which was traveling downstream to the combustion turbine.		None.	The gas side tubes of the unit 7 (and unit 8) heat exchangers were chemically cleaned to remove the corrosion. Annual inspections of the tubes will be completed and future chemical cleanings will be planned as inspections dictate the need.
HBR CC 2x1	OMC	Other Fuel Quality Problems	10/26/2015	10/28/2015	This is an OMC (Out of Management Control) event. No plant equipment was involved in this outage. The gas line supplying High Bridge required a valve replacement and therefore had to be taken out of service. High Bridge could not run during the gas line outage.	N/A		There was one similar event during this reporting period.	N/A
RIV CC 1x1	Forced	Gas Turbine Control System - Hardware Problems....	10/13/2015	10/15/2015	Unit 9 Mark VI GE control card	Internal electronic card failure		No similar failures during reporting period	Spare control cards are available for overnight delivery should failure reoccur.
RIV CC 1x1	Maintenance	Boiler Drums And Drum Internals (single drum)	10/24/2015	10/26/2015	No failure occurred, this was an early start to a planned outage since Unit was not dispatched.	No equipment failed.		No equipment failed.	No equipment failed.
RIV CC 2x1	Maintenance	Boiler Drums And Drum Internals (single drum)	10/24/2015	10/26/2015	No failure occurred, this was an early start to a planned outage since Unit was not dispatched.	No equipment failed.		No equipment failed.	No equipment failed.
Sherburne.1	Forced	Boiler Recirculation Pumps	10/12/2015	10/16/2015	13 Boiler Circ Pump	Thrust pad wear caused increased vibration which forced removal of the pump from service. The thrust pads were changed on this pump from an asbestos pad to a non-asbestos grade material when the vendor stopped supplying the asbestos grade in 2006. The vendor stands behind the new "T2" non-asbestos grade material and they have not seen any failures like this in similar applications, so the same grade pads were used as replacement. Unit had been derated since 10/8/15 due to this pump until it was taken off line at this time to repair the pump.		Similar event on Unit 2 for this reporting period from 11/23/15 to 12/19/15.	The vendor has since gone to a third generation of pad, which was installed in 13 Boiler Circ Pump. All other Unit 1 Boiler Circ Pumps will be gone through during the next overhaul to replace with this new generation of pad.
NOVEMBER 2015									

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Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	[TRADE SECRET BEGINS Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
Sherburne.2	Forced	Boiler Recirculation Pumps	11/23/2015	11/30/2015	24 Boiler Circ Pump	Thrust pad wear caused increased vibration which forced removal of the pump from service. The thrust pads were changed on this pump from an asbestos pad to a non-asbestos grade material when the vendor stopped supplying the asbestos grade in 2006. The vendor stands behind the new "T2" non-asbestos grade material and they have not seen any failures like this in similar applications, so the same grade pads were used as replacement. Unit was de-rated until 12/13/15 at which time it was taken off line to repair the pump .		Similar event on Unit 1 for this reporting period from 10/8/15 to 10/16/15.	The vendor has since gone to a third generation of pad, which was installed in 24 Boiler Circ Pump. All other Unit 2 Boiler Circ Pumps have be gone through during the 2016 overhaul and replaced with this new generation of pad.
Monticello.1	Forced	Main Steam Flow Instrument Line	11/23/2015	11/30/2015	# 11 Reactor Recirculation Pump and 'C' main steam flow instrument line	The cause of the #11 Reactor Recirculation Pump trip that precipitated the down power was a loose wire on the #11 Recirculation Pump Motor-Generator set voltage regulator. This loose wire led to a trip of the #11 Reactor Recirculation Pump, a core flow reduction, and a reactor power reduction. The Group 1 isolation and subsequent reactor scram was caused by legacy foreign material in the common high side instrument line tap of the 'C' main steam flow instrument line which obstructed proper steam line flow instrument operation. This foreign material resulted in a high sensed flow condition by all four flow switches on the 'C' main steam flow instrument line.		No similar events during this reporting period (July 1, 2015 to June 30, 2016).	Immediate corrective actions included removing the foreign material from the instrumentation line and properly attaching the loose wire. Long term corrective actions were to revise a fleet procedure to require verification of proper torque on accessible electrical connections for critical components which are bench tested, and also to ensure that accessible soldered and crimped electrical terminations are inspected for signs of degradation during bench testing. The foreign material in the instrument line is considered a legacy issue (believed to be from initial construction). Since the original plant construction, the FME programs and controls have been improved to preclude similar conditions. Therefore, no additional FME corrective actions are required.
Red.Wing.2	Forced	First Superheater Leaks	11/01/2015	11/07/2015	Unit 2 Superheat Tubes	Unit 2 Superheat Tubes leak due to fuel composition that creates a highly corrosive environment.		Eight similar events during this reporting period (July 1, 2015 to June 30, 2016).	Repaired leak / transitioned to less errosive sootblowing methods / capital project to replace superheat tubes in Feb 2018.
Red.Wing.2	Forced	First Superheater Leaks	11/15/2015	11/19/2015	Unit 2 Superheat Tubes	Unit 2 Superheat Tubes leak due to fuel composition that creates a highly corrosive environment.		Eight similar events during this reporting period (July 1, 2015 to June 30, 2016).	Repaired leak / transitioned to less errosive sootblowing methods / capital project to replace superheat tubes in Feb 2018.
Red.Wing.2	Forced	First Superheater Leaks	11/25/2015	11/28/2015	Unit 2 Superheat Tubes	Unit 2 Superheat Tubes leak due to fuel composition that creates a highly corrosive environment.		Eight similar events during this reporting period (July 1, 2015 to June 30, 2016).	Repaired leak / transitioned to less errosive sootblowing methods / capital project to replace superheat tubes in Feb 2018.

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Wheaton.2G	Forced	Major Gas Turbine Overhaul	11/01/2015	11/30/2015	Unit 2 blade migration	During fall PM's blades were inspected and row 3 showed blade migration.		No similar events	Units are inspected based on number of starts and hours of operation. Unit was inspected and a problem found before failure took place. Unit removed from service and hot gas path overhaul scheduled for the unit. Continue to follow the inspection schedule.
DECEMBER 2015									
Prairie Island 2	Forced	Generator Voltage Control. (The reason for this outage on the NRC and INPO website was shown as a chemistry hold.)	12/06/2015	12/09/2015	This was not a forced outage, unplanned derate or equipment failure. During power ascension from the refueling outage power was held at approximately 30% power while testing and troubleshooting of the generation voltage control of the new electrical generator was completed. Upon successful completion of the testing the unit continued to increase in power.	See explanation under Q1.		See explanation under Q1.	See explanation under Q1.
Sherburne.2	Forced	Boiler Recirculation Pumps	12/01/2015	12/13/2015	24 Boiler Circ Pump	Thrust pad wear caused increased vibration which forced removal of the pump from service. The thrust pads were changed on this pump from an asbestos pad to a non-asbestos grade material when the vendor stopped supplying the asbestos grade in 2006. The vendor stands behind the new "T2" non-asbestos grade material and they have not seen any failures like this in similar applications, so the same grade pads were used as replacement. Unit was de-rated until 12/13/15 at which time it was taken off line to repair the pump .		Similar event on Unit 1 for this reporting period from 10/8/15 to 10/16/15.	The vendor has since gone to a third generation of pad, which was installed in 24 Boiler Circ Pump. All other Unit 2 Boiler Circ Pumps have be gone through during the 2016 overhaul and replaced with this new generation of pad.
Prairie Island 2	Forced	Generator Rotor Windings	12/17/2015	12/31/2015	Please see letter dated May 4, 2016 from Xcel Energy to Minnesota Public Utilities Commission - UNIT 2 GENERATOR FAILURE RECOVERY OUTAGE REPORT DOCKET NOS. E002/RP-15-21 & E002/GR-15-826	See explanation under Q1.		See explanation under Q1.	See explanation under Q1.

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	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
Northern States Power Company - Minnesota									
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Sherburne.2	Forced	Boiler Recirculation Pumps	12/13/2015	12/19/2015	24 Boiler Circ Pump	Thrust pad wear caused increased vibration which forced removal of the pump from service. The thrust pads were changed on this pump from an asbestos pad to a non-asbestos grade material when the vendor stopped supplying the asbestos grade in 2006. The vendor stands behind the new "T2" non-asbestos grade material and they have not seen any failures like this in similar applications, so the same grade pads were used as replacement. Unit had been derated since 11/23/15 due to this pump until it was taken off line at this time to repair the pump.		Similar event on Unit 1 for this reporting period from 10/8/15 to 10/16/15.	The vendor has since gone to a third generation of pad, which was installed in 24 Boiler Circ Pump. All other Unit 2 Boiler Circ Pumps have be gone through during the 2016 overhaul and replaced with this new generation of pad.
JANUARY 2016									
Prairie Island 1	Derate	Heater Drain Valves	01/22/2016	01/30/2016	This was a 1% derate and not a forced outage. Approximately 6 MWe of output was lost, a 1% reduction in power and steam flow, when Control Valve-31096 failed closed from its normally open position.	Control Valve-31096 failed closed when the valve plug separated from the valve stem. The valve plug separated from the stem when the plug unscrewed itself stem because a groove pin had not been installed when the valve was overhauled in May 2011.		No similar events during this reporting period (July 1, 2015 to June 30, 2016).	Control Valve-31096 was repaired and returned to service.
Sherburne.3	Forced	Condensate/hotwell Pump Motor	01/21/2016	01/31/2016	31 Condensate Pump	During routine inspection of 31 Condensate Pump Motor, it was found to have oil leaking onto the motor windings. It was decided to remove the pump from service and send the motor out for cleaning, reconditioning, and a bearing seal inspection to determine the source of the oil leak. During this work, the vendor discovered lower bearing journal and babbit bearing scoring. Decision was made to hard chrome plate the journal and machine to keep the bearing the original size.		No similar events during this reporting period (July 1, 2015 to June 30, 2016)	Oil contamination caused by excessive seal clearance. The seal clearance issue may be related to incorrect locating pin positions. Leaking oil caused the inlet screen to become plugged causing a DP which may have encouraged additional contaminants to enter the oil reservoir. Severe oil contamination eventually led to bearing and shaft damage.
Allen.S.King.1	Forced	Waterwall (Furnace Wall)	01/01/2016	01/04/2016	Boiler Leak	Leak in boiler waterwall due to erosion on tube from sootblower turning on too soon		No similar failures were reported during this reporting period	Adjustment made to sootblower to ensure correct timing to prevent erosion on tube. Tube that was repaired was replaced during spring 2016 outage along with 2 surrounding tubes that also had shown signs of wear.

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French.Is.1	Forced	Induced Draft Fan Motor Outbourd Bearing Failure	01/21/2016	01/31/2016	Induced Draft Fan Motor	Motor bearing failed.		No other occurance during the reporting period.	The motor is being replaced with a new motor.
Prairie Island 2	Forced	~~Condensate/hotwell Pump Motor~~Generator Rotor Windings	01/01/2016	01/31/2016	Continuation of outage beginning on 12/17/2015. See explanation above.	Continuation of outage beginning on 12/17/2015. See explanation above.		Continuation of outage beginning on 12/17/2015. See explanation above.	Continuation of outage beginning on 12/17/2015. See explanation above.
FEBRUARY 2016									
Allen.S.King.1	Forced	Issues with governer valve not functioning	02/07/2016	02/12/2016	#3 Governor Valve	Inconsistent operation of the #3 governor valve resulted in valve being forced to a fixed position as to not negatively affect the operations of the other 3 governor valves.		No similar failures were reported during this reporting period	Valve was rebuilt, servo motor was replaced. Flush of control oil system, replacement of control oil, control wiring checked, and control components replaced.
Sherburne.3	Forced	Condensate/hotwell Pump Motor	02/08/2016	02/11/2016	36-2 High Pressure Heater	Heater tube failure neccessitated the need to remove the high pressure string from service and derate the unit. 84 tubes were previously plugged prior to this incident. The damage was split between the inlet and outlet sections and appears to be general erosion.		No similar events during this reporting period (July 1, 2015 to June 30, 2016)	76 tubes were inspected on the outlet section and 32 on the inlet section. 13 tubes were plugged which includes the leaking tubes, surrounding tubes, and any inspected tube with 70% or greater wall loss. This heater is original equipment. Heater is at end of life and is scheduled to be replaced in 2020.
Allen.S.King.1	Forced	Offline due to governer valve repairs	02/12/2016	02/17/2016	#3 Governor Valve	Inconsistent operation of the #3 governor valve resulted in valve being forced to a fixed position as to not negatively affect the operations of the other 3 governor valves.		No similar failures were reported during this reporting period continuation of 2/7 event	Valve was rebuilt, servo motor was replaced. Flush of control oil system, replacement of control oil, control wiring checked, and control components replaced.
French.Is.4	Maintenance	Replace 4L73 69kv switch	02/22/2016	02/23/2016	This was not a forced outage. This was a scheduled maintenance activity.	69 KV Swithch		None	Rebuilding of this switch was a preventative maintenance activity to prevent equipment failure.
Prairie Island 2	Forced	Generator Rotor Windings	02/01/2016	02/12/2016	Continuation of outage beginning on 12/17/2015. See explanation above.	Continuation of outage beginning on 12/17/2015. See explanation above.		Continuation of outage beginning on 12/17/2015. See explanation above.	Continuation of outage beginning on 12/17/2015. See explanation above.
Sherburne.3	Forced	36-2 HP heater leak repair	02/11/2016	02/12/2016	36-2 High Pressure Heater	Due to single block isolation valve arrangement on these heaters, the unit had to be removed from service to facilitate repairs. 84 tubes were previously plugged prior to this incident. The damage was split between the inlet and outlet sections and appears to be general erosion.		No similar events during this reporting period (July 1, 2015 to June 30, 2016)	76 tubes were inspected on the outlet section and 32 on the inlet section. 13 tubes were plugged which includes the leaking tubes, surrounding tubes, and any inspected tube with 70% or greater wall loss. This heater is original equipment. Heater is at end of life and is scheduled to be replaced in 2020.
MARCH 2016									
Blk_Dog_G52	Forced	Turbine Governing System	03/05/2016	03/06/2016	Steam Turbine Speed Probe	Speed Probe assembly failed to read speed		No similar events occurred during this reporting period	All three speed probes were replaced and orientation was changed to limit variations in readings. The entire assembly will be replaced in the fall of 2016 to a more robust design.

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Unit	**Outage Category**	**Primary Reason for outage**	**Outage Dates Start**	**End**	**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**
French_2	Maintenance	Minor Boiler Overhaul (less Than 720 Hours)	03/13/2016	03/15/2016	This was not a forced outage.	This was a maintenance outage for periodic cleaning and inspection.		One similar event for French Island Unit 2 in May 2015	RDF fuel causes boiler fouling. We believe we are cleaning at appropriate intervals.
French_2	Forced	Generating Tube Leaks	03/30/2016	03/31/2016	Boiler Tube	Failure due to erosion.		Two similar events occurred during the reporting period.	Generating tubes will be replaced in 2017 as part of a capital project.
King_G1	Forced	Feedwater Pump Drive - Gear	03/20/2016	03/23/2016	11 boiler feed pump	11 BFP removed from service due to high vibrations on the pump, as a result of using the startup pump as a normal operating pump during the 12 BFP replacement process that began with the 7/14 event.		One similar event for this unit occurred during this reporting period.	Pump was removed from service, and replaced with rebuilt element pump. Pump was originally scheduled for replacement spring of 2016.
Redwing_1	Forced	Turbine Lube Oil Pumps	03/06/2016	03/08/2016	Turbine Lube Oil Pumps	Turbine Lube Oil Pumps		No similar events during this reporting period (July 1, 2015 to June 30, 2016)	Repaired pump
Redwing_1	OMC	Lack Of Fuel (Outside Management Control)	03/27/2016	03/30/2016	Fuel (RDF)	N/A		Two similar events during this reporting period (July 1, 2015 to June 30, 2016)	N/A
APRIL 2016									
Blk_Dog_G52	Forced	Unit tripped due to Static Frequency Converter fault.	04/17/2016	04/18/2016	Combustion Turbine Starting Equipment	Voltage fluctuations prevented operation		One similar event occurred during this reporting period	The Static Frequency Converter is past useful life and is scheduled for replacement in 2018
CC Highbridge1	OMC	Gas Line Leak, Gas dept had to drop pressure on the line to fix.	04/05/2016	04/08/2016	This is an OMC (Out of Management Control) event. No plant equipment was involved in this outage. The gas line supplying High Bridge required work and therefore had to be taken out of service. High Bridge could not run during the gas line outage.	N/A		There was one similar event during this reporting period.	N/A
CC Highbridge2	OMC	Gas Line Leak, Gas dept had to drop pressure on the line to fix.	04/05/2016	04/08/2016	This is an OMC (Out of Management Control) event. No plant equipment was involved in this outage. The gas line supplying High Bridge required work and therefore had to be taken out of service. High Bridge could not run during the gas line outage.	N/A		There was one similar event during this reporting period.	N/A
Redwing_1	Forced	Unit 1 Baghouse Maintenance	04/10/2016	04/13/2016	Unit 1 Baghouse	Unit 1 Baghouse - several bags needed to be replaced.		No similar events during this reporting period (July 1, 2015 to June 30, 2016)	Replaced bags / developed cleaning method to extend bag life.
MAY 2016									
King_G1	Forced	Thrust Bearings	05/22/2016	05/24/2016	Turbine Thrust bearing	Turbine removed from service due		No similar failures were	Repairs on the IP turbine intercept valves
Anson_G4	Forced	Main transformer	05/11/2016	06/01/2016	GSU Transformer	Shorted windings		There was one similar event during this reporting period.	Transformer replacement
Redwing_2	Forced	First Superheater Leaks	05/05/2016	05/08/2016	Unit 1 Superheat Tubes	Unit 1 Superheat Tubes		Seven similar events during this reporting period (July 1, 2015 to June 30, 2016)	Repaired leak / transitioned to less errosive sootblowing methods / capital project to replace superheat tubes in Feb 2017
Redwing_2	Forced	First Superheater Leaks	05/23/2016	05/26/2016	Unit 1 Superheat Tubes	Unit 1 Superheat Tubes		Seven similar events during this reporting period (July 1, 2015 to June 30, 2016)	Repaired leak / transitioned to less errosive sootblowing methods / capital project to replace superheat tubes in Feb 2018
JUNE 2016									

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company - Minnesota
Unit Outage Information
2016 AAA Reporting Period: July 1, 2015 - June 30, 2016

Updated since originally filed in monthly FCAs due to further analysis.

Unit	Outage Category	Primary Reason for outage	Outage Dates Start	End	Q1. Equipment that resulted in the forced outage	Q2. Description of Equipment Failure	[TRADE SECRET BEGINS Q3. Change in Energy Costs	Q4. Failure History During Reporting Period	Q5. Steps Taken to Alleviate Reoccurrence
King_G1	Forced	Forced Draft Fans	06/22/2016	06/24/2016	11 Forced Draft Fan	Fan in board bearing failure and inlet damper linkage failure		No similar failures were reported during this reporting period	Repairs made to the inlet damper linkage, inboard bearing replaced, thrust collar machined, and fan/motor aligned.
SHERCO_G2	Forced	Switchyard Circuit Breakers - external (OMC)	06/27/2016	07/01/2016	Unit 2 MegaWatt Transducer	Unit 2 Megawatt transducer failed during startup following the 2016 overhaul. The data aquisition and information signal could be used for power output indication, but the unit had to be operated in boiler base/turbine follow mode. There was a risk of not being able to control throttle pressure at the upper end of the load range which could have resulted in a Unit trip so the unit was de-rated to 650 MWnet.		No similar events during this reporting period (July 1, 2015 to June 30, 2016)	New MW transducer was received by the site and installed. A second transducer was also received by the site as Unit 1's transducer is of the same vintage.
SHERC3	Forced	High Pressure Heater Tube Leaks	06/07/2016	06/14/2016	36-1 High Pressure Heater	Heater tube failure neccessitated the need to remove the high pressure string from service and derate the unit. 2 tubes were previously plugged in this heater prior to this incident. Most of the damage was found in the drain cooler section. The damage appears to be mainly from fretting at tube support areas.		Similar event during this reporting period involving 36-2 High Pressure Heater from 2/8/16 to 2/12/16.	Inspected 12 tubes on the outlet section, 105 on the inlet section. Found 2 leaking tubes. 19 total tubes were plugged which includes the leakers, surrounding tubes and anything with 70% or greater wall loss. This heater is original equipment. Heater is at end of life and is scheduled to be replaced in 2020.
Anson_G4	Forced	Main Transformer	06/01/2016	07/01/2016	GSU Transformer	Shorted windings		There was one similar event during this reporting period.	Transformer replacement
King_G1	Forced	Other Slag And Ash Removal Problems	06/24/2016	06/28/2016	Slag Tank	Slag tank plugged with hardened slag (molten ash).		Two similar events occurred during the reporting period.	This event was the result of being unable to go higher on load due to repairs made to 11 FD fan.Slag tank inspected and nozzles replaced/cleaned. Operational practices changed to run until at higher load for 48 hours following a unit start up to improve tapping of boiler. Working with OEM on study to improve slag tank performance.
CCRiverside1	Forced	Gas Turbine - Gas Fuel System	06/26/2016	06/27/2016	Unit 9 fuel gas performance heater	Heat exchanger end bell gasket failure		No similar events during this reporting period.	Original equipment manufacturer gasket installed and torqued to specifications.
SHERC3	Forced	High Pressure Heater Tube Leaks	06/14/2016	06/15/2016	36-1 High Pressure Heater	Due to single block isolation valve arrangement on these heaters, the unit had to be removed from service to facilitate repairs. 2 tubes were previously plugged in this heater prior to this incident. Most of the damage was found in the drain cooler section. The damage appears to be mainly from fretting at tube support areas.		Similar event during this reporting period involving 36-2 High Pressure Heater from 2/8/16 to 2/12/16.	Inspected 12 tubes on the outlet section, 105 on the inlet section. Found 2 leaking tubes. 19 total tubes were plugged which includes the leakers, surrounding tubes and anything with 70% or greater wall loss. This heater is original equipment. Heater is at end of life and is scheduled to be replaced in 2020.
							TRADE SECRET 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, 2015	July, 2015
Network Resource	ICAP (Summer)	UCAP (Summer)	ICAP (summer) (1)	UCAP (summer) (1)
NSP.ALDRIHERC	34	23	34	22
NSP.ANSON2	93	83	99	92
NSP.ANSON3	93	76	99	88
NSP.ANSON4	149	144	151	144
NSP.BAYFRN	67	64	71	26
NSP.BIGFALL_A	4	3	7	3
NSP.CC.BLKD52	285	247	281	199
NSP.BLUEL1	39	35	41	40
NSP.BLUEL2	39	39	40	40
NSP.BLUEL3	38	38	39	39
NSP.BLUEL4	41	41	45	45
NSP.BLUE_LK7	154	154	150	144
NSP.BLUE_LK8	155	150	153	141
NSP.CANFLSG1	179	157	155	155
NSP.CANFLSG2	179	155	155	151
NSP.CEDARFAL	3	2	7	3
NSP.CHEMOLSPO	262	235	245	231
NSP.CHPFAL	9	7	21	8
NSP.CORNEL	15	11	31	8
OTP.FIBROMIN	55	47	55	53
NSP.FRENCH1	16	15	18	0
NSP.FRENCH2			10	8
NSP.FRENCH4	61	56	61	56
NSP.GDMEADOW	101	14	100	14
NSP.GRANCT1	13	9	13	12
NSP.GRANCT2	14	12	14	13
NSP.GRANCT3	14	12	14	13
NSP.GRANCT4	13	11	13	12
NSP.HENNIPIN1	5	4	15	5
NSP.CC.HIBRDG	544	515	536	524
NSP.HOLCOM	15	11	35	12
NSP.INVRHL1	48	41	48	40
NSP.INVRHL2	48	46	47	45
NSP.INVRHL3	48	44	48	43
NSP.INVRHL4	48	40	48	42
NSP.INVRHL5	47	41	46	39
NSP.INVRHL6	48	39	48	40
NSP.JIMFL	24	18	56	18
NSP.KING1	541	519	541	525
NSP.CC.MANKATO	357	277	302	276
NSP.MENOMOA	2	2	5	1
NSP.MNMETHANE	5	1	4	4
NSP.MNTCEL1	624	608	607	570
NSP.NOBLES	201	34	200	34
NSP.PINEBEND	12	5	4	4
NSP.PKFLSFLAM	13	11	15	12

NSP.PRISL	1,038	1,035	1040	1027
NSP.RAPIDA1	5	3	4	2
NSP.REDWIN1	21	20	10	8
NSP.REDWIN2			10	8
NSP.CC.RIVRSD	470	443	469	458
NSP.SHAKOBIO1	12	12	15	12
NSP.SHERCO1	709	694	706	696
NSP.SHERCO2	694	667	705	686
NSP.SHERC3	527	515	535	528
NSP.SPGSPG1 (St. Paul Co-Gen)	25	25	37	25
NSP.STCLOUD1	9	7	9	7
NSP.STCRO	15	11	24	13
NSP.WHEATO1	46	40	48	40
NSP.WHEATO2	55	48	57	43
NSP.WHEATO3	46	42	48	40
NSP.WHEATO4	47	45	50	40
NSP.WHEATO5	53	42	57	42
NSP.WHEATO6	51	31	54	42
NSP.WILMAR1	19	17	8	8
NSP.WILMAR2			8	8
NSP.WISSOT	17	12	36	15
MHEB (375/325 MW System Purchase)	375	363	375	369
MHEB (350 MW Diversity Exchange)	350	342	350	344
Laurentian Energy Authority	35	32	40	38
Solar Aggregate PPA's	2	1	0	0
Hydro Aggregate PPA's	37	13	17	17
Wind Aggregate PPA's	1,393	181	1393	193
Total	10,806	8,737	10,830	8,701

(1) Resources and Capacity as reported in the 2015/2016 MISO GVTC

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

FCA Filing Period	Item Pertaining To	Period Affected	Descriptions	Amounts	FCA Impact
Jul-15	None				
Aug-15	632000- Purchases - Long Term Contracts (IPPs)	May 2012 - Sept. 2014	Fibrominn - The Consent approving the assignment of the PPA to the new legal entity Benson Power LLC was approved on 8/20/2015. The Consent & Assignment Agreement releases all previous claims made by the FibroMinn LLC, therefore the previously recorded accrual for transportation expense was reversed.	($1,574,307)	Yes
Sep-15	None				
Oct-15	None				
Nov-15	None				
Dec-15	Purchases - MISO JDE Object 632150.2110	Dec-15	MISO RT Miscellaneous Charge for the payment to SPP for dispatch service charges.	$1,909,647	Yes
Dec-15	Coal JDE Object 614000	Oct-15	Fall Coal Survey Adjustment impacting King and Sherco Plants	($2,474,667)	Yes
Jan-16	Oil SAP 5003011	Jan-16	Wheaton Plant oil inventory adjustment due to meter calibrations.	$604,947	Yes
Feb-16	None				
Mar-16	None				
Apr-16	MISO SAP 5066016	Dec-15	In April 2016, an error relating to prior period MISO costs was found within our financial systems that inadvertently increased Gen margins and FCA costs. A correction was booked this month that reduced Gen margins and also reduced FCA costs. There will be corrections booked in May and June for lesser amounts to correct similar errors.	($566,054)	Yes
May-16	Coal JDE Object 614000	Mar-16	Spring Coal Survey Adjustment impacting King and Sherco Plants	($989,676)	Yes
Jun-16	MISO SAP 5066016	Feb-16	In April 2016, an error relating to prior period MISO costs was found within our financial systems that inadvertently increased Gen margins and FCA costs. A correction was booked this month that reduced Gen margins and also reduced FCA costs. This correction was related to February 2016 S105 MISO settlements..	($731,636)	Yes

* Reporting requirement pursuant to Commission Order on 2008-2009 and 2009-2010 AAA (Docket Nos. E999/AA-09-961 & E999/AA-10-884) item 30:
"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."

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 2014-2015 AAA reporting period as well as for the 2013-2014 AAA reporting period for comparison. MISO Schedule 10 costs decreased between 2014 and 2015, and , therefore do not meet the threshold for additional reporting. The accompanying support for why the allocation factors are reasonable 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 2015-2016 to be sent to the Department on a CD as an Access database. Two of the data fields ("MW" and "NativeMW") are Trade Secret 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	**This field is TRADE SECRET**.
NativeMW	**This field is TRADE SECRET.**
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
[TRADE SECRET BEGINS		
		TRADE SECRET ENDS]

NSP's FTR portfolio for these Generation-Load Node pairs during the reporting period was: **Generation Node**	**Load Node**	**Summer 2015**	
[TRADE SECRET BEGINS		**Peak**	**Peak Off**
			TRADE SECRET ENDS]

Generation Node	**Load Node**	**Fall 2015**	
[TRADE SECRET BEGINS		**Peak**	**Peak Off**

			TRADE SECRET ENDS]
Generation Node	**Load Node**	**Winter 2015-2016**	
[TRADE SECRET BEGINS		**Peak**	**Peak Off**
			TRADE SECRET ENDS]

Generation Node	**Load Node**	**Spring 2016**	
[TRADE SECRET BEGINS		**Peak**	**Peak Off**
			TRADE SECRET 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 **[TRADE SECRET BEGINS** **TRADE SECRET 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 **[TRADE SECRET BEGINS** **TRADE SECRET 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)
[TRADE SECRET BEGINS				
				TRADE SECRET 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 2014 and 2015 compared to the amounts built into base rates for the 2016 test year in Docket No. E002/GR-15-826 . The table shows State of Minnesota jurisdictional amounts.

2014 Actual	2015 Actual	Two-Year Average	2014 Test Year & 2015 Step	2016 Test Year As Filed
$13,404,466	$11,575,448	$12,489,957	$15,291,479	$14,519,959

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.

Order Point 23b requires utilities to:

> *…provide information regarding policy on backup strategies for transformers*

Part K, Section 5, Schedule 2 provides a policy we submit with MISO which provides the criteria used by the Transmission Planning area when studying the performance of the NSP System.

Order Point 23c requires utilities to:

> …*provide their policy for transformer maintenance*

Part K, Section 5, Schedule 3 provides a draft 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.

PURPOSE

This document, effective March 18th, 2015 provides the criteria to be used by the transmission planners when studying the 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. The document also provides guidance for acceptable forms of mitigation plans and NSP's policy for use of remedial action schemes.

APPLICABILITY AND RESPONSIBILITIES

Northern States Power Company – Minnesota and Northern States Power Company – Wisconsin

APPROVERS

Name	Title
Mark J. Wehlage	Manager, NSP Transmission Planning
Ian R. Benson	Director, Transmission Planning & Business Relations

VERSION HISTORY

Effective Date	Version Number	Supercedes	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)

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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 conditions:

Table 1

Facility	Maximum voltage (p.u.) Pre Contingent	Minimum voltage (p.u.) Pre Contingent	Maximum voltage (p.u.) Post Contingent	Minimum voltage (p.u.) 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

*For 34.5 kV load serving buses, pre and post contingent voltage of above 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.) Pre Contingent	Minimum (p.u.) Pre Contingent	Maximum (p.u.) Post Contingent	Minimum (p.u.) Post Contingent
Roseau 500 kV bus	1.14	0.95	1.14	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

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.

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. During transmission outages, it should be assumed that the system operators, if required, would take remedial action when the current on a facility is lower than the emergency rating and greater than the normal rating. When such remedial action is not available, the normal rating of the facility should be used.

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. Voltage Deviation Criteria for Shunt Device switching

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.

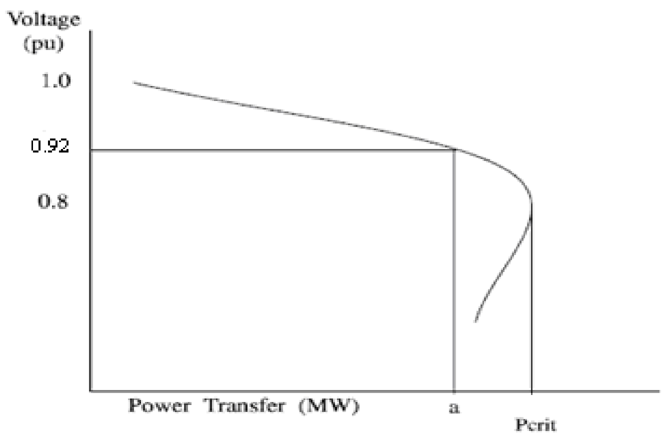

Figure 4.1

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.

6. Transient Voltage Criteria

When performing transient stability studies, after the fault is cleared, the following criteria apply to transient voltage on NSP's buses.

Table 4

Facility	Vmax P.U	Vmin P.U
Default for all Buses	1.2	0.7
Fast Switched Capacitor buses	1.65 P.U for <5 cycles	0.7

NSP does not allow the transient voltage to dip below .7 p.u. for any amount of time.

7. Damping Criteria for Transient Stability Studies

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

- The generator 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%

The PSS/E model "DAMPCK" performs the calculation of damping based on successive positive peak ratios. For cases where "DAMPCK" fails, 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.

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.

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. 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.

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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 Special Protection Systems, 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.

14.5 RAS policy Exception

The only exception to this policy is the case when a RAS is necessary to mitigate sub-synchronous resonance on series compensated transmission lines owned by NSP. However, the remediation action scheme would be limited to only bypassing the series compensation.

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 1453.1™-2012, IEEE Guide—Adoption of IEC/TR 61000-3-7:2008, Electromagnetic compatibility (EMC)—Limits—Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems.

Maintenance Plan for Transmission & Distribution Power Transformers and Load Tap Changers	VERSION: 1.0
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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
	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.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-523

Xcel Energy®

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-16-523

Xcel Energy®

PART M

NOTICE OF REPORT AVAILABILITY,
CERTIFICATE OF SERVICE, AND SERVICE LISTS

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

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

NOTICE OF REPORT AVAILABILITY

DOCKET NO. E999/AA-16-523

On September 1, 2016, Northern States Power Company, doing business as Xcel Energy, filed a report with the Minnesota Public Utilities Commission for the 12 months ending June 30, 2016 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
401 Nicollet Mall
Minneapolis, Minnesota 55401

CERTIFICATE OF SERVICE

I, Jim Erickson, 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. E002/GR-13-868; E002/GR-15-856; E999/AA-16-523; AND MISCELLANEOUS ELECTRIC

Dated this 1st day of September 2016

/s/
____
Jim Erickson

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