414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

September 1, 2015

- 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
2015 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT - ELECTRIC
DOCKET NO. E999/AA-15-611

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 Rebecca Eilers at (612) 330-5570 or rebecca.d.eilers@xcelenergy.com or John Chow at (612) 330-7588 or john.chow@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

DEBRA J. PAULSON
MANAGER, RATE CASES

Enclosures
c Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	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-15-611

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 of Charges (AAA) for electric utilities for the period July 1, 2014 to June 30, 2015.

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

Mara K. Ascheman
Associate Attorney
Xcel Energy
414 Nicollet Mall – 5th Floor
Minneapolis, Minnesota 55401
(612) 215-4505

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, 2015. The information contained in this filing is submitted in compliance with the aforementioned Rules concerning Automatic Adjustment of Charges.

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

Debra J. Paulson
Manager, Rate Cases
Xcel Energy
414 Nicollet Mall – 7th Floor
Minneapolis, Minnesota 55401
(612) 330-7571

IV. DESCRIPTION AND PURPOSE OF FILING

A. Background

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

We provide the Annual Notice of Reports Availability under Minn.R.7825.2840 at the end of our filing. In addition to the required schedules, we provide a brief discussion for each of the rules or their applicable subparts. 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 Energy Supply
Section 5 Conservation and Load Management Policy
Section 6 Nuclear Plant Projects
Section 7 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, 2014 and ending June 30, 2015. 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, 2015.

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 2012 and 2013 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 Automatic Adjustment of Charges.

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 Annual Automatic Adjustment of Charges 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
MISO Ancillary Services Market (ASM)	E002/M-08-528	Part J, Sections 6 and 7
2006 AAA & MISO Filing Requirements	E,G999/AA-06-1208 and E002/M-04-1970 *et al*	Part K, Section 1
2007 AAA Filing Requirements	E,G999/AA-07-1130	Part K, Section 2
2008 AAA Filing Requirements	E,G999/AA-08-995	Part K, Section 3
2009 & 2010 AAA Filing Requirements	E999/AA-09-961 and E999/AA-10-884	Part K, Section 4
2011 AAA Filing Requirements	E999/AA-11-792	Part K, Section 5

The Department's August 26, 2015 Response Comments in Docket E002/AA-14-579 suggest two opportunities for improved transparency in showing the allocation of asset-based wholesale portion of certain MISO ASM charge types in future AAA filings. The Company is willing to incorporate these suggestions in the near future, beginning with our monthly FCA filings.

C. Request to Consolidate and Streamline Certain Compliance Reports

Due to fundamental changes and volatilities in fuel costs and the energy market since 2004, the Company has devised solutions to meet the challenges presented by these changes that ensure 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 already thoroughly evaluated, and thus we believe the associated compliance reporting requirements can be revised or discontinued. Moreover, due to the MISO reporting requirements aggregating from more than one docket, some reports are: (1) repetitive from our monthly FCA reports; or (2) provide the same numbers reported, but in different formats or in different ordered reporting requirements. As a result, the Company proposes to work with the Department in an effort to consolidate and streamline the various additional reporting requirements, thereby making the AAA report 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:

Mara K. Ascheman
Associate Attorney
Xcel Energy
414 Nicollet Mall – 5th Floor
Minneapolis, Minnesota 55401
Mara.K.Ascheman@xcelenergy.com

SaGonna Thompson
Regulatory Administrator
Xcel Energy
414 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, 2015

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner
Betsy Wergin	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-15-611

SUMMARY

Please take notice that on September 1, 2015, 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
2014-2015
ANNUAL AUTOMATIC ADJUSTMENTS REPORTS
(Electric Utility)

SUBMITTED TO THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Docket No. E999/AA-15-611

September 1, 2015

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2014-2015 ELECTRIC AAA REPORT

A. OVERVIEW

This report provides an overview of the events during the course of the twelve-month period ending June 2015. 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 supplemental information in its monthly FCA filings to keep the agencies informed of any significant events.

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 16 representatives from the 2005 rate case intervening parties who have signed the protective agreements and are receiving the FCA forecast information.

B. REPORTING REQUIREMENTS

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.

C. ADDITIONAL COMPLIANCE REPORTS

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

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
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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
MISO Ancillary Services Market (ASM)	E002/M-08-528	Part J, Sections 6 and 7
2006 AAA & MISO Filing Requirements	E,G999/AA-06-1208 and E002/M-04-1970 *et al*	Part K, Section 1
2007 AAA Filing Requirements	E,G999/AA-07-1130	Part K, Section 2
2008 AAA Filing Requirements	E,G999/AA-08-995	Part K, Section 3
2009 & 2010 AAA Filing Requirements	E999/AA-09-961 and E999/AA-10-884	Part K, Section 4
2011 AAA Filing Requirements	E999/AA-11-792	Part K, Section 5

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-611

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 change is shown on Part D, Section 1, Schedules 2, 3, and 5.

Formal analyses of coal supply requirements for future years are performed on a regular basis. These analyses generally lead 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**

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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. Imbalances between purchased coal supplies and station requirements are 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.

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Transportation 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 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 2015 has been relatively stable with a high spot market price of $39.50 per pound in March to a low of $35.00 per pound in May. The spot market ended the second quarter at $36.50 per pound. From the pre-Fukushima price peak in January 2011, the market price for uranium is at 50 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. 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 2021 for all demand scenarios, but will continue to be dependent on the willingness of suppliers to bring new supply into the market, as well as the willingness 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 may 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 base load 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 very modest rise in price, commensurate with local wood markets. Biomass pricing is maintained below pulpwood prices, to avoid potential competition for woody biomass with the pulp and paper industry.

Refuse-Derived Fuel (RDF):

Xcel Energy has established four contracts for the supply of refuse-derived fuel (RDF) for three power plants. Three 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 Xcel Energy facility. Essentially all of the county's MSW is processed and disposed at the Xcel Energy facility, with the exception of materials recovered for recycling, and non-combustible or non-recoverable materials and ash byproducts which are disposed in the County's landfill.

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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.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Nuclear Fuel Components of Services for the Period of July 2014 through June 2015

	Supplier & Corporate Headquarters Location	Description of Fuel or Services	Quantity of Volume	Contract Expiration Date
[TRADE SECRET BEGINS				
1				
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9				
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12				
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				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				
1				
2				
3				
4				
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10				
11				
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				TRADE SECRET ENDS]

* New contracts

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Transportation & Related Services Contracts

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[TRADE SECRET BEGINS				
1				
2				
3				
4				
5				
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7				
				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				
1				
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TRADE SECRET ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[TRADE SECRET BEGINS				
12				
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TRADE SECRET ENDS]

	Supplier & Corporate Headquarters Location	Description of Fuel or Service	Quantity or Volume	Contract Expiration Date
[TRADE SECRET BEGINS				
24				
25				
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31				

TRADE SECRET ENDS]

Cost Changes - July 1, 2014 to June 30, 2015

	Contract	Percent Change
[TRADE SECRET BEGINS		
		TRADE SECRET ENDS]

* New contracts
** Pending contracts

Cost Changes - July 1, 2014 to June 30, 2015

	Contract	Percent Change
[TRADE SECRET BEGINS		
		TRADE SECRET ENDS]

* New contract
** Pending contract
*** A legacy, fixed price (25 yr) contract expired. Pricing set to current market.

DISPATCHING POLICIES AND PROCEDURES

The goal for Xcel Energy's dispatch 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 decremental cost of generation. Since neither decremental costs nor 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 decremental 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).

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 2014, the NSP Mean Absolute Error was 9.04 percent. This represents a decrease in forecast error of roughly 52 percent. Differences between Day Ahead market cleared wind generation output and actual wind generation output are trued up in MISO Real Time. 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 dispatch policies and procedures, while focused on reliable service, are influenced by a goal of lowest cost in an increasingly 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. 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 2014.

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]**

   Contract amendments have 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 $2.34/MBtu during 2013. (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 2012 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 calculations and the charges billed by MISO in the Day 2 energy market. From July 2014 through June 2015, the Company has disputed approximately 3 days of 106 MISO invoices. From that action, approximately $470.15 in disputed amounts were granted by MISO for the NSP System (through adjustments to MISO settlements), and the Minnesota jurisdictional portion of the dollars were reflected in the FCA true-up.

NSP MISO Dispute Status

Sum of Disputed $ Amount			Dispute Status			
YEAR	Op Month	Operating Date	GRANTED	DENIED	OPEN	TOTAL
2014	2014-10	10/19/14	$0.00	$9.17	$0.00	$9.17
	2014-12	12/18/14	$470.15	$0.00	$0.00	$470.15
2014 Total			$470.15	$9.17	$0.00	$479.32
2015	2015-3	03/04/15	$0.00	$391.85	$0.00	$391.85
2015 Total			$0.00	$391.85	$0.00	$391.85
TOTAL			$470.15	$401.02	$0.00	$871.17

The number of disputed items and the dollar value disputed in the 2014-2015 AAA period are both significantly lower than in the 2013-2014 AAA period. As markets mature, the number of disputes naturally decreases as issues are resolved and calculations are fine-tuned. Disputes will never be a constant flow because they center on certain issues in the market that people are objecting to at a given time. From a settlements perspective, there were not many disputable issues in the MISO market during the 2014-2015 AAA timeframe.

ENERGY SUPPLY

a. Ongoing Projects at Existing Generating Plants

Cost effective projects at existing generating plants help Xcel Energy minimize costs and meet demand requirements.

1. Replace the Boiler Bottom on Sherco Unit 1
2. Replace 16A Feedwater Heater at King Plant
3. Replace a wall on boiler #2 at Red Wing

b. Planned Projects at Existing Generating Plants

1. Replace a wall on boiler #1 at Wilmarth
2. Replace air heater baskets at King Plant

c. Generating Plant Performance

Overall plant availability continues to trend in a positive direction as shown by the following performance:

1. NSP System fossil plants' availability stands at 80.74% for the period 2012-2014.
2. NSP System nuclear plants' availability stands at 84.38% for the period 2012-2014.
3. NSP System peaking plants' availability stands at 88.69% for the period 2012-2014.

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 legal 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 and customer education to controls on central air conditioners to manage energy demand. 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 energy resource planning process and also in the daily operations in the MISO Day Ahead and Real Time energy markets.

Xcel Energy 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, 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 Xcel Energy 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 operation, 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 Xcel Energy'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 is subject for approval from 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 Department approved the Company's 2014 Electric and Gas CIP Status Report on July 7, 2015.[2]

[1] Docket No. E,G002/CIP-12-447.
[2] Docket No. E,G002/CIP-12-447.07.

NUCLEAR PLANT PROJECTS

Both Monticello and Prairie Island have received renewed operating licenses from the Nuclear Regulatory Commission (NRC) and have had the additional spent fuel storage capacity needed to support plant operations for 60 years approved by the Minnesota Public Utility Commission (MPUC). Life cycle management (LCM) projects have been or are being implemented at both plants to ensure safe and reliable operation for the extended 20 years of plant operation.

Monticello Nuclear Plant Capacity Addition

Xcel Energy received the final required approval for an Extended Power Uprate (EPU) at Monticello from the NRC in December 2013. The plant completed power ascension testing and achieved sustained operations at 100 percent of the uprated power level on July 14, 2015. Operations at the newly authorized level of 2004 megawatts thermal of reactor power have resulted in the plant producing more than the expected 71 megawatts-electric (MWe) of additional power originally estimated in the Certificate of Need. Since achieving 100 percent of the uprated power level on July 14, 2015 the plant has produced approximately 2 additional megawatts above the planned 71 megawatt increase. Over the 15-years of remaining plant operation under the current operating license this additional capacity will yield more than 250,000 megawatt-hours of clean energy for our customers.

Prairie Island Nuclear Capacity Addition

On March 30, 2012, the Company filed a change of circumstance to the Commission on the Prairie Island EPU. In that filing the Company requested that the Commission review and reaffirm the project before we proceed further. The Commission issued an order terminating the Prairie Island Certificate of Need for the power uprate on February 27, 2013.

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 Midcontinent Independent System Operator Transmission Owners (MISO 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

The Company and its utility operating company affiliate Northern States Power Company, a Wisconsin corporation (NSPW),[1] are transmission-owning members of the Midcontinent Independent System Operator, Inc. (MISO).[2] The NSP Companies participate in the MISO TOs Committee.

The MISO TOs intervene in numerous FERC and other proceedings. The MISO TOs 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 utilities that are MISO TO 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. By intervening through the MISO TO group, Xcel Energy is able to more vigorously represent the interests of its customers at MISO and at FERC. Xcel Energy is also a participant on the Transmission Owners Tariff Working Group, which makes decisions on certain rate and revenue distribution changes pursuant to the MISO Transmission Owners

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[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."

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

Agreement (TOA). Xcel Energy representatives also participate in all other MISO committees, such as the Market Sub-committee, at least to some extent.

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-15-611

PART E

Automatic Adjustment Charges

BASE COST OF FUEL

As part of our 2013 rate case (Docket No. E002/GR-13-868), the new system base cost of energy of $0.02780 per kWh was approved by the Commission in Docket No. E002/MR-13-869. This base cost of energy has been in effect since January 3, 2014.

The Fuel Adjustment Factor (FAF) ratios applicable to the AAA reporting period were approved by the Commission in our 2012 rate case (Docket No. E002/GR-12-961). The ratios have been effective since December 1, 2013.

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

Effective July 2014 to June 2015

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

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

[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 refund is included in the monthly Fuel Cost Charge on a two months lag basis.

b. Non-Asset Based Margin Sharing

Pursuant to Commission Order in our 2011 rate case (Docket No. E002/GR-10-971) issued May 14, 2012, the Company implemented a change related to the treatment of 2011 realized non-asset based margins for sharing in the 2012 FCC. The realized non-asset based margins are no longer credited through the Fuel Clause mechanism. As a result, the non-asset based margin sharing tracker has been discontinued.

c. Deferred 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 3 new Financial Transmission Rights (FTRs) amounts:

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

And the following 4 Auction Revenue Rights (ARRs) charge types:

- 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 imposed by the Midcontinent

Independent System Operator, Inc., for MISO Day 2 operations.[6] On February 6, 2008 the Commission issued an order in Docket No. E001/M-05-406, et al., which made certain amendments to the December 20, 2006 Order, namely requiring Revenue Sufficiency Guarantee (RSG) charges and Revenue Neutrality Uplift (RNU) charges to be allocated on a straight megawatt-hour basis. Finally, and as noted above, on August 23, 2010 the Commission issued an order in Docket No. E001, E015, E002, E017/M-08-528[7], which authorized the Company to recover costs and flow through revenues related to the new MISO ASM charge types. Line items 14d of Part E Section 5 Schedule 1, Page 1 of 4 contains the monthly MISO ASM charges.

5. Nuclear Fuel Disposal Fee

The Company received notification from the DOE on May 12, 2014 that the Spent Nuclear Fuel Disposal Fee, which was 1.0 mill per kilowatt hour of electricity generated and sold, would be discontinued effective May 16, 2014.[8] The Disposal Fee is an authorized component of FERC account 518. The charge had been collected from customers via a line item in our monthly Fuel Cost Charge fillings. We no longer collect the Disposal Fee from Minnesota customers through Fuel Cost Charge filings and will not do so unless the DOE reinstates a fee.

6. Alliant-WAPA Settlement

On July 18, 2014, Xcel Energy filed with the Minnesota Public Utilities Commission a Petition[9] to include in the fuel clause a net credit resulting from two one-time payments to reimburse for incorrect accounting of services provided between NSP and Alliant and between NSP and WAPA. On November 24, 2014, the Commission approved the requested rule variance resulting in a refund of $4,284,907 credited to customers through the December 2014 fuel clause filing. This refund is shown in line item 28c of Part E Section 5 Schedule 1, Page 1 of 4.

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[6] Those stakeholders included Minnesota investor-owned electric utilities, Minnesota Department of Commerce, MISO, Minnesota Chamber of Commerce and Large Power Interveners.
[7] Pursuant to the final Order, the Contingency Reserve Deployment Failure and the Excess/Deficient Energy charges are subject to refund.
[8] The Company submitted an informational filing to the Commission on May 19, 2014 regarding this charge.
[9] Docket No. E002/M-14-614

7. Sherco Unit 3 Excess Fuel Oil Reimbursement from Insurance Companies

The March 2015 FERC Account 151 (fossil fuel) included a $503,486 settlement reimbursement from the insurance companies for the excess fuel oil that was consumed during the startup of Sherco Unit 3 following repairs. The Minnesota customers' share of this credit embedded in May 2015 Fuel Cost Charge was $364,429 based on March 2015 Minnesota jurisdictional MWh sales weighting relative to the NSP System total.

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 2014 through June 2015. The individual class totals were reported on line items 37(i) through 37(vi).

REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED

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

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.

The class differentiated FCC method was adopted during the reporting period, July 2014 through June 2015. 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 refund.

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.

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Charge July 2014 - June 2015

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	12 Months
FORECASTED COST OF FUEL														
	Account 151 Fossil Fuel													
[1]	Coal	33,837,640	31,872,764	25,975,898	30,202,759	28,041,310	33,180,858	34,011,970	25,368,039	23,756,722	12,488,318	17,709,573	24,722,125	321,167,976
[2]	Wood/RDF	1,092,703	1,064,063	711,232	207,718	663,857	1,091,235	1,042,956	951,516	957,467	878,561	1,216,504	1,162,130	11,039,942
[3]	Natural Gas CC	15,774,019	9,661,342	8,822,725	4,628,862	8,830,480	7,585,718	10,555,463	13,745,370	6,466,226	14,163,204	8,945,548	10,500,639	119,679,596
[4]	Natural Gas / Oil CT	3,529,802	2,663,677	552,815	362,715	122,523	122,523	122,523	1,461,996	477,266	2,736,124	3,156,175	2,584,616	17,892,755
[5]	Total Fossil Fuel	54,234,164	45,261,846	36,062,670	35,402,054	37,658,170	41,980,334	45,732,912	41,526,921	31,657,681	30,266,207	31,027,800	38,969,510	469,780,269
[6]	Account 518 Nuclear Fuel	10,399,528	10,502,366	10,058,539	7,409,831	7,942,455	10,233,412	10,398,375	7,469,729	10,881,622	5,482,984	7,805,771	9,595,156	108,179,768
[7]	Account 555 Energy Purchases	56,010,202	54,318,747	48,485,180	51,807,807	50,083,874	49,044,251	47,811,010	44,019,953	48,179,894	51,993,499	50,414,340	49,175,663	601,344,420
[8]	Net System Cost	120,643,894	110,082,959	94,606,389	94,619,692	95,684,499	101,257,997	103,942,297	93,016,603	90,719,197	87,742,690	89,247,911	97,740,329	1,179,304,457
[9]	Forecasted System MWH Sales *	3,938,436	3,853,348	3,367,040	3,335,622	3,290,690	3,511,138	3,609,510	3,213,552	3,421,724	3,129,462	3,239,965	3,543,025	41,453,513
[10]	Forecasted Minn. Retail Sales Subject to FCC *	2,945,437	2,870,184	2,495,581	2,475,770	2,396,780	2,529,606	2,590,763	2,321,890	2,474,234	2,276,642	2,370,588	2,619,411	30,366,885
[11]	Forecasted Cost of Fuel Per kWh [8]/[9]/10 **	3.063	2.857	2.810	2.837	2.908	2.884	2.880	2.895	2.651	2.804	2.755	2.759	
ACTUAL COST OF FUEL														
[12]	Account 151 Fossil Fuel	40,296,537	50,710,522	36,722,573	47,290,204	42,328,130	51,460,555	44,941,924	47,850,869	40,648,805	28,741,330	34,454,820	43,880,588	509,326,857
[13]	Account 518 Nuclear Fuel	10,690,492	10,714,115	9,669,747	5,755,755	7,073,944	8,700,192	10,473,127	8,777,256	8,425,116	5,166,948	5,991,354	9,040,523	100,478,569
[14]	Account 555 Economic Dispatch	40,795,699	31,844,211	37,426,703	40,825,794	47,161,234	39,331,530	41,523,072	43,939,929	43,584,945	40,861,001	41,394,843	35,410,693	484,099,653
[14] a	Acct 555 Wind Curtailment Payment	461,358	859,764	149,742	328,716	1,121,507	1,266,822	386,958	499,844	712,711	1,191,294	630,372	346,132	7,955,219
[14] b	Account 555 MISO Day 2	16,196,936	12,907,701	5,662,960	7,791,951	9,407,951	4,418,667	5,629,384	8,617,678	8,702,435	10,803,895	11,697,510	5,708,268	107,545,337
	- Account 555 MISO Day 2 - Sched. 16 & 17	558,270	501,964	490,575	520,545	684,213	601,244	561,080	682,167	771,713	583,779	574,985	644,817	7,175,353
	- Account 555 MISO Day 2 - Sched. 24	63,569	73,480	75,206	67,443	73,700	64,885	68,054	71,704	63,735	66,716	67,235	74,240	829,966
	- RSG/RNU Allocation Adjustment	11,361	30,030	39,413	94,618	89,488	85,252	40,126	59,156	58,729	10,739	32,926	41,455	593,292
	- Congestion and Loss Allocation Adjustment	137,132	165,296	404,408	1,042,507	741,926	861,401	471,008	501,219	361,190	109,185	237,936	213,970	5,247,179
	Account 555 MISO Day 2 - Net	15,426,604	12,136,931	4,653,359	6,066,838	7,818,623	2,805,885	4,489,116	7,303,432	7,447,068	10,033,477	10,784,427	4,733,786	93,699,546
[14] d	Account 555 MISO ASM	1,116,868	1,790,234	1,515,333	2,509,549	3,956,755	5,055,778	3,284,462	(683,154)	(277,351)	2,399,940	1,949,271	2,028,466	24,646,149
[15]	Fuel Cost - Intersystem Sales	4,263,576	5,849,212	4,531,926	10,015,322	8,724,508	12,051,483	9,742,335	9,436,666	7,117,084	4,114,198	2,876,511	6,214,716	84,937,539
[16]	Net Windsource Program Expenses***	1,060,758	445,566	910,077	661,845	(219,663)	997,852	725,681	573,549	562,523	463,534	438,268	316,226	6,936,215
[17]	Final Adjusted Net System Cost	103,463,224	101,760,999	84,695,453	92,099,690	100,955,348	95,571,426	94,630,643	97,677,961	92,861,686	83,816,258	91,890,307	88,909,246	1,128,332,240
[18]	Total MWH Sales (Cal. Month)	3,774,887	3,972,867	3,370,156	3,312,705	3,362,295	3,564,948	3,630,891	3,257,897	3,402,309	3,060,887	3,181,146	3,458,996	41,349,984
[19]	To Retail State of Minnesota	2,824,616	2,980,766	2,516,896	2,442,026	2,442,354	2,577,853	2,616,082	2,345,601	2,466,541	2,248,153	2,348,012	2,576,393	30,385,293
[19] a	Minnesota Windsource MWh not subject to FCA	15,942	15,373	14,265	14,072	12,141	13,985	14,351	11,826	14,162	12,843	11,137	10,781	160,878
[19] b	To Retail State of Minnesota subject to FCA	2,808,674	2,965,393	2,502,631	2,427,954	2,430,213	2,563,868	2,601,731	2,333,775	2,452,379	2,235,310	2,336,875	2,565,612	30,224,415
[20]	Actual Cost of Fuel per kWh [17])/([18]-[19]a)/10**	2.752	2.571	2.524	2.792	3.013	2.691	2.617	3.009	2.741	2.750	2.899	2.578	
[21]	Deviation (Actual Vs. Forecast) [20] - [11] **	(0.311)	(0.286)	(0.286)	(0.045)	0.105	(0.193)	(0.263)	0.114	0.090	(0.054)	0.144	(0.181)	
MONTHLY FUEL CLAUSE ADJUSTMENT FACTOR														
[22]	Prior (2 Months Lag) Unrecovered Expenses	$ (7,181,531)	$ 439,802	$ (8,811,297)	$ (3,587,644)	$ (9,129,520)	$ (8,562,343)	$ (7,214,385)	$ (1,217,786)	$ 2,567,112	$ (4,731,984)	$ (6,594,337)	$ 2,714,556	(51,309,357)
	[26] from two months ago													-
[23]	Prior (2 Months Lag) Recovered Expenses	$ (7,341,626)	$ 447,385	$ (8,399,273)	$ (3,714,307)	$ (9,139,156)	$ (8,391,608)	$ (7,324,973)	$ (1,230,894)	$ 2,569,400	$ (4,754,020)	$ (6,534,181)	$ 2,659,890	(51,153,363)
	[27]X([19]b)X10 from two months ago													-
[24]	Total Unrecovered Expenses (2 Months Lag)	$ (8,971,392)	$ (3,641,409)	$ (8,704,163)	$ (8,654,891)	$ (7,032,043)	$ (1,047,051)	$ 2,456,524	$ (4,745,092)	$ (6,592,049)	$ 2,692,520	$ 2,227,338	$ (1,078,957)	(43,090,665)
	[21]X([19]b)X10 from two months ago													-
[25]	Saver's Switch Discount	$ -	$ 61,348	$ (13,333)	$ (34,115)	$ (191,978)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(178,078)
[26]	Balance of Unrecovered Expenses [22]-[23]+[24]+[25]	$ (8,811,297)	$ (3,587,644)	$ (9,129,520)	$ (8,562,343)	$ (7,214,385)	$ (1,217,786)	$ 2,567,112	$ (4,731,984)	$ (6,594,337)	$ 2,714,556	$ 2,167,182	$ (1,024,291)	(43,424,737)
[27]	System True-Up Factor [26]/[10]/10 **	(0.299)	(0.125)	(0.366)	(0.346)	(0.301)	(0.048)	0.099	(0.204)	(0.267)	0.119	0.091	(0.039)	
[28]	Total System Refunds	(0.008)	(0.019)	(0.029)	(0.015)	(0.011)	(0.184)	(0.003)	(0.019)	(0.012)	(0.012)	(0.020)	(0.003)	
[28] a	System Asset Based Margins Sharing Refund	(0.008)	(0.019)	(0.029)	(0.015)	(0.011)	(0.015)	(0.003)	(0.019)	(0.012)	(0.012)	(0.020)	(0.003)	
[28] c	Other Refund **	-	-	-	-	-	(0.169)	-	-	-	-	-	-	
[29]	Fuel Clause Charge [11]+[27]+[28] **	2.755	2.713	2.415	2.476	2.596	2.652	2.976	2.672	2.372	2.911	2.826	2.717	

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

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Charge July 2014 - June 2015

Docket No. E999/AA-15-611
Part E, Section 5
Schedule 1

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	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	2.780	2.780	2.780	2.780	2.780	2.780	
[30]-(i) Residential [30]*1.0132	2.817	2.817	2.817	2.817	2.817	2.817	2.817	2.817	2.817	2.817	2.817	2.817	
[30]-(ii) C & I Non-Demand [30]*1.0472	2.911	2.911	2.911	2.911	2.911	2.911	2.911	2.911	2.911	2.911	2.911	2.911	
[30]-(iii) C & I Demand Non-TOD [30]*1.0091	2.805	2.805	2.805	2.805	2.805	2.805	2.805	2.805	2.805	2.805	2.805	2.805	
[30]-(iv) C & I Demand TOD On-Peak [30]*1.2776	3.552	3.552	3.552	3.552	3.552	3.552	3.552	3.552	3.552	3.552	3.552	3.552	
[30]-(v) C & I Demand TOD Off-Peak [30]*0.7940	2.207	2.207	2.207	2.207	2.207	2.207	2.207	2.207	2.207	2.207	2.207	2.207	
[30]-(vi) Outdoor Lighting [30]*0.7421	2.063	2.063	2.063	2.063	2.063	2.063	2.063	2.063	2.063	2.063	2.063	2.063	
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] **	0.283	0.077	0.030	0.057	0.128	0.104	0.100	0.115	(0.129)	0.024	(0.025)	(0.021)	
[31]-(i) Residential [31]*1.0132	0.287	0.078	0.030	0.058	0.130	0.105	0.101	0.117	(0.131)	0.024	(0.025)	(0.021)	
[31]-(ii) C & I Non-Demand [31]*1.0472	0.296	0.081	0.031	0.060	0.134	0.109	0.105	0.120	(0.135)	0.025	(0.026)	(0.022)	
[31]-(iii) C & I Demand Non-TOD [31]*1.0091	0.286	0.078	0.030	0.058	0.129	0.105	0.101	0.116	(0.130)	0.024	(0.025)	(0.021)	
[31]-(iv) C & I Demand TOD On-Peak [31]*1.2776	0.362	0.098	0.038	0.073	0.164	0.133	0.128	0.147	(0.165)	0.031	(0.032)	(0.027)	
[31]-(v) C & I Demand TOD Off-Peak [31]*0.7940	0.225	0.061	0.024	0.045	0.102	0.083	0.079	0.091	(0.102)	0.019	(0.020)	(0.017)	
[31]-(vi) Outdoor Lighting [31]*0.7421	0.210	0.057	0.022	0.042	0.095	0.077	0.074	0.085	(0.096)	0.018	(0.019)	(0.016)	
[32] System True-Up Factor [27] **	(0.299)	(0.125)	(0.366)	(0.346)	(0.301)	(0.048)	0.099	(0.204)	(0.267)	0.119	0.091	(0.039)	
[32]-(i) Residential [32]*1.0132	(0.303)	(0.127)	(0.371)	(0.350)	(0.305)	(0.049)	0.100	(0.206)	(0.270)	0.121	0.093	(0.040)	
[32]-(ii) C & I Non-Demand [32]*1.0472	(0.313)	(0.131)	(0.383)	(0.362)	(0.315)	(0.050)	0.104	(0.213)	(0.279)	0.125	0.096	(0.041)	
[32]-(iii) C & I Demand Non-TOD [32]*1.0091	(0.302)	(0.126)	(0.369)	(0.349)	(0.304)	(0.049)	0.100	(0.206)	(0.269)	0.120	0.092	(0.039)	
[32]-(iv) C & I Demand TOD On-Peak [32]*1.2776	(0.382)	(0.160)	(0.467)	(0.442)	(0.385)	(0.062)	0.127	(0.260)	(0.341)	0.152	0.117	(0.050)	
[32]-(v) C & I Demand TOD Off-Peak [32]*0.7940	(0.238)	(0.099)	(0.290)	(0.275)	(0.239)	(0.038)	0.079	(0.162)	(0.212)	0.095	0.073	(0.031)	
[32]-(vi) Outdoor Lighting [32]*0.7421	(0.222)	(0.093)	(0.271)	(0.257)	(0.223)	(0.036)	0.074	(0.151)	(0.198)	0.088	0.068	(0.029)	
[33] Refunds													
[33] a System Asset Based Margins Sharing Refund [28] a	(0.008)	(0.019)	(0.029)	(0.015)	(0.011)	(0.015)	(0.003)	(0.019)	(0.012)	(0.012)	(0.020)	(0.003)	
[33] a-(i) Residential [33] a*1.0132	(0.008)	(0.019)	(0.029)	(0.016)	(0.011)	(0.015)	(0.003)	(0.020)	(0.012)	(0.012)	(0.020)	(0.003)	
[33] a-(ii) C & I Non-Demand [33] a*1.0472	(0.009)	(0.019)	(0.030)	(0.016)	(0.011)	(0.015)	(0.003)	(0.020)	(0.013)	(0.013)	(0.021)	(0.003)	
[33] a-(iii) C & I Demand Non-TOD [33] a*1.0091	(0.008)	(0.019)	(0.029)	(0.015)	(0.011)	(0.015)	(0.003)	(0.020)	(0.012)	(0.012)	(0.020)	(0.003)	
[33] a-(iv) C & I Demand TOD On-Peak [33] a*1.2776	(0.011)	(0.024)	(0.037)	(0.020)	(0.014)	(0.019)	(0.004)	(0.025)	(0.015)	(0.015)	(0.026)	(0.003)	
[33] a-(v) C & I Demand TOD Off-Peak [33] a*0.7940	(0.007)	(0.015)	(0.023)	(0.012)	(0.009)	(0.012)	(0.002)	(0.015)	(0.010)	(0.010)	(0.016)	(0.002)	
[33] a-(vi) Outdoor Lighting [33] a*0.7421	(0.006)	(0.014)	(0.021)	(0.011)	(0.008)	(0.011)	(0.002)	(0.014)	(0.009)	(0.009)	(0.015)	(0.002)	
[33] c Other Refund [28] c **	-	-	-	-	-	(0.169)	-	-	-	-	-	-	
[33] c-(i) Residential [33] c*1.0132	-	-	-	-	-	(0.172)	-	-	-	-	-	-	
[33] c-(ii) C & I Non-Demand [33] c*1.0472	-	-	-	-	-	(0.177)	-	-	-	-	-	-	
[33] c-(iii) C & I Demand Non-TOD [33] c*1.0091	-	-	-	-	-	(0.171)	-	-	-	-	-	-	
[33] c-(iv) C & I Demand TOD On-Peak [33] c*1.2776	-	-	-	-	-	(0.216)	-	-	-	-	-	-	
[33] c-(v) C & I Demand TOD Off-Peak [33] c*0.7940	-	-	-	-	-	(0.134)	-	-	-	-	-	-	
[33] c-(vi) Outdoor Lighting [33] c*0.7421	-	-	-	-	-	(0.126)	-	-	-	-	-	-	
[34] System Fuel Clause Charge Factor ** [29]	2.755	2.713	2.415	2.476	2.596	2.652	2.976	2.672	2.372	2.911	2.826	2.717	
[34] -(i) Residential	2.792	2.750	2.448	2.509	2.631	2.687	3.016	2.707	2.404	2.950	2.864	2.753	
[34] -(ii) C & I Non-Demand	2.885	2.841	2.529	2.592	2.719	2.777	3.116	2.798	2.484	3.048	2.960	2.845	
[34] -(iii) C & I Demand Non-TOD	2.780	2.738	2.437	2.498	2.620	2.676	3.003	2.696	2.394	2.937	2.852	2.742	
[34] -(iv) C & I Demand TOD On-Peak	3.521	3.467	3.086	3.163	3.317	3.388	3.802	3.414	3.031	3.720	3.611	3.472	
[34] -(v) C & I Demand TOD Off-Peak	2.188	2.154	1.917	1.965	2.061	2.105	2.363	2.121	1.883	2.311	2.244	2.157	
[34] -(vi) Outdoor Lighting	2.045	2.014	1.792	1.837	1.927	1.968	2.208	1.983	1.761	2.160	2.097	2.016	
RULE 7825.2810 SUBPART 1 D: TOTAL COST OF FUEL DELIVERED TO CUSTOMERS													
[35] Actual Cost of Fuel Per kWh [20] **	2.752	2.571	2.524	2.792	3.013	2.691	2.617	3.009	2.741	2.750	2.899	2.578	
[36] Minnesota MWh Retail Sales (Cal. Mo) [19]	2,824,616	2,980,766	2,516,896	2,442,026	2,442,354	2,577,853	2,616,082	2,345,601	2,466,541	2,248,153	2,348,012	2,576,393	30,385,293
[36]-(i) Residential	841,045	899,193	651,238	614,833	690,909	773,288	805,292	713,810	661,371	549,943	578,810	729,240	8,508,972
[36]-(ii) C & I Non-Demand	76,152	83,484	67,656	67,233	70,850	79,981	87,233	75,685	82,374	68,726	68,452	71,076	898,902
[36]-(iii) C & I Demand Non-TOD	844,085	922,083	785,590	773,114	757,974	773,353	803,475	704,308	784,387	712,509	768,483	807,663	9,437,024
[36]-(iv) C & I Demand TOD On-Peak	406,038	422,417	384,850	381,078	361,861	349,771	330,901	321,894	359,996	347,509	359,922	367,253	4,393,490
[36]-(v) C & I Demand TOD Off-Peak	647,211	642,822	612,579	591,247	543,779	580,442	568,761	518,993	556,882	558,995	561,924	590,235	6,973,870
[36]-(vi) Outdoor Lighting	10,085	10,767	14,983	14,521	16,981	21,018	20,420	10,911	21,531	10,471	10,421	10,926	173,035

* Calendar Month
** In Cents Per KWh

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	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)	15,942	15,373	14,265	14,072	12,141	13,985	14,351	11,826	14,162	12,843	11,137	10,781	160,878
[36] a-(i) Residential	9,227	8,943	8,623	7,963	6,735	8,697	8,974	7,639	8,735	7,696	6,895	8,178	98,305
[36] a-(ii) C & I Non-Demand	85	92	92	81	73	88	417	81	89	78	65	90	1,331
[36] a-(iii) C & I Demand Non-TOD	3,354	3,748	3,077	3,380	3,005	3,048	2,599	2,055	2,984	2,935	1,758	1,817	33,760
[36] a-(iv) C & I Demand TOD On-Peak	1,356	1,071	1,024	1,095	963	889	975	847	973	882	1,001	287	11,363
[36] a-(v) C & I Demand TOD Off-Peak	1,916	1,513	1,447	1,548	1,360	1,257	1,378	1,198	1,375	1,247	1,414	405	16,058
[36] a-(vi) Outdoor Lighting	4	6	2	5	5	6	8	6	6	5	4	4	61
[36] b To Retail State of Minnesota subject to FCA ([19] b)	2,808,674	2,965,393	2,502,631	2,427,954	2,430,213	2,563,868	2,601,731	2,333,775	2,452,379	2,235,310	2,336,875	2,565,612	30,224,415
[36] b-(i) Residential	831,818	890,250	642,615	606,870	684,174	764,591	796,318	706,171	652,636	542,247	571,915	721,062	8,410,667
[36] b-(ii) C & I Non-Demand	76,067	83,392	67,564	67,152	70,777	79,893	86,816	75,604	82,285	68,648	68,387	70,986	897,571
[36] b-(iii) C & I Demand Non-TOD	840,731	918,335	782,513	769,734	754,969	770,305	800,876	702,253	781,403	709,574	766,725	805,846	9,403,264
[36] b-(iv) C & I Demand TOD On-Peak	404,682	421,346	383,826	379,983	360,898	348,882	329,926	321,047	359,023	346,627	358,921	366,966	4,382,127
[36] b-(v) C & I Demand TOD Off-Peak	645,295	641,309	611,132	589,699	542,419	579,185	567,383	517,795	555,507	557,748	560,510	589,830	6,957,812
[36] b-(vi) Outdoor Lighting	10,081	10,761	14,981	14,516	16,976	21,012	20,412	10,905	21,525	10,466	10,417	10,922	172,974
[37] Total Cost of Fuel Delivered [35]x([36] b)x10	$ 77,294,708	$ 76,240,254	$ 63,166,406	$ 67,788,476	$ 73,222,318	$ 68,993,688	$ 68,087,300	$ 70,223,290	$ 67,219,708	$ 61,471,025	$ 67,746,006	$ 66,141,477	$ 827,594,656
[37]-(i) Residential	$ 22,891,631	$ 22,888,328	$ 16,219,603	$ 16,943,810	$ 20,614,163	$ 20,575,144	$ 20,839,642	$ 21,248,685	$ 17,888,753	$ 14,911,793	$ 16,579,816	$ 18,588,978	$ 230,190,346
[37]-(ii) C & I Non-Demand	$ 2,093,364	$ 2,144,008	$ 1,705,315	$ 1,874,884	$ 2,132,511	$ 2,149,921	$ 2,271,975	$ 2,274,924	$ 2,255,432	$ 1,887,820	$ 1,982,539	$ 1,830,019	$ 24,602,712
[37]-(iii) C & I Demand Non-TOD	$ 23,136,917	$ 23,610,393	$ 19,750,628	$ 21,490,973	$ 22,747,216	$ 20,728,908	$ 20,958,925	$ 21,130,793	$ 21,418,256	$ 19,513,285	$ 22,227,358	$ 20,774,710	$ 257,488,362
[37]-(iv) C & I Demand TOD On-Peak	$ 11,136,849	$ 10,832,806	$ 9,687,768	$ 10,609,125	$ 10,873,857	$ 9,388,415	$ 8,634,163	$ 9,660,304	$ 9,840,820	$ 9,532,243	$ 10,405,120	$ 9,460,383	$ 120,061,853
[37]-(v) C & I Demand TOD Off-Peak	$ 17,758,518	$ 16,488,054	$ 15,424,972	$ 16,464,396	$ 16,343,084	$ 15,585,868	$ 14,848,413	$ 15,580,452	$ 15,226,447	$ 15,338,070	$ 16,249,185	$ 15,205,817	$ 190,513,276
[37]-(vi) Outdoor Lighting	$ 277,429	$ 276,665	$ 378,120	$ 405,287	$ 511,487	$ 565,433	$ 534,182	$ 328,131	$ 590,000	$ 287,815	$ 301,989	$ 281,569	$ 4,738,107
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	2,808,674	2,965,393	2,502,631	2,427,954	2,430,213	2,563,868	2,601,731	2,333,775	2,452,379	2,235,310	2,336,875	2,565,612	30,224,415
[38]-(i) Residential	831,818	890,250	642,615	606,870	684,174	764,591	796,318	706,171	652,636	542,247	571,915	721,062	8,410,667
[38]-(ii) C & I Non-Demand	76,067	83,392	67,564	67,152	70,777	79,893	86,816	75,604	82,285	68,648	68,387	70,986	897,571
[38]-(iii) C & I Demand Non-TOD	840,731	918,335	782,513	769,734	754,969	770,305	800,876	702,253	781,403	709,574	766,725	805,846	9,403,264
[38]-(iv) C & I Demand TOD On-Peak	404,682	421,346	383,826	379,983	360,898	348,882	329,926	321,047	359,023	346,627	358,921	366,966	4,382,127
[38]-(v) C & I Demand TOD Off-Peak	645,295	641,309	611,132	589,699	542,419	579,185	567,383	517,795	555,507	557,748	560,510	589,830	6,957,812
[38]-(vi) Outdoor Lighting	10,081	10,761	14,981	14,516	16,976	21,012	20,412	10,905	21,525	10,466	10,417	10,922	172,974
[39] Base Cost Revenues [30]x [38] x10	$ 78,081,137	$ 82,437,925	$ 69,573,142	$ 67,497,121	$ 67,559,921	$ 71,275,530	$ 72,328,122	$ 64,878,945	$ 68,176,136	$ 62,141,618	$ 64,965,125	$ 71,324,014	$ 840,238,736
[39]-(i) Residential	$ 23,432,313	$ 25,078,343	$ 18,102,465	$ 17,095,528	$ 19,273,182	$ 21,538,528	$ 22,432,278	$ 19,892,837	$ 18,384,756	$ 15,275,098	$ 16,110,846	$ 20,312,317	$ 236,928,491
[39]-(ii) C & I Non-Demand	$ 2,214,310	$ 2,427,541	$ 1,966,788	$ 1,954,795	$ 2,060,318	$ 2,325,685	$ 2,527,214	$ 2,200,832	$ 2,395,316	$ 1,998,343	$ 1,990,746	$ 2,066,402	$ 26,128,290
[39]-(iii) C & I Demand Non-TOD	$ 23,582,505	$ 25,759,297	$ 21,949,490	$ 21,591,039	$ 21,176,880	$ 21,607,055	$ 22,464,572	$ 19,698,197	$ 21,918,354	$ 19,903,551	$ 21,506,636	$ 22,603,980	$ 263,761,556
[39]-(iv) C & I Demand TOD On-Peak	$ 14,374,305	$ 14,966,210	$ 13,633,500	$ 13,496,996	$ 12,819,097	$ 12,392,289	$ 11,718,972	$ 11,403,589	$ 12,752,497	$ 12,312,191	$ 12,748,874	$ 13,034,632	$ 155,653,152
[39]-(v) C & I Demand TOD Off-Peak	$ 14,241,661	$ 14,153,690	$ 13,487,683	$ 13,014,657	$ 11,971,187	$ 12,782,613	$ 12,522,143	$ 11,427,736	$ 12,260,039	$ 12,309,498	$ 12,370,456	$ 13,017,548	$ 153,558,911
[39]-(vi) Outdoor Lighting	$ 207,971	$ 221,999	$ 309,058	$ 299,465	$ 350,215	$ 433,478	$ 421,100	$ 224,970	$ 444,061	$ 215,914	$ 214,903	$ 225,321	$ 3,568,455
[39]-(vii) Total	$ 78,053,065	$ 82,607,080	$ 69,448,984	$ 67,452,480	$ 67,650,879	$ 71,079,648	$ 72,086,279	$ 64,848,161	$ 68,155,023	$ 62,014,595	$ 64,942,461	$ 71,260,200	$ 839,598,855
Fuel Clause Revenues													
[40] Fuel Cost Excess of Base [31]x[38]x10	$ 7,948,547	$ 2,283,353	$ 750,789	$ 1,383,934	$ 3,110,673	$ 2,666,423	$ 2,601,731	$ 2,683,841	$ (3,163,569)	$ 536,474	$ (584,219)	$ (538,779)	$ 19,679,198
[40]-(i) Residential	$ 2,385,122	$ 694,537	$ 195,329	$ 350,480	$ 887,305	$ 805,672	$ 806,829	$ 822,816	$ (853,015)	$ 131,858	$ (144,866)	$ (153,420)	$ 5,928,647
[40]-(ii) C & I Non-Demand	$ 225,431	$ 67,242	$ 21,226	$ 40,083	$ 94,871	$ 87,011	$ 90,914	$ 91,048	$ (111,158)	$ 17,253	$ (17,904)	$ (15,611)	$ 590,406
[40]-(iii) C & I Demand Non-TOD	$ 2,400,918	$ 713,555	$ 236,890	$ 442,743	$ 975,156	$ 808,404	$ 808,164	$ 814,944	$ (1,017,184)	$ 171,845	$ (193,422)	$ (170,767)	$ 5,991,246
[40]-(iv) C & I Demand TOD On-Peak	$ 1,463,172	$ 414,499	$ 147,113	$ 276,715	$ 590,187	$ 463,560	$ 421,513	$ 471,695	$ (591,706)	$ 106,283	$ (114,639)	$ (98,457)	$ 3,549,935
[40]-(v) C & I Demand TOD Off-Peak	$ 1,449,991	$ 392,083	$ 145,572	$ 266,886	$ 551,271	$ 478,268	$ 450,502	$ 472,799	$ (568,984)	$ 106,284	$ (111,261)	$ (98,348)	$ 3,535,063
[40]-(vi) Outdoor Lighting	$ 21,172	$ 6,149	$ 3,335	$ 6,140	$ 16,125	$ 16,217	$ 15,148	$ 9,307	$ (20,606)	$ 1,864	$ (1,933)	$ (1,702)	$ 71,216
[40]-(vii) Total	$ 7,945,806	$ 2,288,065	$ 749,465	$ 1,383,047	$ 3,114,915	$ 2,659,132	$ 2,593,070	$ 2,682,609	$ (3,162,653)	$ 535,387	$ (584,025)	$ (538,305)	$ 19,666,513
[41] True-Up [32]x[38]x10	$ (8,402,176)	$ (3,706,652)	$ (9,155,300)	$ (8,396,982)	$ (7,315,014)	$ (1,234,272)	$ 2,577,977	$ (4,756,210)	$ (6,536,081)	$ 2,665,272	$ 2,136,371	$ (1,003,257)	$ (43,126,324)
[41]-(i) Residential	$ (2,521,240)	$ (1,127,475)	$ (2,381,891)	$ (2,126,539)	$ (2,086,566)	$ (372,937)	$ 799,463	$ (1,458,165)	$ (1,762,365)	$ 655,083	$ 529,748	$ (285,685)	$ (12,138,569)
[41]-(ii) C & I Non-Demand	$ (238,296)	$ (109,158)	$ (258,834)	$ (243,204)	$ (223,096)	$ (40,276)	$ 90,084	$ (161,353)	$ (229,657)	$ 85,716	$ 65,470	$ (29,069)	$ (1,291,673)
[41]-(iii) C & I Demand Non-TOD	$ (2,537,940)	$ (1,158,333)	$ (2,888,694)	$ (2,686,318)	$ (2,293,158)	$ (374,206)	$ 800,788	$ (1,444,211)	$ (2,101,544)	$ 853,759	$ 707,319	$ (317,987)	$ (13,440,525)
[41]-(iv) C & I Demand TOD On-Peak	$ (1,546,674)	$ (672,873)	$ (1,793,930)	$ (1,678,966)	$ (1,387,873)	$ (214,580)	$ 417,667	$ (835,923)	$ (1,222,495)	$ 528,034	$ 419,213	$ (183,333)	$ (8,171,733)
[41]-(v) C & I Demand TOD Off-Peak	$ (1,532,743)	$ (636,486)	$ (1,775,137)	$ (1,619,325)	$ (1,296,360)	$ (221,388)	$ 446,389	$ (837,875)	$ (1,175,547)	$ 528,037	$ 406,857	$ (183,136)	$ (7,896,714)
[41]-(vi) Outdoor Lighting	$ (22,380)	$ (9,982)	$ (40,670)	$ (37,256)	$ (37,920)	$ (7,507)	$ 15,009	$ (16,493)	$ (42,573)	$ 9,261	$ 7,067	$ (3,169)	$ (186,613)
[41]-(vii) Total	$ (8,399,273)	$ (3,714,307)	$ (9,139,156)	$ (8,391,608)	$ (7,324,973)	$ (1,230,894)	$ 2,569,400	$ (4,754,020)	$ (6,534,181)	$ 2,659,890	$ 2,135,674	$ (1,002,379)	$ (43,125,827)
[42] Refunds Total [46]	$ (235,258)	$ (550,058)	$ (719,386)	$ (372,161)	$ (261,872)	$ (4,706,361)	$ (80,100)	$ (452,870)	$ (294,396)	$ (267,472)	$ (466,452)	$ (68,006)	$ (8,474,392)

* Calendar Month
** In Cents Per KWh

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Charge July 2014 - June 2015

	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	12 Months
RULE 7825.2810 SUBPART 1 E: REVENUE COLLECTED FROM CUSTOMERS FOR ENERGY DELIVERED													
[43] Fuel Clause Revenues [40]+[41]+[42]	$ (688,968)	$ (1,972,223)	$ (9,125,169)	$ (7,385,448)	$ (4,465,856)	$ (3,287,110)	$ 5,099,341	$ (2,525,448)	$ (9,994,132)	$ 2,933,732	$ 1,085,548	$ (1,610,102)	$ (31,935,833)
[43]-(i) Residential	$ (206,736)	$ (599,907)	$ (2,374,052)	$ (1,870,369)	$ (1,273,857)	$ (993,210)	$ 1,581,369	$ (774,255)	$ (2,694,783)	$ 721,067	$ 269,180	$ (458,487)	$ (8,674,040)
[43]-(ii) C & I Non-Demand	$ (19,539)	$ (58,081)	$ (257,982)	$ (213,907)	$ (136,201)	$ (107,264)	$ 178,190	$ (85,676)	$ (351,162)	$ 94,350	$ 33,267	$ (46,652)	$ (970,658)
[43]-(iii) C & I Demand Non-TOD	$ (208,108)	$ (616,318)	$ (2,879,187)	$ (2,362,711)	$ (1,399,984)	$ (996,590)	$ 1,583,988	$ (766,843)	$ (3,213,413)	$ 939,752	$ 359,412	$ (510,328)	$ (10,070,329)
[43]-(iv) C & I Demand TOD On-Peak	$ (126,823)	$ (358,021)	$ (1,788,026)	$ (1,476,712)	$ (847,303)	$ (571,469)	$ 826,159	$ (443,858)	$ (1,869,280)	$ 581,219	$ 213,014	$ (294,228)	$ (6,155,328)
[43]-(v) C & I Demand TOD Off-Peak	$ (125,683)	$ (338,661)	$ (1,769,294)	$ (1,424,255)	$ (791,435)	$ (589,599)	$ 882,975	$ (444,893)	$ (1,797,495)	$ 581,223	$ 206,734	$ (293,909)	$ (5,904,291)
[43]-(vi) Outdoor Lighting	$ (1,835)	$ (5,311)	$ (40,536)	$ (32,768)	$ (23,151)	$ (19,992)	$ 29,689	$ (8,757)	$ (65,097)	$ 10,194	$ 3,590	$ (5,086)	$ (159,060)
[43]-(vii) Total	$ (688,725)	$ (1,976,300)	$ (9,109,077)	$ (7,380,722)	$ (4,471,930)	$ (3,278,123)	$ 5,082,370	$ (2,524,281)	$ (9,991,230)	$ 2,927,805	$ 1,085,197	$ (1,608,690)	$ (31,933,706)
[44] Total Fuel Clause Revenues [39]+[40]	$ 86,029,684	$ 84,721,278	$ 70,323,931	$ 68,881,055	$ 70,670,594	$ 73,941,953	$ 74,929,853	$ 67,562,786	$ 65,012,567	$ 62,678,092	$ 64,380,906	$ 70,785,235	$ 859,917,934
[44]-(i) Residential	$ 25,817,435	$ 25,772,880	$ 18,297,794	$ 17,446,008	$ 20,160,487	$ 22,344,200	$ 23,239,107	$ 20,715,653	$ 17,531,741	$ 15,406,956	$ 15,965,980	$ 20,158,897	$ 242,857,138
[44]-(ii) C & I Non-Demand	$ 2,439,741	$ 2,494,783	$ 1,988,014	$ 1,994,878	$ 2,155,189	$ 2,412,696	$ 2,618,128	$ 2,291,880	$ 2,284,158	$ 2,015,596	$ 1,972,842	$ 2,050,791	$ 26,718,696
[44]-(iii) C & I Demand Non-TOD	$ 25,983,423	$ 26,472,852	$ 22,186,380	$ 22,033,782	$ 22,152,036	$ 22,415,459	$ 23,272,736	$ 20,513,141	$ 20,901,170	$ 20,075,396	$ 21,313,214	$ 22,433,213	$ 269,752,802
[44]-(iv) C & I Demand TOD On-Peak	$ 15,837,477	$ 15,380,709	$ 13,780,613	$ 13,773,711	$ 13,409,284	$ 12,855,849	$ 12,140,485	$ 11,875,284	$ 12,160,791	$ 12,418,474	$ 12,634,235	$ 12,936,175	$ 159,203,087
[44]-(v) C & I Demand TOD Off-Peak	$ 15,691,652	$ 14,545,773	$ 13,633,255	$ 13,281,543	$ 12,522,458	$ 13,260,881	$ 12,972,645	$ 11,900,535	$ 11,691,055	$ 12,415,782	$ 12,259,195	$ 12,919,200	$ 157,093,974
[44]-(vi) Outdoor Lighting	$ 229,143	$ 228,148	$ 312,393	$ 305,605	$ 366,340	$ 449,695	$ 436,248	$ 234,277	$ 423,455	$ 217,778	$ 212,970	$ 223,619	$ 3,639,671
[44]-(vii) Total	$ 85,998,871	$ 84,895,145	$ 70,198,449	$ 68,835,527	$ 70,765,794	$ 73,738,780	$ 74,679,349	$ 67,530,770	$ 64,992,370	$ 62,549,982	$ 64,358,436	$ 70,721,895	$ 859,265,368
[45] Total Fuel Clause Revenues including True-Up & Refund [39]+[43]	$ 77,392,169	$ 80,465,702	$ 60,447,973	$ 60,111,673	$ 63,094,065	$ 67,988,420	$ 77,427,463	$ 62,353,497	$ 58,182,004	$ 65,075,350	$ 66,050,673	$ 69,713,912	$ 808,302,903
[45]-(i) Residential	$ 23,225,577	$ 24,478,436	$ 15,728,413	$ 15,225,159	$ 17,999,325	$ 20,545,318	$ 24,013,647	$ 19,118,582	$ 15,689,973	$ 15,996,165	$ 16,380,026	$ 19,853,830	$ 228,254,451
[45]-(ii) C & I Non-Demand	$ 2,194,771	$ 2,369,460	$ 1,708,806	$ 1,740,888	$ 1,924,117	$ 2,218,421	$ 2,705,404	$ 2,115,156	$ 2,044,154	$ 2,092,693	$ 2,024,013	$ 2,019,750	$ 25,157,632
[45]-(iii) C & I Demand Non-TOD	$ 23,374,397	$ 25,142,979	$ 19,070,303	$ 19,228,328	$ 19,776,896	$ 20,610,465	$ 24,048,560	$ 18,931,354	$ 18,704,941	$ 20,843,303	$ 21,866,048	$ 22,093,652	$ 253,691,227
[45]-(iv) C & I Demand TOD On-Peak	$ 14,247,482	$ 14,608,189	$ 11,845,474	$ 12,020,284	$ 11,971,794	$ 11,820,820	$ 12,545,131	$ 10,959,731	$ 10,883,217	$ 12,893,410	$ 12,961,888	$ 12,740,404	$ 149,497,824
[45]-(v) C & I Demand TOD Off-Peak	$ 14,115,978	$ 13,815,029	$ 11,718,389	$ 11,590,402	$ 11,179,752	$ 12,193,014	$ 13,405,118	$ 10,982,843	$ 10,462,544	$ 12,890,721	$ 12,577,190	$ 12,723,639	$ 147,654,620
[45]-(vi) Outdoor Lighting	$ 206,136	$ 216,688	$ 268,522	$ 266,697	$ 327,064	$ 413,486	$ 450,789	$ 216,213	$ 378,964	$ 226,108	$ 218,493	$ 220,235	$ 3,409,395
[45]-(vii) Total	$ 77,364,340	$ 80,630,780	$ 60,339,907	$ 60,071,758	$ 63,178,949	$ 67,801,525	$ 77,168,649	$ 62,323,880	$ 58,163,793	$ 64,942,400	$ 66,027,658	$ 69,651,510	$ 807,665,149
RULE 7825.2810 SUBPART 1 G: AMOUNT OF REFUNDS CREDITED TO CUSTOMERS													
[46] a System Asset Based Margins Sharing Refund ([33] a)*[38]*10	$ (235,339)	$ (548,924)	$ (720,658)	$ (372,400)	$ (261,515)	$ (376,325)	$ (80,367)	$ (453,079)	$ (294,482)	$ (268,014)	$ (466,604)	$ (68,066)	$ (4,145,771)
[46] a-(i) Residential	$ (70,618)	$ (166,969)	$ (187,490)	$ (94,310)	$ (74,596)	$ (113,708)	$ (24,923)	$ (138,906)	$ (79,403)	$ (65,874)	$ (115,702)	$ (19,382)	$ (1,151,881)
[46] a-(ii) C & I Non-Demand	$ (6,674)	$ (16,165)	$ (20,374)	$ (10,786)	$ (7,976)	$ (12,280)	$ (2,808)	$ (15,371)	$ (10,347)	$ (8,619)	$ (14,299)	$ (1,972)	$ (127,673)
[46] a-(iii) C & I Demand Non-TOD	$ (71,086)	$ (171,540)	$ (227,383)	$ (119,136)	$ (81,982)	$ (114,094)	$ (24,964)	$ (137,576)	$ (94,685)	$ (85,852)	$ (154,485)	$ (21,574)	$ (1,304,357)
[46] a-(iv) C & I Demand TOD On-Peak	$ (43,321)	$ (99,647)	$ (141,209)	$ (74,461)	$ (49,617)	$ (65,424)	$ (13,021)	$ (79,630)	$ (55,079)	$ (53,098)	$ (91,560)	$ (12,438)	$ (778,506)
[46] a-(v) C & I Demand TOD Off-Peak	$ (42,931)	$ (94,258)	$ (139,729)	$ (71,816)	$ (46,346)	$ (67,500)	$ (13,916)	$ (79,817)	$ (52,964)	$ (53,098)	$ (88,862)	$ (12,425)	$ (763,661)
[46] a-(vi) Outdoor Lighting	$ (627)	$ (1,478)	$ (3,201)	$ (1,652)	$ (1,356)	$ (2,289)	$ (468)	$ (1,571)	$ (1,918)	$ (931)	$ (1,544)	$ (215)	$ (17,250)
[46] a-(vii) Total	$ (235,258)	$ (550,058)	$ (719,386)	$ (372,161)	$ (261,872)	$ (375,296)	$ (80,100)	$ (452,870)	$ (294,396)	$ (267,472)	$ (466,452)	$ (68,006)	$ (4,143,327)
[46] c Other Refund ([33] c)*[38] *10	$ -	$ -	$ -	$ -	$ -	$ (4,342,936)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,342,936)
[46] c-(i) Residential	$ -	$ -	$ -	$ -	$ -	$ (1,312,237)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,312,237)
[46] c-(ii) C & I Non-Demand	$ -	$ -	$ -	$ -	$ -	$ (141,718)	$ -	$ -	$ -	$ -	$ -	$ -	$ (141,718)
[46] c-(iii) C & I Demand Non-TOD	$ -	$ -	$ -	$ -	$ -	$ (1,316,693)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,316,693)
[46] c-(iv) C & I Demand TOD On-Peak	$ -	$ -	$ -	$ -	$ -	$ (755,025)	$ -	$ -	$ -	$ -	$ -	$ -	$ (755,025)
[46] c-(v) C & I Demand TOD Off-Peak	$ -	$ -	$ -	$ -	$ -	$ (778,979)	$ -	$ -	$ -	$ -	$ -	$ -	$ (778,979)
[46] c-(vi) Outdoor Lighting	$ -	$ -	$ -	$ -	$ -	$ (26,413)	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,413)
[46] c-(vii) Total	$ -	$ -	$ -	$ -	$ -	$ (4,331,065)	$ -	$ -	$ -	$ -	$ -	$ -	$ (4,331,065)
[46] Total System Refunds ([46]a)+([46]c)	$ (235,339)	$ (548,924)	$ (720,658)	$ (372,400)	$ (261,515)	$ (4,719,261)	$ (80,367)	$ (453,079)	$ (294,482)	$ (268,014)	$ (466,604)	$ (68,066)	$ (8,488,707)
[46]-(i) Residential	$ (70,618)	$ (166,969)	$ (187,490)	$ (94,310)	$ (74,596)	$ (1,425,945)	$ (24,923)	$ (138,906)	$ (79,403)	$ (65,874)	$ (115,702)	$ (19,382)	$ (2,464,118)
[46]-(ii) C & I Non-Demand	$ (6,674)	$ (16,165)	$ (20,374)	$ (10,786)	$ (7,976)	$ (153,999)	$ (2,808)	$ (15,371)	$ (10,347)	$ (8,619)	$ (14,299)	$ (1,972)	$ (269,391)
[46]-(iii) C & I Demand Non-TOD	$ (71,086)	$ (171,540)	$ (227,383)	$ (119,136)	$ (81,982)	$ (1,430,788)	$ (24,964)	$ (137,576)	$ (94,685)	$ (85,852)	$ (154,485)	$ (21,574)	$ (2,621,050)
[46]-(iv) C & I Demand TOD On-Peak	$ (43,321)	$ (99,647)	$ (141,209)	$ (74,461)	$ (49,617)	$ (820,449)	$ (13,021)	$ (79,630)	$ (55,079)	$ (53,098)	$ (91,560)	$ (12,438)	$ (1,533,530)
[46]-(v) C & I Demand TOD Off-Peak	$ (42,931)	$ (94,258)	$ (139,729)	$ (71,816)	$ (46,346)	$ (846,479)	$ (13,916)	$ (79,817)	$ (52,964)	$ (53,098)	$ (88,862)	$ (12,425)	$ (1,542,640)
[46]-(vi) Outdoor Lighting	$ (627)	$ (1,478)	$ (3,201)	$ (1,652)	$ (1,356)	$ (28,702)	$ (468)	$ (1,571)	$ (1,918)	$ (931)	$ (1,544)	$ (215)	$ (43,663)
[46] (vii) Total	$ (235,258)	$ (550,058)	$ (719,386)	$ (372,161)	$ (261,872)	$ (4,706,361)	$ (80,100)	$ (452,870)	$ (294,396)	$ (267,472)	$ (466,452)	$ (68,006)	$ (8,474,392)

* Calendar Month

** In Cents Per KWh

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2014 - June 2015
Fuel, Purchased Power and Other Costs

Docket No. E999/AA-15-611
Part E, Section 5
Schedule 2

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Total
A.	**Actual Costs of Fuel Used by Company to Generate Electricity**													
	Account 151 Fossil Fuel													
[1]	Coal	30,961,519	37,371,198	28,696,133	31,607,521	32,650,083	35,409,728	32,463,930	30,646,607	21,150,396	14,987,618	24,472,215	31,184,146	351,601,094
[2]	Wood/Refuse-Derived Fuel	951,001	857,727	409,866	549,682	537,987	975,147	617,554	879,256	647,312	637,005	897,635	850,665	8,810,837
[3]	Natural Gas / Oil CC (611000)	264,870	318,148	171,135	424,600	370,099	65,018	326,759	264,978	209,905	81,914	63,261	31,919	2,592,606
[4]	Natural Gas / Oil CT (611100 612000 612100)	8,119,147	12,163,449	7,445,439	14,708,401	8,769,961	15,010,662	11,533,681	16,060,028	18,641,192	13,034,793	9,021,709	11,813,858	146,322,320
[5]	Total Fossil Fuel	40,296,537	50,710,522	36,722,573	47,290,204	42,328,130	51,460,555	44,941,924	47,850,869	40,648,805	28,741,330	34,454,820	43,880,588	509,326,857
[6]	Account 518 Nuclear Fuel	10,690,492	10,714,115	9,669,747	5,755,755	7,073,944	8,700,192	10,473,127	8,777,256	8,425,116	5,166,948	5,991,354	9,040,523	100,478,569
[7]	Total Own Generation	50,987,029	61,424,637	46,392,320	53,045,959	49,402,074	60,160,747	55,415,051	56,628,125	49,073,921	33,908,278	40,446,174	52,921,111	609,805,426
B.	**Cost of Energy/Power Purchased by Company**													
	Account 555 Energy Purchases													
[8]	Long Term Energy Purchase Contract Total (632000)	23,673,125	23,237,271	20,333,075	17,090,349	19,924,746	20,054,804	18,073,800	20,731,420	19,569,164	16,580,974	20,528,964	21,338,493	241,136,185
[8A]	MISO	17,316,404	14,697,788	7,175,062	10,293,403	13,351,958	9,478,458	8,924,255	7,924,460	8,438,064	13,202,698	13,630,884	7,748,895	132,182,329
[8B]	Less: MISO Schedule 16 and 17	(558,270)	(501,964)	(490,575)	(520,545)	(684,213)	(601,244)	(561,080)	(682,167)	(771,713)	(583,779)	(574,985)	(644,817)	(7,175,352)
[8C]	Less: MISO Schedule 24	(63,569)	(73,480)	(75,206)	(67,443)	(73,700)	(64,885)	(68,054)	(71,704)	(63,735)	(66,716)	(67,235)	(74,240)	(829,967)
[8D]	Less: RSG/RNU	(11,361)	(30,030)	(39,413)	(94,618)	(89,488)	(85,252)	(40,126)	(59,156)	(58,729)	(10,739)	(32,926)	(41,455)	(593,293)
[8E]	Less: MISO ARR	-	-	-	-	-	-	-	-	-	-	-	-	-
[8F]	Less: MISO Congestion & Loss	(139,731)	(165,149)	(401,177)	(1,034,410)	(729,178)	(865,413)	(481,417)	(491,156)	(374,170)	(108,048)	(222,040)	(226,131)	(5,238,020)
[9]	Short Term & Market Purchases 632100	703	-	-	-	-	-	-	-	-	4,642	-	-	5,345
[10]	Others - Wind 634000+634005+634100	14,808,103	5,921,036	14,810,054	18,223,808	23,935,121	17,671,867	19,601,053	18,393,469	20,280,034	21,470,486	19,455,782	10,450,047	205,020,860
[11]	Others - MAPP MW-Mile Charge	-	-	-	-	-	-	-	-	-	-	-	-	-
[12]	Others - Tolling (Plant Gas & Oil) 632050+632060	748,018	667,761	947,007	2,357,838	694,039	224,999	263,299	750,224	1,099,720	1,274,023	668,196	755,238	10,450,362
[13]	Others - Qualifying Facilities 632200	111,687	106,092	126,158	246,052	41,192	156,926	180,894	231,775	229,014	205,867	198,599	199,184	2,033,440
	Solar 634500	-	40	330	635	341	8	4	177	1,509	2,573	4,415	3,935	13,967
[14]	Others - Asset Based 633400	(628,785)	396,261	249,599	1,252,647	802,398	122,837	6,159	473,208	171,877	42,041	147,577	356,592	3,392,411
[15]	Others - Non-Asset Based 632105	2,544,205	2,375,514	1,110,222	1,983,182	2,884,903	2,366,911	3,784,821	3,859,500	2,946,338	2,471,689	1,021,682	2,653,336	30,002,303
[16]	Other - REC Related Fuel Costs	(363,643)	(148,393)	(276,683)	(99,246)	395,282	(273,108)	(146,401)	(85,916)	(52,549)	62,508	(39,704)	(37,334)	(1,065,187)
[17]	Total Purchases	57,436,886	46,482,747	43,468,453	49,631,652	60,453,401	48,186,908	49,537,207	50,974,134	51,414,824	54,548,219	54,719,209	42,481,743	609,335,383
C.	**Fuel-Related Costs Recovered through Intersystem Sales**													
[18]	Estimated Energy Generated by Company Total	2,348,156	3,077,437	3,172,105	6,779,493	5,037,207	9,561,735	5,951,355	5,103,958	3,998,869	1,600,468	1,707,252	3,204,788	51,542,823
[19]	Estimated Energy Purchased by Company Total	1,915,420	2,771,775	1,359,821	3,235,829	3,687,301	2,489,748	3,790,980	4,332,708	3,118,215	2,513,730	1,169,259	3,009,928	33,394,714
[20]	Total	4,263,576	5,849,212	4,531,926	10,015,322	8,724,508	12,051,483	9,742,335	9,436,666	7,117,084	4,114,198	2,876,511	6,214,716	84,937,537
D.	**Other Deductions or Additions to Fuel Clause Adjustment Calculation**													
	Deduction from Account 555													
[21]	Purchased Power for WindSource Program	697,115	297,173	633,394	562,598	175,619	724,743	579,280	487,632	509,974	526,042	398,564	278,892	5,871,026
E.	**TOTAL**													
[22]	Total [7]+[17]-[20]-[21]	103,463,224	101,760,999	84,695,453	92,099,691	100,955,348	95,571,429	94,630,643	97,677,961	92,861,687	83,816,257	91,890,308	88,909,246	1,128,332,246

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Total
F. MWh of Generation														
	Account 151 Fossil Fuel													
[1]	Coal	1,221,265	1,551,877	1,188,610	1,335,622	1,625,073	1,631,484	1,378,419	1,269,322	889,864	653,312	1,064,357	1,294,749	15,103,954
[2]	Wood/Refuse-Derived Fuel	40,164	37,458	24,767	24,118	31,140	36,992	31,349	32,038	29,506	36,655	45,930	40,875	410,992
[3]	Natural Gas CC	2,551	4,470	2,132	6,079	3,752	671	5,167	620	3,407	(2,971)	533	322	26,733
[4]	Natural Gas / Oil CT	133,350	288,821	130,092	386,965	173,250	377,563	269,881	396,052	566,950	501,577	193,617	470,220	3,888,338
[5]	Total Fossil Fuel	1,397,330	1,882,626	1,345,601	1,752,784	1,833,215	2,046,710	1,684,816	1,698,032	1,489,727	1,188,573	1,304,437	1,806,166	19,430,017
[6]	Account 518 Nuclear Fuel	1,186,574	1,183,889	1,093,127	624,096	814,905	1,022,862	1,213,552	997,202	964,325	577,592	655,514	1,050,267	11,383,905
[7]	Total Own Generation	2,583,904	3,066,515	2,438,728	2,376,880	2,648,120	3,069,572	2,898,368	2,695,234	2,454,052	1,766,165	1,959,951	2,856,433	30,813,922
G. Purchased Energy/Power MWh														
	Account 555 Energy Purchases	**[TRADE SECRET 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													
[11]	Others - MAPP MW-Mile Charge													
[12]	Others - Tolling													
[13]	Others - Qualifying Facilities													
[14]	Others - Asset Based													
[15]	Others - Non-Asset Based													
[16]	Other - REC Related Fuel Costs													
[17]	Total Purchases													
H. Intersystem Sales MWh														
[18]	Estimated Energy Generated by Company Total													
[19]	Estimated Energy Purchased by Company Total													
[20]	Total													
I. MWh Related to Other Deductions or Additions to Fuel Clause Adjustment Calculation														
	Deduction from Account 555													
[21]	Purchased Power for WindSource Program													
J. TOTAL MWH														**TRADE SECRET ENDS]**
[22]	Total [7]+[17]-[20]-[21]	3,728,219	3,960,004	3,142,225	3,048,767	3,474,416	3,503,771	3,574,760	3,303,355	3,219,920	2,974,124	3,127,707	3,471,496	40,528,764

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

	(in $/MWh)	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Total
K.	**Estimated Company's Generated Electricity Sold to Retail Customers**													
	Account 151 Fossil Fuel	**[TRADE SECRET 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													
[11]	Others - MAPP MW-Mile Charge													
[12]	Others - Tolling													
[13]	Others - Qualifying Facilities													
[14]	Others - Asset Based													
[15]	Others - Non-Asset Based													
[16]	Other - REC Related Fuel Costs													
[17]	Total Purchases													
M.	**Estimated Intersystem Sales-Related**													
[18]	Estimated Energy Generated by Company Total													
[19]	Estimated Energy Purchased by Company Total													
[20]	Total													
N.	**Other Deductions or Additions**													
	Deduction from Account 555													
[21]	Purchased Power for WindSource Program													
O.	**SYSTEM TOTAL**													**TRADE SECRET ENDS]**
[22]	Total	$ 27.75	$ 25.70	$ 26.95	$ 30.21	$ 29.06	$ 27.28	$ 26.47	$ 29.57	$ 28.84	$ 28.18	$ 29.38	$ 25.61	$ 27.84

Northern States Power Company
Electric Operations - State of Minnesota
Monthly Fuel Clause Adjustment July 2014 - June 2015
Costs Recovered from Sales of Energy to Other Utilities

Docket No. E999/AA-15-611
Part E, Section 5
Schedule 5

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Total
Costs Recovered from Sales of Energy to Other Utilities														
		[TRADE SECRET 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 ENDS]

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-611

PART F

AUDITOR'S REPORT

Xcel Energy[SM]

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

July 9, 2015

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

RE: XCEL ENERGY 2015 MINNESOTA AUTOMATIC ADJUSTMENT OF CHARGES REPORT (ELECTRIC OPERATION)

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 (MPUC) for the upcoming Electric Annual Automatic Adjustment of Charges Report (AAA) filing. The Company's 2014-2015 Electric AAA Report will be filed with the MPUC and Minnesota Department of Commerce – Division of Energy Resources by September 1, 2015.

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 2014 to June 2015. The Department will then prepare a comprehensive analysis of the AAA reports filed by all regulated electric utilities, and the MPUC will conduct a meeting to review and act on the Electric AAA Report and Department recommendations.

AAA Report Independent Audit Requirements

MPUC rules govern the automatic adjustment clauses for Minnesota electric utilities and AAA Reports and are set forth in Minn. Rule 7825.2700 *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 rate case (Docket No. E002/GR-05-1428), the Fuel Clause Adjustment (FCA) is based on Xcel Energy's monthly forecast of system energy costs and sales including a "true-up" that reflects the following two changes:

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
2. Instead of a single factor, the monthly fuel cost factors are differentiated by 6 customer class categories

On November 4, 2013 the Company filed a Petition to increase electric rates (Docket No. E002/GR-13-868). In the associated docket, E002/MR-13-869, a new Base Cost of Fuel of $0.02780 per kWh was approved (an increase of $0.00051 over the previous Base Cost of Fuel) along with the interim rates that have been in effect since January 3, 2014.

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 ($/kWh)[1]**	**Prior Base Cost of Energy ($/kWh)[2]**	**Prior Base Cost of Energy ($/kWh)[3]**
Residential	$0.02817	$0.02765	$0.02764
C & I Non-Demand	$0.02911	$0.02858	$0.02804
C & I Demand	$0.02805	$0.02754	$0.02768
C & I Demand Time of Day On-Peak	$0.03552	$0.03487	$0.03505
C & I Demand Time of Day Off-Peak	$0.02207	$0.02167	$0.02147
Outdoor Lighting	$0.02063	$0.02025	$0.02036

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, E,G002/M-97-985

[1] 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).
[2] 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).
[3] Effective January 1, 2013, pursuant to the MPUC's acceptance of the proposed Base Cost of Energy dated December 20, 2012 (Docket Nos. E002/GR-12-961 and E002/MR-12-1150).

- 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 and E002/M-06-589, E002/M-07-484, E002/M-08-451, E002/M-14-364

For the twelve months reporting period ended June 30, 2014, 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, 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[4]
  - 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[5]
  - WM Renewable Energy, LLC, E002/M-10-161, Order dated April 30, 2010
  - Big Blue, LLC, E002/M-10-733, Notice of Approval dated August 26, 2010[6]
  - 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

[4] 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.
[5] The amended PPA was approved by the Commission's September 8, 2014 Order in Docket No. E002/M-14-490.
[6] The amended PPA was approved by the Commission's February 27, 2014 Order in Docket No. E002/M-13-1002.

  - 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 [7]
- End-Of-Life Nuclear Fuel Accrual – E002/M-05-1648

The 2014-2015 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.[8]

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.

The Company received a net credit resulting from corrections made to load assignments at certain interconnection points with Alliant Energy (IPL) and the East River Electric Power Cooperative (EREPC) dated from October 2007 to December 2013. Pursuant to the Commission's Order dated November 24, 2014 in Docket No. E002/M-14-614, the December 2014 FCC computation included a one-time refund of the appropriate net credit to customers for this out-of-period adjustment. The Company received a net system settlement payment of $5,650,409 which the Company refunded to Minnesota customers subject to the FCA based on the ordered 73.81% allocator. The refund amount to Minnesota customers was $4,170,567[9]. The

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

[8] 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.

[9] This Minnesota refund amount is slightly higher than the $4,170,423.92 stated in the Order due to rounding when the 73.81% allocator was applied to the $5,650,409 system total.

Company also included an interest payment of $114,339 based on the prime lending interest rate (3.25%) for the 10 months the Company held the funding (February 2014 to November 2014). The overall one-time refund to Minnesota customers included in the December 2014 FCC was $4,284,907.

The March 2015 FERC Account 151 (fossil fuel) included a $503,486 settlement reimbursement from the insurance companies for the excess fuel oil that was consumed during the startup of Sherco Unit 3 following repairs. The Minnesota customers' share of this credit was about $364,429 based on March 2015 Minnesota jurisdictional MWh sales weighting relative to the NSP System total.

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. Ultimately the SES will impact future FCA recoveries, but there has been little on impact on the 2014-2015 Electric AAA Report.

<u>Spent Nuclear Fuel Disposal Fee</u>
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 will no longer collect this disposal fee from customers unless the DOE changes the rate again in the future.

<u>AAA Report Additional Independent Audit Requirements</u>
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 2014-2015 Electric AAA Report to be filed by September 1, 2015, the Company's external auditors should include a statement certifying the following:

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

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[10] Minn. Stat. § 216B.1691

<u>Status of 2011-2012, 2012-2013, and 2013-2014 Electric AAA Reports (Docket Nos. E999/AA-12-757, E999/AA-13-599, and E999/AA-14-579)</u>

The 2011-2012, 2012-2013, and 2013-2014 Electric AAA Reports are 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.

<u>Targeted Audit Completion Date</u>

In the past the Company had met with Deloitte & Touche to discuss the independent audit requirements in detail and answer any questions. At those meetings, the Company and Deloitte & Touche defined responsibilities, and established a schedule and contact list to facilitate communications between internal Company departments and the assigned auditors.

The audit is typically in process now and expected to be completed by late August 2015. The Deloitte & Touche independent audit report should be provided to Paul Lehman, Manager, Regulatory Compliance and Filings (414 Nicollet Mall, 7th Floor) no later than August 26, 2015, for timely inclusion in the Company's 2014-2015 Electric AAA Report on September 1, 2015.

Thank you for your prompt attention to this matter. Please do not hesitate to call me at 612-330-5570 with any questions. If necessary, we could conduct a follow-up meeting within the next two weeks to ensure that all the audit requirements are understood.

Sincerely,

/s/

REBECCA EILERS
REGULATORY CASE SPECIALIST

cc: Paul Lehman
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, 2014 to June 30, 2015, and Independent Accountants' Report

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

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

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, 2014 to June 30, 2015. 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, 2014 to June 30, 2015, 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-00-420 (dated June 27, 2000, and supplemented November 1, 2000)
- Docket No. E002/M-00-622 (dated February 11, 2002, and supplemented July 17, 2002)
- Docket No. E002/M-01-477 (dated July 27, 2001)
- Docket No. E000/AA-01-838 (dated November 14, 2002, and supplemented December 23, 2002, January 9, 2003, October 20, 2003, and July 7, 2004)
- 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)

- o Docket No. E002/M-02-645 (dated July 17, 2002)
- o Docket No. E002/M-03-0585 (dated July 10, 2003)
- o Docket No. E002/M-04-404 (dated October 4, 2004)
- o Docket No. E002/M-04-595 (dated August 13, 2004)
- o Docket No. E999/AA-04-1279 (dated December 7, 2005, and supplemented April 4, 2006)
- o Docket No. E002/M-04-1970 (dated April 7, 2005, and supplemented December 21, 2005, February 24, 2006, and April 24, 2006, December 21, 2006, and February 7, 2008)
- o Docket No. E002/M-05-613 (dated July 27, 2005)
- o Docket No. E002/M-05-1850 (dated March 31, 2006)
- o Docket No. E002/M-05-1934 (dated March 31, 2006)
- o Docket No. E002/M-04-864 (dated July 19, 2006)
- o Docket No. E002/GR-05-1428 (dated September 1, 2006)
- o Docket No. E002/M-05-1648 (dated March 23, 2006, and supplemented July 20, 2006)
- o Docket No. E002/M-06-85 (dated May 3, 2006)
- o Docket No. E002/M-06-589 (dated July 17, 2006)
- o Docket No. E002/M-08-451 (dated July 16, 2008)
- o Docket No. E002/M-11-452 (dated May 4, 2012)
- o Docket No. E002/GR-10-971 (dated May 14, 2012)
- o Docket No. E002/MR-10-972 (dated December 27, 2010)
- o Docket No. E999/AA-09-961 (dated April 6, 2012)
- o Docket No. E999/AA-10-884 (dated April 6, 2012)
- o Docket No. E999/AA-11-792 (dated August 16, 2013)

This report is intended solely for the information and use of the 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 28, 2015

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, 2014 TO JUNE 30, 2015
(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, 2014	2.792	2.885	2.780	3.521	2.188	2.045
August 1, 2014	2.750	2.841	2.738	3.467	2.154	2.014
September 1, 2014	2.448	2.529	2.437	3.086	1.917	1.792
October 1, 2014	2.509	2.592	2.498	3.163	1.965	1.837
November 1, 2014	2.631	2.719	2.620	3.317	2.061	1.927
December 1, 2014	2.687	2.777	2.676	3.388	2.105	1.968
January 1, 2015	3.016	3.116	3.003	3.802	2.363	2.208
February 1, 2015	2.707	2.798	2.696	3.414	2.121	1.983
March 1, 2015	2.404	2.484	2.394	3.031	1.883	1.761
April 1, 2015	2.950	3.048	2.937	3.720	2.311	2.160
May 1, 2015	2.864	2.960	2.852	3.611	2.244	2.097
June 1, 2015	2.753	2.845	2.742	3.472	2.157	2.016

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-15-611

PART G

FIVE-YEAR PROJECTION

ANNUAL FIVE-YEAR PROJECTION

In compliance with the reporting requirement, the following schedules contain the trade secret monthly five-year (2016 - 2020) 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, and wood commodity prices; etc. 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. Nuclear fuel cost for the Monticello plant and the two Prairie Island units is from the Nuclear Fuel Monthly Forecast Model for the 2016 Budget. The monthly projected generation and nuclear fuel expenses for these three units are prepared by the Xcel Energy Services Inc. Fuels Organization. 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 2016 through 2020 are based on Xcel Energy's August 2015 forecast. Part G, Section 1, Schedule 8 includes the estimated load management impact for the same period.

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2016 - NSPM 2016 (COB 15.07.27 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)													
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]

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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)													
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]

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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)													
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]

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2019 - NSPM 2016 (COB 15.07.27 pricing)
Production Cost Summary ($/MWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
COST	**[TRADE SECRET BEGINS**												
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Hydro (WI)													
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]

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Xcel Energy (Northern States Power Company)
2020 - NSPM 2016 (COB 15.07.27 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)													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
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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													
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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]

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Xcel Energy (Northern States Power Company)
2016 - NSPM 2016 (COB 15.07.27 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)													
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]

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RDF (MN)													
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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													

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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]

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Xcel Energy (Northern States Power Company)

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

TRADE SECRET ENDS]

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Xcel Energy (Northern States Power Company)
2020 - NSPM 2016 (COB 15.07.27 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)													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
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Fuel Oil (WI)													
Total Fossil Cost													
Nuclear													
Purchase - Energy (other)													
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Market Sale - Energy													
Total Gross Revenue													
NET COST													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2016 - NSPM 2016 (COB 15.07.27 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)													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
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Natural Gas 1 (MN)													
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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													
Net Interchange													
Total GWh													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)

2017 - NSPM 2016 (COB 15.07.27 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)													
Wind (MN)													
Total Renewable													
Coal (MN)													
Coal (WI)													
Wood (WI)													
RDF (MN)													
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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													
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Mkt Purchase - Energy													
Purchase - Demand													
Mkt Purchase - Demand													
Total Purchases													
Net Interchange													
Total GWh													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

TRADE SECRET ENDS]

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Xcel Energy (Northern States Power Company)
2018 - NSPM 2016 (COB 15.07.27 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)													
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Total Fossil													
Nuclear													
Purchase - Energy (other)													
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Sale - Energy													
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	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
RESOURCES	**[TRADE SECRET BEGINS**												
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Hydro (WI)													
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RDF (MN)													
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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													
Net Interchange													
Total GWh													
SALES													
Sale - Demand													
Sale - Energy													
Market Sale - Energy													
Total Gross Sales													
NET													

TRADE SECRET ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

Xcel Energy (Northern States Power Company)
2020 - NSPM 2016 (COB 15.07.27 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)													
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													
Net Interchange													
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
2016

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

[TRADE SECRET BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2016 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	COST													
Black Dog 25 CC	Gas													
Black Dog 3C	Coal													
Black Dog 3G	Gas													
Black Dog 4C	Coal													
Black Dog 4G	Gas													
Black Dog 6	Gas													
Black Dog	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	COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
High Bridge	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	COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	COST													
SYSTEM MN	COST													

TRADE SECRET ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Work papers for Five Year Projection of Fuel Costs

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 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													
Black Dog 25 CC	Gas													
Black Dog 3C	Coal													
Black Dog 3G	Gas													
Black Dog 4C	Coal													
Black Dog 4G	Gas													
Black Dog 6	Gas													
Black Dog	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	COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	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	COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	COST													
SYSTEM MN	COST													

TRADE SECRET ENDS]

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

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2018 Total AVG
		[TRADE SECRET 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													
Black Dog 25 CC	Gas													
Black Dog 3C	Coal													
Black Dog 3G	Gas													
Black Dog 4C	Coal													
Black Dog 4G	Gas													
Black Dog 6	Gas													
Black Dog	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	COST													
Granite City 1	Gas													
Granite City 2	Gas													
Granite City 3	Gas													
Granite City 4	Gas													
Granite City	COST													
High Bridge CC 1x1	Gas													
High Bridge CC 2x1	Gas													
HighBridge	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	COST													
Red Wing 1	Gas													
Red Wing 1	RDF													
Red Wing 2	Gas													
Red Wing 2	RDF													
Red Wing	COST													
Riverside CC 1x1	Gas													
Riverside CC 2x1	Gas													
Riverside	COST													
Sherburne 1	Coal													
Sherburne 2	Coal													
Sherburne 3	Coal													
Sherburne	COST													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	COST													
SYSTEM MN	COST													

TRADE SECRET ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Work papers for Five Year Projection of Fuel Costs

Docket No. E999/AA-15-611
Part G, Section 1
Schedule 4

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

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

[TRADE SECRET BEGINS

Unit	Fuel	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2019 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	COST													
Black Dog 25 CC	Gas													
Black Dog 3C	Coal													
Black Dog 3G	Gas													
Black Dog 4C	Coal													
Black Dog 4G	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													
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													
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													
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													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	AVG													
SYSTEM MN	AVG													

TRADE SECRET ENDS]

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

PUBLIC DOCUMENT WITH TRADE SECRET DATA EXCISED

[TRADE SECRET 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	COST													
Black Dog 25 CC	Gas													
Black Dog 3C	Coal													
Black Dog 3G	Gas													
Black Dog 4C	Coal													
Black Dog 4G	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													
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													
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													
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													
Wilmarth 1	Gas													
Wilmarth 1	RDF													
Wilmarth 2	Gas													
Wilmarth 2	RDF													
Wilmarth	AVG													
SYSTEM MN	AVG													

TRADE SECRET ENDS]

Coal Expense
$/Mbtu
2016

NON-PUBLIC DOCUMENT CONTAINS TRADE SECRET DATA

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2016
	[TRADE SECRET BEGINS												
Allen S King 1													
Bay Front 4													
Bay Front 5													
Bay Front 6													
Bay Front AVG													
Black Dog 3C													
Black Dog 4C													
Black Dog AVG													
Sherburne 1													
Sherburne 2													
Sherburne 3													
Sherco AVG													
System													

TRADE SECRET ENDS]

Coal Expense
$/Mbtu
2017

NON-PUBLIC DOCUMENT CONTAINS TRADE SECRET DATA

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

TRADE SECRET ENDS]

Coal Expense
$/Mbtu
2018

NON-PUBLIC DOCUMENT CONTAINS TRADE SECRET DATA

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

TRADE SECRET ENDS]

Coal Expense
$/Mbtu
2019

NON-PUBLIC DOCUMENT CONTAINS TRADE SECRET DATA

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

TRADE SECRET ENDS]

Coal Expense
$/Mbtu
2020

NON-PUBLIC DOCUMENT CONTAINS TRADE SECRET DATA

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

TRADE SECRET ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Work Papers For Five Year Projection of Fuel Costs
Nuclear Fuel Expense (Units noted in row)

Docket No. E999/AA-15-611
Part G, Section 1
Schedule 6

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

[TRADE SECRET BEGINS

Item ID	Item Description (AAA-2014 08-14-13 11:12:38)	Jan 2016	Feb 2016	Mar 2016	Apr 2016	May 2016	Jun 2016	Jul 2016	Aug 2016	Sep 2016	Oct 2016	Nov 2016	Dec 2016
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 Refueling												
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 ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

[TRADE SECRET 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 Refueling												
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												
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2016 Electric Production Forecast
Peak Demand and Energy Requirements
(2016 Budget)

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,439	4,024,425	84.00%
February	6,292	3,629,808	85.85%
March	6,101	3,735,121	82.29%
April	5,553	3,383,560	84.63%
May	7,223	3,501,155	65.16%
June	8,612	3,853,279	62.15%
July	9,327	4,359,320	62.82%
August	8,824	4,213,945	64.19%
September	7,903	3,663,057	64.38%
October	5,845	3,583,402	82.40%
November	5,949	3,536,741	82.57%
December	6,541	3,921,843	80.59%
Annual	**9,327**	**45,405,657**	**55.57%**

2017 Electric Production Forecast
Peak Demand and Energy Requirements
(2016 Budget)

	Base Peak Demand (MW)	**Energy Requirements (MWH)**	**Load Factor (%)**
January	6,519	4,051,603	83.54%
February	6,376	3,552,675	82.92%
March	6,166	3,739,061	81.51%
April	5,606	3,402,388	84.29%
May	7,330	3,545,575	65.01%
June	8,699	3,868,036	61.76%
July	9,403	4,375,659	62.55%
August	8,908	4,227,374	63.78%
September	7,978	3,671,858	63.92%
October	5,883	3,605,211	82.36%
November	5,994	3,559,565	82.48%
December	6,589	3,941,255	80.40%
Annual	**9,403**	**45,540,260**	**55.29%**

2018 Electric Production Forecast
Peak Demand and Energy Requirements
(2016 Budget)

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,557	4,064,059	83.30%
February	6,409	3,562,526	79.86%
March	6,198	3,758,383	81.50%
April	5,637	3,436,568	84.67%
May	7,419	3,575,076	64.77%
June	8,770	3,886,999	61.56%
July	9,463	4,402,628	62.53%
August	8,974	4,248,015	63.62%
September	8,040	3,687,077	63.69%
October	5,910	3,629,841	82.55%
November	6,028	3,579,427	82.48%
December	6,625	3,963,216	80.41%
Annual	**9,463**	**45,793,813**	**55.24%**

2019 Electric Production Forecast
Peak Demand and Energy Requirements
(2016 Budget)

	Base Peak Demand (MW)	Energy Requirements (MWH)	Load Factor (%)
January	6,592	4,087,613	83.35%
February	6,445	3,591,581	80.06%
March	6,233	3,784,620	81.61%
April	5,668	3,470,184	85.03%
May	7,510	3,597,454	64.38%
June	8,846	3,916,774	61.50%
July	9,526	4,431,782	62.53%
August	9,043	4,267,330	63.43%
September	8,108	3,719,029	63.70%
October	5,941	3,652,972	82.64%
November	6,068	3,601,442	82.43%
December	6,670	3,999,189	80.59%
Annual	**9,526**	**46,119,969**	**55.27%**

2020 Electric Production Forecast
Peak Demand and Energy Requirements
(2016 Budget)

	Base Peak Demand (MW)	**Energy Requirements (MWH)**	**Load Factor (%)**
January	6,612	4,096,041	83.27%
February	6,464	3,736,124	86.00%
March	6,250	3,800,733	81.73%
April	5,678	3,479,401	85.11%
May	7,587	3,615,579	64.05%
June	8,902	3,929,938	61.31%
July	9,561	4,437,869	62.39%
August	9,076	4,286,693	63.48%
September	8,145	3,731,664	63.63%
October	5,945	3,662,722	82.81%
November	6,084	3,618,259	82.60%
December	6,688	4,007,194	80.53%
Annual	**9,561**	**46,402,215**	**55.41%**

Estimated Load Management Impact

Summer Peak (MW)

	System Base Peak	Total Load Mgmt/ Load Relief	Net Peak
2015	9,191	654	8,537
2016	9,327	657	8,670
2017	9,403	661	8,742
2018	9,463	666	8,797
2019	9,526	671	8,855
2020	9,561	676	8,885
2021	9,602	681	8,921
2022	9,665	685	8,980
2023	9,686	690	8,996
2024	9,687	695	8,992
2025	9,707	695	9,012
2026	9,733	695	9,038
2027	9,768	695	9,073
2028	9,796	695	9,101
2029	9,839	695	9,144
2030	9,887	695	9,192
2031	9,946	695	9,251

Average Annual Growth Rates

2015-2025	0.55%		0.54%
2025-2031	0.41%		0.44%
2015-2031	0.49%		0.50%

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-611

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 Annual Automatic Adjustment of Charges (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 Ancillary Services Market (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 nuclear fuel interim storage and disposal expenses included in the determination of electric automatic adjustment charges.

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 2014 data available until mid-September, the Company will report the September data in a subsequent supplemental filing after the data has been booked.

Since the Department of Commerce's June 8, 2005 review of the Company's 2003-2004 electric AAA Report (Docket No. E,G999/AA-04-1279), the Department has annually noted in its AAA reviews that the information filed by the Company has complied with the requirements of the Commission's Order. The Department indicated that the average generation costs allocated to retail customers were less than both the average generation costs allocated only to wholesale customers and the average costs for both retail and wholesale customers for all three months since 2003. This information thus provides a high-level indication that the Company has reasonably allocated generation costs between retail and wholesale customers.

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. Part F Schedule 1 contains a copy of the letter that was sent to facilitate 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 Annual Automatic Adjustment 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 annually in their AAA reports, and biannually in their biennial transmission projects reports, the number of transformers over 100 kV (low side) by size, and to assess whether they are maintaining in inventory or

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[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.

otherwise have reasonable 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:

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	Scheduled for Delivery Sept. 2015
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 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)

On July 17, 2002, the Commission issued Orders approving Xcel Energy's wind Power Purchase Agreements (PPA) with Chanarambie Power Partners, LLC and Navitas Energy, LLC (now Moraine Wind, LLC) in Docket Nos. E002/M-00-622 and E002/M-02-51. In addition to approving the PPAs, the Commission required the Company to report the date, length, cost to ratepayers, and reason for each transmission constraint curtailment with these two contracts in the monthly FCA filing and summarize such events in the Company's AAA reports.

Similar reporting requirements were instituted by the Commission in approving other wind PPAs.[2] 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 January 2013 through May 2015.

Part H, Section 5, Schedule 2 contains an explanation of the factors affecting wind curtailment costs for the 2014-15 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.

[2] See Docket No. E002/M-04-404, Order dated October 4, 2004 (approving the Ivanhoe PPA); Docket No. E002/M-04-864, Order dated December 29, 2004 (Velva Windfarm, LLC); Docket Nos. E002/M-05-1850 and E002/M-05-1934, Orders dated March 31, 2006 (Fenton Power Partners I, LLC and FPL Energy-Mower County, LLC); and Docket No. E002/M-06-85, Order dated May 3, 2006 (MinnDakota Wind, LLC).

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

On January 29, 2009, the Commission issued an Order in the above referenced docket which approved the Company's Renewable Energy Purchase Agreement (REPA) with KODA Energy LLC. KODA is a partnership between the Shakopee Mdewakanton Sioux Community and the Rahr Malting Company. The KODA facility produces heat for the adjacent Rahr malting plant and electricity for sale from the biomass waste produced by Rahr and other biomass sources. The Commission approved this REPA and the cost recovery as requested by the Company. In addition, 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 fuel clause adjustment 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. The Diamond K Dairy generator was commissioned and loaded to design levels on December 31, 2013. 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 no Community Solar Gardens in-service during this reporting period, and thus the Company has not issued any bill credits to participants in the Company's Solar*Rewards Community program. We anticipate that some Community Solar Gardens will begin operations during the next AAA reporting period (July 2015-June 2016). In future reporting years, the Company will treat Solar*Rewards Community costs similar to costs arising under a Power Purchase Agreement.

	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
201506								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.

PUBLIC DOCUMENT - WITH TRADE SECRET DATA EXCISED

Table 1: GENERATION COSTS ALLOCATION BETWEEN RETAIL & WHOLESALE CLASS
DOCKET NO. E002/CI-00-415

[TRADE SECRET BEGINS

	Retail		Wholesale		Retail & Wholesale	
	MWh	Cost ($/MWh)	MWh	Cost ($/MWh)	MWh	Cost ($/MWh)
	[1]	[2]	[3]	[4]	[5] [1] + [3]	[6] {[1]x[2]+[3]x[4]}/[5]
June 2015						
July 2015						
August 2015						

TRADE SECRET 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	115	448	Minnesota	Brookings County Substation	In-service duplicate
6	345	115	448	Minnesota	Brookings County Substation	In-service duplicate
7	345	115	448	Minnesota	Chisago County Substation	In-service duplicate
8	345	115	448	Minnesota	Chisago County Substation	In-service duplicate
9	500	345	1200	Minnesota	Chisago County Substation	In-service duplicate
10	500	345	1200	Minnesota	Chisago County Substation	In-service duplicate
11	161	115	187	Minnesota	Collville Substation	In-service standalone
12	345	115	672	Minnesota	Coon Creek Substation	In-service duplicate
13	345	115	672	Minnesota	Coon Creek Substation	In-service duplicate
14	161	115	186	Wisconsin	Crystal Cave Substation	In-service standalone
15	345	161	300	Wisconsin	Eau Claire Substation	In-service duplicate
16	345	161	300	Wisconsin	Eau Claire Substation	In-service duplicate
17	345	115	448	Minnesota	Eden Prairie Substation	In-service duplicate
18	345	115	448	Minnesota	Eden Prairie Substation	In-service duplicate
19	345	115	448	Minnesota	Elm Creek Substation	In-service standalone
20	161	115	187	Wisconsin	Gingles Substation	In-service standalone
21	345	230	336	Minnesota	Hazel Creek Substation	In-service standalone
22	161	115	187	Wisconsin	Hydro Lane Substation	In-service standalone
23	345	115	672	Minnesota	Inver Hills Substation	In-service standalone
24	345	115	448	Minnesota	Kohlman Lake Substation	In-service duplicate
25	345	115	448	Minnesota	Kohlman Lake Substation	In-service duplicate
26	161	115	336	Wisconsin	Lawrence Creek	In-service standalone
27	345	115	448	Minnesota	Lyon County	In-service standalone
28	230	115	187	Minnesota	Maple River Substation	In-service duplicate
29	230	115	186	Minnesota	Maple River Substation	In-service duplicate
30	230	115	187	Minnesota	Minnesota Valley Substation	In-service duplicate
31	230	115	186	Minnesota	Minnesota Valley Substation	In-service duplicate
32	345	230	336	Minnesota	Monticello Substation	In-service duplicate
33	345	115	336	Minnesota	Monticello Substation	In-service duplicate
34	345	115	672	Minnesota	Nobles County Substation	In-service duplicate
35	345	115	672	Minnesota	Nobles County Substation	In-service duplicate
36	345	161	672	Minnesota	North Rochester	In-service standalone
37	345	115	450	Minnesota	Parkers Lake Substation	In-service duplicate
38	345	115	450	Minnesota	Parkers Lake Substation	In-service duplicate
39	230	115	336	Minnesota	Paynesville Transmission Substation	In-service standalone
40	161	115	112	Wisconsin	Pine Lake Substation	In-service standalone
41	345	161	224	Minnesota	Prairie Island Substation	In-service standalone
42	230	115	336	Minnesota	Prairie Substation	In-service duplicate
43	230	115	336	Minnesota	Prairie Substation	In-service duplicate
44	345	115	448	Minnesota	Quarry Substation	In-service standalone
45	345	230	336	Minnesota	Red Rock Substation	In-service duplicate
46	345	115	448	Minnesota	Red Rock Substation	In-service duplicate
47	345	115	448	Minnesota	Red Rock Substation	In-service duplicate
48	345	115	336	Minnesota	Sheas Lake Substation	In-service standalone
49	345	115	448	Minnesota	Sherco Substation	In-service standalone
50	230	115	187	Minnesota	Sheyenne Substation	In-service duplicate
51	230	115	187	Minnesota	Sheyenne Substation	In-service duplicate
52	161	115	187	Minnesota	Split Rock Substation	In-service duplicate
53	230	115	336	Minnesota	Split Rock Substation	In-service duplicate
54	345	115	448	Minnesota	Split Rock Substation	In-service duplicate
55	345	115	448	Minnesota	Split Rock Substation	In-service duplicate
56	161	115	187	Minnesota	South Bend Substation	In-service standalone
57	345	115	672	Minnesota	Terminal Substation	In-service duplicate
58	345	115	672	Minnesota	Terminal Substation	In-service duplicate
59	345	115	448	Minnesota	Wilmarth Substation	In-service duplicate
60	345	115	448	Minnesota	Wilmarth Substation	In-service duplicate
61	345	161	336	Wisconsin	Stone Lake Substation	In-service standalone

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Total
For January 2013 to June 2015

	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-13			414,433.00	$ 16,263,046.75	3,485.00	$ 99,847.03	$ 16,362,893.78
Feb-13			333,614.00	$ 13,025,644.94	2,305.00	$ 77,830.54	$ 13,103,475.48
Mar-13			345,786.00	$ 13,497,049.60	5,915.00	$ 241,878.53	$ 13,738,928.13
Apr-13			372,099.00	$ 14,548,304.09	18,127.00	$ 780,564.80	$ 15,328,868.89
May-13			371,018.00	$ 14,729,182.55	14,849.00	$ 443,050.30	$ 15,172,232.85
Jun-13			283,123.00	$ 11,128,472.51	8,913.00	$ 270,229.36	$ 11,398,701.87
Jul-13			248,971.00	$ 9,585,997.80	1,293.00	$ 62,076.75	$ 9,648,074.55
Aug-13			190,382.00	$ 7,416,745.98	379.00	$ 16,046.59	$ 7,432,792.57
Sep-13			291,939.00	$ 11,535,176.44	36,303.00	$ 1,789,352.32	$ 13,324,528.76
Oct-13			334,205.00	$ 13,114,329.26	80,620.00	$ 4,047,550.61	$ 17,161,879.87
Nov-13			457,360.00	$ 18,030,417.35	52,883.00	$ 1,874,343.43	$ 19,904,760.78
Dec-13			321,377.00	$ 12,630,329.08	41,592.00	$ 1,838,978.11	$ 14,469,307.19
Total-13			3,964,307.00	$ 155,504,696.35	266,664.00	$ 11,541,748.37	$ 167,046,444.72
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	34,533.00	$ 1,314,112.81	$ 18,810,495.43 *
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	12,304.00	$ 463,822.30	$ 11,586,723.26
Jul-14			276,189.00	$ 11,076,232.75	25,300.00	$ 904,356.54	$ 11,980,589.29
Aug-14			126,515.00	$ 5,120,318.25	4,402.00	$ 150,458.32	$ 5,270,776.57
Sep-14			300,800.00	$ 11,917,192.20	8,549.00	$ 331,616.85	$ 12,248,809.05
Oct-14			374,552.00	$ 14,959,305.81	34,474.00	$ 1,248,149.07	$ 16,207,454.88
Nov-14			482,136.00	$ 19,152,652.62	36,991.00	$ 1,417,771.91	$ 20,570,424.53
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	268,266.00	$ 10,523,635.44	$ 182,449,304.70
Jan-15			430,437.00	$ 17,187,922.21	7,624.00	$ 331,500.15	$ 17,519,422.36
Feb-15			375,215.00	$ 14,988,985.89	12,640.00	$ 544,047.79	$ 15,533,033.68
Mar-15			419,845.00	$ 16,848,980.29	32,755.00	$ 1,211,708.37	$ 18,060,688.66
Apr-15			444,726.00	$ 17,770,333.68	13,183.00	$ 495,011.09	$ 18,265,344.77
May-15			399,998.00	$ 16,011,402.43	8,851.00	$ 357,751.08	$ 16,369,153.51
Jun-15				$ -		$ -	
Jul-15				$ -		$ -	
Aug-15				$ -		$ -	
Sep-15				$ -		$ -	
Oct-15				$ -		$ -	
Nov-15				$ -		$ -	
Dec-15				$ -		$ -	
Total-15			2,070,221.00	$ 82,807,624.50	75,053.00	$ 2,940,018.48	$ 85,747,642.98

* 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 2013 to June 2015

	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-13			*0.00*	*$ -*	*0.00*	*$ -*	
Feb-13			*0.00*	*$ -*	*0.00*	*$ -*	
Mar-13			*0.00*	*$ -*	*0.00*	*$ -*	
Apr-13			*188.19*	*$ 5,017.07*	*32.00*	*$ 853.20*	*$ 5,870.27*
May-13			*0.00*	*$ -*	*0.00*	*$ -*	
Jun-13			*0.00*	*$ -*	*0.00*	*$ -*	
Jul-13			*0.00*	*$ -*	*0.00*	*$ -*	
Aug-13			*0.00*	*$ -*	*0.00*	*$ -*	
Sep-13			*0.00*	*$ -*	*0.00*	*$ -*	
Oct-13			*0.00*	*$ -*	*0.00*	*$ -*	
Nov-13			*0.00*	*$ -*	*0.00*	*$ -*	
Dec-13			*0.00*	*$ -*	*0.00*	*$ -*	
Total-13			***188.19***	***$ 5,017.07***	***32.00***	***$ 853.20***	***$ 5,870.27***
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							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 2 (Low Load)
For January 2013 to June 2015

	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-13			0.00	$ -	0.00	$ -	
Feb-13			0.00	$ -	0.00	$ -	
Mar-13			0.00	$ -	0.00	$ -	
Apr-13			0.00	$ -	0.00	$ -	
May-13			0.00	$ -	0.00	$ -	
Jun-13			0.00	$ -	0.00	$ -	
Jul-13			0.00	$ -	0.00	$ -	
Aug-13			0.00	$ -	0.00	$ -	
Sep-13			76,548.00	$ 2,901,817.33	838.00	$ 60,482.56	$ 2,962,299.89
Oct-13			0.00	$ -	0.00	$ -	
Nov-13			0.00	$ -	0.00	$ -	
Dec-13			0.00	$ -	0.00	$ -	
Total-13			76,548.00	$ 2,901,817.33	838.00	$ 60,482.56	$ 2,962,299.89
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							

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 3 (MISO)
For January 2013 to June 2015

	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-13			*72,450.00*	*$*	*2,082,854.97*	*3,485.00*	*$*	*99,847.03*	*$ 2,182,702.00*
Feb-13			*124,791.00*	*$*	*4,430,834.71*	*1,606.00*	*$*	*59,496.20*	*$ 4,490,330.91*
Mar-13			*130,304.00*	*$*	*3,740,576.42*	*5,915.00*	*$*	*241,878.53*	*$ 3,982,454.95*
Apr-13			*214,542.81*	*$*	*7,835,630.25*	*18,095.00*	*$*	*779,711.60*	*$ 8,615,341.85*
May-13			*172,368.00*	*$*	*6,676,131.24*	*14,849.00*	*$*	*443,050.30*	*$ 7,119,181.54*
Jun-13			*121,792.00*	*$*	*4,382,117.43*	*8,913.00*	*$*	*270,229.36*	*$ 4,652,346.79*
Jul-13			*53,096.00*	*$*	*1,642,558.63*	*980.00*	*$*	*53,881.69*	*$ 1,696,440.32*
Aug-13			*37,477.00*	*$*	*1,582,277.95*	*379.00*	*$*	*16,046.59*	*$ 1,598,324.54*
Sep-13			*126,607.00*	*$*	*4,851,723.76*	*35,465.00*	*$*	*1,728,869.76*	*$ 6,580,593.52*
Oct-13			*226,538.00*	*$*	*8,728,293.26*	*80,620.00*	*$*	*4,047,550.61*	*$ 12,775,843.87*
Nov-13			*289,636.00*	*$*	*11,075,512.84*	*52,883.00*	*$*	*1,874,343.43*	*$ 12,949,856.27*
Dec-13			*207,681.00*	*$*	*8,041,172.11*	*41,592.00*	*$*	*1,838,978.11*	*$ 9,880,150.22*
Total-13			***1,777,282.81***	***$***	***65,069,683.57***	***264,782.00***	***$***	***11,453,883.21***	***$ 76,523,566.78***
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*	*$*	*9,888,827.56*	*34,489.00*	*$*	*1,312,837.86*	*$ 11,201,665.42*
May-14			*137,551.00*	*$*	*5,259,198.52*	*4,989.00*	*$*	*213,648.70*	*$ 5,472,847.22*
Jun-14			*196,092.00*	*$*	*7,764,350.85*	*12,304.00*	*$*	*463,822.30*	*$ 8,228,173.15*
Jul-14			*184,316.00*	*$*	*7,332,372.22*	*25,300.00*	*$*	*904,356.54*	*$ 8,236,728.76*
Aug-14			*50,900.00*	*$*	*2,013,327.92*	*4,402.00*	*$*	*150,458.32*	*$ 2,163,786.24*
Sep-14			*179,299.00*	*$*	*6,870,476.62*	*8,549.00*	*$*	*331,616.85*	*$ 7,202,093.47*
Oct-14			*274,412.00*	*$*	*10,884,349.98*	*34,474.00*	*$*	*1,248,149.07*	*$ 12,132,499.05*
Nov-14			*357,732.00*	*$*	*14,199,215.53*	*36,991.00*	*$*	*1,417,771.91*	*$ 15,616,987.44*
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***	***$***	***109,437,909.94***	***268,183.00***	***$***	***10,521,204.19***	***$ 119,959,114.13***
Jan-15			*214,847.00*	*$*	*8,505,929.28*	*7,624.00*	*$*	*331,500.15*	*$ 8,837,429.43*
Feb-15			*202,707.00*	*$*	*7,762,179.09*	*12,640.00*	*$*	*544,047.79*	*$ 8,306,226.88*
Mar-15			*186,585.00*	*$*	*7,230,936.47*	*32,755.00*	*$*	*1,211,708.37*	*$ 8,442,644.84*
Apr-15			*187,399.00*	*$*	*7,228,526.78*	*13,183.00*	*$*	*495,011.09*	*$ 7,723,537.87*
May-15			*161,025.00*	*$*	*6,178,315.06*	*8,851.00*	*$*	*357,751.08*	*$ 6,536,066.14*
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			***952,563.00***	***$***	***36,905,886.68***	***75,053.00***	***$***	***2,940,018.48***	***$ 39,845,905.16***

Northern States Power Company
Electric Utility - State of Minnesota
Wind Curtailment Summary Report - Curtailment Reason Code 4 (Other-Paid)
For January 2013 to June 2015

	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-13			0.00	$ -	0.00	$ -	
Feb-13			19,700.00	$ 516,531.75	699.00	$ 18,334.34	$ 534,866.09
Mar-13			0.00	$ -	0.00	$ -	
Apr-13			0.00	$ -	0.00	$ -	
May-13			0.00	$ -	0.00	$ -	
Jun-13			0.00	$ -	0.00	$ -	
Jul-13			27,170.00	$ 712,391.32	313.00	$ 8,195.06	$ 720,586.38
Aug-13			0.00	$ -	0.00	$ -	
Sep-13			0.00	$ -	0.00	$ -	
Oct-13			0.00	$ -	0.00	$ -	
Nov-13			0.00	$ -	0.00	$ -	
Dec-13			0.00	$ -	0.00	$ -	
Total-13			46,870.00	$ 1,228,923.07	1,012.00	$ 26,529.40	$ 1,255,452.47
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							

2014/2015 CURTAILMENT REPORT

I. INTRODUCTION

The Commission's April 4, 2006 Order regarding curtailment payments to wind developers (Docket No. E999/AA-04-1279) requires the Company to provide in future Annual Automatic Adjustment 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 causes 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 may continue across several AAA periods. Such is the case with work required as a result of a major ice storm that occurred in April 2013. Another example is the on-going work to help reduce transmission line galloping.

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 Locational Marginal Pricing (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 facilities 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 Midcontinent Independent System Operator (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 discussed later in this report.

To better manage regional congestion, MISO and the industry have implemented Dispatchable Intermittent Resources (DIR) 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 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
Dispatchable Intermittent Resources

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) program, which provides tax subsidies to Wind Generating Plants has been extended again and now grants eligibility to projects that have begun construction prior to the end of 2016. 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. This will likely be the case going forward, as a significant number of projects are being placed in service prior to completion of all the necessary transmission upgrades. The Company is aware of 1,817 MW[1] 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 2015. In addition to this generation, the Company will add 750 MW of Company-owned and PPA wind facilities in 2015 and 2016 and MidAmerican Energy[2] has announced they will add 1,600 MW of wind generation in Iowa by the end of 2016. 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 NSPM System. This potential impact will lessen as the required transmission facilities and transmission system improvements are placed in service.

III. Transmission System Improvements

Since 1994, the Company's wind energy purchases 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.

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[1] Projects that have recently gone into service or are scheduled to go into service soon include G573/G574/G575 (200 MW); G735/J091 (266 MW); G798 (150 MW); G870 (200 MW); G947 (99 MW); H007 (41 MW); H008 (36 MW); H009 (100 MW); H078 (119.6 MW); H096 (50 MW); J191/R65 (193.2 MW); J201 (20 MW); J289 (20 MW); J343 (150 MW); R49 (12 MW); G540/G548 (160 MW); (Total of 1816.8 MW).

[2] 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 by the end of 2016.

Table 2
Southwest Minnesota Wind Limits

Transmission Project	Wind Outlet Increase	SW MN Wind Limit
425 MW Wind Transmission Expansion Project	October 2004[3]	425 MW
825 MW Wind Transmission Expansion Project	December 2007[4]	880 MW
Buffalo Ridge Incremental Generation Outlet (BRIGO)	December 2009[5]	1250 MW
CapX Brookings County - Southeast Twin Cities 345 kV Line	March 2015[6]	1950 MW

The Company is also participating in the development of the CapX2020 transmission projects (CapX) which include a number of projects that will positively impact transmission capacity and wind curtailment on the NSP system. These CapX transmission projects are listed in the following table.

Table 3
CapX Transmission Projects

Transmission Project	Transmission Owner	Actual/Planned In-Service Date
CapX Brookings County - Southeast Twin Cities 345 kV Line	Xcel Energy, Great River Energy	March 2015
CapX - Fargo North Dakota - Northwest Twin Cities 345 kV Line	Xcel Energy, Great River Energy	April 2015
CapX - Southeast Twin Cities - LaCrosse, Wisconsin 345 kV Line	Xcel Energy, SMMPA and non-MISO	Late 2016

[3] 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.

[4] 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.

[5] 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.

[6] The CapX 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.

The CapX transmission lines will increase the capacity of the bulk power transmission system and thus remove impediments to the delivery of power from wind farms around the region.

In addition to transmission projects developed by the Company, MISO has identified and approved a significant number of new transmission infrastructure projects including 17 Multi-Value Projects (MVPs) which are designed to accommodate the planned and expected generation expansion in the MISO footprint.[7] The completion of the MVP projects, particularly the ones listed in the following table, will have a positive impact on Company-owned and PPA wind facilities.

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 345 kV Line	Ottertail Power Company, Xcel Energy	End 2017
Lakefield Jct. - Winnebago - Winco - Kossuth County & Obrien Coutny - 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.

[7] The MISO Board of Directors approved the new transmission projects, which included the CapX Brookings County – Southeast Twin Citites 345 kV line as a 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)

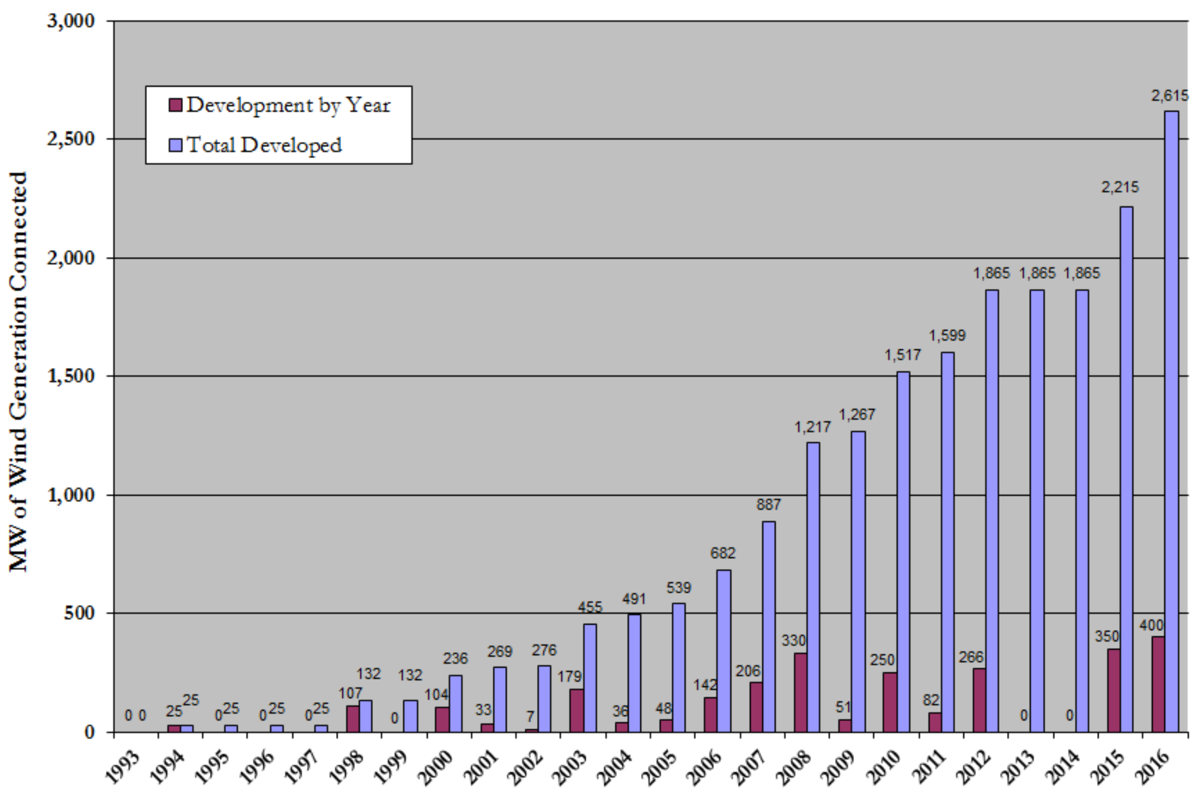
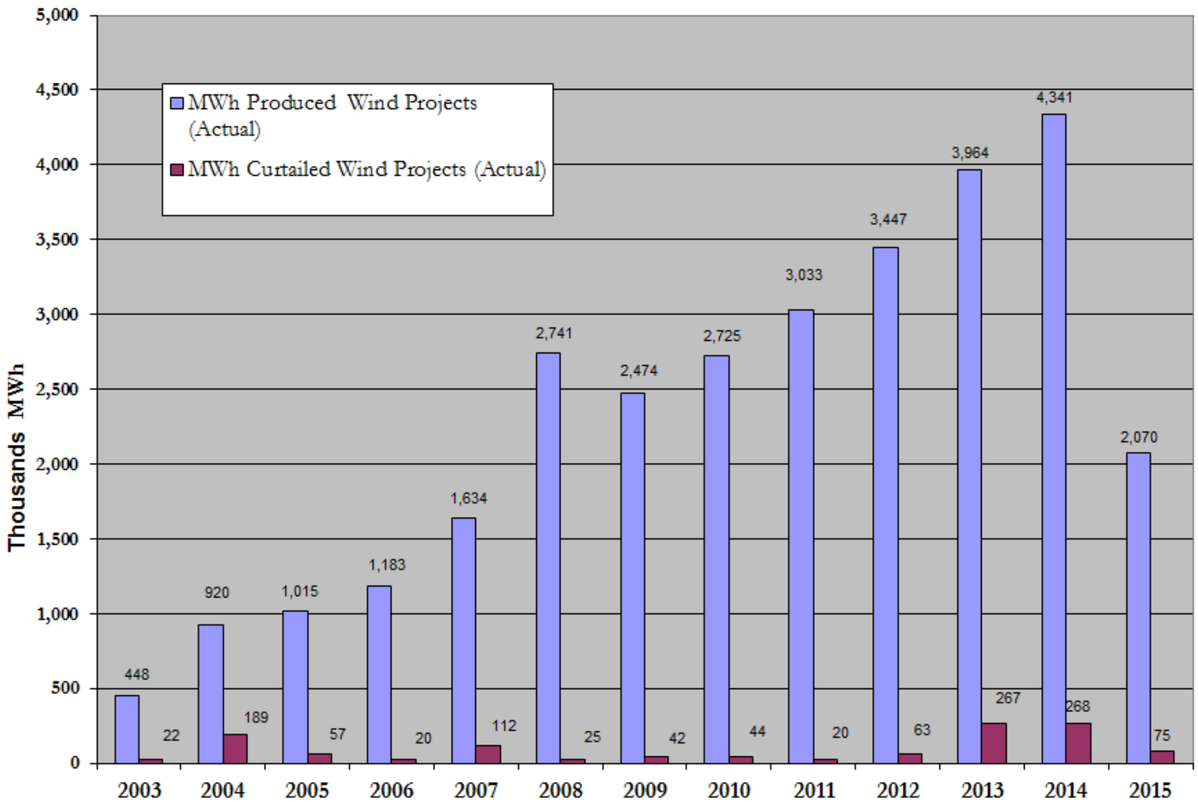


Chart 2 shows the comparison between total wind energy produced and the wind energy curtailed from the projects through May 2015[8]. Despite the lead/lag time associated with generation and transmission development, Chart 2 shows that wind curtailment is small compared to the total wind generation delivered.

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.

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

Chart 2
NSP Wind Production & Curtailment (MWh)
(2015 Partial Year through May)



Curtailment during July 2014 to June 2015[9] was broken up into different categories to better explain the reasons for the curtailment and its cause. To support the analysis the Company identified hours during the 2014/2015 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 – 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. The events resulting in curtailment payments for this reporting period fall into three categories:

1) Transmission Events; which include storm related repair/restoration on the Split Rock-Nobles-Lakefield Junction 345 kV lines along with transformer/

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

substation outages at the Buffalo Ridge, Chanarambie, and Fenton substations (Transmission Events);
2) DIR Curtailments for negative LMP related reasons (DIR Curtailment Events); and
3) Manual curtailments for negative LMP related reasons (Manual Curtailment Events).

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
2014/2015 Wind Curtailment MWh

Events	MWh		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	45,378	43,865	1,513
DIR Curtailment Events	43,049	38,867	4,182
Manual Curtailment Events	107,483	107,483	0
Total	195,910	190,215	5,695

Table 6
2014/2015 Wind Curtailment Costs

Events	Costs		
	Total	Projects / No PTC	Projects / PTC
Transmission Events	$1,667,666	$1,544,591	$123,075
DIR Curtailment Events	$2,466,279	$2,140,447	$325,832
Manual Curtailment Events	$3,305,034	$3,305,034	$0
Total	$7,438,980	$6,990,073	$448,907

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

It is important to note that of the $7,438,980 in total curtailment costs, the vast majority of these total costs, $7,219,378, 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.[10]

Transmission Curtailment Events

Wind curtailment costs totaling $1,667,666 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 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 – 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,'[11] bringing down and/or weakening equipment, conductor and ground wires all along one of the key high-voltage transmission lines providing electric service support as well as wind generation outlet across the southern portion of Minnesota – the Split Rock-Nobles-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

[10] 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.

[11] 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.

damage, more work was needed and a permanent repair plan was developed. This work continued through the 2014 and 2015 reporting period.

The Split Rock-Nobles-Lakefield 345 kV line provides a significant portion of the wind generation outlet from the southwestern Minnesota area and outages incurred along this line require 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 that mitigate galloping. Some mitigation designs create sufficient spacing between conductor phases to prevent flashovers, and ice/snow prevention and removal applications. Other more recent techniques include technologies to increase conductor tension or stiffness; weight pendulums and air dampers to limit motion; and different conductor configurations to counter wind effects. EPRI advised on placement of line monitoring stations that serve as data collections points to monitor device effectiveness in minimizing or preventing conductor gallop. Additionally, motion sensors were installed on select conductor spans to analyze movement and collect data. Since the exact location and date of the next galloping event cannot be predicted, EPRI will aid the Xcel Energy team in result evaluation over a period of time. Collected data will aid in choosing anti-galloping devices to use in the region and assist in determining areas where geographic orientation of transmission lines and prevailing winds would combine unfavorably, and therefore should be designed to special galloping requirements.

Buffalo Ridge, Chanarambie, Fenton and Brookings 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 Brookings County substations that contributed to curtailment during this period.

Transformer outages were the primary contributors to the curtailment. Animal contact with energized components caused damage to Fenton and Chanarambie transformers that required outages to make repairs. Buffalo Ridge transformers were taken out of service for scheduled preventative maintenance. A Brookings County transformer was taken out of service to allow installation of new reactive support equipment. In addition, a Buffalo Ridge breaker and a Chanarambie transformer were taken out of service 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. Brookings County outages could impact MinnDakota.

DIR Curtailment Events

Wind curtailment costs totaling $2,466,279 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.

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 $3,305,034 were due to the Manual Curtailment Events as described below.

Unlike DIR wind farms where MISO controls the wind farms output, non-DIR wind facilities require recognition of trends and action by an NSP system dispatcher. The economic decision to curtail a wind farm is specifically affected by whether or not a wind farm qualifies for federal PTCs. As a result, the comparison of the Contractual price, including PTC, for the wind farm with the relevant LMP determines if it is economic to curtail the wind farm or accept the generation.

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 nearly $500,000 as shown in Table 7.

Table 7
Manual Actions Related to Economics

Connection Node	MWh	Curtailment Benefit $	Average Benefit $/MWh	PTC or No PTC
Chanarambie	25,365.62	$108,953.15	$ 4.30	No PTC
Lake Benton I	34,112.53	$156,255.02	$ 4.58	No PTC
Lake Benton II	25,476.11	$61,989.13	$ 2.43	No PTC
Moraine	9,067.00	$72,961.13	$ 8.05	No PTC
Ridgewind Power Partners	6,544.06	$39,522.33	$ 6.04	No PTC
Wind Power Partners 1993	6,918.04	$59,795.83	$ 8.64	No PTC
Total	107,483.37	$499,476.60	$ 4.65	

To perform this analysis the Company started with estimated hourly averaged curtailment volumes[12] 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.

[12] 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.

III. Wind Production and Curtailment Payments

Chart 3 shows the corresponding production and curtailment costs through May, 2015[13]. As with wind generation produced and curtailed, paid curtailment is a very small portion of total cost of wind generation on the system.

Chart 3
NSP Wind Production & Curtailment Payments
(2015 Partial Year through May)

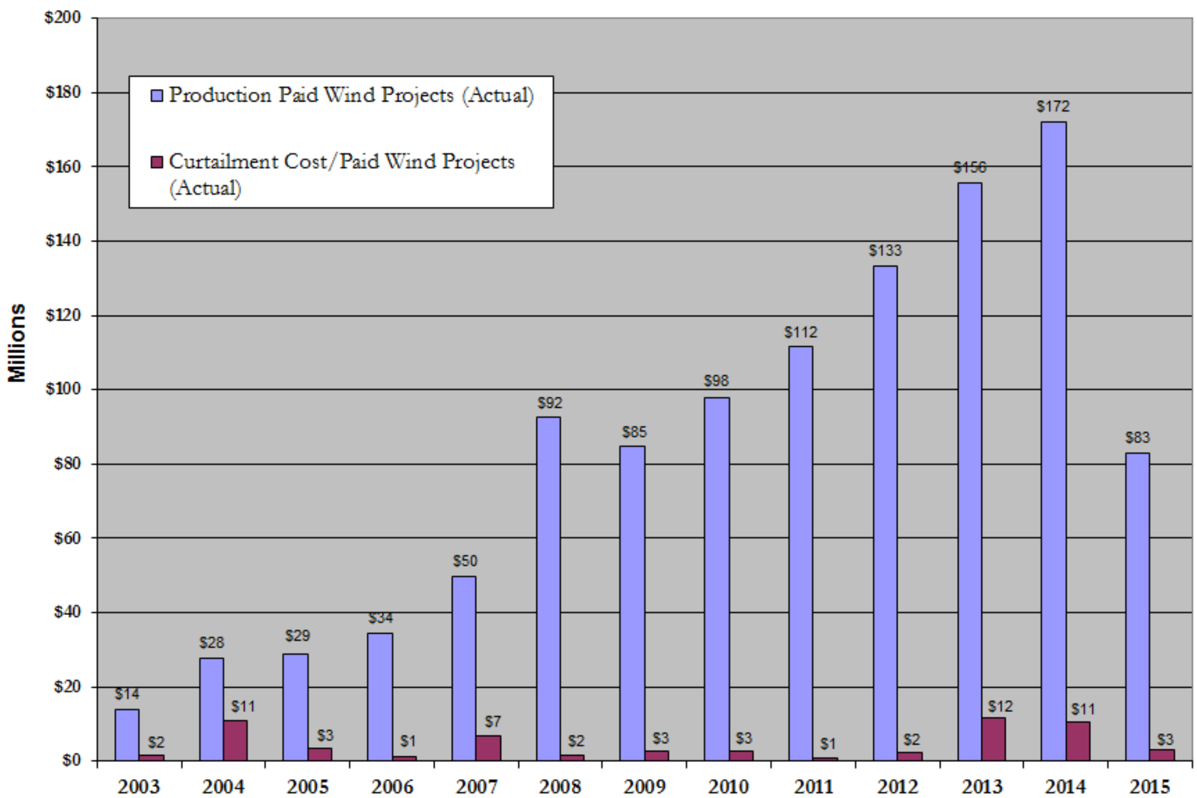
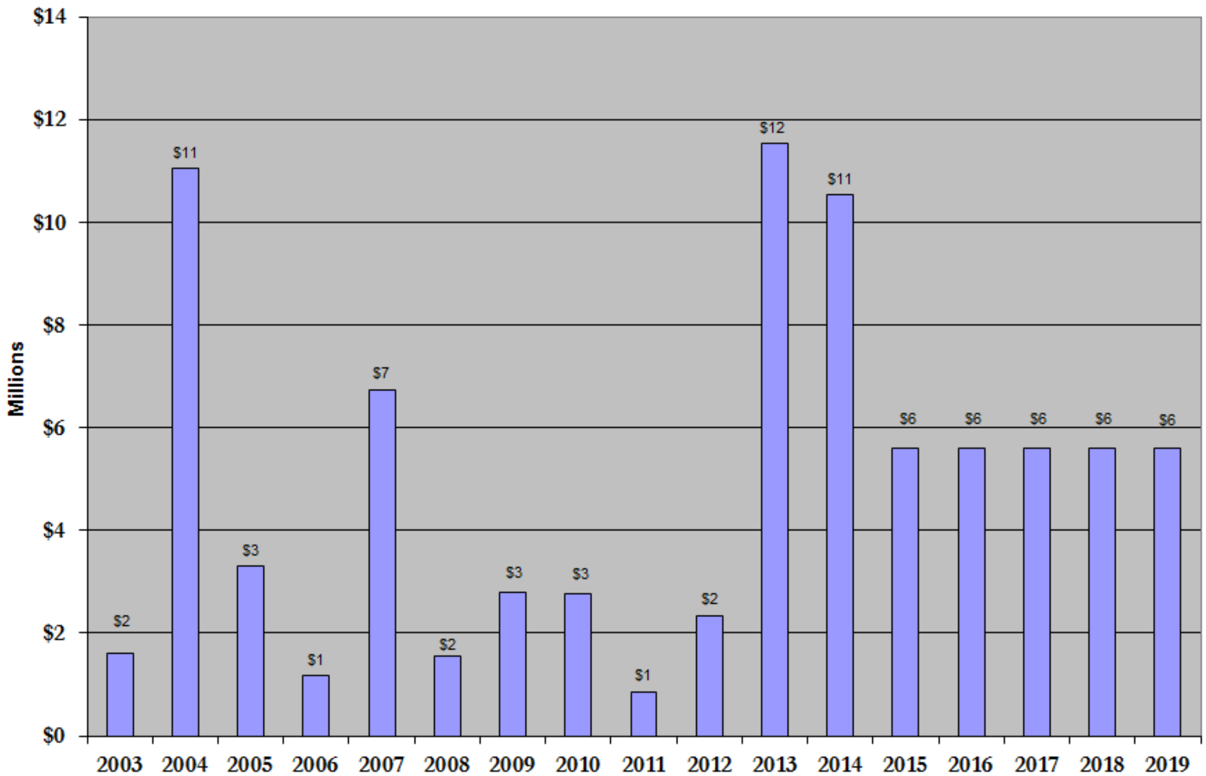


Chart 4 shows the Company's historical wind curtailment costs along with the five-year estimate of future costs. Over the next five years, we anticipate that the wind generation curtailment and associated payments to vendors will result from planned and unplanned transmission outages and negative LMP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

13 AAA Part H, Section 5, Schedule 1

Chart 4
NSP Wind Curtailment Payments
(2003 –2014 Actual, 2015 – 2019 Projected)



As was the case in the 2013/2014 AAA Report, we are projecting a value for future curtailment differently than in curtailment reports prior to 2013. In those earlier reports, curtailment associated with maintaining transmission reliability during system intact conditions was the primary focus. However, we believe given the current MISO market and the amount of wind generation installed in southern Minnesota and Iowa, it would be reasonable to expect there will be ongoing wind curtailment due to negative LMP events, congestion and transmission outages.

The Company believes using recent actual experience as the basis for estimating future wind curtailment to be a reasonable methodology and has used the average of the last 5 years of historical curtailment data to project the level of future curtailment. The basis for moving to this type of curtailment estimate was that by 2008 and 2009, the transmission infrastructure caught up with wind generation development and curtailment began to be more consistent. With completion of all of the CapX2020 lines, the next needed increase in the bulk transmission system will be in place. Using the last five years to predict curtailment 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 CapX 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 CapX 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 reductions 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. 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-15-611

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 is required to report the following information as part of its electric AAA report:

- Section 2, Item C, Part 3(a):
  The Schedule 10 administrative charges paid to MISO under the MISO tariff.
- Section 2, Item C, Part 3(b):
  Any amount of MISO administrative charges deferred by MISO for later recovery.
- Section 2, Item C, Part 5(c):
  Each instance where MISO directed the Company to curtail the Company's own generation for reliability reasons that resulted in an interruption of firm retail electric service to the Company's retail customers in Minnesota.
- 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.
- Section 2, Item C, Part 8(b):
  Changes to MISO tariffs that may ultimately affect the rates of retail customers in Minnesota and the Company's efforts to minimize MISO transmission service costs.
- Section 2, Item C, Part 8(c):
  An annual analysis of how the transfer of operational control to MISO has affected the Company's overall transmission costs and revenues and its overall energy costs for retail customers, including:

i. an analysis of how MISO membership has affected the Company's ability to use its own generating sources when they are the least-cost power source; and
ii. the Company's ability to access low-cost power on the wholesale market for its retail customers.

- Section 2, Item C, Part 8(d):
  Each instance where MISO directed the Company to redispatch the Company's owned generation for reliability reasons, including an explanation of financial impact on rates, if any, and the reason for the redispatch, if known.

The Company provides the following information in compliance with the May 9, 2002 Order.

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

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	87.6729%	84.7923%	$763,290.36
August 2014	$778,766.86	87.6729%	84.7923%	$578,934.26
September 2014	$880,193.31	87.6729%	84.7923%	$654,334.55
October 2014	$757,951.64	87.6729%	84.7923%	$563,460.25
November 2014	$814,082.76	87.6729%	84.7923%	$605,188.05
December 2014	$853,407.56	87.6729%	84.7923%	$634,422.06
January 2015	$875,014.93	87.4041%	84.5789%	$646,858.52
February 2015	$800,794.52	87.4041%	84.5789%	$591,990.76
March 2015	$910,150.10	87.4041%	84.5789%	$672,832.34
April 2015	$791,689.78	87.4041%	84.5789%	$585,260.05
May 2015	$792,038.90	87.4041%	84.5789%	$585,518.13
June 2015	$1,114,334.94	87.4041%	84.5789%	$823,776.86
Total	**$10,395,183.05**			**$7,705,866.19**

*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.

2013-2014 AAA Period

Period*	Invoiced Amount (NSP System)	Jurisdictional Transmission Allocator	Interchange Allocator	MN Jurisdiction Net of Interchange
July 2013	$1,156,185.11	87.9164%	84.8812%	$862,797.30
August 2013	$757,867.64	87.9164%	84.8812%	$565,554.90
September 2013	$963,037.35	87.9164%	84.8812%	$718,661.76
October 2013	$733,132.42	87.9164%	84.8812%	$547,096.37
November 2013	$679,671.01	87.9164%	84.8812%	$507,201.06
December 2013	$812,019.63	87.9164%	84.8812%	$605,965.55
January 2014	$799,592.69	87.6729%	84.7923%	$594,416.15
February 2014	$789,693.09	87.6729%	84.7923%	$587,056.80
March 2014	$874,411.63	87.6729%	84.7923%	$650,036.45
April 2014	$694,516.63	87.6729%	84.7923%	$516,302.75
May 2014	$811,441.22	87.6729%	84.7923%	$603,224.33
June 2014	$747,196.95	87.6729%	84.7923%	$555,465.23
Total	**$9,818,765.37**			**$7,313,778.65**

*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.*

We have provided the corresponding data for the 2013-2014 reporting year from our 2014 AAA Report above for comparison. The 2015 AAA period MISO Schedule 10 invoiced amount increased $576,417 or 5.9 percent over 2014. The deviation reflected an increase in NSP's proportionate share of MISO Operating Expenses and FERC Operating Expenses as a result of MISO energy, capacity and flat FERC rates increases. The allocated Minnesota jurisdictional amount, net of interchange, increased by less than 5.9 percent (5.4 percent) due to lower jurisdictional transmission and interchange allocators effective January 2015.

MISO Schedule 10 costs are recovered through base rates and are subject to review in rate case proceedings. To ensure consistency between the AAA proceedings and future base rate proceedings, the Company requests that any proposed changes to the allocator be addressed in base rate proceedings.

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, 2014 to June 30, 2015, 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 (Tariff), compliance filings, generation interconnection agreements subject to the Tariff, 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.midwestiso.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] That 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

[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.

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. Daniel Kline in the most recent NSP electric rate case (Docket No. E002/GR-13-868). That testimony is also incorporated by reference.

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

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

The impact of MISO Day 2 market operations is 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.midwestiso.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-15-611

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 5% 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 Company with "buy signals" whereby trading personnel can lower expected costs by

[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.

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. As discussed below, this has typically been a long-term issue for the NSP System due to the predominance 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.

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. 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. The incremental cost forecast is updated bi-weekly and provides monthly purchase price signals for the following twelve months. For example, the forecast will provide the price below which Xcel Energy Services trading personnel would have to purchase specific quantities of energy to ensure the purchase is economic for customers. These purchases are expected to reduce the cost of serving native load customers, based on the best information known at the time of the forecast, to a level below the cost that would be incurred if the Company served all requirements with available native generation and energy under long-term power purchase agreements (PPAs).

As would be expected, unit availability plays a key role in driving the purchase signals provided to the trading personnel. When a key generation unit is expected to be out of service (for example, for boiler maintenance), incremental costs for that period would typically be higher than would incremental costs absent the outage. Thus, the purchase price signals developed through the PLEXOS® analysis would be elevated for this period.

Ultimately, trading personnel take actions based upon these buy signals. However, trading personnel do not simply carry out instructions provided by the PLEXOS® analysis. Rather, this analysis serves to inform purchase decisions made by trading personnel. **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]

As discussed above, the PLEXOS® purchase signals are updated every two weeks. These revised signals incorporate any changes in load forecast or unit availability and also include any forward purchases executed by trading personnel. Thus, as forward purchases are made, the Company would expect new purchase signals to reflect reduced unmet energy requirements, unless other circumstances (e.g., load, fuel prices, unit availability, and transmission outages) have changed as well. For example, if the near-term forecast is for cooler than normal weather over the next two weeks during a summer month, the load forecast may signal there is no unserved energy to procure. By contrast, if the forecast is for much warmer than normal summer weather, the forecast will signal additional resources should be procured. This iterative process of purchase signal development and purchase action continues throughout the year, thus ensuring that the Company is continuously responding to changing circumstances while at the same time acquiring sufficient energy resources to serve its native load requirements in a reliable manner.

ii. FTR and Congestion Analysis

The Company operates in the MISO wholesale energy and ancillary services market, which uses security constrained regional dispatch with 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 currently uses storage to hedge a portion of its natural gas requirements during the winter heating season. Storage is projected to cover approximately 100 percent of the winter requirements beginning with the 2015-2016 heating season, therefore the Company does not use any financial instruments to hedge its remaining natural gas electric generation fuel supply requirements.

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. As discussed above, the Company will purchase replacement energy to cover these required outages either through the MISO energy and ancillary services market, or bilaterally pursuant to the buy signals developed through the PLEXOS® analysis.

B. Summary of 2016 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 2016 as compared to actual and forecast costs for 2015, prior to cost adjustment for wholesale sales revenues. Forecast costs for 2016 are projected to be slightly higher than actual costs through July 2015 plus the forecast for the remainder of the year. The cost change between 2015 and 2016 is driven by a number of different factors that are discussed below. For 2016, 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.

NSP System fuel costs for 2016 are projected to increase by approximately $20.2 million compared to actual and forecast costs for 2015 based on current assumptions. Although the total NSP system production for 2016 is projected to be 1.7 percent higher than 2015, the cost per MWh is projected to decrease by approximately 2.3 percent in 2016 versus the blended actual and forecast rate for 2015.

i. <u>Cost Drivers for Company-Owned Coal Generation</u>

In 2016, fuel costs for the Company's base load coal generating units are expected to increase by approximately $1.4 million due to **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Coal production is forecast to be relatively flat at an increased output of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in 2016. Black Dog units 3 and 4 were retired in April 2015 and are therefore not in the 2016 forecast.

ii. <u>Cost Drivers for Company-Owned Nuclear Generation</u>

Compared to 2015, fuel costs for the Company's base load nuclear generating units are expected to increase by approximately $12.1 million on **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

iii. Company-Owned Renewable Generation

Company owned renewable generation is projected to increase by **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in 2016. This is due to the assumed start of two new owned wind projects late in 2015. 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 2016.

iv. Long-Term Purchase Power Contracts

Costs for purchases of energy from long-term purchase power agreements (PPAs) increase in 2016 as compared to 2015 by $6.0 million. This is primarily due to yearly contract price escalations as well as higher prices for new contracts. The quantity of energy purchased under long-term contracts is projected to decrease by **[TRADE SECRET BEGINS TRADE SECRET ENDS]** for 2016. The main drivers of the decrease in generation purchased from long-term purchase power contracts are new contracts with the Manitoba Hydro-Electric Board (MHEB) that took effect beginning May 1, 2015. Purchase volumes of energy were reduced under the new agreements and account for the majority of the decrease in energy purchases from long-term PPAs. Offsetting the decrease in the volume of energy purchased are higher prices for energy purchased under the new agreements as compared to pricing terms for the expired contracts. Another driver to the long-term purchase power generation decrease is the termination of the MPC Coyote contract at the end of October 2015. Offsetting these generation decreases is the increased generation from the new Geronimo Odell contract, expected to come online in June 2016. Increased costs from the new MHEB and Odell PPAs are the main contributors to the $6.0 million increase in costs for long-term purchase power contracts.

v. Solar Generation and Costs

Costs for purchases of energy from long-term solar purchase power contracts are forecast to increase in 2016 as compared to 2015 by $4.7 million. Solar generation is forecast to increase by **[TRADE SECRET BEGINS TRADE SECRET ENDS]** in 2016. The primary contributors to this increase are four new Solar PPA projects: Aurora, Juwi, North Star, and Marshall, which are set to go online in 2016.

vi. Natural Gas Generation and Prices

As of July 2015, forward prices for natural gas are projected to be 4.5 percent higher for 2016 than 2015. Total costs for gas generation are projected to increase by $26.1 million due to higher projected generation of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. The increase in natural gas generation is driven by the combination of lower forecast purchases from the MISO market discussed below as well as the reduction in purchases of energy from long-term purchased power contracts discussed previously.

vii. Market Purchases and MISO Forward Prices

For 2016, forecast costs for purchases of energy from the MISO market and other market charges decrease by $29.6 million on lower purchase volumes of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Lower volume and costs for purchases from the MISO market are driven by higher MISO forward prices and greater generation from company-owned renewable, nuclear, and natural gas resources discussed previously. MISO forwards for 2016 are projected to increase by 19.1 percent in the on-peak and 16.3 percent in the off-peak, as compared to prices for 2015.

C. Other Considerations for the 2016 Forecast

Certain factors may serve to affect a portion of forecast 2016 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.

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

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 2016.

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 for 2016 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 2016 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.

QUARTERLY FORECAST OF 12 MONTHLY FCC AND DEVIATION ANALYSIS

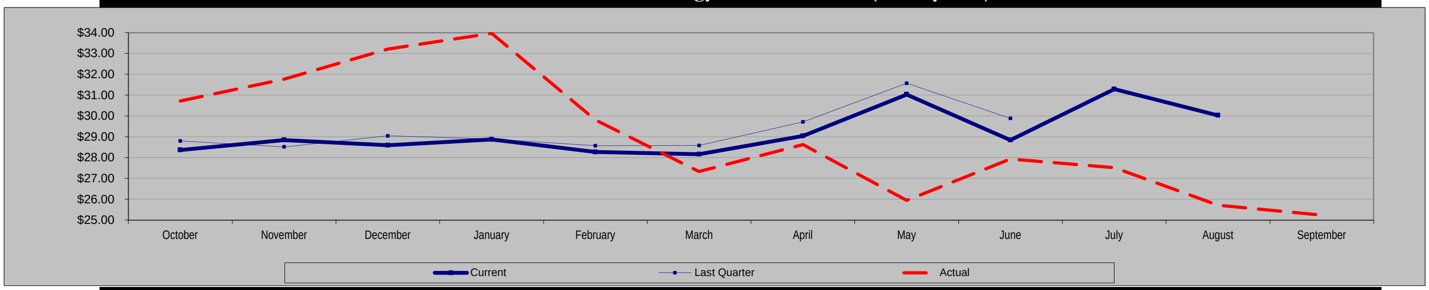
During this AAA reporting period, the Company has prepared and distributed four (4) proprietary quarterly forecasts dated October 2, 2014, January 5, 2015, April 2, 2015 and July 2, 2015 to interested parties who have signed a protective agreement with the Company. These quarterly forecasts are included 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 2014 to June 2015 is included in Part J, Section 4 Schedule 2.

PUBLIC DOCUMENT - WITH TRADE SECRET INFORMATION EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(October 1st, 2014)

[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	2014	$28.37	$28.80	-1.5%	2013	$30.72	$28.46	7.9%	8.3%
November	2014	$28.85	$28.52	1.2%	2013	$31.76	$29.13	9.0%	10.1%
December	2014	$28.59	$29.04	-1.5%	2013	$33.21	$29.73	11.7%	16.1%
January	2015	$28.87	$28.89	-0.1%	2014	$33.97	$29.24	16.2%	17.7%
February	2015	$28.27	$28.57	-1.1%	2014	$29.81	$28.74	3.7%	5.5%
March	2015	$28.16	$28.58	-1.5%	2014	$27.34	$29.89	-8.5%	-2.9%
April	2015	$29.04	$29.72	-2.3%	2014	$28.62	$28.46	0.6%	-1.5%
May	2015	$31.03	$31.57	-1.7%	2014	$25.95	$29.76	-12.8%	-16.4%
June	2015	$28.84	$29.88	-3.5%	2014	$27.93	$29.31	-4.7%	-3.2%
July	2015	$31.29			2014	$27.52	$30.63	-10.2%	-12.0%
August	2015	$30.03			2014	$25.71	$28.57	-10.0%	-14.4%
		[TRADE SECRET BEGINS							[TRADE SECRET BEGINS
September	2015				2014	$25.24	$28.10	-10.2%	
		TRADE SECRET ENDS]							TRADE SECRET ENDS]
Average (Unweighted)		$29.21				$28.98	$29.17	-0.6%	-0.8%

Forecast Assumption Highlights

[TRADE SECRET BEGINS

Factors impacting costs in the forecast period:

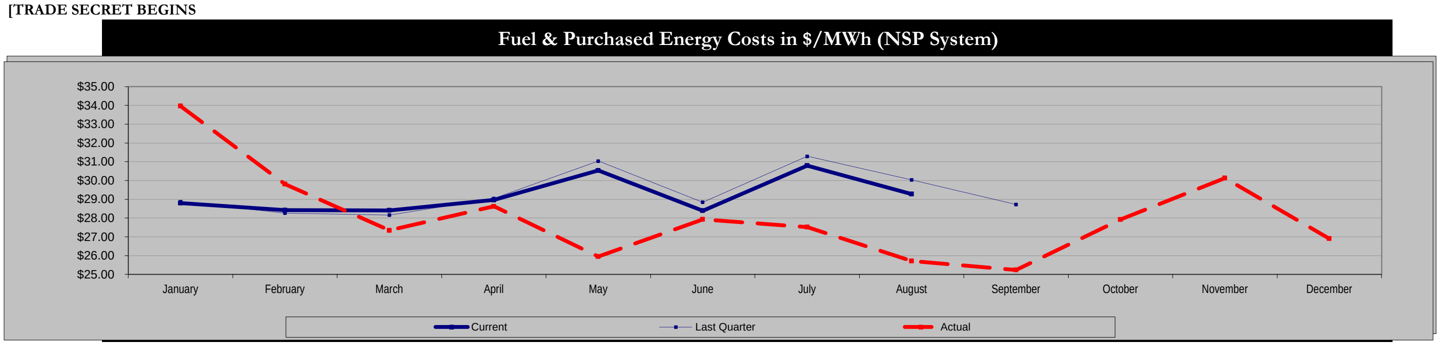
Other factors potentially contributing to costs in the forecast period:

TRADE SECRET ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET INFORMATION EXCISED

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

[TRADE SECRET BEGINS



TRADE SECRET ENDS]

		Quarterly Forecast				Prior Year			Deviation
		Current	Last Quarter	Change		Actual	Forecast	Actual vs Forecast	Year ago Actual vs Current FCST
January	2015	$28.80	$28.87	-0.3%	2014	$33.97	$29.24	16.2%	18.0%
February	2015	$28.42	$28.27	0.6%	2014	$29.81	$28.74	3.7%	4.9%
March	2015	$28.41	$28.16	0.9%	2014	$27.34	$29.89	-8.5%	-3.8%
April	2015	$28.96	$29.04	-0.3%	2014	$28.62	$28.46	0.6%	-1.2%
May	2015	$30.53	$31.03	-1.6%	2014	$25.95	$29.76	-12.8%	-15.0%
June	2015	$28.39	$28.84	-1.6%	2014	$27.93	$29.31	-4.7%	-1.6%
July	2015	$30.80	$31.29	-1.6%	2014	$27.52	$30.63	-10.2%	-10.6%
August	2015	$29.28	$30.03	-2.5%	2014	$25.71	$28.57	-10.0%	-12.2%
		[TRADE SECRET BEGINS	[TRADE SECRET BEGINS						[TRADE SECRET BEGINS
September	2015		$28.72		2014	$25.24	$28.10	-10.2%	
October	2015				2014	$27.92	$28.37	-1.6%	
November	2015				2014	$30.13	$29.08	3.6%	
December	2015				2014	$26.91	$28.84	-6.7%	
		TRADE SECRET ENDS]		TRADE SECRET ENDS]					TRADE SECRET ENDS]
Average (Unweighted)		$29.20				$28.09	$29.08	-3.4%	-3.8%

Forecast Assumption Highlights

[TRADE SECRET BEGINS

Factors impacting costs in the forecast period:

Other factors potentially contributing to costs in the forecast period:

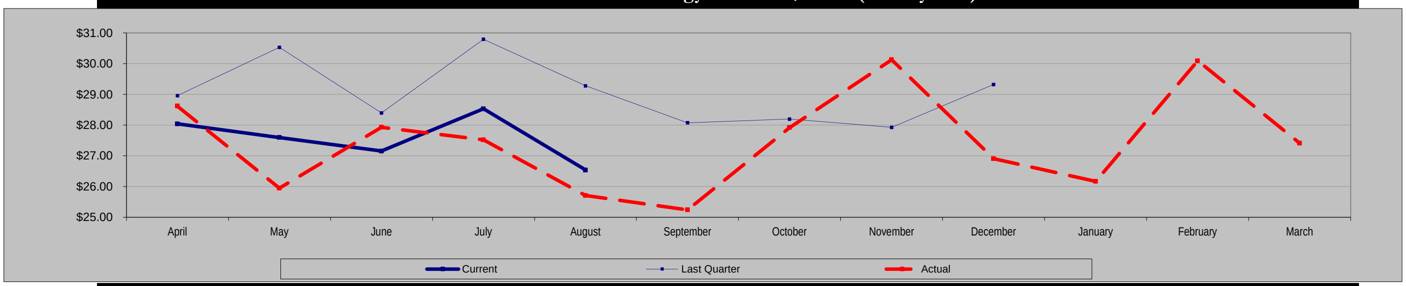
TRADE SECRET ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET INFORMATION EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(April 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
April	2015	$28.04	$28.96	-3.2%	2014	$28.62	$28.46	0.6%	2.1%
May	2015	$27.60	$30.53	-9.6%	2014	$25.95	$29.76	-12.8%	-6.0%
June	2015	$27.15	$28.39	-4.4%	2014	$27.93	$29.31	-4.7%	2.9%
July	2015	$28.53	$30.80	-7.4%	2014	$27.52	$30.63	-10.2%	-3.5%
August	2015	$26.54	$29.28	-9.4%	2014	$25.71	$28.57	-10.0%	-3.1%
		[TRADE SECRET BEGINS		[TRADE SECRET BEGINS					[TRADE SECRET BEGINS
September	2015		$28.08		2014	$25.24	$28.10	-10.2%	
October	2015		$28.20		2014	$27.92	$28.37	-1.6%	
November	2015		$27.93		2014	$30.13	$29.08	3.6%	
December	2015		$29.32		2014	$26.91	$28.84	-6.7%	
January	2016				2015	$26.17	$28.80	-9.1%	
February	2016				2015	$30.09	$28.95	3.9%	
March	2016				2015	$27.41	$26.51	0.0%	
		TRADE SECRET ENDS]		TRADE SECRET ENDS]					TRADE SECRET ENDS]
Average (Unweighted)		$27.57				$27.47	$28.78	-4.6%	-0.4%

Forecast Assumption Highlights

[TRADE SECRET BEGINS

Factors impacting costs in the forecast period:

Other factors potentially contributing to costs in the forecast period:

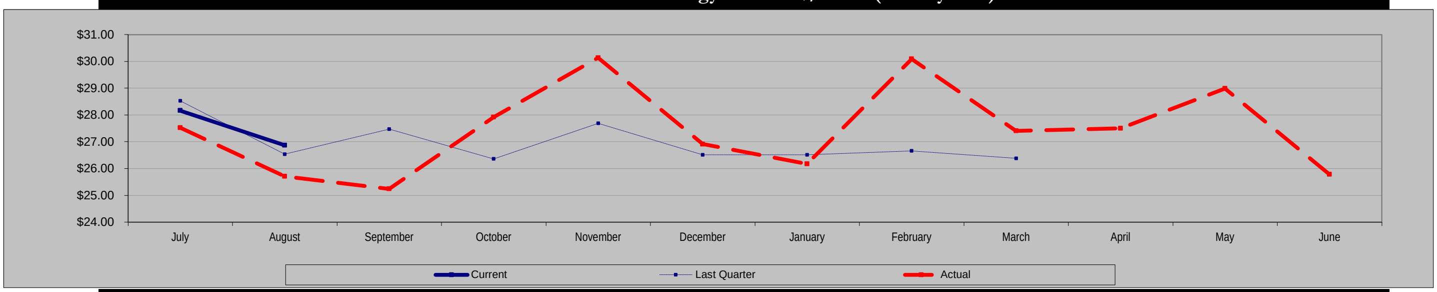
TRADE SECRET ENDS]

PUBLIC DOCUMENT - WITH TRADE SECRET INFORMATION EXCISED

Quarterly Forecast of Fuel & Purchased Energy Costs
(July 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
July	2015	$28.17	$28.53	-1.3%	2014	$27.52	$30.63	-10.2%	-2.3%
August	2015	$26.87	$26.54	1.2%	2014	$25.71	$28.57	-10.0%	-4.3%
		[TRADE SECRET BEGINS		[TRADE SECRET BEGINS					[TRADE SECRET BEGINS
September	2015		$27.47		2014	$25.24	$28.10	-10.2%	
October	2015		$26.36		2014	$27.92	$28.37	-1.6%	
November	2015		$27.69		2014	$30.13	$29.08	3.6%	
December	2015		$26.51		2014	$26.91	$28.84	-6.7%	
January	2016		$26.51		2015	$26.17	$28.80	-9.1%	
February	2016		$26.66		2015	$30.09	$28.95	3.9%	
March	2016		$26.38		2015	$27.41	$26.51	3.4%	
April	2016				2015	$27.50	$28.04	-1.9%	
May	2016				2015	$28.99	$27.55	5.2%	
June	2016				2015	$25.78	$27.59	0.0%	
		TRADE SECRET ENDS]		TRADE SECRET ENDS]					TRADE SECRET ENDS]
Average (Unweighted)		$27.52				$27.45	$28.42	-3.4%	-0.3%

Forecast Assumption Highlights

[TRADE SECRET BEGINS

Factors impacting costs in the forecast period:

Other factors potentially contributing to costs in the forecast period:

TRADE SECRET ENDS]

Northern States Power Company
Electric Operations - State of Minnesota
Deviation Analysis
Actual Costs and Projected Costs (July 2014 - June 2015)

Monthly Forecast & Quarterly Forecast Deviation

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
1	Monthly Forecast - Current Month	3.063¢	2.857¢	2.810¢	2.837¢	2.908¢	2.884¢	2.880¢	2.895¢	2.651¢	2.804¢	2.755¢	2.759¢
		2014 3rd Quarter (7/1/2014)			2014 4th Quarter (10/1/2014)			2015 1st Quarter (1/1/2015)			2015 2nd Quarter (4/1/2015)		
2	Quarterly Forecast - Most Recent Quarter	3.063¢	3.059¢	2.930¢	2.837¢	2.885¢	2.859¢	2.880¢	2.842¢	2.841¢	2.804¢	2.760¢	2.715¢
3	Deviation	0.000	-0.202	-0.120	0.000	0.023	0.025	0.000	0.053	-0.190	0.000	-0.005	0.044
4	In Percent	0.0%	-6.6%	-4.1%	0.0%	0.8%	0.9%	0.0%	1.9%	-6.7%	0.0%	-0.2%	1.6%
		2014 2nd Quarter (4/1/2014)			2014 3rd Quarter (7/1/2014)			2014 4th Quarter (10/1/2014)			2015 1st Quarter (1/1/2015)		
5	Quarterly Forecast - Previous Quarter	3.098¢	3.069¢	2.964¢	2.880¢	2.852¢	2.904¢	2.887¢	2.827¢	2.816¢	2.896¢	3.053¢	2.839¢
6	Deviation	-0.035	-0.212	-0.154	-0.043	0.056	-0.020	-0.007	0.068	-0.165	-0.092	-0.298	-0.080
7	In Percent	-1.1%	-6.9%	-5.2%	-1.5%	2.0%	-0.7%	-0.2%	2.4%	-5.9%	-3.2%	-9.8%	-2.8%

Actual and Forecasted Cost Deviation

		Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
8	Actual System Costs	2.752¢	2.571¢	2.524¢	2.792¢	3.013¢	2.691¢	2.617¢	3.009¢	2.741¢	2.750¢	2.899¢	2.578¢
9	Forecasted System Costs (From Filing 2 Months Ago)	3.063¢	2.857¢	2.810¢	2.837¢	2.908¢	2.884¢	2.880¢	2.895¢	2.651¢	2.804¢	2.755¢	2.759¢
10	Deviation	-0.311¢	-0.286¢	-0.286¢	-0.045¢	0.105¢	-0.193¢	-0.263¢	0.114¢	0.090¢	-0.054¢	0.144¢	-0.181¢
11	In Percent	-10.2%	-10.0%	-10.2%	-1.6%	3.6%	-6.7%	-9.1%	3.9%	3.4%	-1.9%	5.2%	-6.6%

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	July 2014 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 25,076,071.07	$ 718,219.88	$ 25,794,290.95
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,676,603.29	$ (30,250.62)	$ 1,646,352.67
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,281,991.77	$ (41,173.52)	$ 2,240,818.25
1	Day-Ahead Asset Energy Amount	$ 29,034,666.13	$ 646,795.74	$ 29,681,461.87
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 8,141.62		$ 8,141.62
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 882.59		$ 882.59
4	Day-Ahead Market Administration Amount	$ 486,188.19	$ (2,446.62)	$ 483,741.57
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (18,159,042.06)		$ (18,159,042.06)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,413,337.89	$ (25,500.57)	$ 1,387,837.32
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 2,609,170.60	$ (47,076.74)	$ 2,562,093.86
5	Day-Ahead Non-Asset Energy Amount	$ (14,136,533.57)	$ (72,577.31)	$ (14,209,110.88)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (8,141.62)		$ (8,141.62)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (882.59)		$ (882.59)
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	$ 105,260.42	$ (1,899.19)	$ 103,361.23
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (43,976.83)	$ 60,961.22	$ 16,984.39
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 2,435,716.47	$ 1,225,059.68	$ 3,660,776.15
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 189.78	$ (3.42)	$ 186.36
13 c	Real-Time Asset Energy Amount - Loss Component	$ 38,837.80	$ (700.74)	$ 38,137.06
13	Real-Time Asset Energy Amount	$ 2,474,744.05	$ 1,224,355.51	$ 3,699,099.56
14	Real-Time Distribution of Losses Amount	$ (1,821,265.65)		$ (1,821,265.65)
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	$ 27,660.64	$ (1,961.39)	$ 25,699.25
20	Real-Time Miscellaneous Amount	$ (42,408.27)	$ 33,840.59	$ (8,567.68)
21	Real-time Net inadvertent Distribution	$ 68,153.72		$ 68,153.72
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (903,083.91)		$ (903,083.91)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (412,812.00)	$ 7,448.28	$ (405,363.72)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (6,953.64)	$ 125.46	$ (6,828.18)
22	Real-Time Non-Asset Energy Amount	$ (1,322,849.55)	$ 7,573.75	$ (1,315,275.80)
23	Real-Time Revenue Neutrality Uplift Amount	$ 651,313.12	$ (11,751.51)	$ 639,561.61
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (126,910.35)	$ 2,289.82	$ (124,620.53)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 11,487.71	$ 1,576,097.42	$ 1,587,585.13
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,868,018.23)	$ -	$ (1,868,018.23)
29	Financial Transmission Rights Market Administration Amount	$ 48,829.52	$ -	$ 48,829.52
30	Financial Transmission Rights Monthly Allocation Amount	$ (55,827.49)		$ (55,827.49)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 63,723.20	$ (309.86)	$ 63,413.34
34	Real -Time Schedule 24 Allocation Amount	$ (27,501.05)	$ 27,656.78	$ 155.73
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 52,451.19		$ 52,451.19
37	Financial Transmission Guarantee Uplift Amount	$ (51,644.46)		$ (51,644.46)
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,267,335.64		$ 7,267,335.64
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,682,508.05)		$ (7,682,508.05)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (279,224.93)		$ (279,224.93)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 198,282.96		$ 198,282.96
43	Real Time Price Volatility Make Whole Payment	$ (478,571.94)	$ 6,962.59	$ (471,609.35)
	TOTAL MISO CHARGES	**$ 12,552,856.12**	**$ 3,495,587.53**	**$ 16,048,443.65**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 558,270.34**
	SCHEDULE 24 (FOR RETAIL)			**$ 63,569.07**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 15,426,604.24**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	August 2014 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 21,976,219.43	$ 2,310,446.12	$ 24,286,665.55
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 692,607.44	$ (16,542.89)	$ 676,064.55
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,292,405.44	$ (78,638.91)	$ 3,213,766.53
1	Day-Ahead Asset Energy Amount	$ 25,961,232.31	$ 2,215,264.33	$ 28,176,496.64
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (1,208.89)		$ (1,208.89)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,102.35		$ 2,102.35
4	Day-Ahead Market Administration Amount	$ 445,212.99	$ (3,281.51)	$ 441,931.48
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (16,485,508.52)		$ (16,485,508.52)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,149,758.60	$ (27,461.92)	$ 1,122,296.68
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,597,156.70	$ (38,147.99)	$ 1,559,008.71
5	Day-Ahead Non-Asset Energy Amount	$ (13,738,593.22)	$ (65,609.91)	$ (13,804,203.13)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 1,208.89		$ 1,208.89
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,102.35)		$ (2,102.35)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -		$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -		$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 200,932.19	$ (4,799.25)	$ 196,132.94
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (63,618.66)	$ 6,378.39	$ (57,240.27)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 698,727.83	$ 995,163.05	$ 1,693,890.88
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 235,056.24	$ (5,614.30)	$ 229,441.94
13 c	Real-Time Asset Energy Amount - Loss Component	$ 84,196.25	$ (2,011.02)	$ 82,185.23
13	Real-Time Asset Energy Amount	$ 1,017,980.32	$ 987,537.72	$ 2,005,518.04
14	Real-Time Distribution of Losses Amount	$ (2,398,013.37)		$ (2,398,013.37)
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	$ 23,974.68	$ (2,084.34)	$ 21,890.34
20	Real-Time Miscellaneous Amount	$ 13,902.48	$ 36,163.70	$ 50,066.18
21	Real-time Net inadvertent Distribution	$ (430,660.00)		$ (430,660.00)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 139,806.02		$ 139,806.02
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (128,574.03)	$ 3,070.98	$ (125,503.05)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (2,098.88)	$ 50.13	$ (2,048.75)
22	Real-Time Non-Asset Energy Amount	$ 9,133.11	$ 3,121.11	$ 12,254.22
23	Real-Time Revenue Neutrality Uplift Amount	$ 853,732.89	$ (20,391.36)	$ 833,341.53
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 202,603.59	$ (4,839.17)	$ 197,764.42
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (103,743.31)	$ 9,337.52	$ (94,405.79)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,627,573.70)	$ -	$ (1,627,573.70)
29	Financial Transmission Rights Market Administration Amount	$ 38,142.48	$ -	$ 38,142.48
30	Financial Transmission Rights Monthly Allocation Amount	$ (46,048.45)		$ (46,048.45)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 70,280.28	$ (525.72)	$ 69,754.56
34	Real -Time Schedule 24 Allocation Amount	$ (32,757.67)	$ 36,483.13	$ 3,725.46
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (59,134.67)		$ (59,134.67)
37	Financial Transmission Guarantee Uplift Amount	$ 56,113.75		$ 56,113.75
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,267,335.64		$ 7,267,335.64
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,682,508.05)		$ (7,682,508.05)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (279,006.76)		$ (279,006.76)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 198,286.15		$ 198,286.15
43	Real Time Price Volatility Make Whole Payment	$ (390,622.27)	$ 13,038.13	$ (377,584.14)
	TOTAL MISO CHARGES	**$ 9,506,582.73**	**$ 3,205,792.77**	**$ 12,712,375.50**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 501,964.30**
	SCHEDULE 24 (FOR RETAIL)			**$ 73,480.02**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 12,136,931.18**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	September 2014 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 11,197,079.78	$ 2,635,689.84	$ 13,832,769.62
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,394,425.43	$ (150,571.23)	$ 3,243,854.20
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,675,740.31	$ (118,691.52)	$ 2,557,048.79
1	Day-Ahead Asset Energy Amount	$ 17,267,245.52	$ 2,366,427.09	$ 19,633,672.61
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 791.93		$ 791.93
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 536.35		$ 536.35
4	Day-Ahead Market Administration Amount	$ 443,822.55	$ (7,142.39)	$ 436,680.16
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (13,372,565.58)		$ (13,372,565.58)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,440,004.66	$ (63,876.28)	$ 1,376,128.38
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,369,407.86	$ (60,744.72)	$ 1,308,663.14
5	Day-Ahead Non-Asset Energy Amount	$ (10,563,153.06)	$ (124,621.00)	$ (10,687,774.06)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (791.93)		$ (791.93)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (536.35)		$ (536.35)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -		$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -		$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 182,635.74	$ (8,101.43)	$ 174,534.31
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (101,443.45)	$ 25,127.91	$ (76,315.54)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 128,772.36	$ 915,685.05	$ 1,044,457.41
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 232,780.09	$ (10,325.75)	$ 222,454.34
13 c	Real-Time Asset Energy Amount - Loss Component	$ 46,824.00	$ (2,077.04)	$ 44,746.96
13	Real-Time Asset Energy Amount	$ 408,376.45	$ 903,282.26	$ 1,311,658.71
14	Real-Time Distribution of Losses Amount	$ (1,159,550.93)		$ (1,159,550.93)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 144.52		$ 144.52
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (64.21)		$ (64.21)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (144.52)		$ (144.52)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 64.21		$ 64.21
19	Real-Time Market Administration Amount	$ 28,288.37	$ (2,458.68)	$ 25,829.69
20	Real-Time Miscellaneous Amount	$ (51,318.81)	$ 29,332.67	$ (21,986.14)
21	Real-time Net inadvertent Distribution	$ (19,182.14)		$ (19,182.14)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 437,767.37		$ 437,767.37
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (42,936.58)	$ 1,904.60	$ (41,031.98)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 586.12	$ (26.00)	$ 560.12
22	Real-Time Non-Asset Energy Amount	$ 395,416.91	$ 1,878.60	$ 397,295.51
23	Real-Time Revenue Neutrality Uplift Amount	$ 552,825.55	$ (24,522.45)	$ 528,303.10
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 153,058.51	$ (6,789.43)	$ 146,269.08
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (91,310.88)	$ 43,079.66	$ (48,231.22)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,607,044.49)	$ -	$ (4,607,044.49)
29	Financial Transmission Rights Market Administration Amount	$ 28,065.12	$ -	$ 28,065.12
30	Financial Transmission Rights Monthly Allocation Amount	$ (147,426.41)		$ (147,426.41)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 71,951.88	$ (1,156.98)	$ 70,794.90
34	Real -Time Schedule 24 Allocation Amount	$ (34,088.45)	$ 38,499.06	$ 4,410.61
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (401,477.05)		$ (401,477.05)
37	Financial Transmission Guarantee Uplift Amount	$ 414,079.29		$ 414,079.29
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,044,899.06		$ 6,044,899.06
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,528,060.99)		$ (6,528,060.99)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (295,795.44)		$ (295,795.44)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 165,034.21		$ 165,034.21
43	Real Time Price Volatility Make Whole Payment	$ (167,622.56)	$ (1,920.18)	$ (169,542.74)
	TOTAL MISO CHARGES	**$ 1,988,224.50**	**$ 3,230,914.71**	**$ 5,219,139.21**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 490,574.97**
	SCHEDULE 24 (FOR RETAIL)			**$ 75,205.51**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,653,358.73**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	October 2014 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 8,053,479.74	$ 7,809,079.49	$ 15,862,559.23
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 4,127,571.69	$ (325,269.32)	$ 3,802,302.37
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,626,282.04	$ (206,961.63)	$ 2,419,320.41
1	Day-Ahead Asset Energy Amount	$ 14,807,333.47	$ 7,276,848.54	$ 22,084,182.01
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,508.75		$ 1,508.75
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,944.46		$ 1,944.46
4	Day-Ahead Market Administration Amount	$ 481,762.21	$ (16,154.42)	$ 465,607.79
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (15,067,199.80)		$ (15,067,199.80)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 5,075,832.85	$ (399,996.13)	$ 4,675,836.72
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,442,653.08	$ (113,686.89)	$ 1,328,966.19
5	Day-Ahead Non-Asset Energy Amount	$ (8,548,713.87)	$ (513,683.02)	$ (9,062,396.89)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,508.75)		$ (1,508.75)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,944.46)		$ (1,944.46)
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	$ 152,832.02	$ (12,043.78)	$ 140,788.24
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (200,330.96)	$ 121,267.09	$ (79,063.87)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (267,718.41)	$ 1,138,611.97	$ 870,893.56
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (562.00)	$ 44.29	$ (517.71)
13 c	Real-Time Asset Energy Amount - Loss Component	$ (17,101.55)	$ 1,347.67	$ (15,753.88)
13	Real-Time Asset Energy Amount	$ (285,381.96)	$ 1,140,003.93	$ 854,621.97
14	Real-Time Distribution of Losses Amount	$ (1,236,679.64)		$ (1,236,679.64)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 440.25		$ 440.25
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (48.58)		$ (48.58)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (440.25)		$ (440.25)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 48.58		$ 48.58
19	Real-Time Market Administration Amount	$ 34,090.50	$ (2,780.16)	$ 31,310.34
20	Real-Time Miscellaneous Amount	$ (54,710.46)	$ 29,213.68	$ (25,496.78)
21	Real-time Net inadvertent Distribution	$ 71,496.69		$ 71,496.69
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (21,419.55)		$ (21,419.55)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (9,207.90)	$ 725.62	$ (8,482.28)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (16,365.63)	$ 1,289.68	$ (15,075.95)
22	Real-Time Non-Asset Energy Amount	$ (46,993.08)	$ 2,015.30	$ (44,977.78)
23	Real-Time Revenue Neutrality Uplift Amount	$ 868,925.28	$ (68,474.82)	$ 800,450.46
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 178,912.09	$ (14,099.00)	$ 164,813.09
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (47,021.92)	$ 19,273.51	$ (27,748.41)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (6,623,772.88)	$ -	$ (6,623,772.88)
29	Financial Transmission Rights Market Administration Amount	$ 23,626.96	$ -	$ 23,626.96
30	Financial Transmission Rights Monthly Allocation Amount	$ (140,934.26)		$ (140,934.26)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 66,695.92	$ (2,239.02)	$ 64,456.90
34	Real -Time Schedule 24 Allocation Amount	$ (29,650.06)	$ 32,636.22	$ 2,986.16
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (739,710.56)		$ (739,710.56)
37	Financial Transmission Guarantee Uplift Amount	$ 755,421.53		$ 755,421.53
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,044,899.06		$ 6,044,899.06
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,528,060.99)		$ (6,528,060.99)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (290,711.50)		$ (290,711.50)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 165,031.72		$ 165,031.72
43	Real Time Price Volatility Make Whole Payment	$ (224,857.01)	$ 9,544.06	$ (215,312.95)
	TOTAL MISO CHARGES	**$ (1,346,501.70)**	**$ 8,001,328.12**	**$ 6,654,826.42**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 520,545.09**
	SCHEDULE 24 (FOR RETAIL)			**$ 67,443.06**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,066,838.27**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	November 2014 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 3,204,847.02	$ 5,184,337.83	$ 8,389,184.85
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 6,798,706.85	$ (360,655.35)	$ 6,438,051.50
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 4,794,236.59	$ (254,322.93)	$ 4,539,913.66
1	Day-Ahead Asset Energy Amount	$ 14,797,790.46	$ 4,569,359.55	$ 19,367,150.01
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 7,598.24		$ 7,598.24
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 4,148.31		$ 4,148.31
4	Day-Ahead Market Administration Amount	$ 632,552.65	$ (14,526.95)	$ 618,025.70
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,526,418.41)		$ (11,526,418.41)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 615,289.41	$ (32,639.65)	$ 582,649.76
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,533,468.53	$ (81,346.89)	$ 1,452,121.64
5	Day-Ahead Non-Asset Energy Amount	$ (9,377,660.47)	$ (113,986.54)	$ (9,491,647.01)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (7,598.24)		$ (7,598.24)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (4,148.31)		$ (4,148.31)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -		$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -		$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 109,833.21	$ (5,826.39)	$ 104,006.82
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (122,498.38)	$ 65,472.06	$ (57,026.32)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,277,815.39	$ 850,149.83	$ 2,127,965.22
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 274,205.42	$ (14,545.95)	$ 259,659.47
13 c	Real-Time Asset Energy Amount - Loss Component	$ 55,031.63	$ (2,919.30)	$ 52,112.33
13	Real-Time Asset Energy Amount	$ 1,607,052.44	$ 832,684.58	$ 2,439,737.02
14	Real-Time Distribution of Losses Amount	$ (1,961,143.28)		$ (1,961,143.28)
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	$ 44,097.88	$ (3,557.87)	$ 40,540.01
20	Real-Time Miscellaneous Amount	$ 7,393.58	$ 29,687.34	$ 37,080.92
21	Real-time Net inadvertent Distribution	$ (28,411.36)		$ (28,411.36)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 36,309.57		$ 36,309.57
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (76,234.13)	$ 4,044.04	$ (72,190.09)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (8,674.53)	$ 460.16	$ (8,214.37)
22	Real-Time Non-Asset Energy Amount	$ (48,599.09)	$ 4,504.20	$ (44,094.89)
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,429,445.11	$ (75,828.69)	$ 1,353,616.42
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 147,663.09	$ (7,833.18)	$ 139,829.91
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (54,840.00)	$ 14,249.16	$ (40,590.84)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,774,741.95)	$ -	$ (2,774,741.95)
29	Financial Transmission Rights Market Administration Amount	$ 25,647.20	$ -	$ 25,647.20
30	Financial Transmission Rights Monthly Allocation Amount	$ (100,868.14)		$ (100,868.14)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 68,164.28	$ (1,533.31)	$ 66,630.97
34	Real -Time Schedule 24 Allocation Amount	$ (31,408.08)	$ 38,477.25	$ 7,069.17
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (375,496.38)		$ (375,496.38)
37	Financial Transmission Guarantee Uplift Amount	$ 483,540.13		$ 483,540.13
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,044,899.06		$ 6,044,899.06
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,528,060.99)		$ (6,528,060.99)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (349,320.42)		$ (349,320.42)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 165,031.72		$ 165,031.72
43	Real Time Price Volatility Make Whole Payment	$ (598,855.81)	$ 33,988.81	$ (564,867.00)
	TOTAL MISO CHARGES	**$ 3,211,206.46**	**$ 5,365,330.03**	**$ 8,576,536.49**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 684,212.91**
	SCHEDULE 24 (FOR RETAIL)			**$ 73,700.14**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,818,623.44**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	December 2014 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,100,919.46	$ 9,472,266.95	$ 10,573,186.41
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,592,918.96	$ (243,501.17)	$ 2,349,417.79
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,319,822.23	$ (311,764.70)	$ 3,008,057.53
1	Day-Ahead Asset Energy Amount	$ 7,013,660.65	$ 8,917,001.08	$ 15,930,661.73
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (926.26)		$ (926.26)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 5,644.27		$ 5,644.27
4	Day-Ahead Market Administration Amount	$ 549,587.30	$ (22,995.82)	$ 526,591.48
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (13,501,007.27)		$ (13,501,007.27)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,280,300.77	$ (120,233.12)	$ 1,160,067.65
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 2,029,696.15	$ (190,608.88)	$ 1,839,087.27
5	Day-Ahead Non-Asset Energy Amount	$ (10,191,010.35)	$ (310,842.01)	$ (10,501,852.36)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 926.26		$ 926.26
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (5,644.27)		$ (5,644.27)
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	$ 181,370.20	$ (17,314.40)	$ 164,055.80
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (42,131.91)	$ 15,732.48	$ (26,399.43)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,033,908.15	$ 1,236,349.57	$ 2,270,257.72
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (38,310.70)	$ 3,597.76	$ (34,712.94)
13 c	Real-Time Asset Energy Amount - Loss Component	$ (11,887.94)	$ 1,116.40	$ (10,771.54)
13	Real-Time Asset Energy Amount	$ 983,709.51	$ 1,241,063.73	$ 2,224,773.24
14	Real-Time Distribution of Losses Amount	$ (1,344,972.09)		$ (1,344,972.09)
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	$ 39,535.95	$ (3,692.07)	$ 35,843.88
20	Real-Time Miscellaneous Amount	$ (211,261.44)	$ 52,210.57	$ (159,050.87)
21	Real-time Net inadvertent Distribution	$ 8,320.04		$ 8,320.04
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,535.65		$ 8,535.65
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 337.59	$ (31.70)	$ 305.89
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (262.50)	$ 24.65	$ (237.85)
22	Real-Time Non-Asset Energy Amount	$ 8,610.74	$ (7.05)	$ 8,603.69
23	Real-Time Revenue Neutrality Uplift Amount	$ 544,351.65	$ (51,966.22)	$ 492,385.43
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 167,304.49	$ (15,971.63)	$ 151,332.86
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (177,129.60)	$ (1,364.09)	$ (178,493.69)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,748,265.03)	$ -	$ (3,748,265.03)
29	Financial Transmission Rights Market Administration Amount	$ 38,808.88	$ -	$ 38,808.88
30	Financial Transmission Rights Monthly Allocation Amount	$ (181,752.04)		$ (181,752.04)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 65,081.95	$ (2,721.27)	$ 62,360.68
34	Real -Time Schedule 24 Allocation Amount	$ (27,169.44)	$ 29,694.15	$ 2,524.71
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (82,900.03)		$ (82,900.03)
37	Financial Transmission Guarantee Uplift Amount	$ 88,845.34		$ 88,845.34
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,250,896.00		$ 7,250,896.00
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,412,271.29)	$ 117,353.14	$ (7,294,918.15)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (163,750.35)		$ (163,750.35)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 215,785.30		$ 215,785.30
43	Real Time Price Volatility Make Whole Payment	$ (60,664.96)	$ 13,244.26	$ (47,420.70)
	TOTAL MISO CHARGES	**$ (6,487,410.53)**	**$ 9,959,424.84**	**$ 3,472,014.31**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 601,244.24**
	SCHEDULE 24 (FOR RETAIL)			**$ 64,885.39**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,805,884.68**

		System	Intersystem	System Retail
	January 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 2,591,924.99	$ 5,156,228.15	$ 7,748,153.14
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,503,488.11	$ (213,010.63)	$ 3,290,477.48
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,018,262.73	$ (305,108.31)	$ 4,713,154.42
1	Day-Ahead Asset Energy Amount	$ 11,113,675.83	$ 4,638,109.21	$ 15,751,785.04
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 845.35		$ 845.35
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,961.72		$ 3,961.72
4	Day-Ahead Market Administration Amount	$ 500,873.36	$ (12,091.60)	$ 488,781.76
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,128,583.31)		$ (8,128,583.31)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 453,878.46	$ (27,595.62)	$ 426,282.84
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ (850,409.95)	$ 51,704.57	$ (798,705.38)
5	Day-Ahead Non-Asset Energy Amount	$ (8,525,114.80)	$ 24,108.95	$ (8,501,005.85)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (845.35)		$ (845.35)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,961.72)		$ (3,961.72)
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	$ 163,641.43	$ (9,949.33)	$ 153,692.10
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (111,103.02)	$ 45,145.06	$ (65,957.96)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,448,654.35	$ 1,151,464.36	$ 2,600,118.71
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (292,699.49)	$ 17,796.01	$ (274,903.48)
13 c	Real-Time Asset Energy Amount - Loss Component	$ (85,017.45)	$ 5,169.03	$ (79,848.42)
13	Real-Time Asset Energy Amount	$ 1,070,937.41	$ 1,174,429.39	$ 2,245,366.80
14	Real-Time Distribution of Losses Amount	$ (1,511,371.31)		$ (1,511,371.31)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (12.51)		$ (12.51)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (23.77)		$ (23.77)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 12.51		$ 12.51
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 23.77		$ 23.77
19	Real-Time Market Administration Amount	$ 37,302.32	$ (3,163.81)	$ 34,138.51
20	Real-Time Miscellaneous Amount	$ (405,509.67)	$ 95,051.51	$ (310,458.16)
21	Real-time Net inadvertent Distribution	$ (96,680.24)		$ (96,680.24)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,020.62		$ 8,020.62
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (2,336.69)	$ 142.07	$ (2,194.62)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 1,734.88	$ (105.48)	$ 1,629.40
22	Real-Time Non-Asset Energy Amount	$ 7,418.81	$ 36.59	$ 7,455.40
23	Real-Time Revenue Neutrality Uplift Amount	$ 379,920.53	$ (23,099.01)	$ 356,821.52
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 116,402.97	$ (7,077.25)	$ 109,325.72
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,267.67)	$ (798.19)	$ (2,065.86)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,088,429.08)	$ -	$ (3,088,429.08)
29	Financial Transmission Rights Market Administration Amount	$ 38,159.60	$ -	$ 38,159.60
30	Financial Transmission Rights Monthly Allocation Amount	$ (187,254.82)		$ (187,254.82)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 63,799.38	$ (1,528.00)	$ 62,271.38
34	Real -Time Schedule 24 Allocation Amount	$ (29,413.48)	$ 35,196.11	$ 5,782.63
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (54,659.01)		$ (54,659.01)
37	Financial Transmission Guarantee Uplift Amount	$ 46,900.17		$ 46,900.17
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,250,896.00		$ 7,250,896.00
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,412,271.29)	$ 19,168.06	$ (7,393,103.23)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (104,620.47)		$ (104,620.47)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 215,789.60		$ 215,789.60
43	Real Time Price Volatility Make Whole Payment	$ (348,515.12)	$ 15,204.93	$ (333,310.19)
	TOTAL MISO CHARGES	**$ (870,492.57)**	**$ 5,988,742.62**	**$ 5,118,250.05**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 561,079.87**
	SCHEDULE 24 (FOR RETAIL)			**$ 68,054.01**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,489,116.17**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	February 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 8,091,355.95	$ 4,195,308.89	$ 12,286,664.84
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,495,521.83	$ (136,965.65)	$ 2,358,556.18
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,746,588.94	$ (205,629.94)	$ 3,540,959.00
1	Day-Ahead Asset Energy Amount	$ 14,333,466.72	$ 3,852,713.29	$ 18,186,180.01
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,571.24		$ 4,571.24
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 6,378.65		$ 6,378.65
4	Day-Ahead Market Administration Amount	$ 623,735.83	$ (11,477.47)	$ 612,258.36
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,731,613.87)		$ (11,731,613.87)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,447,300.89	$ (79,434.49)	$ 1,367,866.40
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,059,024.79	$ (58,124.13)	$ 1,000,900.66
5	Day-Ahead Non-Asset Energy Amount	$ (9,225,288.19)	$ (137,558.62)	$ (9,362,846.81)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,571.24)		$ (4,571.24)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (6,378.65)		$ (6,378.65)
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	$ 206,399.66	$ (11,328.16)	$ 195,071.50
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (100,928.64)	$ 33,732.18	$ (67,196.46)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 789,094.69	$ 1,743,666.38	$ 2,532,761.07
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 298,360.38	$ (16,375.38)	$ 281,985.00
13 c	Real-Time Asset Energy Amount - Loss Component	$ 72,520.67	$ (3,980.27)	$ 68,540.40
13	Real-Time Asset Energy Amount	$ 1,159,975.74	$ 1,723,310.73	$ 2,883,286.47
14	Real-Time Distribution of Losses Amount	$ (1,785,962.00)		$ (1,785,962.00)
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	$ 40,413.21	$ (5,980.02)	$ 34,433.19
20	Real-Time Miscellaneous Amount	$ (378,713.36)	$ 70,005.00	$ (308,708.36)
21	Real-time Net inadvertent Distribution	$ (59,939.70)		$ (59,939.70)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (5,530.01)		$ (5,530.01)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 12,085.15	$ (663.29)	$ 11,421.86
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 840.85	$ (46.15)	$ 794.70
22	Real-Time Non-Asset Energy Amount	$ 7,395.99	$ (709.44)	$ 6,686.55
23	Real-Time Revenue Neutrality Uplift Amount	$ 716,461.93	$ (39,322.71)	$ 677,139.22
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 154,958.46	$ (8,504.83)	$ 146,453.63
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (68,367.77)	$ 5,944.00	$ (62,423.77)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,638,215.63)	$ -	$ (2,638,215.63)
29	Financial Transmission Rights Market Administration Amount	$ 35,475.84	$ -	$ 35,475.84
30	Financial Transmission Rights Monthly Allocation Amount	$ (113,847.87)		$ (113,847.87)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 67,939.47	$ (1,239.19)	$ 66,700.28
34	Real -Time Schedule 24 Allocation Amount	$ (31,611.17)	$ 36,614.75	$ 5,003.58
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (71,077.02)		$ (71,077.02)
37	Financial Transmission Guarantee Uplift Amount	$ 67,927.21		$ 67,927.21
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,250,896.00		$ 7,250,896.00
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,412,271.29)	$ 28,268.10	$ (7,384,003.19)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (165,295.02)		$ (165,295.02)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 215,789.60		$ 215,789.60
43	Real Time Price Volatility Make Whole Payment	$ (327,724.31)	$ 21,241.80	$ (306,482.51)
	TOTAL MISO CHARGES	**$ 2,501,593.69**	**$ 5,555,709.42**	**$ 8,057,303.11**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 682,167.39**
	SCHEDULE 24 (FOR RETAIL)			**$ 71,703.86**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,303,431.86**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	March 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 10,011,388.35	$ 3,404,076.88	$ 13,415,465.23
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,503,187.90	$ (144,319.14)	$ 2,358,868.76
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,141,039.63	$ (181,093.93)	$ 2,959,945.70
1	Day-Ahead Asset Energy Amount	$ 15,655,615.88	$ 3,078,663.81	$ 18,734,279.69
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,855.11		$ 4,855.11
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,755.65		$ 2,755.65
4	Day-Ahead Market Administration Amount	$ 704,788.90	$ (14,271.21)	$ 690,517.69
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (9,837,021.18)		$ (9,837,021.18)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 183,787.18	$ (10,596.09)	$ 173,191.09
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 535,511.28	$ (30,874.44)	$ 504,636.84
5	Day-Ahead Non-Asset Energy Amount	$ (9,117,722.72)	$ (41,470.53)	$ (9,159,193.25)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,855.11)		$ (4,855.11)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,755.65)		$ (2,755.65)
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	$ 473,335.28	$ (27,289.74)	$ 446,045.54
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (408,433.12)	$ 75,478.05	$ (332,955.07)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (37,503.89)	$ 1,200,976.08	$ 1,163,472.19
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (71,176.63)	$ 4,103.63	$ (67,073.00)
13 c	Real-Time Asset Energy Amount - Loss Component	$ (27,655.28)	$ 1,594.44	$ (26,060.84)
13	Real-Time Asset Energy Amount	$ (136,335.80)	$ 1,206,674.15	$ 1,070,338.35
14	Real-Time Distribution of Losses Amount	$ (1,047,242.39)		$ (1,047,242.39)
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	$ 51,256.26	$ (5,714.35)	$ 45,541.91
20	Real-Time Miscellaneous Amount	$ (365,421.26)	$ 69,381.57	$ (296,039.69)
21	Real-time Net inadvertent Distribution	$ 41,702.18		$ 41,702.18
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 6,239.00		$ 6,239.00
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ 66.12	$ (3.81)	$ 62.31
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 8.67	$ (0.50)	$ 8.17
22	Real-Time Non-Asset Energy Amount	$ 6,313.79	$ (4.31)	$ 6,309.48
23	Real-Time Revenue Neutrality Uplift Amount	$ 303,189.66	$ (17,480.14)	$ 285,709.52
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 242,120.87	$ (13,959.27)	$ 228,161.60
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (487,867.25)	$ 251,432.56	$ (236,434.69)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,033,457.66)	$ -	$ (2,033,457.66)
29	Financial Transmission Rights Market Administration Amount	$ 35,653.20	$ -	$ 35,653.20
30	Financial Transmission Rights Monthly Allocation Amount	$ (73,502.00)		$ (73,502.00)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 71,907.79	$ (1,431.59)	$ 70,476.20
34	Real -Time Schedule 24 Allocation Amount	$ (32,610.10)	$ 25,868.51	$ (6,741.59)
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 25,507.49		$ 25,507.49
37	Financial Transmission Guarantee Uplift Amount	$ (34,323.72)		$ (34,323.72)
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,666,528.17		$ 6,666,528.17
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,785,365.96)	$ 16,306.18	$ (6,769,059.78)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (218,926.71)		$ (218,926.71)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 293,678.17		$ 293,678.17
43	Real Time Price Volatility Make Whole Payment	$ (162,062.63)	$ 12,005.62	$ (150,057.01)
	TOTAL MISO CHARGES	**$ 3,668,326.32**	**$ 4,614,189.30**	**$ 8,282,515.62**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 771,712.80**
	SCHEDULE 24 (FOR RETAIL)			**$ 63,734.61**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,447,068.21**

Northern States Power Company

Docket No. E999/AA-15-611

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

Part J, Section 5

Schedule 1

			System		Intersystem		System Retail
	April 2015 Actual						
1 a	Day-Ahead Asset Energy Amount - Energy Component	$	13,839,801.09	$	1,134,682.23	$	14,974,483.32
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$	(389,266.03)	$	8,983.90	$	(380,282.13)
1 c	Day-Ahead Asset Energy Amount - Loss Component	$	1,544,637.91	$	(35,648.83)	$	1,508,989.08
1	Day-Ahead Asset Energy Amount	$	14,995,172.97	$	1,108,017.30	$	16,103,190.27
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$	6,827.19			$	6,827.19
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$	2,250.67			$	2,250.67
4	Day-Ahead Market Administration Amount	$	517,134.72	$	(4,343.43)	$	512,791.29
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$	(9,116,033.45)			$	(9,116,033.45)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$	2,083,502.87	$	(48,085.34)	$	2,035,417.53
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$	1,353,856.51	$	(31,245.77)	$	1,322,610.74
5	Day-Ahead Non-Asset Energy Amount	$	(5,678,674.07)	$	(79,331.11)	$	(5,758,005.18)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$	(6,827.19)			$	(6,827.19)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$	(2,250.67)			$	(2,250.67)
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	$	19,515.91	$	(450.41)	$	19,065.50
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$	(165,087.62)	$	41,897.65	$	(123,189.97)
12	Day-Ahead Virtual Energy Amount	$	-			$	-
13 a	Real-Time Asset Energy Amount - Energy Component	$	1,181,757.37	$	366,699.88	$	1,548,457.25
13 b	Real-Time Asset Energy Amount - Congestion Component	$	95,379.26	$	(2,201.27)	$	93,177.99
13 c	Real-Time Asset Energy Amount - Loss Component	$	45,812.59	$	(1,057.31)	$	44,755.28
13	Real-Time Asset Energy Amount	$	1,322,949.22	$	363,441.30	$	1,686,390.52
14	Real-Time Distribution of Losses Amount	$	(925,745.90)			$	(925,745.90)
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	$	38,281.67	$	(1,917.32)	$	36,364.35
20	Real-Time Miscellaneous Amount	$	(260,323.94)	$	47,609.77	$	(212,714.17)
21	Real-time Net inadvertent Distribution	$	(32,185.36)			$	(32,185.36)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$	8,501.86			$	8,501.86
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$	(1,982.35)	$	45.75	$	(1,936.60)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$	(1,025.28)	$	23.66	$	(1,001.62)
22	Real-Time Non-Asset Energy Amount	$	5,494.23	$	69.41	$	5,563.64
23	Real-Time Revenue Neutrality Uplift Amount	$	414,074.06	$	(9,556.45)	$	404,517.61
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$	31,703.22	$	(731.68)	$	30,971.54
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$	(10,022.13)	$	1,435.18	$	(8,586.95)
26	Real-Time Uninstructed Deviation Amount	$	-	$	-	$	-
27	Real-Time Virtual Energy Amount	$	-			$	-
28	Financial Transmission Rights Hourly Allocation Amount	$	(173,880.77)	$	-	$	(173,880.77)
29	Financial Transmission Rights Market Administration Amount	$	34,623.04	$	-	$	34,623.04
30	Financial Transmission Rights Monthly Allocation Amount	$	(45,114.09)			$	(45,114.09)
31	Financial Transmission Rights Transaction Amount	$	-			$	-
32	Financial Transmission Rights Yearly Allocation Amount	$	(780,712.59)			$	(780,712.59)
33	Day-Ahead Schedule 24 Allocation Amount	$	62,391.69	$	(534.22)	$	61,857.47
34	Real -Time Schedule 24 Allocation Amount	$	(29,955.60)	$	34,813.93	$	4,858.33
35	Schedule 24 Admin Allocation			$	-	$	-
36	Financial Transmission Rights Full Funding Guarantee Amount	$	888,137.17			$	888,137.17
37	Financial Transmission Guarantee Uplift Amount	$	(866,657.41)			$	(866,657.41)
38	Financial Transmission Rights Monthly Transacton Amount	$	-			$	-
39	Auction Revenue Rights - FTR Auction Transactions	$	6,666,528.17			$	6,666,528.17
40	Auction Revenue Rights - Monthly ARR Revenue	$	(6,785,365.96)	$	22,235.70	$	(6,763,130.26)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$	(216,392.08)			$	(216,392.08)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$	293,678.17			$	293,678.17
43	Real Time Price Volatility Make Whole Payment	$	(163,764.17)	$	5,513.09	$	(158,251.08)
	TOTAL MISO CHARGES	**$**	**9,155,802.55**	**$**	**1,528,168.72**	**$**	**10,683,971.27**
	SCHEDULE 16 & 17 (FOR RETAIL)					**$**	**583,778.68**
	SCHEDULE 24 (FOR RETAIL)					**$**	**66,715.80**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)					**$**	**10,033,476.79**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	May 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 17,252,953.52	$ 1,271,708.58	$ 18,524,662.10
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 799,034.88	$ (29,214.14)	$ 769,820.74
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,896,380.59	$ (69,335.05)	$ 1,827,045.54
1	Day-Ahead Asset Energy Amount	$ 19,948,368.99	$ 1,173,159.39	$ 21,121,528.38
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,675.74		$ 4,675.74
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,852.22		$ 1,852.22
4	Day-Ahead Market Administration Amount	$ 510,387.75	$ (5,835.93)	$ 504,551.82
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,077,244.02)		$ (11,077,244.02)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,286,302.21	$ (83,591.28)	$ 2,202,710.93
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,232,148.84	$ (45,049.56)	$ 1,187,099.28
5	Day-Ahead Non-Asset Energy Amount	$ (7,558,792.97)	$ (128,640.84)	$ (7,687,433.81)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,675.74)		$ (4,675.74)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,852.22)		$ (1,852.22)
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	$ 43,140.27	$ (1,577.29)	$ 41,562.98
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (10,305.01)	$ (4,542.82)	$ (14,847.83)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,067,564.51)	$ 831,015.25	$ (236,549.26)
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 241,176.99	$ (8,817.86)	$ 232,359.13
13 c	Real-Time Asset Energy Amount - Loss Component	$ 76,484.98	$ (2,796.43)	$ 73,688.55
13	Real-Time Asset Energy Amount	$ (749,902.54)	$ 819,400.96	$ 69,498.42
14	Real-Time Distribution of Losses Amount	$ (786,313.16)		$ (786,313.16)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (8.00)		$ (8.00)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (1.93)		$ (1.93)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8.00		$ 8.00
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 1.93		$ 1.93
19	Real-Time Market Administration Amount	$ 40,108.78	$ (3,876.18)	$ 36,232.60
20	Real-Time Miscellaneous Amount	$ (78,037.09)	$ 64,040.02	$ (13,997.07)
21	Real-time Net inadvertent Distribution	$ (38,015.41)		$ (38,015.41)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 76,958.60		$ 76,958.60
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (19,977.46)	$ 730.41	$ (19,247.05)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (3,761.33)	$ 137.52	$ (3,623.81)
22	Real-Time Non-Asset Energy Amount	$ 53,219.81	$ 867.93	$ 54,087.74
23	Real-Time Revenue Neutrality Uplift Amount	$ 697,474.62	$ (5,847.79)	$ 691,626.83
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 159,942.57	$ (25,500.92)	$ 134,441.65
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (54,669.10)	$ 35,866.46	$ (18,802.64)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,568,938.67)	$ -	$ (2,568,938.67)
29	Financial Transmission Rights Market Administration Amount	$ 34,200.72	$ -	$ 34,200.72
30	Financial Transmission Rights Monthly Allocation Amount	$ (47,991.31)		$ (47,991.31)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 62,047.01	$ (709.65)	$ 61,337.36
34	Real -Time Schedule 24 Allocation Amount	$ (29,960.39)	$ 35,858.30	$ 5,897.91
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (11,782.92)		$ (11,782.92)
37	Financial Transmission Guarantee Uplift Amount	$ 11,782.92		$ 11,782.92
38	Financial Transmission Rights Monthly Transacton Amount	$ -		$ -
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,666,528.17		$ 6,666,528.17
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,785,365.96)	$ 23,718.08	$ (6,761,647.88)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (218,818.02)		$ (218,818.02)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 293,678.17		$ 293,678.17
43	Real Time Price Volatility Make Whole Payment	$ (135,002.09)	$ 3,282.38	$ (131,719.71)
	TOTAL MISO CHARGES	**$ 9,446,985.14**	**$ 1,979,662.11**	**$ 11,426,647.25**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 574,985.14**
	SCHEDULE 24 (FOR RETAIL)			**$ 67,235.27**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 10,784,426.84**

MISO DAY 2 MARKET SETTLEMENT CALCULATIONS BY CHARGE TYPES

		System	Intersystem	System Retail
	June 2015 Actual			
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 8,799,747.75	$ 2,974,148.26	$ 11,773,896.01
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ (143,069.84)	$ 6,273.36	$ (136,796.48)
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,412,016.83	$ (105,762.71)	$ 2,306,254.12
1	Day-Ahead Asset Energy Amount	$ 11,068,694.74	$ 2,874,658.91	$ 13,943,353.65
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (1,132.03)		$ (1,132.03)
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,197.31		$ 1,197.31
4	Day-Ahead Market Administration Amount	$ 583,501.85	$ (9,893.81)	$ 573,608.04
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,256,283.68)		$ (11,256,283.68)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,446,476.67	$ (63,425.47)	$ 1,383,051.20
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,204,680.32	$ (52,823.12)	$ 1,151,857.20
5	Day-Ahead Non-Asset Energy Amount	$ (8,605,126.69)	$ (116,248.59)	$ (8,721,375.28)
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 1,132.03		$ 1,132.03
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,197.31)		$ (1,197.31)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -		$ -
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -		$ -
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 114,315.22	$ (5,012.52)	$ 109,302.70
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (26,220.18)	$ 9,255.55	$ (16,964.63)
12	Day-Ahead Virtual Energy Amount	$ -		$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,044,919.96	$ 792,543.90	$ 1,837,463.86
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 3,528.85	$ (154.73)	$ 3,374.12
13 c	Real-Time Asset Energy Amount - Loss Component	$ 4,286.65	$ (187.96)	$ 4,098.69
13	Real-Time Asset Energy Amount	$ 1,052,735.46	$ 792,201.21	$ 1,844,936.67
14	Real-Time Distribution of Losses Amount	$ (1,190,722.49)		$ (1,190,722.49)
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	$ 39,876.48	$ (2,828.56)	$ 37,047.92
20	Real-Time Miscellaneous Amount	$ (37,149.98)	$ 40,146.52	$ 2,996.54
21	Real-time Net inadvertent Distribution	$ 20,092.04		$ 20,092.04
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (183,721.04)		$ (183,721.04)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (42,837.66)	$ 1,878.36	$ (40,959.30)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (5,287.17)	$ 231.83	$ (5,055.34)
22	Real-Time Non-Asset Energy Amount	$ (231,845.87)	$ 2,110.19	$ (229,735.68)
23	Real-Time Revenue Neutrality Uplift Amount	$ 672,176.95	$ (6,968.90)	$ 665,208.05
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 158,932.21	$ (29,473.78)	$ 129,458.43
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (117,146.13)	$ 65,810.60	$ (51,335.53)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -		$ -
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,439,393.93)	$ -	$ (1,439,393.93)
29	Financial Transmission Rights Market Administration Amount	$ 34,161.28	$ -	$ 34,161.28
30	Financial Transmission Rights Monthly Allocation Amount	$ (50,654.52)		$ (50,654.52)
31	Financial Transmission Rights Transaction Amount	$ -		$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -		$ -
33	Day-Ahead Schedule 24 Allocation Amount	$ 81,719.83	$ (1,392.47)	$ 80,327.36
34	Real -Time Schedule 24 Allocation Amount	$ (94,321.37)	$ 88,233.67	$ (6,087.70)
35	Schedule 24 Admin Allocation		$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 9,151.86		$ 9,151.86
37	Financial Transmission Guarantee Uplift Amount	$ (10,567.73)		$ (10,567.73)
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)	$ 4,447.14	$ (3,583,891.24)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (116,560.48)		$ (116,560.48)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 67,063.94		$ 67,063.94
43	Real Time Price Volatility Make Whole Payment	$ (169,145.79)	$ 5,569.60	$ (163,576.19)
	TOTAL MISO CHARGES	**$ 1,742,228.00**	**$ 3,710,614.76**	**$ 5,452,842.76**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 644,817.24**
	SCHEDULE 24 (FOR RETAIL)			**$ 74,239.66**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,733,785.86**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	July 2014 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 25,076,071.07	$ 718,219.88	$ 25,794,290.95	$ 19,273,427.61
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,281,991.77	$ (41,173.52)	$ 2,240,818.25	$ 1,674,333.61
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 882.59	$ -	$ 882.59	$ 659.47
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (18,159,042.06)	$ -	$ (18,159,042.06)	$ (13,568,389.35)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 2,609,170.60	$ (47,076.74)	$ 2,562,093.86	$ 1,914,389.92
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (882.59)	$ -	$ (882.59)	$ (659.47)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 2,435,716.47	$ 1,225,059.68	$ 3,660,776.15	$ 2,735,322.49
13 c	Real-Time Asset Energy Amount - Loss Component	$ 38,837.80	$ (700.74)	$ 38,137.06	$ 28,495.91
14	Real-Time Distribution of Losses Amount	$ (1,821,265.65)	$ -	$ (1,821,265.65)	$ (1,360,844.99)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 68,153.72	$ -	$ 68,153.72	$ 50,924.28
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (903,083.91)	$ -	$ (903,083.91)	$ (674,781.97)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (6,953.64)	$ 125.46	$ (6,828.18)	$ (5,102.00)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,676,603.29	$ (30,250.62)	$ 1,646,352.67	$ 1,230,150.47
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 8,141.62	$ -	$ 8,141.62	$ 6,083.40
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,413,337.89	$ (25,500.57)	$ 1,387,837.32	$ 1,036,988.46
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (8,141.62)	$ -	$ (8,141.62)	$ (6,083.40)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 189.78	$ (3.42)	$ 186.36	$ 139.24
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	$ (412,812.00)	$ 7,448.28	$ (405,363.72)	$ (302,886.72)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,868,018.23)	$ -	$ (1,868,018.23)	$ (1,395,778.40)
30	Financial Transmission Rights Monthly Allocation Amount	$ (55,827.49)	$ -	$ (55,827.49)	$ (41,714.16)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 52,451.19	$ -	$ 52,451.19	$ 39,191.39
37	Financial Transmission Guarantee Uplift Amount	$ (51,644.46)	$ -	$ (51,644.46)	$ (38,588.61)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 651,313.12	$ (11,751.51)	$ 639,561.61	$ 477,878.78
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 105,260.42	$ (1,899.19)	$ 103,361.23	$ 77,231.24
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (43,976.83)	$ 60,961.22	$ 16,984.39	$ 12,690.69
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ (126,910.35)	$ 2,289.82	$ (124,620.53)	$ (93,116.14)
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 11,487.71	$ 1,576,097.42	$ 1,587,585.13	$ 1,186,239.51
43	Real Time Price Volatility Make Whole Payment	$ (478,571.94)	$ 6,962.59	$ (471,609.35)	$ (352,385.29)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 486,188.19	$ (2,446.62)	$ 483,741.57	$ 361,450.45
19	Real-Time Market Administration Amount	$ 27,660.64	$ (1,961.39)	$ 25,699.25	$ 19,202.41
29	Financial Transmission Rights Market Administration Amount	$ 48,829.52	$ -	$ 48,829.52	$ 36,485.29
33	Day-Ahead Schedule 24 Allocation Amount	$ 63,723.20	$ (309.86)	$ 63,413.34	$ 47,382.28
34	Real -Time Schedule 24 Allocation Amount	$ (27,501.05)	$ 27,656.78	$ 155.73	$ 116.36
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	$ (42,408.27)	$ 33,840.59	$ (8,567.68)	$ (6,401.75)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,267,335.64	$ -	$ 7,267,335.64	$ 5,430,134.43
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,682,508.05)	$ -	$ (7,682,508.05)	$ (5,740,350.18)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (279,224.93)	$ -	$ (279,224.93)	$ (208,636.15)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 198,282.96	$ -	$ 198,282.96	$ 148,156.52
	TOTAL MISO CHARGES	**$ 12,552,856.12**	**$ 3,495,587.53**	**$ 16,048,443.65**	**$ 11,991,355.67**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 558,270.34**	**$ 417,138.16**
	SCHEDULE 24 (FOR RETAIL)			**$ 63,569.07**	**$ 47,498.64**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 15,426,604.24**	**$ 11,526,718.86**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	August 2014 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 21,976,219.43	$ 2,310,446.12	$ 24,286,665.55	$ 18,198,260.82
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,292,405.44	$ (78,638.91)	$ 3,213,766.53	$ 2,408,109.98
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,102.35	$ -	$ 2,102.35	$ 1,575.31
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (16,485,508.52)	$ -	$ (16,485,508.52)	$ (12,352,769.60)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,597,156.70	$ (38,147.99)	$ 1,559,008.71	$ 1,168,182.06
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,102.35)	$ -	$ (2,102.35)	$ (1,575.31)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 698,727.83	$ 995,163.05	$ 1,693,890.88	$ 1,269,250.73
13 c	Real-Time Asset Energy Amount - Loss Component	$ 84,196.25	$ (2,011.02)	$ 82,185.23	$ 61,582.28
14	Real-Time Distribution of Losses Amount	$ (2,398,013.37)	$ -	$ (2,398,013.37)	$ (1,796,857.32)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (430,660.00)	$ -	$ (430,660.00)	$ (322,698.19)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 139,806.02	$ -	$ 139,806.02	$ 104,758.16
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (2,098.88)	$ 50.13	$ (2,048.75)	$ (1,535.15)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 692,607.44	$ (16,542.89)	$ 676,064.55	$ 506,582.47
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (1,208.89)	$ -	$ (1,208.89)	$ (905.83)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,149,758.60	$ (27,461.92)	$ 1,122,296.68	$ 840,949.03
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 1,208.89	$ -	$ 1,208.89	$ 905.83
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 235,056.24	$ (5,614.30)	$ 229,441.94	$ 171,923.32
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	$ (128,574.03)	$ 3,070.98	$ (125,503.05)	$ (94,040.79)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,627,573.70)	$ -	$ (1,627,573.70)	$ (1,219,558.55)
30	Financial Transmission Rights Monthly Allocation Amount	$ (46,048.45)	$ -	$ (46,048.45)	$ (34,504.60)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (59,134.67)	$ -	$ (59,134.67)	$ (44,310.25)
37	Financial Transmission Guarantee Uplift Amount	$ 56,113.75	$ -	$ 56,113.75	$ 42,046.64
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 853,732.89	$ (20,391.36)	$ 833,341.53	$ 624,431.81
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 200,932.19	$ (4,799.25)	$ 196,132.94	$ 146,964.53
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (63,618.66)	$ 6,378.39	$ (57,240.27)	$ (42,890.75)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 202,603.59	$ (4,839.17)	$ 197,764.42	$ 148,187.01
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (103,743.31)	$ 9,337.52	$ (94,405.79)	$ (70,739.28)
43	Real Time Price Volatility Make Whole Payment	$ (390,622.27)	$ 13,038.13	$ (377,584.14)	$ (282,927.87)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 445,212.99	$ (3,281.51)	$ 441,931.48	$ 331,144.03
19	Real-Time Market Administration Amount	$ 23,974.68	$ (2,084.34)	$ 21,890.34	$ 16,402.67
29	Financial Transmission Rights Market Administration Amount	$ 38,142.48	$ -	$ 38,142.48	$ 28,580.57
33	Day-Ahead Schedule 24 Allocation Amount	$ 70,280.28	$ (525.72)	$ 69,754.56	$ 52,267.85
34	Real -Time Schedule 24 Allocation Amount	$ (32,757.67)	$ 36,483.13	$ 3,725.46	$ 2,791.53
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	$ 13,902.48	$ 36,163.70	$ 50,066.18	$ 37,515.13
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,267,335.64	$ -	$ 7,267,335.64	$ 5,445,493.09
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,682,508.05)	$ -	$ (7,682,508.05)	$ (5,756,586.26)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (279,006.76)	$ -	$ (279,006.76)	$ (209,062.78)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 198,286.15	$ -	$ 198,286.15	$ 148,577.95
	TOTAL MISO CHARGES	**$ 9,506,582.73**	**$ 3,205,792.77**	**$ 12,712,375.50**	**$ 9,525,520.27**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 501,964.30**	**$ 376,127.27**
	SCHEDULE 24 (FOR RETAIL)			**$ 73,480.02**	**$ 55,059.37**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 12,136,931.18**	**$ 9,094,333.63**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	September 2014 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 11,197,079.78	$ 2,635,689.84	$ 13,832,769.62	$ 10,315,686.08
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,675,740.31	$ (118,691.52)	$ 2,557,048.79	$ 1,906,900.30
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 536.35	$ -	$ 536.35	$ 399.98
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (13,372,565.58)	$ -	$ (13,372,565.58)	$ (9,972,492.30)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,369,407.86	$ (60,744.72)	$ 1,308,663.14	$ 975,925.90
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (536.35)	$ -	$ (536.35)	$ (399.98)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 128,772.36	$ 915,685.05	$ 1,044,457.41	$ 778,896.42
13 c	Real-Time Asset Energy Amount - Loss Component	$ 46,824.00	$ (2,077.04)	$ 44,746.96	$ 33,369.72
14	Real-Time Distribution of Losses Amount	$ (1,159,550.93)	$ -	$ (1,159,550.93)	$ (864,726.57)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (64.21)	$ -	$ (64.21)	$ (47.88)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 64.21	$ -	$ 64.21	$ 47.88
21	Real-time Net inadvertent Distribution	$ (19,182.14)	$ -	$ (19,182.14)	$ (14,304.94)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 437,767.37	$ -	$ 437,767.37	$ 326,461.79
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 586.12	$ (26.00)	$ 560.12	$ 417.71
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,394,425.43	$ (150,571.23)	$ 3,243,854.20	$ 2,419,080.38
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 791.93	$ -	$ 791.93	$ 590.58
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,440,004.66	$ (63,876.28)	$ 1,376,128.38	$ 1,026,237.60
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (791.93)	$ -	$ (791.93)	$ (590.58)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 232,780.09	$ (10,325.75)	$ 222,454.34	$ 165,893.69
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 144.52	$ -	$ 144.52	$ 107.77
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (144.52)	$ -	$ (144.52)	$ (107.77)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (42,936.58)	$ 1,904.60	$ (41,031.98)	$ (30,599.30)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (4,607,044.49)	$ -	$ (4,607,044.49)	$ (3,435,669.50)
30	Financial Transmission Rights Monthly Allocation Amount	$ (147,426.41)	$ -	$ (147,426.41)	$ (109,942.16)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (401,477.05)	$ -	$ (401,477.05)	$ (299,398.55)
37	Financial Transmission Guarantee Uplift Amount	$ 414,079.29	$ -	$ 414,079.29	$ 308,796.58
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 552,825.55	$ (24,522.45)	$ 528,303.10	$ 393,978.15
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 182,635.74	$ (8,101.43)	$ 174,534.31	$ 130,157.68
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (101,443.45)	$ 25,127.91	$ (76,315.54)	$ (56,911.75)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 153,058.51	$ (6,789.43)	$ 146,269.08	$ 109,079.09
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (91,310.88)	$ 43,079.66	$ (48,231.22)	$ (35,968.08)
43	Real Time Price Volatility Make Whole Payment	$ (167,622.56)	$ (1,920.18)	$ (169,542.74)	$ (126,435.25)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 443,822.55	$ (7,142.39)	$ 436,680.16	$ 325,651.01
19	Real-Time Market Administration Amount	$ 28,288.37	$ (2,458.68)	$ 25,829.69	$ 19,262.30
29	Financial Transmission Rights Market Administration Amount	$ 28,065.12	$ -	$ 28,065.12	$ 20,929.36
33	Day-Ahead Schedule 24 Allocation Amount	$ 71,951.88	$ (1,156.98)	$ 70,794.90	$ 52,794.78
34	Real -Time Schedule 24 Allocation Amount	$ (34,088.45)	$ 38,499.06	$ 4,410.61	$ 3,289.18
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	$ (51,318.81)	$ 29,332.67	$ (21,986.14)	$ (16,396.00)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,044,899.06	$ -	$ 6,044,899.06	$ 4,507,938.96
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,528,060.99)	$ -	$ (6,528,060.99)	$ (4,868,253.41)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (295,795.44)	$ -	$ (295,795.44)	$ (220,587.27)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 165,034.21	$ -	$ 165,034.21	$ 123,073.05
	TOTAL MISO CHARGES	**$ 1,988,224.50**	**$ 3,230,914.71**	**$ 5,219,139.21**	**$ 3,892,134.63**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 490,574.97**	**$ 365,842.67**
	SCHEDULE 24 (FOR RETAIL)			**$ 75,205.51**	**$ 56,083.96**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,653,358.73**	**$ 3,470,208.01**

Northern States Power Company

Docket No. E999/AA-15-611

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

Part J, Section 5

Schedule 2

		System	Intersystem	System Retail	Minnestoa Retail
	October 2014 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 8,053,479.74	$ 7,809,079.49	$ 15,862,559.23	$ 11,675,613.54
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,626,282.04	$ (206,961.63)	$ 2,419,320.41	$ 1,780,737.25
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,944.46	$ -	$ 1,944.46	$ 1,431.22
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (15,067,199.80)	$ -	$ (15,067,199.80)	$ (11,090,190.40)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,442,653.08	$ (113,686.89)	$ 1,328,966.19	$ 978,183.62
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,944.46)	$ -	$ (1,944.46)	$ (1,431.22)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (267,718.41)	$ 1,138,611.97	$ 870,893.56	$ 641,019.93
13 c	Real-Time Asset Energy Amount - Loss Component	$ (17,101.55)	$ 1,347.67	$ (15,753.88)	$ (11,595.62)
14	Real-Time Distribution of Losses Amount	$ (1,236,679.64)	$ -	$ (1,236,679.64)	$ (910,256.24)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (48.58)	$ -	$ (48.58)	$ (35.76)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 48.58	$ -	$ 48.58	$ 35.76
21	Real-time Net inadvertent Distribution	$ 71,496.69	$ -	$ 71,496.69	$ 52,625.03
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (21,419.55)	$ -	$ (21,419.55)	$ (15,765.83)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (16,365.63)	$ 1,289.68	$ (15,075.95)	$ (11,096.63)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 4,127,571.69	$ (325,269.32)	$ 3,802,302.37	$ 2,798,679.11
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 1,508.75	$ -	$ 1,508.75	$ 1,110.51
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 5,075,832.85	$ (399,996.13)	$ 4,675,836.72	$ 3,441,642.79
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (1,508.75)	$ -	$ (1,508.75)	$ (1,110.51)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (562.00)	$ 44.29	$ (517.71)	$ (381.06)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ 440.25	$ -	$ 440.25	$ 324.05
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ (440.25)	$ -	$ (440.25)	$ (324.05)
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (9,207.90)	$ 725.62	$ (8,482.28)	$ (6,243.37)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (6,623,772.88)	$ -	$ (6,623,772.88)	$ (4,875,418.35)
30	Financial Transmission Rights Monthly Allocation Amount	$ (140,934.26)	$ -	$ (140,934.26)	$ (103,734.46)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (739,710.56)	$ -	$ (739,710.56)	$ (544,462.88)
37	Financial Transmission Guarantee Uplift Amount	$ 755,421.53	$ -	$ 755,421.53	$ 556,026.91
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 868,925.28	$ (68,474.82)	$ 800,450.46	$ 589,170.39
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 152,832.02	$ (12,043.78)	$ 140,788.24	$ 103,626.98
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (200,330.96)	$ 121,267.09	$ (79,063.87)	$ (58,194.85)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 178,912.09	$ (14,099.00)	$ 164,813.09	$ 121,310.44
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (47,021.92)	$ 19,273.51	$ (27,748.41)	$ (20,424.18)
43	Real Time Price Volatility Make Whole Payment	$ (224,857.01)	$ 9,544.06	$ (215,312.95)	$ (158,480.78)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 481,762.21	$ (16,154.42)	$ 465,607.79	$ 342,709.93
19	Real-Time Market Administration Amount	$ 34,090.50	$ (2,780.16)	$ 31,310.34	$ 23,045.93
29	Financial Transmission Rights Market Administration Amount	$ 23,626.96	$ -	$ 23,626.96	$ 17,390.59
33	Day-Ahead Schedule 24 Allocation Amount	$ 66,695.92	$ (2,239.02)	$ 64,456.90	$ 47,443.41
34	Real -Time Schedule 24 Allocation Amount	$ (29,650.06)	$ 32,636.22	$ 2,986.16	$ 2,197.96
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	$ (54,710.46)	$ 29,213.68	$ (25,496.78)	$ (18,766.87)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,044,899.06	$ -	$ 6,044,899.06	$ 4,449,339.12
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,528,060.99)	$ -	$ (6,528,060.99)	$ (4,804,969.75)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (290,711.50)	$ -	$ (290,711.50)	$ (213,977.77)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 165,031.72	$ -	$ 165,031.72	$ 121,471.36
	TOTAL MISO CHARGES	**$ (1,346,501.70)**	**$ 8,001,328.12**	**$ 6,654,826.42**	**$ 4,898,275.26**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 520,545.09**	**$ 383,146.45**
	SCHEDULE 24 (FOR RETAIL)			**$ 67,443.06**	**$ 49,641.37**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 6,066,838.27**	**$ 4,465,487.44**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	November 2014 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 3,204,847.02	$ 5,184,337.83	$ 8,389,184.85	$ 6,085,542.96
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 4,794,236.59	$ (254,322.93)	$ 4,539,913.66	$ 3,293,268.66
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 4,148.31	$ -	$ 4,148.31	$ 3,009.20
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,526,418.41)	$ -	$ (11,526,418.41)	$ (8,361,302.75)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,533,468.53	$ (81,346.89)	$ 1,452,121.64	$ 1,053,373.93
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (4,148.31)	$ -	$ (4,148.31)	$ (3,009.20)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,277,815.39	$ 850,149.83	$ 2,127,965.22	$ 1,543,633.14
13 c	Real-Time Asset Energy Amount - Loss Component	$ 55,031.63	$ (2,919.30)	$ 52,112.33	$ 37,802.46
14	Real-Time Distribution of Losses Amount	$ (1,961,143.28)	$ -	$ (1,961,143.28)	$ (1,422,619.94)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (28,411.36)	$ -	$ (28,411.36)	$ (20,609.70)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 36,309.57	$ -	$ 36,309.57	$ 26,339.08
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (8,674.53)	$ 460.16	$ (8,214.37)	$ (5,958.73)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 6,798,706.85	$ (360,655.35)	$ 6,438,051.50	$ 4,670,184.25
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 7,598.24	$ -	$ 7,598.24	$ 5,511.79
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 615,289.41	$ (32,639.65)	$ 582,649.76	$ 422,656.10
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (7,598.24)	$ -	$ (7,598.24)	$ (5,511.79)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 274,205.42	$ (14,545.95)	$ 259,659.47	$ 188,357.85
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	$ (76,234.13)	$ 4,044.04	$ (72,190.09)	$ (52,366.93)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,774,741.95)	$ -	$ (2,774,741.95)	$ (2,012,807.16)
30	Financial Transmission Rights Monthly Allocation Amount	$ (100,868.14)	$ -	$ (100,868.14)	$ (73,170.09)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (375,496.38)	$ -	$ (375,496.38)	$ (272,386.34)
37	Financial Transmission Guarantee Uplift Amount	$ 483,540.13	$ -	$ 483,540.13	$ 350,761.64
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 1,429,445.11	$ (75,828.69)	$ 1,353,616.42	$ 981,917.91
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 109,833.21	$ (5,826.39)	$ 104,006.82	$ 75,446.90
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (122,498.38)	$ 65,472.06	$ (57,026.32)	$ (41,367.08)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 147,663.09	$ (7,833.18)	$ 139,829.91	$ 101,433.09
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (54,840.00)	$ 14,249.16	$ (40,590.84)	$ (29,444.73)
43	Real Time Price Volatility Make Whole Payment	$ (598,855.81)	$ 33,988.81	$ (564,867.00)	$ (409,756.43)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 632,552.65	$ (14,526.95)	$ 618,025.70	$ 448,317.93
19	Real-Time Market Administration Amount	$ 44,097.88	$ (3,557.87)	$ 40,540.01	$ 29,407.86
29	Financial Transmission Rights Market Administration Amount	$ 25,647.20	$ -	$ 25,647.20	$ 18,604.57
33	Day-Ahead Schedule 24 Allocation Amount	$ 68,164.28	$ (1,533.31)	$ 66,630.97	$ 48,334.33
34	Real -Time Schedule 24 Allocation Amount	$ (31,408.08)	$ 38,477.25	$ 7,069.17	$ 5,128.00
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	$ 7,393.58	$ 29,687.34	$ 37,080.92	$ 26,898.62
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,044,899.06	$ -	$ 6,044,899.06	$ 4,384,990.15
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,528,060.99)	$ -	$ (6,528,060.99)	$ (4,735,477.44)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (349,320.42)	$ -	$ (349,320.42)	$ (253,398.21)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 165,031.72	$ -	$ 165,031.72	$ 119,714.57
	TOTAL MISO CHARGES	**$ 3,211,206.46**	**$ 5,365,330.03**	**$ 8,576,536.49**	**$ 6,221,448.47**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 684,212.91**	**$ 496,330.35**
	SCHEDULE 24 (FOR RETAIL)			**$ 73,700.14**	**$ 53,462.33**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,818,623.44** X	**$ 5,671,655.79**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	December 2014 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 1,100,919.46	$ 9,472,266.95	$ 10,573,186.41	$ 7,634,057.10
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,319,822.23	$ (311,764.70)	$ 3,008,057.53	$ 2,171,879.13
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 5,644.27	$ -	$ 5,644.27	$ 4,075.28
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (13,501,007.27)	$ -	$ (13,501,007.27)	$ (9,748,003.71)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 2,029,696.15	$ (190,608.88)	$ 1,839,087.27	$ 1,327,858.66
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (5,644.27)	$ -	$ (5,644.27)	$ (4,075.28)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,033,908.15	$ 1,236,349.57	$ 2,270,257.72	$ 1,639,172.56
13 c	Real-Time Asset Energy Amount - Loss Component	$ (11,887.94)	$ 1,116.40	$ (10,771.54)	$ (7,777.27)
14	Real-Time Distribution of Losses Amount	$ (1,344,972.09)	$ -	$ (1,344,972.09)	$ (971,097.39)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 8,320.04	$ -	$ 8,320.04	$ 6,007.24
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,535.65	$ -	$ 8,535.65	$ 6,162.91
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (262.50)	$ 24.65	$ (237.85)	$ (171.73)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,592,918.96	$ (243,501.17)	$ 2,349,417.79	$ 1,696,327.75
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (926.26)	$ -	$ (926.26)	$ (668.78)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,280,300.77	$ (120,233.12)	$ 1,160,067.65	$ 837,592.60
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 926.26	$ -	$ 926.26	$ 668.78
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (38,310.70)	$ 3,597.76	$ (34,712.94)	$ (25,063.45)
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	$ 337.59	$ (31.70)	$ 305.89	$ 220.86
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,748,265.03)	$ -	$ (3,748,265.03)	$ (2,706,324.11)
30	Financial Transmission Rights Monthly Allocation Amount	$ (181,752.04)	$ -	$ (181,752.04)	$ (131,228.69)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (82,900.03)	$ -	$ (82,900.03)	$ (59,855.52)
37	Financial Transmission Guarantee Uplift Amount	$ 88,845.34	$ -	$ 88,845.34	$ 64,148.15
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 544,351.65	$ (51,966.22)	$ 492,385.43	$ 355,512.36
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 181,370.20	$ (17,314.40)	$ 164,055.80	$ 118,451.64
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (42,131.91)	$ 15,732.48	$ (26,399.43)	$ (19,060.93)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 167,304.49	$ (15,971.63)	$ 151,332.86	$ 109,265.42
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (177,129.60)	$ (1,364.09)	$ (178,493.69)	$ (128,876.10)
43	Real Time Price Volatility Make Whole Payment	$ (60,664.96)	$ 13,244.26	$ (47,420.70)	$ (34,238.72)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 549,587.30	$ (22,995.82)	$ 526,591.48	$ 380,209.83
19	Real-Time Market Administration Amount	$ 39,535.95	$ (3,692.07)	$ 35,843.88	$ 25,880.02
29	Financial Transmission Rights Market Administration Amount	$ 38,808.88	$ -	$ 38,808.88	$ 28,020.81
33	Day-Ahead Schedule 24 Allocation Amount	$ 65,081.95	$ (2,721.27)	$ 62,360.68	$ 45,025.69
34	Real -Time Schedule 24 Allocation Amount	$ (27,169.44)	$ 29,694.15	$ 2,524.71	$ 1,822.89
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -
Virtual Energy Charges					
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -
Other MISO Charges					
20	Real-Time Miscellaneous Amount	$ (211,261.44)	$ 52,210.57	$ (159,050.87)	$ (114,837.99)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,250,896.00	$ -	$ 7,250,896.00	$ 5,235,295.39
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,412,271.29)	$ 117,353.14	$ (7,294,918.15)	$ (5,267,080.28)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (163,750.35)	$ -	$ (163,750.35)	$ (118,231.11)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 215,785.30	$ -	$ 215,785.30	$ 155,801.41
	TOTAL MISO CHARGES	**$ (6,487,410.53)**	**$ 9,959,424.84**	**$ 3,472,014.31**	**$ 2,506,865.43**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 601,244.24**	**$ 434,110.65**
	SCHEDULE 24 (FOR RETAIL)			**$ 64,885.39**	**$ 46,848.58**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 2,805,884.68**	**$ 2,025,906.20**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
January 2015 Actual					
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 2,591,924.99	$ 5,156,228.15	$ 7,748,153.14	$ 5,574,004.50
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 5,018,262.73	$ (305,108.31)	$ 4,713,154.42	$ 3,390,633.03
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 3,961.72	$ -	$ 3,961.72	$ 2,850.05
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (8,128,583.31)	$ -	$ (8,128,583.31)	$ (5,847,685.13)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ (850,409.95)	$ 51,704.57	$ (798,705.38)	$ (574,586.91)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (3,961.72)	$ -	$ (3,961.72)	$ (2,850.05)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,448,654.35	$ 1,151,464.36	$ 2,600,118.71	$ 1,870,519.74
13 c	Real-Time Asset Energy Amount - Loss Component	$ (85,017.45)	$ 5,169.03	$ (79,848.42)	$ (57,442.78)
14	Real-Time Distribution of Losses Amount	$ (1,511,371.31)	$ -	$ (1,511,371.31)	$ (1,087,277.23)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (23.77)	$ -	$ (23.77)	$ (17.10)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 23.77	$ -	$ 23.77	$ 17.10
21	Real-time Net inadvertent Distribution	$ (96,680.24)	$ -	$ (96,680.24)	$ (69,551.55)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,020.62	$ -	$ 8,020.62	$ 5,770.02
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 1,734.88	$ (105.48)	$ 1,629.40	$ 1,172.19
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 3,503,488.11	$ (213,010.63)	$ 3,290,477.48	$ 2,367,162.33
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 845.35	$ -	$ 845.35	$ 608.14
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 453,878.46	$ (27,595.62)	$ 426,282.84	$ 306,666.94
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (845.35)	$ -	$ (845.35)	$ (608.14)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (292,699.49)	$ 17,796.01	$ (274,903.48)	$ (197,764.97)
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (12.51)	$ -	$ (12.51)	$ (9.00)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 12.51	$ -	$ 12.51	$ 9.00
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (2,336.69)	$ 142.07	$ (2,194.62)	$ (1,578.81)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (3,088,429.08)	$ -	$ (3,088,429.08)	$ (2,221,809.15)
30	Financial Transmission Rights Monthly Allocation Amount	$ (187,254.82)	$ -	$ (187,254.82)	$ (134,710.71)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (54,659.01)	$ -	$ (54,659.01)	$ (39,321.57)
37	Financial Transmission Guarantee Uplift Amount	$ 46,900.17	$ -	$ 46,900.17	$ 33,739.88
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 379,920.53	$ (23,099.01)	$ 356,821.52	$ 256,696.62
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 163,641.43	$ (9,949.33)	$ 153,692.10	$ 110,565.76
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (111,103.02)	$ 45,145.06	$ (65,957.96)	$ (47,450.01)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 116,402.97	$ (7,077.25)	$ 109,325.72	$ 78,648.68
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (1,267.67)	$ (798.19)	$ (2,065.86)	$ (1,486.18)
43	Real Time Price Volatility Make Whole Payment	$ (348,515.12)	$ 15,204.93	$ (333,310.19)	$ (239,782.62)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 500,873.36	$ (12,091.60)	$ 488,781.76	$ 351,628.53
19	Real-Time Market Administration Amount	$ 37,302.32	$ (3,163.81)	$ 34,138.51	$ 24,559.17
29	Financial Transmission Rights Market Administration Amount	$ 38,159.60	$ -	$ 38,159.60	$ 27,451.93
33	Day-Ahead Schedule 24 Allocation Amount	$ 63,799.38	$ (1,528.00)	$ 62,271.38	$ 44,797.90
34	Real -Time Schedule 24 Allocation Amount	$ (29,413.48)	$ 35,196.11	$ 5,782.63	$ 4,160.01
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	$ (405,509.67)	$ 95,051.51	$ (310,458.16)	$ (223,342.92)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,250,896.00	$ -	$ 7,250,896.00	$ 5,216,278.79
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,412,271.29)	$ 19,168.06	$ (7,393,103.23)	$ (5,318,582.36)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (104,620.47)	$ -	$ (104,620.47)	$ (75,263.74)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 215,789.60	$ -	$ 215,789.60	$ 155,238.57
	TOTAL MISO CHARGES	**$ (870,492.57)**	**$ 5,988,742.62**	**$ 5,118,250.05**	**$ 3,682,057.94**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 561,079.87**	**$ 403,639.64**
	SCHEDULE 24 (FOR RETAIL)			**$ 68,054.01**	**$ 48,957.91**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,489,116.17**	**$ 3,229,460.40**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	February 2015 Actual				
	Energy and Loss Charges				
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 8,091,355.95	$ 4,195,308.89	$ 12,286,664.84	$ 8,801,478.76
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,746,588.94	$ (205,629.94)	$ 3,540,959.00	$ 2,536,544.77
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 6,378.65	$ -	$ 6,378.65	$ 4,569.31
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,731,613.87)	$ -	$ (11,731,613.87)	$ (8,403,871.32)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,059,024.79	$ (58,124.13)	$ 1,000,900.66	$ 716,989.20
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (6,378.65)	$ -	$ (6,378.65)	$ (4,569.31)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 789,094.69	$ 1,743,666.38	$ 2,532,761.07	$ 1,814,328.22
13 c	Real-Time Asset Energy Amount - Loss Component	$ 72,520.67	$ (3,980.27)	$ 68,540.40	$ 49,098.51
14	Real-Time Distribution of Losses Amount	$ (1,785,962.00)	$ -	$ (1,785,962.00)	$ (1,279,363.18)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (59,939.70)	$ -	$ (59,939.70)	$ (42,937.45)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (5,530.01)	$ -	$ (5,530.01)	$ (3,961.39)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 840.85	$ (46.15)	$ 794.70	$ 569.28
	Congestion Related Charges				
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,495,521.83	$ (136,965.65)	$ 2,358,556.18	$ 1,689,537.59
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,571.24	$ -	$ 4,571.24	$ 3,274.58
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,447,300.89	$ (79,434.49)	$ 1,367,866.40	$ 979,862.90
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,571.24)	$ -	$ (4,571.24)	$ (3,274.58)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 298,360.38	$ (16,375.38)	$ 281,985.00	$ 201,998.26
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	$ 12,085.15	$ (663.29)	$ 11,421.86	$ 8,181.98
	FTR Related Charges				
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,638,215.63)	$ -	$ (2,638,215.63)	$ (1,889,869.96)
30	Financial Transmission Rights Monthly Allocation Amount	$ (113,847.87)	$ -	$ (113,847.87)	$ (81,554.24)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (71,077.02)	$ -	$ (71,077.02)	$ (50,915.60)
37	Financial Transmission Guarantee Uplift Amount	$ 67,927.21	$ -	$ 67,927.21	$ 48,659.25
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
	Uplift (RNU) Charges				
23	Real-Time Revenue Neutrality Uplift Amount	$ 716,461.93	$ (39,322.71)	$ 677,139.22	$ 485,064.63
	Revenue Sufficiency Guarantee (RSG) Charges				
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 206,399.66	$ (11,328.16)	$ 195,071.50	$ 139,738.30
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (100,928.64)	$ 33,732.18	$ (67,196.46)	$ (48,135.78)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 154,958.46	$ (8,504.83)	$ 146,453.63	$ 104,911.18
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (68,367.77)	$ 5,944.00	$ (62,423.77)	$ (44,716.89)
43	Real Time Price Volatility Make Whole Payment	$ (327,724.31)	$ 21,241.80	$ (306,482.51)	$ (219,546.91)
	Market Adminstration Charges				
4	Day-Ahead Market Administration Amount	$ 623,735.83	$ (11,477.47)	$ 612,258.36	$ 438,587.61
19	Real-Time Market Administration Amount	$ 40,413.21	$ (5,980.02)	$ 34,433.19	$ 24,666.01
29	Financial Transmission Rights Market Administration Amount	$ 35,475.84	$ -	$ 35,475.84	$ 25,412.91
33	Day-Ahead Schedule 24 Allocation Amount	$ 67,939.47	$ (1,239.19)	$ 66,700.28	$ 47,780.35
34	Real -Time Schedule 24 Allocation Amount	$ (31,611.17)	$ 36,614.75	$ 5,003.58	$ 3,584.28
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	$ (378,713.36)	$ 70,005.00	$ (308,708.36)	$ (221,141.38)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
	Auction Revenue Rights (ARR)				
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,250,896.00	$ -	$ 7,250,896.00	$ 5,194,135.91
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,412,271.29)	$ 28,268.10	$ (7,384,003.19)	$ (5,289,486.45)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (165,295.02)	$ -	$ (165,295.02)	$ (118,408.10)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 215,789.60	$ -	$ 215,789.60	$ 154,579.59
	TOTAL MISO CHARGES	**$ 2,501,593.69**	**$ 5,555,709.42**	**$ 8,057,303.11**	**$ 5,771,800.82**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 682,167.39**	**$ 488,666.52**
	SCHEDULE 24 (FOR RETAIL)			**$ 71,703.86**	**$ 51,364.63**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,303,431.86**	**$ 5,231,769.66**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	March 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 10,011,388.35	$ 3,404,076.88	$ 13,415,465.23	$ 9,631,074.42
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 3,141,039.63	$ (181,093.93)	$ 2,959,945.70	$ 2,124,969.71
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,755.65	$ -	$ 2,755.65	$ 1,978.30
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (9,837,021.18)	$ -	$ (9,837,021.18)	$ (7,062,079.58)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 535,511.28	$ (30,874.44)	$ 504,636.84	$ 362,283.00
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,755.65)	$ -	$ (2,755.65)	$ (1,978.30)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (37,503.89)	$ 1,200,976.08	$ 1,163,472.19	$ 835,266.39
13 c	Real-Time Asset Energy Amount - Loss Component	$ (27,655.28)	$ 1,594.44	$ (26,060.84)	$ (18,709.29)
14	Real-Time Distribution of Losses Amount	$ (1,047,242.39)	$ -	$ (1,047,242.39)	$ (751,824.05)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 41,702.18	$ -	$ 41,702.18	$ 29,938.34
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 6,239.00	$ -	$ 6,239.00	$ 4,479.03
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ 8.67	$ (0.50)	$ 8.17	$ 5.87
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 2,503,187.90	$ (144,319.14)	$ 2,358,868.76	$ 1,693,451.56
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,855.11	$ -	$ 4,855.11	$ 3,485.52
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 183,787.18	$ (10,596.09)	$ 173,191.09	$ 124,335.33
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,855.11)	$ -	$ (4,855.11)	$ (3,485.52)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ (71,176.63)	$ 4,103.63	$ (67,073.00)	$ (48,152.27)
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	$ 66.12	$ (3.81)	$ 62.31	$ 44.73
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,033,457.66)	$ -	$ (2,033,457.66)	$ (1,459,836.22)
30	Financial Transmission Rights Monthly Allocation Amount	$ (73,502.00)	$ -	$ (73,502.00)	$ (52,767.70)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 25,507.49	$ -	$ 25,507.49	$ 18,312.04
37	Financial Transmission Guarantee Uplift Amount	$ (34,323.72)	$ -	$ (34,323.72)	$ (24,641.28)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 303,189.66	$ (17,480.14)	$ 285,709.52	$ 205,113.25
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 473,335.28	$ (27,289.74)	$ 446,045.54	$ 320,219.82
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (408,433.12)	$ 75,478.05	$ (332,955.07)	$ (239,031.22)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 242,120.87	$ (13,959.27)	$ 228,161.60	$ 163,799.12
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (487,867.25)	$ 251,432.56	$ (236,434.69)	$ (169,738.44)
43	Real Time Price Volatility Make Whole Payment	$ (162,062.63)	$ 12,005.62	$ (150,057.01)	$ (107,727.18)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 704,788.90	$ (14,271.21)	$ 690,517.69	$ 495,728.41
19	Real-Time Market Administration Amount	$ 51,256.26	$ (5,714.35)	$ 45,541.91	$ 32,694.92
29	Financial Transmission Rights Market Administration Amount	$ 35,653.20	$ -	$ 35,653.20	$ 25,595.73
33	Day-Ahead Schedule 24 Allocation Amount	$ 71,907.79	$ (1,431.59)	$ 70,476.20	$ 50,595.45
34	Real -Time Schedule 24 Allocation Amount	$ (32,610.10)	$ 25,868.51	$ (6,741.59)	$ (4,839.84)
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	$ (365,421.26)	$ 69,381.57	$ (296,039.69)	$ (212,529.36)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,666,528.17	$ -	$ 6,666,528.17	$ 4,785,956.19
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,785,365.96)	$ 16,306.18	$ (6,769,059.78)	$ (4,859,564.49)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (218,926.71)	$ -	$ (218,926.71)	$ (157,169.31)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 293,678.17	$ -	$ 293,678.17	$ 210,834.01
	TOTAL MISO CHARGES	**$ 3,668,326.32**	**$ 4,614,189.30**	**$ 8,282,515.62**	**$ 5,946,087.07**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 771,712.80**	**$ 554,019.06**
	SCHEDULE 24 (FOR RETAIL)			**$ 63,734.61**	**$ 45,755.61**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 7,447,068.21** X	**$ 5,346,312.40**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	April 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 13,839,801.09	$ 1,134,682.23	$ 14,974,483.32	$ 10,981,669.66
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,544,637.91	$ (35,648.83)	$ 1,508,989.08	$ 1,106,630.47
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 2,250.67	$ -	$ 2,250.67	$ 1,650.55
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (9,116,033.45)	$ -	$ (9,116,033.45)	$ (6,685,323.68)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,353,856.51	$ (31,245.77)	$ 1,322,610.74	$ 969,948.27
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (2,250.67)	$ -	$ (2,250.67)	$ (1,650.55)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,181,757.37	$ 366,699.88	$ 1,548,457.25	$ 1,135,574.81
13 c	Real-Time Asset Energy Amount - Loss Component	$ 45,812.59	$ (1,057.31)	$ 44,755.28	$ 32,821.68
14	Real-Time Distribution of Losses Amount	$ (925,745.90)	$ -	$ (925,745.90)	$ (678,903.94)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ (32,185.36)	$ -	$ (32,185.36)	$ (23,603.42)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 8,501.86	$ -	$ 8,501.86	$ 6,234.91
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (1,025.28)	$ 23.66	$ (1,001.62)	$ (734.55)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ (389,266.03)	$ 8,983.90	$ (380,282.13)	$ (278,883.26)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 6,827.19	$ -	$ 6,827.19	$ 5,006.78
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,083,502.87	$ (48,085.34)	$ 2,035,417.53	$ 1,492,691.43
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (6,827.19)	$ -	$ (6,827.19)	$ (5,006.78)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 95,379.26	$ (2,201.27)	$ 93,177.99	$ 68,332.91
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	$ (1,982.35)	$ 45.75	$ (1,936.60)	$ (1,420.22)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (173,880.77)	$ -	$ (173,880.77)	$ (127,517.00)
30	Financial Transmission Rights Monthly Allocation Amount	$ (45,114.09)	$ -	$ (45,114.09)	$ (33,084.82)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ (780,712.59)	$ -	$ (780,712.59)	$ (572,542.48)
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 888,137.17	$ -	$ 888,137.17	$ 651,323.24
37	Financial Transmission Guarantee Uplift Amount	$ (866,657.41)	$ -	$ (866,657.41)	$ (635,570.87)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 414,074.06	$ (9,556.45)	$ 404,517.61	$ 296,656.56
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 19,515.91	$ (450.41)	$ 19,065.50	$ 13,981.85
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (165,087.62)	$ 41,897.65	$ (123,189.97)	$ (90,342.45)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 31,703.22	$ (731.68)	$ 30,971.54	$ 22,713.25
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (10,022.13)	$ 1,435.18	$ (8,586.95)	$ (6,297.32)
43	Real Time Price Volatility Make Whole Payment	$ (163,764.17)	$ 5,513.09	$ (158,251.08)	$ (116,054.83)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 517,134.72	$ (4,343.43)	$ 512,791.29	$ 376,060.02
19	Real-Time Market Administration Amount	$ 38,281.67	$ (1,917.32)	$ 36,364.35	$ 26,668.12
29	Financial Transmission Rights Market Administration Amount	$ 34,623.04	$ -	$ 34,623.04	$ 25,391.11
33	Day-Ahead Schedule 24 Allocation Amount	$ 62,391.69	$ (534.22)	$ 61,857.47	$ 45,363.72
34	Real -Time Schedule 24 Allocation Amount	$ (29,955.60)	$ 34,813.93	$ 4,858.33	$ 3,562.90
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	$ (260,323.94)	$ 47,609.77	$ (212,714.17)	$ (155,995.82)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,666,528.17	$ -	$ 6,666,528.17	$ 4,888,957.34
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,785,365.96)	$ 22,235.70	$ (6,763,130.26)	$ (4,959,801.34)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (216,392.08)	$ -	$ (216,392.08)	$ (158,693.04)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 293,678.17	$ -	$ 293,678.17	$ 215,371.48
	TOTAL MISO CHARGES	**$ 9,155,802.55**	**$ 1,528,168.72**	**$ 10,683,971.27**	**$ 7,835,184.73**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 583,778.68**	**$ 428,119.25**
	SCHEDULE 24 (FOR RETAIL)			**$ 66,715.80**	**$ 48,926.62**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 10,033,476.79**	**$ 7,358,138.86**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	May 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 17,252,953.52	$ 1,271,708.58	$ 18,524,662.10	$ 13,656,055.79
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 1,896,380.59	$ (69,335.05)	$ 1,827,045.54	$ 1,346,865.90
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,852.22	$ -	$ 1,852.22	$ 1,365.42
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,077,244.02)	$ -	$ (11,077,244.02)	$ (8,165,949.88)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,232,148.84	$ (45,049.56)	$ 1,187,099.28	$ 875,108.76
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,852.22)	$ -	$ (1,852.22)	$ (1,365.42)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ (1,067,564.51)	$ 831,015.25	$ (236,549.26)	$ (174,379.96)
13 c	Real-Time Asset Energy Amount - Loss Component	$ 76,484.98	$ (2,796.43)	$ 73,688.55	$ 54,321.91
14	Real-Time Distribution of Losses Amount	$ (786,313.16)	$ -	$ (786,313.16)	$ (579,656.26)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ (1.93)	$ -	$ (1.93)	$ (1.42)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ 1.93	$ -	$ 1.93	$ 1.42
21	Real-time Net inadvertent Distribution	$ (38,015.41)	$ -	$ (38,015.41)	$ (28,024.29)
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ 76,958.60	$ -	$ 76,958.60	$ 56,732.53
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (3,761.33)	$ 137.52	$ (3,623.81)	$ (2,671.41)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 799,034.88	$ (29,214.14)	$ 769,820.74	$ 567,498.34
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 4,675.74	$ -	$ 4,675.74	$ 3,446.87
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 2,286,302.21	$ (83,591.28)	$ 2,202,710.93	$ 1,623,799.84
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (4,675.74)	$ -	$ (4,675.74)	$ (3,446.87)
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 241,176.99	$ (8,817.86)	$ 232,359.13	$ 171,291.07
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ (8.00)	$ -	$ (8.00)	$ (5.90)
17	Real-Time Congestion Rebate on Carve-Out Grandfathered Agreements	$ 8.00	$ -	$ 8.00	$ 5.90
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (19,977.46)	$ 730.41	$ (19,247.05)	$ (14,188.59)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (2,568,938.67)	$ -	$ (2,568,938.67)	$ (1,893,776.50)
30	Financial Transmission Rights Monthly Allocation Amount	$ (47,991.31)	$ -	$ (47,991.31)	$ (35,378.35)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ (11,782.92)	$ -	$ (11,782.92)	$ (8,686.16)
37	Financial Transmission Guarantee Uplift Amount	$ 11,782.92	$ -	$ 11,782.92	$ 8,686.16
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 697,474.62	$ (5,847.79)	$ 691,626.83	$ 509,855.16
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 43,140.27	$ (1,577.29)	$ 41,562.98	$ 30,639.50
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (10,305.01)	$ (4,542.82)	$ (14,847.83)	$ (10,945.56)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 159,942.57	$ (25,500.92)	$ 134,441.65	$ 99,108.03
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (54,669.10)	$ 35,866.46	$ (18,802.64)	$ (13,860.98)
43	Real Time Price Volatility Make Whole Payment	$ (135,002.09)	$ 3,282.38	$ (131,719.71)	$ (97,101.46)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 510,387.75	$ (5,835.93)	$ 504,551.82	$ 371,946.75
19	Real-Time Market Administration Amount	$ 40,108.78	$ (3,876.18)	$ 36,232.60	$ 26,710.04
29	Financial Transmission Rights Market Administration Amount	$ 34,200.72	$ -	$ 34,200.72	$ 25,212.17
33	Day-Ahead Schedule 24 Allocation Amount	$ 62,047.01	$ (709.65)	$ 61,337.36	$ 45,216.83
34	Real -Time Schedule 24 Allocation Amount	$ (29,960.39)	$ 35,858.30	$ 5,897.91	$ 4,347.84
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	$ (78,037.09)	$ 64,040.02	$ (13,997.07)	$ (10,318.39)
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -
Auction Revenue Rights (ARR)					
39	Auction Revenue Rights - FTR Auction Transactions	$ 6,666,528.17	$ -	$ 6,666,528.17	$ 4,914,447.57
40	Auction Revenue Rights - Monthly ARR Revenue	$ (6,785,365.96)	$ 23,718.08	$ (6,761,647.88)	$ (4,984,568.15)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (218,818.02)	$ -	$ (218,818.02)	$ (161,308.80)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 293,678.17	$ -	$ 293,678.17	$ 216,494.39
	TOTAL MISO CHARGES	**$ 9,446,985.14**	**$ 1,979,662.11**	**$ 11,426,647.25**	**$ 8,423,523.81**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 574,985.14**	**$ 423,868.95**
	SCHEDULE 24 (FOR RETAIL)			**$ 67,235.27**	**$ 49,564.66**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 10,784,426.84**	**$ 7,950,090.20**

MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES *

		System	Intersystem	System Retail	Minnestoa Retail
	June 2015 Actual				
Energy and Loss Charges					
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 8,799,747.75	$ 2,974,148.26	$ 11,773,896.01	$ 8,760,256.80
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,412,016.83	$ (105,762.71)	$ 2,306,254.12	$ 1,715,946.73
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 1,197.31	$ -	$ 1,197.31	$ 890.85
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (11,256,283.68)	$ -	$ (11,256,283.68)	$ (8,375,132.20)
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,204,680.32	$ (52,823.12)	$ 1,151,857.20	$ 857,028.54
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (1,197.31)	$ -	$ (1,197.31)	$ (890.85)
9	Day-Ahead Losses Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 a	Real-Time Asset Energy Amount - Energy Component	$ 1,044,919.96	$ 792,543.90	$ 1,837,463.86	$ 1,367,147.74
13 c	Real-Time Asset Energy Amount - Loss Component	$ 4,286.65	$ (187.96)	$ 4,098.69	$ 3,049.59
14	Real-Time Distribution of Losses Amount	$ (1,190,722.49)	$ -	$ (1,190,722.49)	$ (885,945.89)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ -	$ -
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ -	$ -
21	Real-time Net inadvertent Distribution	$ 20,092.04	$ -	$ 20,092.04	$ 14,949.29
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (183,721.04)	$ -	$ (183,721.04)	$ (136,695.92)
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (5,287.17)	$ 231.83	$ (5,055.34)	$ (3,761.38)
Congestion Related Charges					
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ (143,069.84)	$ 6,273.36	$ (136,796.48)	$ (101,782.14)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ (1,132.03)	$ -	$ (1,132.03)	$ (842.28)
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,446,476.67	$ (63,425.47)	$ 1,383,051.20	$ 1,029,046.26
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ 1,132.03	$ -	$ 1,132.03	$ 842.28
8	Day-Ahead Congestion Rebate on Option B Grandfathered Agreements	$ -	$ -	$ -	$ -
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 3,528.85	$ (154.73)	$ 3,374.12	$ 2,510.48
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	$ (42,837.66)	$ 1,878.36	$ (40,959.30)	$ (30,475.38)
FTR Related Charges					
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,439,393.93)	$ -	$ (1,439,393.93)	$ (1,070,967.54)
30	Financial Transmission Rights Monthly Allocation Amount	$ (50,654.52)	$ -	$ (50,654.52)	$ (37,689.02)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 9,151.86	$ -	$ 9,151.86	$ 6,809.36
37	Financial Transmission Guarantee Uplift Amount	$ (10,567.73)	$ -	$ (10,567.73)	$ (7,862.82)
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -
Uplift (RNU) Charges					
23	Real-Time Revenue Neutrality Uplift Amount	$ 672,176.95	$ (6,968.90)	$ 665,208.05	$ 494,941.81
Revenue Sufficiency Guarantee (RSG) Charges					
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 114,315.22	$ (5,012.52)	$ 109,302.70	$ 81,325.65
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount	$ (26,220.18)	$ 9,255.55	$ (16,964.63)	$ (12,622.37)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 158,932.21	$ (29,473.78)	$ 129,458.43	$ 96,322.33
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ (117,146.13)	$ 65,810.60	$ (51,335.53)	$ (38,195.72)
43	Real Time Price Volatility Make Whole Payment	$ (169,145.79)	$ 5,569.60	$ (163,576.19)	$ (121,707.33)
Market Adminstration Charges					
4	Day-Ahead Market Administration Amount	$ 583,501.85	$ (9,893.81)	$ 573,608.04	$ 426,787.68
19	Real-Time Market Administration Amount	$ 39,876.48	$ (2,828.56)	$ 37,047.92	$ 27,565.16
29	Financial Transmission Rights Market Administration Amount	$ 34,161.28	$ -	$ 34,161.28	$ 25,417.38
33	Day-Ahead Schedule 24 Allocation Amount	$ 81,719.83	$ (1,392.47)	$ 80,327.36	$ 59,766.82
34	Real -Time Schedule 24 Allocation Amount	$ (94,321.37)	$ 88,233.67	$ (6,087.70)	$ (4,529.50)
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	$ (37,149.98)	$ 40,146.52	$ 2,996.54	$ 2,229.55
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	$ 2,616,790.60
40	Auction Revenue Rights - Monthly ARR Revenue	$ (3,588,338.38)	$ 4,447.14	$ (3,583,891.24)	$ (2,666,560.63)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (116,560.48)	$ -	$ (116,560.48)	$ (86,725.73)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 67,063.94	$ -	$ 67,063.94	$ 49,898.29
	TOTAL MISO CHARGES	**$ 1,742,228.00**	**$ 3,710,614.76**	**$ 5,452,842.76**	**$ 4,057,136.46**
	SCHEDULE 16 & 17 (FOR RETAIL)			**$ 644,817.24**	**$ 479,770.21**
	SCHEDULE 24 (FOR RETAIL)			**$ 74,239.66**	**$ 55,237.32**
	TOTAL MISO CHARGES LESS SCHEDULES 16 & 17 (FOR RETAIL)			**$ 4,733,785.86** X	**$ 3,522,128.93**

Northern States Power Company

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - SYSTEM

	July 14	August 14	September 14	October 14	November 14	December 14	January 15	February 15	March 15	April 15	May 15	June 15	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	25,076,071.07	21,976,219.43	11,197,079.78	8,053,479.74	3,204,847.02	1,100,919.46	2,591,924.99	8,091,355.95	10,011,388.35	13,839,801.09	17,252,953.52	8,799,747.75	131,195,788.15
5 a Day-Ahead Non-Asset Energy Amount - Energy Component	(18,159,042.06)	(16,485,508.52)	(13,372,565.58)	(15,067,199.80)	(11,526,418.41)	(13,501,007.27)	(8,128,583.31)	(11,731,613.87)	(9,837,021.18)	(9,116,033.45)	(11,077,244.02)	(11,256,283.68)	(149,258,521.15)
13 a Real-Time Asset Energy Amount - Energy Component	2,435,716.47	698,727.83	128,772.36	(267,718.41)	1,277,815.39	1,033,908.15	1,448,654.35	789,094.69	(37,503.89)	1,181,757.37	(1,067,564.51)	1,044,919.96	8,666,579.76
22 a Real-Time Non-Asset Energy Amount - Energy Component	(903,083.91)	139,806.02	437,767.37	(21,419.55)	36,309.57	8,535.65	8,020.62	(5,530.01)	6,239.00	8,501.86	76,958.60	(183,721.04)	(391,615.82)
SUBTOTAL	8,449,661.57	6,329,244.76	(1,608,946.07)	(7,302,858.02)	(7,007,446.43)	(11,357,644.01)	(4,079,983.35)	(2,856,693.24)	143,102.28	5,914,026.87	5,185,103.59	(1,595,337.01)	(9,787,769.06)
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	2,281,991.77	3,292,405.44	2,675,740.31	2,626,282.04	4,794,236.59	3,319,822.23	5,018,262.73	3,746,588.94	3,141,039.63	1,544,637.91	1,896,380.59	2,412,016.83	36,749,405.01
3 Day-Ahead Financial Bilateral Transaction Loss Amount	882.59	2,102.35	536.35	1,944.46	4,148.31	5,644.27	3,961.72	6,378.65	2,755.65	2,250.67	1,852.22	1,197.31	33,654.55
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	2,609,170.60	1,597,156.70	1,369,407.86	1,442,653.08	1,533,468.53	2,029,696.15	(850,409.95)	1,059,024.79	535,511.28	1,353,856.51	1,232,148.84	1,204,680.32	15,116,364.71
13 c Real-Time Asset Energy Amount - Loss Component	38,837.80	84,196.25	46,824.00	(17,101.55)	55,031.63	(11,887.94)	(85,017.45)	72,520.67	(27,655.28)	45,812.59	76,484.98	4,286.65	282,332.35
22 c Real-Time Non-Asset Energy Amount - Loss Component	(6,953.64)	(2,098.88)	586.12	(16,365.63)	(8,674.53)	(262.50)	1,734.88	840.85	8.67	(1,025.28)	(3,761.33)	(5,287.17)	(41,258.44)
14 Real-Time Distribution of Losses Amount	(1,821,265.65)	(2,398,013.37)	(1,159,550.93)	(1,236,679.64)	(1,961,143.28)	(1,344,972.09)	(1,511,371.31)	(1,785,962.00)	(1,047,242.39)	(925,745.90)	(786,313.16)	(1,190,722.49)	(17,168,982.21)
16 Real-Time Financial Bilateral Transaction Loss Amount	-	-	(64.21)	(48.58)	-	-	(23.77)	-	-	-	(1.93)	-	(138.49)
SUBTOTAL	3,102,663.47	2,575,748.49	2,933,479.50	2,800,684.18	4,417,067.25	3,998,040.12	2,577,136.85	3,099,391.90	2,604,417.56	2,019,786.50	2,416,790.21	2,426,171.45	34,971,377.48
Virtual Energy Charges													
12 Day-Ahead Virtual Energy Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
27 Real-Time Virtual Energy Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL	-	-	-	-	-	-	-	-	-	-	-	-	-
Market Adminstration Charges (Schedule 16 & 17)													
4 Day-Ahead Market Administration Amount	486,188.19	445,212.99	443,822.55	481,762.21	632,552.65	549,587.30	500,873.36	623,735.83	704,788.90	517,134.72	510,387.75	583,501.85	6,479,548.30
19 Real-Time Market Administration Amount	27,660.64	23,974.68	28,288.37	34,090.50	44,097.88	39,535.95	37,302.32	40,413.21	51,256.26	38,281.67	40,108.78	39,876.48	444,886.74
29 Financial Transmission Rights Market Administration Amount	48,829.52	38,142.48	28,065.12	23,626.96	25,647.20	38,808.88	38,159.60	35,475.84	35,653.20	34,623.04	34,200.72	34,161.28	415,393.84
33 Day-Ahead Schedule 24 Allocation Amount	63,723.20	70,280.28	71,951.88	66,695.92	68,164.28	65,081.95	63,799.38	67,939.47	71,907.79	62,391.69	62,047.01	81,719.83	815,702.68
34 Real -Time Schedule 24 Allocation Amount	(27,501.05)	(32,757.67)	(34,088.45)	(29,650.06)	(31,408.08)	(27,169.44)	(29,413.48)	(31,611.17)	(32,610.10)	(29,955.60)	(29,960.39)	(94,321.37)	(430,446.86)
35 Schedule 24 Admin Allocation	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL	598,900.50	544,852.76	538,039.47	576,525.53	739,053.93	665,844.64	610,721.18	735,953.18	830,996.05	622,475.52	616,783.87	644,938.07	7,725,084.70
Congestion Related Charges													
1 b Day-Ahead Asset Energy Amount - Congestion Component	1,676,603.29	692,607.44	3,394,425.43	4,127,571.69	6,798,706.85	2,592,918.96	3,503,488.11	2,495,521.83	2,503,187.90	(389,266.03)	799,034.88	(143,069.84)	28,051,730.51
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	1,413,337.89	1,149,758.60	1,440,004.66	5,075,832.85	615,289.41	1,280,300.77	453,878.46	1,447,300.89	183,787.18	2,083,502.87	2,286,302.21	1,446,476.67	18,875,772.46
13 b Real-Time Asset Energy Amount - Congestion Component	189.78	235,056.24	232,780.09	(562.00)	274,205.42	(38,310.70)	(292,699.49)	298,360.38	(71,176.63)	95,379.26	241,176.99	3,528.85	977,928.19
22 b Real-Time Non-Asset Energy Amount - Congestion Component	(412,812.00)	(128,574.03)	(42,936.58)	(9,207.90)	(76,234.13)	337.59	(2,336.69)	12,085.15	66.12	(1,982.35)	(19,977.46)	(42,837.66)	(724,409.94)
2 Day-Ahead Financial Bilateral Transmission Congestion Amount	8,141.62	(1,208.89)	791.93	1,508.75	7,598.24	(926.26)	845.35	4,571.24	4,855.11	6,827.19	4,675.74	(1,132.03)	36,547.99
15 Real-Time Financial Bilateral Transaction Congestion Amount	-	-	144.52	440.25	-	-	(12.51)	-	-	-	(8.00)	-	564.26
28 Financial Transmission Rights Hourly Allocation Amount	(1,868,018.23)	(1,627,573.70)	(4,607,044.49)	(6,623,772.88)	(2,774,741.95)	(3,748,265.03)	(3,088,429.08)	(2,638,215.63)	(2,033,457.66)	(173,880.77)	(2,568,938.67)	(1,439,393.93)	(33,191,732.02)
30 Financial Transmission Rights Monthly Allocation Amount	(55,827.49)	(46,048.45)	(147,426.41)	(140,934.26)	(100,868.14)	(181,752.04)	(187,254.82)	(113,847.87)	(73,502.00)	(45,114.09)	(47,991.31)	(50,654.52)	(1,191,221.40)
32 Financial Transmission Rights Yearly Allocation Amount	-	-	-	-	-	-	-	-	-	(780,712.59)	-	-	(780,712.59)
31 Financial Transmission Rights Transaction Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
36 Financial Transmission Rights Full Funding Guarantee Amount	52,451.19	(59,134.67)	(401,477.05)	(739,710.56)	(375,496.38)	(82,900.03)	(54,659.01)	(71,077.02)	25,507.49	888,137.17	(11,782.92)	9,151.86	(820,989.93)
37 Financial Transmission Guarantee Uplift Amount	(51,644.46)	56,113.75	414,079.29	755,421.53	483,540.13	88,845.34	46,900.17	67,927.21	(34,323.72)	(866,657.41)	11,782.92	(10,567.73)	961,417.02
38 Financial Transmission Rights Monthly Transacton Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL	762,421.59	270,996.29	283,341.39	2,446,587.47	4,851,999.45	(89,751.40)	379,720.49	1,502,626.18	504,943.79	816,233.25	694,274.38	(228,498.33)	12,194,894.55
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	105,260.42	200,932.19	182,635.74	152,832.02	109,833.21	181,370.20	163,641.43	206,399.66	473,335.28	19,515.91	43,140.27	114,315.22	1,953,211.55
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	(43,976.83)	(63,618.66)	(101,443.45)	(200,330.96)	(122,498.38)	(42,131.91)	(111,103.02)	(100,928.64)	(408,433.12)	(165,087.62)	(10,305.01)	(26,220.18)	(1,396,077.78)
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amour	(126,910.35)	202,603.59	153,058.51	178,912.09	147,663.09	167,304.49	116,402.97	154,958.46	242,120.87	31,703.22	159,942.57	158,932.21	1,586,691.72
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	11,487.71	(103,743.31)	(91,310.88)	(47,021.92)	(54,840.00)	(177,129.60)	(1,267.67)	(68,367.77)	(487,867.25)	(10,022.13)	(54,669.10)	(117,146.13)	(1,201,898.05)
43 Real Time Price Volatility Make Whole Payment	(478,571.94)	(390,622.27)	(167,622.56)	(224,857.01)	(598,855.81)	(60,664.96)	(348,515.12)	(327,724.31)	(162,062.63)	(163,764.17)	(135,002.09)	(169,145.79)	(3,227,408.66)
SUBTOTAL	(532,710.99)	(154,448.46)	(24,682.64)	(140,465.78)	(518,697.89)	68,748.22	(180,841.41)	(135,662.60)	(342,906.85)	(287,654.79)	3,106.64	(39,264.67)	(2,285,481.22)
Other MISO Charges													
20 Real-Time Miscellaneous Amount	(42,408.27)	13,902.48	(51,318.81)	(54,710.46)	7,393.58	(211,261.44)	(405,509.67)	(378,713.36)	(365,421.26)	(260,323.94)	(78,037.09)	(37,149.98)	(1,863,558.22)
21 Real-time Net inadvertent Distribution	68,153.72	(430,660.00)	(19,182.14)	71,496.69	(28,411.36)	8,320.04	(96,680.24)	(59,939.70)	41,702.18	(32,185.36)	(38,015.41)	20,092.04	(495,309.54)
23 Real-Time Revenue Neutrality Uplift Amount	651,313.12	853,732.89	552,825.55	868,925.28	1,429,445.11	544,351.65	379,920.53	716,461.93	303,189.66	414,074.06	697,474.62	672,176.95	8,083,891.35
26 Real-Time Uninstructed Deviation Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
SUBTOTAL	677,058.57	436,975.37	482,324.60	885,711.51	1,408,427.33	341,410.25	(122,269.38)	277,808.87	(20,529.42)	121,564.76	581,422.12	655,119.01	5,725,023.59
Auction Revenue Rights (ARR)													-
39 Auction Revenue Rights - FTR Auction Transactions	7,267,335.64	7,267,335.64	6,044,899.06	6,044,899.06	6,044,899.06	7,250,896.00	7,250,896.00	7,250,896.00	6,666,528.17	6,666,528.17	6,666,528.17	3,516,999.68	77,938,640.65
40 Auction Revenue Rights - Monthly ARR Revenue	(7,682,508.05)	(7,682,508.05)	(6,528,060.99)	(6,528,060.99)	(6,528,060.99)	(7,412,271.29)	(7,412,271.29)	(7,412,271.29)	(6,785,365.96)	(6,785,365.96)	(6,785,365.96)	(3,588,338.38)	(81,130,449.20)
41 Auction Revenue Rights - ARR Stage 2 Distribution	(279,224.93)	(279,006.76)	(295,795.44)	(290,711.50)	(349,320.42)	(163,750.35)	(104,620.47)	(165,295.02)	(218,926.71)	(216,392.08)	(218,818.02)	(116,560.48)	(2,698,422.18)
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	198,282.96	198,286.15	165,034.21	165,031.72	165,031.72	215,785.30	215,789.60	215,789.60	293,678.17	293,678.17	293,678.17	67,063.94	2,487,129.71
SUBTOTAL	(496,114.38)	(495,893.02)	(613,923.16)	(608,841.71)	(667,450.63)	(109,340.34)	(50,206.16)	(110,880.71)	(44,086.33)	(41,551.70)	(43,977.64)	(120,835.24)	(3,403,101.02)
Grandfathered Charge Types													
6 Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	(8,141.62)	1,208.89	(791.93)	(1,508.75)	(7,598.24)	926.26	(845.35)	(4,571.24)	(4,855.11)	(6,827.19)	(4,675.74)	1,132.03	(36,547.99)
7 Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	(882.59)	(2,102.35)	(536.35)	(1,944.46)	(4,148.31)	(5,644.27)	(3,961.72)	(6,378.65)	(2,755.65)	(2,250.67)	(1,852.22)	(1,197.31)	(33,654.55)
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	-	-	(144.52)	(440.25)	-	-	12.51	-	-	-	8.00	-	(564.26)
18 Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	-	-	64.21	48.58	-	-	23.77	-	-	-	1.93	-	138.49
SUBTOTAL	(9,024.21)	(893.46)	(1,408.59)	(3,844.88)	(11,746.55)	(4,718.01)	(4,770.79)	(10,949.89)	(7,610.76)	(9,077.86)	(6,518.03)	(65.28)	(70,628.31)
TOTAL MISO DAY 2 CHARGES	12,552,856.12	9,506,582.73	1,988,224.50	(1,346,501.70)	3,211,206.46	(6,487,410.53)	(870,492.57)	2,501,593.69	3,668,326.32	9,155,802.55	9,446,985.14	1,742,228.00	45,069,400.71

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - INTERSYSTEM

	July 14	August 14	September 14	October 14	November 14	December 14	January 15	February 15	March 15	April 15	May 15	June 15	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	$ 718,219.88	$ 2,310,446.12	$ 2,635,689.84	$ 7,809,079.49	$ 5,184,337.83	$ 9,472,266.95	$ 5,156,228.15	$ 4,195,308.89	$ 3,404,076.88	$ 1,134,682.23	$ 1,271,708.58	$ 2,974,148.26	$ 46,266,193.10
5 a Day-Ahead Non-Asset Energy Amount - Energy Component													
13 a Real-Time Asset Energy Amount - Energy Component	$ 1,225,059.68	$ 995,163.05	$ 915,685.05	$ 1,138,611.97	$ 850,149.83	$ 1,236,349.57	$ 1,151,464.36	$ 1,743,666.38	$ 1,200,976.08	$ 366,699.88	$ 831,015.25	$ 792,543.90	$ 12,447,385.00
22 a Real-Time Non-Asset Energy Amount - Energy Component													
SUBTOTAL	$ 1,943,279.56	$ 3,305,609.17	$ 3,551,374.89	$ 8,947,691.46	$ 6,034,487.66	$ 10,708,616.52	$ 6,307,692.51	$ 5,938,975.27	$ 4,605,052.96	$ 1,501,382.11	$ 2,102,723.83	$ 3,766,692.16	$ 58,713,578.10
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	$ (41,173.52)	$ (78,638.91)	$ (118,691.52)	$ (206,961.63)	$ (254,322.93)	$ (311,764.70)	$ (305,108.31)	$ (205,629.94)	$ (181,093.93)	$ (35,648.83)	$ (69,335.05)	$ (105,762.71)	$ (1,914,131.99)
3 Day-Ahead Financial Bilateral Transaction Loss Amount													
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	$ (47,076.74)	$ (38,147.99)	$ (60,744.72)	$ (113,686.89)	$ (81,346.89)	$ (190,608.88)	$ 51,704.57	$ (58,124.13)	$ (30,874.44)	$ (31,245.77)	$ (45,049.56)	$ (52,823.12)	$ (698,024.55)
13 c Real-Time Asset Energy Amount - Loss Component	$ (700.74)	$ (2,011.02)	$ (2,077.04)	$ 1,347.67	$ (2,919.30)	$ 1,116.40	$ 5,169.03	$ (3,980.27)	$ 1,594.44	$ (1,057.31)	$ (2,796.43)	$ (187.96)	$ (6,502.53)
22 c Real-Time Non-Asset Energy Amount - Loss Component	$ 125.46	$ 50.13	$ (26.00)	$ 1,289.68	$ 460.16	$ 24.65	$ (105.48)	$ (46.15)	$ (0.50)	$ 23.66	$ 137.52	$ 231.83	$ 2,164.97
14 Real-Time Distribution of Losses Amount													
16 Real-Time Financial Bilateral Transaction Loss Amount													
SUBTOTAL	$ (88,825.54)	$ (118,747.79)	$ (181,539.28)	$ (318,011.17)	$ (338,128.95)	$ (501,232.54)	$ (248,340.19)	$ (267,780.48)	$ (210,374.43)	$ (67,928.25)	$ (117,043.52)	$ (158,541.96)	$ (2,616,494.10)
Virtual Energy Charges													
12 Day-Ahead Virtual Energy Amount													
27 Real-Time Virtual Energy Amount													
SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Adminstration Charges (Schedule 16 & 17)													
4 Day-Ahead Market Administration Amount	$ (2,446.62)	$ (3,281.51)	$ (7,142.39)	$ (16,154.42)	$ (14,526.95)	$ (22,995.82)	$ (12,091.60)	$ (11,477.47)	$ (14,271.21)	$ (4,343.43)	$ (5,835.93)	$ (9,893.81)	$ (124,461.16)
19 Real-Time Market Administration Amount	$ (1,961.39)	$ (2,084.34)	$ (2,458.68)	$ (2,780.16)	$ (3,557.87)	$ (3,692.07)	$ (3,163.81)	$ (5,980.02)	$ (5,714.35)	$ (1,917.32)	$ (3,876.18)	$ (2,828.56)	$ (40,014.75)
29 Financial Transmission Rights Market Administration Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33 Day-Ahead Schedule 24 Allocation Amount	$ (309.86)	$ (525.72)	$ (1,156.98)	$ (2,239.02)	$ (1,533.31)	$ (2,721.27)	$ (1,528.00)	$ (1,239.19)	$ (1,431.59)	$ (534.22)	$ (709.65)	$ (1,392.47)	$ (15,321.28)
34 Real -Time Schedule 24 Allocation Amount	$ 27,656.78	$ 36,483.13	$ 38,499.06	$ 32,636.22	$ 38,477.25	$ 29,694.15	$ 35,196.11	$ 36,614.75	$ 25,868.51	$ 34,813.93	$ 35,858.30	$ 88,233.67	$ 460,031.86
35 Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 22,938.91	$ 30,591.56	$ 27,741.01	$ 11,462.62	$ 18,859.12	$ 284.99	$ 18,412.70	$ 17,918.07	$ 4,451.36	$ 28,018.96	$ 25,436.54	$ 74,118.83	$ 280,234.67
Congestion Related Charges													
1 b Day-Ahead Asset Energy Amount - Congestion Component	$ (30,250.62)	$ (16,542.89)	$ (150,571.23)	$ (325,269.32)	$ (360,655.35)	$ (243,501.17)	$ (213,010.63)	$ (136,965.65)	$ (144,319.14)	$ 8,983.90	$ (29,214.14)	$ 6,273.36	$ (1,635,042.88)
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	$ (25,500.57)	$ (27,461.92)	$ (63,876.28)	$ (399,996.13)	$ (32,639.65)	$ (120,233.12)	$ (27,595.62)	$ (79,434.49)	$ (10,596.09)	$ (48,085.34)	$ (83,591.28)	$ (63,425.47)	$ (982,435.97)
13 b Real-Time Asset Energy Amount - Congestion Component	$ (3.42)	$ (5,614.30)	$ (10,325.75)	$ 44.29	$ (14,545.95)	$ 3,597.76	$ 17,796.01	$ (16,375.38)	$ 4,103.63	$ (2,201.27)	$ (8,817.86)	$ (154.73)	$ (32,496.98)
22 b Real-Time Non-Asset Energy Amount - Congestion Component	$ 7,448.28	$ 3,070.98	$ 1,904.60	$ 725.62	$ 4,044.04	$ (31.70)	$ 142.07	$ (663.29)	$ (3.81)	$ 45.75	$ 730.41	$ 1,878.36	$ 19,291.31
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 Transacton Amount													
SUBTOTAL	$ (48,306.33)	$ (46,548.12)	$ (222,868.66)	$ (724,495.54)	$ (403,796.91)	$ (360,168.24)	$ (222,668.18)	$ (233,438.82)	$ (150,815.42)	$ (41,256.95)	$ (120,892.87)	$ (55,428.48)	$ (2,630,684.52)
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ (1,899.19)	$ (4,799.25)	$ (8,101.43)	$ (12,043.78)	$ (5,826.39)	$ (17,314.40)	$ (9,949.33)	$ (11,328.16)	$ (27,289.74)	$ (450.41)	$ (1,577.29)	$ (5,012.52)	$ (105,591.89)
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ 60,961.22	$ 6,378.39	$ 25,127.91	$ 121,267.09	$ 65,472.06	$ 15,732.48	$ 45,145.06	$ 33,732.18	$ 75,478.05	$ 41,897.65	$ (4,542.82)	$ 9,255.55	$ 495,904.82
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amour	$ 2,289.82	$ (4,839.17)	$ (6,789.43)	$ (14,099.00)	$ (7,833.18)	$ (15,971.63)	$ (7,077.25)	$ (8,504.83)	$ (13,959.27)	$ (731.68)	$ (25,500.92)	$ (29,473.78)	$ (132,490.32)
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 1,576,097.42	$ 9,337.52	$ 43,079.66	$ 19,273.51	$ 14,249.16	$ (1,364.09)	$ (798.19)	$ 5,944.00	$ 251,432.56	$ 1,435.18	$ 35,866.46	$ 65,810.60	$ 2,020,363.79
43 Real Time Price Volatility Make Whole Payment	$ 6,962.59	$ 13,038.13	$ (1,920.18)	$ 9,544.06	$ 33,988.81	$ 13,244.26	$ 15,204.93	$ 21,241.80	$ 12,005.62	$ 5,513.09	$ 3,282.38	$ 5,569.60	$ 137,675.09
SUBTOTAL	$ 1,644,411.86	$ 19,115.61	$ 51,396.54	$ 123,941.88	$ 100,050.46	$ (5,673.38)	$ 42,525.22	$ 41,084.99	$ 297,667.22	$ 47,663.83	$ 7,527.82	$ 46,149.45	$ 2,415,861.49
Other MISO Charges													
20 Real-Time Miscellaneous Amount	$ 33,840.59	$ 36,163.70	$ 29,332.67	$ 29,213.68	$ 29,687.34	$ 52,210.57	$ 95,051.51	$ 70,005.00	$ 69,381.57	$ 47,609.77	$ 64,040.02	$ 40,146.52	$ 596,682.94
21 Real-time Net inadvertent Distribution													
23 Real-Time Revenue Neutrality Uplift Amount	$ (11,751.51)	$ (20,391.36)	$ (24,522.45)	$ (68,474.82)	$ (75,828.69)	$ (51,966.22)	$ (23,099.01)	$ (39,322.71)	$ (17,480.14)	$ (9,556.45)	$ (5,847.79)	$ (6,968.90)	$ (355,210.05)
26 Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 22,089.08	$ 15,772.34	$ 4,810.22	$ (39,261.14)	$ (46,141.35)	$ 244.35	$ 71,952.50	$ 30,682.29	$ 51,901.43	$ 38,053.32	$ 58,192.23	$ 33,177.62	$ 241,472.89
Auction Revenue Rights (ARR)													
39 Auction Revenue Rights - FTR Auction Transactions													
40 Auction Revenue Rights - Monthly ARR Revenue	$ -	$ -	$ -	$ -	$ -	$ 117,353.14	$ 19,168.06	$ 28,268.10	$ 16,306.18	$ 22,235.70	$ 23,718.08	$ 4,447.14	$ 231,496.40
41 Auction Revenue Rights - ARR Stage 2 Distribution													
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue													
SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ 117,353.14	$ 19,168.06	$ 28,268.10	$ 16,306.18	$ 22,235.70	$ 23,718.08	$ 4,447.14	$ 231,496.40
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	$ 3,495,587.53	$ 3,205,792.77	$ 3,230,914.71	$ 8,001,328.12	$ 5,365,330.03	$ 9,959,424.84	$ 5,988,742.62	$ 5,555,709.42	$ 4,614,189.30	$ 1,528,168.72	$ 1,979,662.11	$ 3,710,614.76	$ 56,635,464.94

SUMMARY OF MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - RETAIL

		July 14	August 14	September 14	October 14	November 14	December 14	January 15	February 15	March 15	April 15	May 15	June 15	YTD
Day Ahead & Real Time Asset & Non-Asset Energy														
1 a	Day-Ahead Asset Energy Amount - Energy Component	$ 25,794,290.95	$ 24,286,665.55	$ 13,832,769.62	$ 15,862,559.23	$ 8,389,184.85	$ 10,573,186.41	$ 7,748,153.14	$ 12,286,664.84	$ 13,415,465.23	$ 14,974,483.32	$ 18,524,662.10	$ 11,773,896.01	$ 177,461,981.25
5 a	Day-Ahead Non-Asset Energy Amount - Energy Component	$ (18,159,042.06)	$ (16,485,508.52)	$ (13,372,565.58)	$ (15,067,199.80)	$ (11,526,418.41)	$ (13,501,007.27)	$ (8,128,583.31)	$ (11,731,613.87)	$ (9,837,021.18)	$ (9,116,033.45)	$ (11,077,244.02)	$ (11,256,283.68)	$ (149,258,521.15)
13 a	Real-Time Asset Energy Amount - Energy Component	$ 3,660,776.15	$ 1,693,890.88	$ 1,044,457.41	$ 870,893.56	$ 2,127,965.22	$ 2,270,257.72	$ 2,600,118.71	$ 2,532,761.07	$ 1,163,472.19	$ 1,548,457.25	$ (236,549.26)	$ 1,837,463.86	$ 21,113,964.76
22 a	Real-Time Non-Asset Energy Amount - Energy Component	$ (903,083.91)	$ 139,806.02	$ 437,767.37	$ (21,419.55)	$ 36,309.57	$ 8,535.65	$ 8,020.62	$ (5,530.01)	$ 6,239.00	$ 8,501.86	$ 76,958.60	$ (183,721.04)	$ (391,615.82)
	SUBTOTAL	$ 10,392,941.13	$ 9,634,853.93	$ 1,942,428.82	$ 1,644,833.44	$ (972,958.77)	$ (649,027.49)	$ 2,227,709.16	$ 3,082,282.03	$ 4,748,155.24	$ 7,415,408.98	$ 7,287,827.42	$ 2,171,355.15	$ 48,925,809.04
Day Ahead & Real Time Energy Loss														
1 c	Day-Ahead Asset Energy Amount - Loss Component	$ 2,240,818.25	$ 3,213,766.53	$ 2,557,048.79	$ 2,419,320.41	$ 4,539,913.66	$ 3,008,057.53	$ 4,713,154.42	$ 3,540,959.00	$ 2,959,945.70	$ 1,508,989.08	$ 1,827,045.54	$ 2,306,254.12	$ 34,835,273.02
3	Day-Ahead Financial Bilateral Transaction Loss Amount	$ 882.59	$ 2,102.35	$ 536.35	$ 1,944.46	$ 4,148.31	$ 5,644.27	$ 3,961.72	$ 6,378.65	$ 2,755.65	$ 2,250.67	$ 1,852.22	$ 1,197.31	$ 33,654.55
5 c	Day-Ahead Non-Asset Energy Amount - Loss Component	$ 2,562,093.86	$ 1,559,008.71	$ 1,308,663.14	$ 1,328,966.19	$ 1,452,121.64	$ 1,839,087.27	$ (798,705.38)	$ 1,000,900.66	$ 504,636.84	$ 1,322,610.74	$ 1,187,099.28	$ 1,151,857.20	$ 14,418,340.16
13 c	Real-Time Asset Energy Amount - Loss Component	$ 38,137.06	$ 82,185.23	$ 44,746.96	$ (15,753.88)	$ 52,112.33	$ (10,771.54)	$ (79,848.42)	$ 68,540.40	$ (26,060.84)	$ 44,755.28	$ 73,688.55	$ 4,098.69	$ 275,829.82
22 c	Real-Time Non-Asset Energy Amount - Loss Component	$ (6,828.18)	$ (2,048.75)	$ 560.12	$ (15,075.95)	$ (8,214.37)	$ (237.85)	$ 1,629.40	$ 794.70	$ 8.17	$ (1,001.62)	$ (3,623.81)	$ (5,055.34)	$ (39,093.47)
14	Real-Time Distribution of Losses Amount	$ (1,821,265.65)	$ (2,398,013.37)	$ (1,159,550.93)	$ (1,236,679.64)	$ (1,961,143.28)	$ (1,344,972.09)	$ (1,511,371.31)	$ (1,785,962.00)	$ (1,047,242.39)	$ (925,745.90)	$ (786,313.16)	$ (1,190,722.49)	$ (17,168,982.21)
16	Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ (64.21)	$ (48.58)	$ -	$ -	$ (23.77)	$ -	$ -	$ -	$ (1.93)	$ -	$ (138.49)
	SUBTOTAL	$ 3,013,837.93	$ 2,457,000.70	$ 2,751,940.22	$ 2,482,673.01	$ 4,078,938.30	$ 3,496,807.58	$ 2,328,796.66	$ 2,831,611.42	$ 2,394,043.13	$ 1,951,858.25	$ 2,299,746.69	$ 2,267,629.49	$ 32,354,883.38
Virtual Energy Charges														
12	Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Adminstration Charges (Schedule 16 & 17)														
4	Day-Ahead Market Administration Amount	$ 483,741.57	$ 441,931.48	$ 436,680.16	$ 465,607.79	$ 618,025.70	$ 526,591.48	$ 488,781.76	$ 612,258.36	$ 690,517.69	$ 512,791.29	$ 504,551.82	$ 573,608.04	$ 6,355,087.14
19	Real-Time Market Administration Amount	$ 25,699.25	$ 21,890.34	$ 25,829.69	$ 31,310.34	$ 40,540.01	$ 35,843.88	$ 34,138.51	$ 34,433.19	$ 45,541.91	$ 36,364.35	$ 36,232.60	$ 37,047.92	$ 404,871.99
29	Financial Transmission Rights Market Administration Amount	$ 48,829.52	$ 38,142.48	$ 28,065.12	$ 23,626.96	$ 25,647.20	$ 38,808.88	$ 38,159.60	$ 35,475.84	$ 35,653.20	$ 34,623.04	$ 34,200.72	$ 34,161.28	$ 415,393.84
33	Day-Ahead Schedule 24 Allocation Amount	$ 63,413.34	$ 69,754.56	$ 70,794.90	$ 64,456.90	$ 66,630.97	$ 62,360.68	$ 62,271.38	$ 66,700.28	$ 70,476.20	$ 61,857.47	$ 61,337.36	$ 80,327.36	$ 800,381.40
34	Real -Time Schedule 24 Allocation Amount	$ 155.73	$ 3,725.46	$ 4,410.61	$ 2,986.16	$ 7,069.17	$ 2,524.71	$ 5,782.63	$ 5,003.58	$ (6,741.59)	$ 4,858.33	$ 5,897.91	$ (6,087.70)	$ 29,585.00
35	Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 621,839.41	$ 575,444.32	$ 565,780.48	$ 587,988.15	$ 757,913.05	$ 666,129.63	$ 629,133.88	$ 753,871.25	$ 835,447.41	$ 650,494.48	$ 642,220.41	$ 719,056.90	$ 8,005,319.37
Congestion Related Charges														
1 b	Day-Ahead Asset Energy Amount - Congestion Component	$ 1,646,352.67	$ 676,064.55	$ 3,243,854.20	$ 3,802,302.37	$ 6,438,051.50	$ 2,349,417.79	$ 3,290,477.48	$ 2,358,556.18	$ 2,358,868.76	$ (380,282.13)	$ 769,820.74	$ (136,796.48)	$ 26,416,687.63
5 b	Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,387,837.32	$ 1,122,296.68	$ 1,376,128.38	$ 4,675,836.72	$ 582,649.76	$ 1,160,067.65	$ 426,282.84	$ 1,367,866.40	$ 173,191.09	$ 2,035,417.53	$ 2,202,710.93	$ 1,383,051.20	$ 17,893,336.49
13 b	Real-Time Asset Energy Amount - Congestion Component	$ 186.36	$ 229,441.94	$ 222,454.34	$ (517.71)	$ 259,659.47	$ (34,712.94)	$ (274,903.48)	$ 281,985.00	$ (67,073.00)	$ 93,177.99	$ 232,359.13	$ 3,374.12	$ 945,431.21
22 b	Real-Time Non-Asset Energy Amount - Congestion Component	$ (405,363.72)	$ (125,503.05)	$ (41,031.98)	$ (8,482.28)	$ (72,190.09)	$ 305.89	$ (2,194.62)	$ 11,421.86	$ 62.31	$ (1,936.60)	$ (19,247.05)	$ (40,959.30)	$ (705,118.63)
2	Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 8,141.62	$ (1,208.89)	$ 791.93	$ 1,508.75	$ 7,598.24	$ (926.26)	$ 845.35	$ 4,571.24	$ 4,855.11	$ 6,827.19	$ 4,675.74	$ (1,132.03)	$ 36,547.99
15	Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ 144.52	$ 440.25	$ -	$ -	$ (12.51)	$ -	$ -	$ -	$ (8.00)	$ -	$ 564.26
28	Financial Transmission Rights Hourly Allocation Amount	$ (1,868,018.23)	$ (1,627,573.70)	$ (4,607,044.49)	$ (6,623,772.88)	$ (2,774,741.95)	$ (3,748,265.03)	$ (3,088,429.08)	$ (2,638,215.63)	$ (2,033,457.66)	$ (173,880.77)	$ (2,568,938.67)	$ (1,439,393.93)	$ (33,191,732.02)
30	Financial Transmission Rights Monthly Allocation Amount	$ (55,827.49)	$ (46,048.45)	$ (147,426.41)	$ (140,934.26)	$ (100,868.14)	$ (181,752.04)	$ (187,254.82)	$ (113,847.87)	$ (73,502.00)	$ (45,114.09)	$ (47,991.31)	$ (50,654.52)	$ (1,191,221.40)
32	Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (780,712.59)	$ -	$ -	$ (780,712.59)
31	Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Financial Transmission Rights Full Funding Guarantee Amount	$ 52,451.19	$ (59,134.67)	$ (401,477.05)	$ (739,710.56)	$ (375,496.38)	$ (82,900.03)	$ (54,659.01)	$ (71,077.02)	$ 25,507.49	$ 888,137.17	$ (11,782.92)	$ 9,151.86	$ (820,989.93)
37	Financial Transmission Guarantee Uplift Amount	$ (51,644.46)	$ 56,113.75	$ 414,079.29	$ 755,421.53	$ 483,540.13	$ 88,845.34	$ 46,900.17	$ 67,927.21	$ (34,323.72)	$ (866,657.41)	$ 11,782.92	$ (10,567.73)	$ 961,417.02
38	Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 714,115.26	$ 224,448.17	$ 60,472.73	$ 1,722,091.93	$ 4,448,202.54	$ (449,919.64)	$ 157,052.31	$ 1,269,187.36	$ 354,128.37	$ 774,976.30	$ 573,381.51	$ (283,926.81)	$ 9,564,210.03
Revenue Sufficiency Guarantee (RSG) Charges														
10	Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 103,361.23	$ 196,132.94	$ 174,534.31	$ 140,788.24	$ 104,006.82	$ 164,055.80	$ 153,692.10	$ 195,071.50	$ 446,045.54	$ 19,065.50	$ 41,562.98	$ 109,302.70	$ 1,847,619.66
11	Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ 16,984.39	$ (57,240.27)	$ (76,315.54)	$ (79,063.87)	$ (57,026.32)	$ (26,399.43)	$ (65,957.96)	$ (67,196.46)	$ (332,955.07)	$ (123,189.97)	$ (14,847.83)	$ (16,964.63)	$ (900,172.96)
24	Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amour	$ (124,620.53)	$ 197,764.42	$ 146,269.08	$ 164,813.09	$ 139,829.91	$ 151,332.86	$ 109,325.72	$ 146,453.63	$ 228,161.60	$ 30,971.54	$ 134,441.65	$ 129,458.43	$ 1,454,201.40
25	Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 1,587,585.13	$ (94,405.79)	$ (48,231.22)	$ (27,748.41)	$ (40,590.84)	$ (178,493.69)	$ (2,065.86)	$ (62,423.77)	$ (236,434.69)	$ (8,586.95)	$ (18,802.64)	$ (51,335.53)	$ 818,465.74
43	Real Time Price Volatility Make Whole Payment	$ (471,609.35)	$ (377,584.14)	$ (169,542.74)	$ (215,312.95)	$ (564,867.00)	$ (47,420.70)	$ (333,310.19)	$ (306,482.51)	$ (150,057.01)	$ (158,251.08)	$ (131,719.71)	$ (163,576.19)	$ (3,089,733.57)
	SUBTOTAL	$ 1,111,700.87	$ (135,332.85)	$ 26,713.90	$ (16,523.90)	$ (418,647.43)	$ 63,074.84	$ (138,316.19)	$ (94,577.61)	$ (45,239.63)	$ (239,990.96)	$ 10,634.46	$ 6,884.78	$ 130,380.27
Other MISO Charges														
20	Real-Time Miscellaneous Amount	$ (8,567.68)	$ 50,066.18	$ (21,986.14)	$ (25,496.78)	$ 37,080.92	$ (159,050.87)	$ (310,458.16)	$ (308,708.36)	$ (296,039.69)	$ (212,714.17)	$ (13,997.07)	$ 2,996.54	$ (1,266,875.28)
21	Real-time Net inadvertent Distribution	$ 68,153.72	$ (430,660.00)	$ (19,182.14)	$ 71,496.69	$ (28,411.36)	$ 8,320.04	$ (96,680.24)	$ (59,939.70)	$ 41,702.18	$ (32,185.36)	$ (38,015.41)	$ 20,092.04	$ (495,309.54)
23	Real-Time Revenue Neutrality Uplift Amount	$ 639,561.61	$ 833,341.53	$ 528,303.10	$ 800,450.46	$ 1,353,616.42	$ 492,385.43	$ 356,821.52	$ 677,139.22	$ 285,709.52	$ 404,517.61	$ 691,626.83	$ 665,208.05	$ 7,728,681.30
26	Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 699,147.65	$ 452,747.71	$ 487,134.82	$ 846,450.37	$ 1,362,285.98	$ 341,654.60	$ (50,316.88)	$ 308,491.16	$ 31,372.01	$ 159,618.08	$ 639,614.35	$ 688,296.63	$ 5,966,496.48
Auction Revenue Rights (ARR)														
39	Auction Revenue Rights - FTR Auction Transactions	$ 7,267,335.64	$ 7,267,335.64	$ 6,044,899.06	$ 6,044,899.06	$ 6,044,899.06	$ 7,250,896.00	$ 7,250,896.00	$ 7,250,896.00	$ 6,666,528.17	$ 6,666,528.17	$ 6,666,528.17	$ 3,516,999.68	$ 77,938,640.65
40	Auction Revenue Rights - Monthly ARR Revenue	$ (7,682,508.05)	$ (7,682,508.05)	$ (6,528,060.99)	$ (6,528,060.99)	$ (6,528,060.99)	$ (7,294,918.15)	$ (7,393,103.23)	$ (7,384,003.19)	$ (6,769,059.78)	$ (6,763,130.26)	$ (6,761,647.88)	$ (3,583,891.24)	$ (80,898,952.80)
41	Auction Revenue Rights - ARR Stage 2 Distribution	$ (279,224.93)	$ (279,006.76)	$ (295,795.44)	$ (290,711.50)	$ (349,320.42)	$ (163,750.35)	$ (104,620.47)	$ (165,295.02)	$ (218,926.71)	$ (216,392.08)	$ (218,818.02)	$ (116,560.48)	$ (2,698,422.18)
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue	$ 198,282.96	$ 198,286.15	$ 165,034.21	$ 165,031.72	$ 165,031.72	$ 215,785.30	$ 215,789.60	$ 215,789.60	$ 293,678.17	$ 293,678.17	$ 293,678.17	$ 67,063.94	$ 2,487,129.71
	SUBTOTAL	$ (496,114.38)	$ (495,893.02)	$ (613,923.16)	$ (608,841.71)	$ (667,450.63)	$ 8,012.80	$ (31,038.10)	$ (82,612.61)	$ (27,780.15)	$ (19,316.00)	$ (20,259.56)	$ (116,388.10)	$ (3,171,604.62)
Grandfathered Charge Types														
6	Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (8,141.62)	$ 1,208.89	$ (791.93)	$ (1,508.75)	$ (7,598.24)	$ 926.26	$ (845.35)	$ (4,571.24)	$ (4,855.11)	$ (6,827.19)	$ (4,675.74)	$ 1,132.03	$ (36,547.99)
7	Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (882.59)	$ (2,102.35)	$ (536.35)	$ (1,944.46)	$ (4,148.31)	$ (5,644.27)	$ (3,961.72)	$ (6,378.65)	$ (2,755.65)	$ (2,250.67)	$ (1,852.22)	$ (1,197.31)	$ (33,654.55)
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	$ -	$ -	$ (144.52)	$ (440.25)	$ -	$ -	$ 12.51	$ -	$ -	$ -	$ 8.00	$ -	$ (564.26)
18	Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ 64.21	$ 48.58	$ -	$ -	$ 23.77	$ -	$ -	$ -	$ 1.93	$ -	$ 138.49
	SUBTOTAL	$ (9,024.21)	$ (893.46)	$ (1,408.59)	$ (3,844.88)	$ (11,746.55)	$ (4,718.01)	$ (4,770.79)	$ (10,949.89)	$ (7,610.76)	$ (9,077.86)	$ (6,518.03)	$ (65.28)	$ (70,628.31)
	TOTAL MISO DAY 2 CHARGES	$ 16,048,443.65	$ 12,712,375.50	$ 5,219,139.21	$ 6,654,826.42	$ 8,576,536.49	$ 3,472,014.31	$ 5,118,250.05	$ 8,057,303.11	$ 8,282,515.62	$ 10,683,971.27	$ 11,426,647.25	$ 5,452,842.76	$ 101,704,865.65

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

	July 14	August 14	September 14	October 14	November 14	December 14	January 15	February 15	March 15	April 15	May 15	June 15	YTD
Day Ahead & Real Time Asset & Non-Asset Energy													
1 a Day-Ahead Asset Energy Amount - Energy Component	$ 19,273,427.61	$ 18,198,260.82	$ 10,315,686.08	$ 11,675,613.54	$ 6,085,542.96	$ 7,634,057.10	$ 5,574,004.50	$ 8,801,478.76	$ 9,631,074.42	$ 10,981,669.66	$ 13,656,055.79	$ 8,760,256.80	$ 130,587,128.02
5 a Day-Ahead Non-Asset Energy Amount - Energy Component	$ (13,568,389.35)	$ (12,352,769.60)	$ (9,972,492.30)	$ (11,090,190.40)	$ (8,361,302.75)	$ (9,748,003.71)	$ (5,847,685.13)	$ (8,403,871.32)	$ (7,062,079.58)	$ (6,685,323.68)	$ (8,165,949.88)	$ (8,375,132.20)	$ (109,633,189.91)
13 a Real-Time Asset Energy Amount - Energy Component	$ 2,735,322.49	$ 1,269,250.73	$ 778,896.42	$ 641,019.93	$ 1,543,633.14	$ 1,639,172.56	$ 1,870,519.74	$ 1,814,328.22	$ 835,266.39	$ 1,135,574.81	$ (174,379.96)	$ 1,367,147.74	$ 15,455,752.21
22 a Real-Time Non-Asset Energy Amount - Energy Component	$ (674,781.97)	$ 104,758.16	$ 326,461.79	$ (15,765.83)	$ 26,339.08	$ 6,162.91	$ 5,770.02	$ (3,961.39)	$ 4,479.03	$ 6,234.91	$ 56,732.53	$ (136,695.92)	$ (294,266.66)
SUBTOTAL	$ 7,765,578.78	$ 7,219,500.12	$ 1,448,551.99	$ 1,210,677.25	$ (705,787.57)	$ (468,611.14)	$ 1,602,609.12	$ 2,207,974.27	$ 3,408,740.26	$ 5,438,155.70	$ 5,372,458.47	$ 1,615,576.42	$ 36,115,423.66
Day Ahead & Real Time Energy Loss													
1 c Day-Ahead Asset Energy Amount - Loss Component	$ 1,674,333.61	$ 2,408,109.98	$ 1,906,900.30	$ 1,780,737.25	$ 3,293,268.66	$ 2,171,879.13	$ 3,390,633.03	$ 2,536,544.77	$ 2,124,969.71	$ 1,106,630.47	$ 1,346,865.90	$ 1,715,946.73	$ 25,456,819.56
3 Day-Ahead Financial Bilateral Transaction Loss Amount	$ 659.47	$ 1,575.31	$ 399.98	$ 1,431.22	$ 3,009.20	$ 4,075.28	$ 2,850.05	$ 4,569.31	$ 1,978.30	$ 1,650.55	$ 1,365.42	$ 890.85	$ 24,454.94
5 c Day-Ahead Non-Asset Energy Amount - Loss Component	$ 1,914,389.92	$ 1,168,182.06	$ 975,925.90	$ 978,183.62	$ 1,053,373.93	$ 1,327,858.66	$ (574,586.91)	$ 716,989.20	$ 362,283.00	$ 969,948.27	$ 875,108.76	$ 857,028.54	$ 10,624,684.95
13 c Real-Time Asset Energy Amount - Loss Component	$ 28,495.91	$ 61,582.28	$ 33,369.72	$ (11,595.62)	$ 37,802.46	$ (7,777.27)	$ (57,442.78)	$ 49,098.51	$ (18,709.29)	$ 32,821.68	$ 54,321.91	$ 3,049.59	$ 205,017.08
22 c Real-Time Non-Asset Energy Amount - Loss Component	$ (5,102.00)	$ (1,535.15)	$ 417.71	$ (11,096.63)	$ (5,958.73)	$ (171.73)	$ 1,172.19	$ 569.28	$ 5.87	$ (734.55)	$ (2,671.41)	$ (3,761.38)	$ (28,866.53)
14 Real-Time Distribution of Losses Amount	$ (1,360,844.99)	$ (1,796,857.32)	$ (864,726.57)	$ (910,256.24)	$ (1,422,619.94)	$ (971,097.39)	$ (1,087,277.23)	$ (1,279,363.18)	$ (751,824.05)	$ (678,903.94)	$ (579,656.26)	$ (885,945.89)	$ (12,589,373.00)
16 Real-Time Financial Bilateral Transaction Loss Amount	$ -	$ -	$ (47.88)	$ (35.76)	$ -	$ -	$ (17.10)	$ -	$ -	$ -	$ (1.42)	$ -	$ (102.16)
SUBTOTAL	$ 2,251,931.92	$ 1,841,057.16	$ 2,052,239.15	$ 1,827,367.84	$ 2,958,875.59	$ 2,524,766.68	$ 1,675,331.25	$ 2,028,407.88	$ 1,718,703.54	$ 1,431,412.49	$ 1,695,332.90	$ 1,687,208.43	$ 23,692,634.83
Virtual Energy Charges													
12 Day-Ahead Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27 Real-Time Virtual Energy Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Market Adminstration Charges (Schedule 16 & 17)													
4 Day-Ahead Market Administration Amount	$ 361,450.45	$ 331,144.03	$ 325,651.01	$ 342,709.93	$ 448,317.93	$ 380,209.83	$ 351,628.53	$ 438,587.61	$ 495,728.41	$ 376,060.02	$ 371,946.75	$ 426,787.68	$ 4,650,222.19
19 Real-Time Market Administration Amount	$ 19,202.41	$ 16,402.67	$ 19,262.30	$ 23,045.93	$ 29,407.86	$ 25,880.02	$ 24,559.17	$ 24,666.01	$ 32,694.92	$ 26,668.12	$ 26,710.04	$ 27,565.16	$ 296,064.60
29 Financial Transmission Rights Market Administration Amount	$ 36,485.29	$ 28,580.57	$ 20,929.36	$ 17,390.59	$ 18,604.57	$ 28,020.81	$ 27,451.93	$ 25,412.91	$ 25,595.73	$ 25,391.11	$ 25,212.17	$ 25,417.38	$ 304,492.41
33 Day-Ahead Schedule 24 Allocation Amount	$ 47,382.28	$ 52,267.85	$ 52,794.78	$ 47,443.41	$ 48,334.33	$ 45,025.69	$ 44,797.90	$ 47,780.35	$ 50,595.45	$ 45,363.72	$ 45,216.83	$ 59,766.82	$ 586,769.39
34 Real -Time Schedule 24 Allocation Amount	$ 116.36	$ 2,791.53	$ 3,289.18	$ 2,197.96	$ 5,128.00	$ 1,822.89	$ 4,160.01	$ 3,584.28	$ (4,839.84)	$ 3,562.90	$ 4,347.84	$ (4,529.50)	$ 21,631.61
35 Schedule 24 Admin Allocation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 464,636.80	$ 431,186.64	$ 421,926.63	$ 432,787.82	$ 549,792.68	$ 480,959.23	$ 452,597.54	$ 540,031.15	$ 599,774.67	$ 477,045.87	$ 473,433.62	$ 535,007.54	$ 5,859,180.19
Congestion Related Charges													$ -
1 b Day-Ahead Asset Energy Amount - Congestion Component	$ 1,230,150.47	$ 506,582.47	$ 2,419,080.38	$ 2,798,679.11	$ 4,670,184.25	$ 1,696,327.75	$ 2,367,162.33	$ 1,689,537.59	$ 1,693,451.56	$ (278,883.26)	$ 567,498.34	$ (101,782.14)	$ 19,257,988.86
5 b Day-Ahead Non-Asset Energy Amount - Congestion Component	$ 1,036,988.46	$ 840,949.03	$ 1,026,237.60	$ 3,441,642.79	$ 422,656.10	$ 837,592.60	$ 306,666.94	$ 979,862.90	$ 124,335.33	$ 1,492,691.43	$ 1,623,799.84	$ 1,029,046.26	$ 13,162,469.28
13 b Real-Time Asset Energy Amount - Congestion Component	$ 139.24	$ 171,923.32	$ 165,893.69	$ (381.06)	$ 188,357.85	$ (25,063.45)	$ (197,764.97)	$ 201,998.26	$ (48,152.27)	$ 68,332.91	$ 171,291.07	$ 2,510.48	$ 699,085.08
22 b Real-Time Non-Asset Energy Amount - Congestion Component	$ (302,886.72)	$ (94,040.79)	$ (30,599.30)	$ (6,243.37)	$ (52,366.93)	$ 220.86	$ (1,578.81)	$ 8,181.98	$ 44.73	$ (1,420.22)	$ (14,188.59)	$ (30,475.38)	$ (525,352.54)
2 Day-Ahead Financial Bilateral Transmission Congestion Amount	$ 6,083.40	$ (905.83)	$ 590.58	$ 1,110.51	$ 5,511.79	$ (668.78)	$ 608.14	$ 3,274.58	$ 3,485.52	$ 5,006.78	$ 3,446.87	$ (842.28)	$ 26,701.29
15 Real-Time Financial Bilateral Transaction Congestion Amount	$ -	$ -	$ 107.77	$ 324.05	$ -	$ -	$ (9.00)	$ -	$ -	$ -	$ (5.90)	$ -	$ 416.92
28 Financial Transmission Rights Hourly Allocation Amount	$ (1,395,778.40)	$ (1,219,558.55)	$ (3,435,669.50)	$ (4,875,418.35)	$ (2,012,807.16)	$ (2,706,324.11)	$ (2,221,809.15)	$ (1,889,869.96)	$ (1,459,836.22)	$ (127,517.00)	$ (1,893,776.50)	$ (1,070,967.54)	$ (24,309,332.45)
30 Financial Transmission Rights Monthly Allocation Amount	$ (41,714.16)	$ (34,504.60)	$ (109,942.16)	$ (103,734.46)	$ (73,170.09)	$ (131,228.69)	$ (134,710.71)	$ (81,554.24)	$ (52,767.70)	$ (33,084.82)	$ (35,378.35)	$ (37,689.02)	$ (869,478.99)
32 Financial Transmission Rights Yearly Allocation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (572,542.48)	$ -	$ -	$ (572,542.48)
31 Financial Transmission Rights Transaction Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36 Financial Transmission Rights Full Funding Guarantee Amount	$ 39,191.39	$ (44,310.25)	$ (299,398.55)	$ (544,462.88)	$ (272,386.34)	$ (59,855.52)	$ (39,321.57)	$ (50,915.60)	$ 18,312.04	$ 651,323.24	$ (8,686.16)	$ 6,809.36	$ (603,700.84)
37 Financial Transmission Guarantee Uplift Amount	$ (38,588.61)	$ 42,046.64	$ 308,796.58	$ 556,026.91	$ 350,761.64	$ 64,148.15	$ 33,739.88	$ 48,659.25	$ (24,641.28)	$ (635,570.87)	$ 8,686.16	$ (7,862.82)	$ 706,201.64
38 Financial Transmission Rights Monthly Transacton Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 533,585.08	$ 168,181.44	$ 45,097.09	$ 1,267,543.25	$ 3,226,741.11	$ (324,851.19)	$ 112,983.09	$ 909,174.76	$ 254,231.71	$ 568,335.72	$ 422,686.78	$ (211,253.08)	$ 6,972,455.77
Revenue Sufficiency Guarantee (RSG) Charges													
10 Day-Ahead Revenue Sufficiency Guarantee Distribution Amount	$ 77,231.24	$ 146,964.53	$ 130,157.68	$ 103,626.98	$ 75,446.90	$ 118,451.64	$ 110,565.76	$ 139,738.30	$ 320,219.82	$ 13,981.85	$ 30,639.50	$ 81,325.65	$ 1,348,349.85
11 Day-Ahead Revenue Sufficiency Guarantee Make Whole Payment Amou	$ 12,690.69	$ (42,890.75)	$ (56,911.75)	$ (58,194.85)	$ (41,367.08)	$ (19,060.93)	$ (47,450.01)	$ (48,135.78)	$ (239,031.22)	$ (90,342.45)	$ (10,945.56)	$ (12,622.37)	$ (654,262.08)
24 Real-Time Revenue Sufficiency Guarantee First Pass Distribution Amou	$ (93,116.14)	$ 148,187.01	$ 109,079.09	$ 121,310.44	$ 101,433.09	$ 109,265.42	$ 78,648.68	$ 104,911.18	$ 163,799.12	$ 22,713.25	$ 99,108.03	$ 96,322.33	$ 1,061,661.50
25 Real-Time Revenue Sufficiency Make Whole Payment Amount	$ 1,186,239.51	$ (70,739.28)	$ (35,968.08)	$ (20,424.18)	$ (29,444.73)	$ (128,876.10)	$ (1,486.18)	$ (44,716.89)	$ (169,738.44)	$ (6,297.32)	$ (13,860.98)	$ (38,195.72)	$ 626,491.63
43 Real Time Price Volatility Make Whole Payment	$ (352,385.29)	$ (282,927.87)	$ (126,435.25)	$ (158,480.78)	$ (409,756.43)	$ (34,238.72)	$ (239,782.62)	$ (219,546.91)	$ (107,727.18)	$ (116,054.83)	$ (97,101.46)	$ (121,707.33)	$ (2,266,144.67)
SUBTOTAL	$ 830,660.02	$ (101,406.36)	$ 19,921.69	$ (12,162.39)	$ (303,688.26)	$ 45,541.32	$ (99,504.37)	$ (67,750.10)	$ (32,477.91)	$ (175,999.49)	$ 7,839.54	$ 5,122.55	$ 116,096.24
Other MISO Charges													
20 Real-Time Miscellaneous Amount	$ (6,401.75)	$ 37,515.13	$ (16,396.00)	$ (18,766.87)	$ 26,898.62	$ (114,837.99)	$ (223,342.92)	$ (221,141.38)	$ (212,529.36)	$ (155,995.82)	$ (10,318.39)	$ 2,229.55	$ (913,087.18)
21 Real-time Net inadvertent Distribution	$ 50,924.28	$ (322,698.19)	$ (14,304.94)	$ 52,625.03	$ (20,609.70)	$ 6,007.24	$ (69,551.55)	$ (42,937.45)	$ 29,938.34	$ (23,603.42)	$ (28,024.29)	$ 14,949.29	$ (367,285.34)
23 Real-Time Revenue Neutrality Uplift Amount	$ 477,878.78	$ 624,431.81	$ 393,978.15	$ 589,170.39	$ 981,917.91	$ 355,512.36	$ 256,696.62	$ 485,064.63	$ 205,113.25	$ 296,656.56	$ 509,855.16	$ 494,941.81	$ 5,671,217.44
26 Real-Time Uninstructed Deviation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL	$ 522,401.32	$ 339,248.75	$ 363,277.21	$ 623,028.56	$ 988,206.84	$ 246,681.61	$ (36,197.86)	$ 220,985.80	$ 22,522.23	$ 117,057.33	$ 471,512.48	$ 512,120.65	$ 4,390,844.91
Auction Revenue Rights (ARR)													
39 Auction Revenue Rights - FTR Auction Transactions	$ 5,430,134.43	$ 5,445,493.09	$ 4,507,938.96	$ 4,449,339.12	$ 4,384,990.15	$ 5,235,295.39	$ 5,216,278.79	$ 5,194,135.91	$ 4,785,956.19	$ 4,888,957.34	$ 4,914,447.57	$ 2,616,790.60	$ 57,069,757.54
40 Auction Revenue Rights - Monthly ARR Revenue	$ (5,740,350.18)	$ (5,756,586.26)	$ (4,868,253.41)	$ (4,804,969.75)	$ (4,735,477.44)	$ (5,267,080.28)	$ (5,318,582.36)	$ (5,289,486.45)	$ (4,859,564.49)	$ (4,959,801.34)	$ (4,984,568.15)	$ (2,666,560.63)	$ (59,251,280.75)
41 Auction Revenue Rights - ARR Stage 2 Distribution	$ (208,636.15)	$ (209,062.78)	$ (220,587.27)	$ (213,977.77)	$ (253,398.21)	$ (118,231.11)	$ (75,263.74)	$ (118,408.10)	$ (157,169.31)	$ (158,693.04)	$ (161,308.80)	$ (86,725.73)	$ (1,981,462.01)
42 Auction Revenue Rights - Monthly infeasible ARR Revenue	$ 148,156.52	$ 148,577.95	$ 123,073.05	$ 121,471.36	$ 119,714.57	$ 155,801.41	$ 155,238.57	$ 154,579.59	$ 210,834.01	$ 215,371.48	$ 216,494.39	$ 49,898.29	$ 1,819,211.18
SUBTOTAL	$ (370,695.38)	$ (371,578.00)	$ (457,828.68)	$ (448,137.05)	$ (484,170.94)	$ 5,785.41	$ (22,328.74)	$ (59,179.05)	$ (19,943.60)	$ (14,165.56)	$ (14,934.99)	$ (86,597.47)	$ (2,343,774.05)
Grandfathered Charge Types													
6 Day-Ahead Congestion Rebate on Carve-Out Grandfathered Agreements	$ (6,083.40)	$ 905.83	$ (590.58)	$ (1,110.51)	$ (5,511.79)	$ 668.78	$ (608.14)	$ (3,274.58)	$ (3,485.52)	$ (5,006.78)	$ (3,446.87)	$ 842.28	$ (26,701.29)
7 Day-Ahead Losses Rebate on Carve-Out Grandfathered Agreements	$ (659.47)	$ (1,575.31)	$ (399.98)	$ (1,431.22)	$ (3,009.20)	$ (4,075.28)	$ (2,850.05)	$ (4,569.31)	$ (1,978.30)	$ (1,650.55)	$ (1,365.42)	$ (890.85)	$ (24,454.94)
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	$ -	$ -	$ (107.77)	$ (324.05)	$ -	$ -	$ 9.00	$ -	$ -	$ -	$ 5.90	$ -	$ (416.92)
18 Real-Time Losses Rebate on Carve-Out Grandfathered Agreements	$ -	$ -	$ 47.88	$ 35.76	$ -	$ -	$ 17.10	$ -	$ -	$ -	$ 1.42	$ -	$ 102.16
SUBTOTAL	$ (6,742.87)	$ (669.48)	$ (1,050.45)	$ (2,830.02)	$ (8,520.99)	$ (3,406.50)	$ (3,432.10)	$ (7,843.89)	$ (5,463.83)	$ (6,657.33)	$ (4,804.98)	$ (48.57)	$ (51,470.99)
TOTAL MISO DAY 2 CHARGES	$ 11,991,355.67	$ 9,525,520.27	$ 3,892,134.63	$ 4,898,275.26	$ 6,221,448.47	$ 2,506,865.43	$ 3,682,057.94	$ 5,771,800.82	$ 5,946,087.07	$ 7,835,184.73	$ 8,423,523.81	$ 4,057,136.46	$ 74,751,390.57

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

July 2014	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	752,609	$25,076,071	794,655	$ 25,794,290.95	(42,046)	($718,220)		
5a Day Ahead Non Asset Energy	(524,152)	($18,159,042)	(524,152)	($18,159,042)			55,839	$1,775,870
13a Real Time Asset Energy	67,931	$2,435,716	97,158	$3,660,776	(29,227)	($1,225,060)		
22a Real Time Non Asset Energy	5,997	($903,084)	5,997	($903,084)			3,720	$108,410
SUBTOTAL	302,385	$8,449,662	373,658	$ 10,392,941.13	(71,273)	($1,943,280)	59,559	$1,884,280
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,281,991.77		$2,240,818		$ 41,173.52		
5c Day Ahead Non Asset Loss		$ 2,609,170.60		$2,562,094		$ 47,076.74		
3 Day Ahead Financial Bilateral Transaction Loss		$ 882.59		$883				
13c Real Time Loss		$ 38,837.80		$38,137		$ 700.74		
22c Real Time Non Asset Loss		$ (6,953.64)		($6,828)		$ (125.46)		
14 Real Time Distribution Losses		$ (1,821,265.65)		($1,821,266)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 3,102,663.47	-	$3,013,838	-	$88,826	-	$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)		$ 486,188.19		$483,742		$ 2,446.62		$3,449
19 Real Time Market Administration (Schedule 17)		$ 27,660.64		$25,699		$ 1,961.39		$231
29 Financial Transmission Rights Administration (Schedule 16)		$ 48,829.52		$48,830		$ -		$17,883
33 Day-Ahead Schedule 24 Allocation Amount		$ 63,723.20		$63,413		$ 309.86		$453
34 Real -Time Schedule 24 Allocation Amount		$ (27,501.05)		$156		$ (27,656.78)		$30
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 598,900.50	-	$621,839	-	$ (22,938.91)	-	$22,045
Congestion & FTRs								
1b Day Ahead Congestion		$ 1,676,603.29		$1,646,353		$ 30,250.62		
5b Day Ahead Non Asset Congestion		$ 1,413,337.89		$1,387,837		$ 25,500.57		
13b Real Time Congestion		$ 189.78		$186		$ 3.42		
22b Real Time Non Asset Congestion		$ (412,812.00)		($405,364)		$ (7,448.28)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 8,141.62		$8,142				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (1,868,018.23)		($1,868,018)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (55,827.49)		($55,827)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 52,451.19		$52,451				
37 Financial Transmission Guarantee Uplift Amount		$ (51,644.46)		($51,644)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 762,421.59	-	$714,115	-	$ 48,306.33	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 105,260.42		$ 103,361.23		$ 1,899		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (43,976.83)		$16,984		$ (60,961)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ (126,910.35)		($124,621)		$ (2,290)		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ 11,487.71		$1,587,585		$ (1,576,097)		
43 Real Time Price Volatility Make Whole Payment		($478,572)		($471,609)		$ (6,963)		
SUBTOTAL	-	$ (532,710.99)	-	$ 1,111,700.87	-	$ (1,644,412)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (42,408.27)		($8,568)		$ (33,840.59)		$0
21 Real Time Net Inadvertent Distribution		$ 68,153.72		$68,154				$418
23 Real Time Revenue Neutrality Uplift Amount		$ 651,313.12		$639,562		$ 11,752		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 677,058.57	-	$699,148	-	$ (22,089)	-	$418
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 7,267,335.64		$7,267,336				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (7,682,508.05)		($7,682,508)				
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (279,224.93)		($279,225)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 198,282.96		$198,283				
SUBTOTAL	-	$ (496,114.38)	-	($496,114)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (8,141.62)		($8,142)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (882.59)		($883)				
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	-	$ (9,024.21)	-	($9,024)	-	$0	-	$0
Total MISO Day 2 Charges	302,385	$ 12,552,856.12	373,658	$ 16,048,443.65	(71,273)	$ (3,495,587.53)	59,559	$ 1,906,743

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 2014	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	681,235	$21,976,219	743,643	$ 24,286,665.55	(62,408)	($2,310,446)		
5a Day Ahead Non Asset Energy	(429,951)	($16,485,509)	(429,951)	($16,485,509)			55,508	$1,830,822
13a Real Time Asset Energy	26,896	$698,728	63,905	$1,693,891	(37,009)	($995,163)		
22a Real Time Non Asset Energy	425	$139,806	425	$139,806			3,720	$112,341
SUBTOTAL	278,605	$6,329,245	378,022	$ 9,634,853.93	(99,417)	($3,305,609)	59,228	$1,943,163
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,292,405.44		$3,213,767		$ 78,638.91		
5c Day Ahead Non Asset Loss		$ 1,597,156.70		$1,559,009		$ 38,147.99		
3 Day Ahead Financial Bilateral Transaction Loss		$ 2,102.35		$2,102				
13c Real Time Loss		$ 84,196.25		$82,185		$ 2,011.02		
22c Real Time Non Asset Loss		$ (2,098.88)		($2,049)		$ (50.13)		
14 Real Time Distribution Losses		$ (2,398,013.37)		($2,398,013)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,575,748.49	-	$2,457,001	-	$118,748	-	$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)		$ 445,212.99		$441,931		$ 3,281.51		$3,022
19 Real Time Market Administration (Schedule 17)		$ 23,974.68		$21,890		$ 2,084.34		$201
29 Financial Transmission Rights Administration (Schedule 16)		$ 38,142.48		$38,142		$ -		$13,434
33 Day-Ahead Schedule 24 Allocation Amount		$ 70,280.28		$69,755		$ 525.72		$476
34 Real -Time Schedule 24 Allocation Amount		$ (32,757.67)		$3,725		$ (36,483.13)		$30
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 544,852.76	-	$575,444	-	$ (30,591.56)	-	$17,163
Congestion & FTRs								
1b Day Ahead Congestion		$ 692,607.44		$676,065		$ 16,542.89		
5b Day Ahead Non Asset Congestion		$ 1,149,758.60		$1,122,297		$ 27,461.92		
13b Real Time Congestion		$ 235,056.24		$229,442		$ 5,614.30		
22b Real Time Non Asset Congestion		$ (128,574.03)		($125,503)		$ (3,070.98)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (1,208.89)		($1,209)				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (1,627,573.70)		($1,627,574)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (46,048.45)		($46,048)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (59,134.67)		($59,135)				
37 Financial Transmission Guarantee Uplift Amount		$ 56,113.75		$56,114				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 270,996.29	-	$224,448	-	$ 46,548.12	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 200,932.19		$ 196,132.94		$ 4,799.25		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (63,618.66)		($57,240)		$ (6,378.39)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 202,603.59		$197,764		$ 4,839.17		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (103,743.31)		($94,406)		$ (9,337.52)		
43 Real Time Price Volatility Make Whole Payment		($390,622)		($377,584)		($13,038)		
SUBTOTAL	-	$ (154,448.46)	-	$ (135,332.85)	-	($19,116)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ 13,902.48		$50,066		$ (36,163.70)		$7,408
21 Real Time Net Inadvertent Distribution		$ (430,660.00)		($430,660)				($2,969)
23 Real Time Revenue Neutrality Uplift Amount		$ 853,732.89		$833,342		$ 20,391.36		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 436,975.37	-	$452,748	-	$ (15,772.34)	-	$4,438
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 7,267,335.64		$7,267,336				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (7,682,508.05)		($7,682,508)				
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (279,006.76)		($279,007)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 198,286.15		$198,286				
SUBTOTAL	-	$ (495,893.02)	-	($495,893)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 1,208.89		$1,209				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (2,102.35)		($2,102)				
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	-	$ (893.46)	-	($893)	-	$0	-	$0
Total MISO Day 2 Charges	278,605	$ 9,506,582.73	378,022	$ 12,712,375.50	(99,417)	$ (3,205,792.77)	59,228	$ 1,964,764

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 2014	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	345,974	$11,197,080	460,570	$ 13,832,769.62	(114,596)	($2,635,690)		
5a	Day Ahead Non Asset Energy	(448,394)	($13,372,566)	(448,394)	($13,372,566)			85,595	$2,645,142
13a	Real Time Asset Energy	7,870	$128,772	47,460	$1,044,457	(39,590)	($915,685)		
22a	Real Time Non Asset Energy	13,887	$437,767	13,887	$437,767			3,600	$96,155
	SUBTOTAL	(80,663)	($1,608,946)	73,523	$ 1,942,428.82	(154,186)	($3,551,375)	89,195	$2,741,297
	Day Ahead & Real Time Energy Loss								
1c	Day Ahead Loss		$ 2,675,740.31		$2,557,049		$ 118,691.52		
5c	Day Ahead Non Asset Loss		$ 1,369,407.86		$1,308,663		$ 60,744.72		
3	Day Ahead Financial Bilateral Transaction Loss		$ 536.35		$536				
13c	Real Time Loss		$ 46,824.00		$44,747		$ 2,077.04		
22c	Real Time Non Asset Loss		$ 586.12		$560		$ 26.00		
14	Real Time Distribution Losses		$ (1,159,550.93)		($1,159,551)				
16	Real Time Financial Bilateral Loss		$ (64.21)		($64)				
	SUBTOTAL	-	$ 2,933,479.50	-	$2,751,940	-	$181,539	-	$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)		$ 443,822.55		$436,680		$ 7,142.39		$5,332
19	Real Time Market Administration (Schedule 17)		$ 28,288.37		$25,830		$ 2,458.68		$223
29	Financial Transmission Rights Administration (Schedule 16)		$ 28,065.12		$28,065		$ -		$14,879
33	Day-Ahead Schedule 24 Allocation Amount		$ 71,951.88		$70,795		$ 1,156.98		$864
34	Real -Time Schedule 24 Allocation Amount		$ (34,088.45)		$4,411		$ (38,499.06)		$36
35	Schedule 24 Admin Allocation						$ -		
	SUBTOTAL	-	$ 538,039.47	-	$565,780	-	$ (27,741.01)	-	$21,334
	Congestion & FTRs								
1b	Day Ahead Congestion		$ 3,394,425.43		$3,243,854		$ 150,571.23		
5b	Day Ahead Non Asset Congestion		$ 1,440,004.66		$1,376,128		$ 63,876.28		
13b	Real Time Congestion		$ 232,780.09		$222,454		$ 10,325.75		
22b	Real Time Non Asset Congestion		$ (42,936.58)		($41,032)		$ (1,904.60)		
2	Day Ahead Financial Bilateral Transaction Congestion		$ 791.93		$792				
15	Real Time Financial Bilateral Congestion		$ 144.52		$145				
28	Financial Transmission Rights Hourly Allocation		$ (4,607,044.49)		($4,607,044)		$ -		
30	Financial Transmission Rights Monthly Allocation		$ (147,426.41)		($147,426)				
32	Financial Transmission Rights Yearly Allocation		$ -		$0				
31	Financial Transmission Rights Transaction		$ -		$0				
36	Financial Transmission Rights Full Funding Guarantee Amount		$ (401,477.05)		($401,477)				
37	Financial Transmission Guarantee Uplift Amount		$ 414,079.29		$414,079				
38	Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
	SUBTOTAL	-	$ 283,341.39	-	$60,473	-	$ 222,868.66	-	$0
	RSG & Make Whole Payments								
10	Day Ahead Revenue Sufficiency Guarantee Distribution		$ 182,635.74		$ 174,534.31		$ 8,101.43		
11	Day Ahead Revenue Sufficiency Make Whole Payment		$ (101,443.45)		($76,316)		$ (25,127.91)		
24	Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 153,058.51		$146,269		$ 6,789.43		
25	Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (91,310.88)		($48,231)		$ (43,079.66)		
43	Real Time Price Volatility Make Whole Payment		($167,623)		($169,543)		$1,920		
	SUBTOTAL	-	$ (24,682.64)	-	$ 26,713.90	-	($51,397)	-	$0
	Other Charges								
20	Real Time Miscellaneous		$ (51,318.81)		($21,986)		$ (29,332.67)		$0
21	Real Time Net Inadvertent Distribution		$ (19,182.14)		($19,182)				($190)
23	Real Time Revenue Neutrality Uplift Amount		$ 552,825.55		$528,303		$ 24,522.45		
26	Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
	SUBTOTAL	-	$ 482,324.60	-	$487,135	-	$ (4,810.22)	-	($190)
	Auction Revenue Rights (ARR)								
39	Auction Revenue Rights - FTR Auction Transactions		$ 6,044,899.06		$6,044,899				
40	Auction Revenue Rights - Monthly ARR Revenue		$ (6,528,060.99)		($6,528,061)				
41	Auction Revenue Rights - ARR Stage 2 Distribution		$ (295,795.44)		($295,795)				
42	Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 165,034.21		$165,034				
	SUBTOTAL	-	$ (613,923.16)	-	($613,923)	-	$0	-	$0
	Grandfathered Charge Types								
6	Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (791.93)		($792)				
7	Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (536.35)		($536)				
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		$ (144.52)		($145)				
18	Real Time Congestion Rebate on Carve Out Grandfathered		$ 64.21		$64				
	SUBTOTAL	-	$ (1,408.59)	-	($1,409)	-	$0	-	$0
	Total MISO Day 2 Charges	(80,663)	$ 1,988,224.50	73,523	$ 5,219,139.21	(154,186)	$ (3,230,914.71)	89,195	$ 2,762,442

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**

October 2014	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	127,738	$8,053,480	365,805	$ 15,862,559.23	(238,067)	($7,809,079)		
5a Day Ahead Non Asset Energy	(385,373)	($15,067,200)	(385,373)	($15,067,200)			55,130	$1,937,425
13a Real Time Asset Energy	(13,646)	($267,718)	27,403	$870,894	(41,049)	($1,138,612)		
22a Real Time Non Asset Energy	9,770	($21,420)	9,770	($21,420)			3,720	$142,464
SUBTOTAL	(261,511)	($7,302,858)	17,605	$ 1,644,833.44	(279,116)	($8,947,691)	58,850	$2,079,889
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,626,282.04		$2,419,320		$ 206,961.63		
5c Day Ahead Non Asset Loss		$ 1,442,653.08		$1,328,966		$ 113,686.89		
3 Day Ahead Financial Bilateral Transaction Loss		$ 1,944.46		$1,944				
13c Real Time Loss		$ (17,101.55)		($15,754)		$ (1,347.67)		
22c Real Time Non Asset Loss		$ (16,365.63)		($15,076)		$ (1,289.68)		
14 Real Time Distribution Losses		$ (1,236,679.64)		($1,236,680)				
16 Real Time Financial Bilateral Loss		$ (48.58)		($49)				
SUBTOTAL	-	$ 2,800,684.18	-	$2,482,673	-	$318,011	-	$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)		$ 481,762.21		$465,608		$ 16,154.42		$3,743
19 Real Time Market Administration (Schedule 17)		$ 34,090.50		$31,310		$ 2,780.16		$222
29 Financial Transmission Rights Administration (Schedule 16)		$ 23,626.96		$23,627		$ -		$12,854
33 Day-Ahead Schedule 24 Allocation Amount		$ 66,695.92		$64,457		$ 2,239.02		$516
34 Real -Time Schedule 24 Allocation Amount		$ (29,650.06)		$2,986		$ (32,636.22)		$37
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 576,525.53	-	$587,988	-	$ (11,462.62)	-	$17,372
Congestion & FTRs								
1b Day Ahead Congestion		$ 4,127,571.69		$3,802,302		$ 325,269.32		
5b Day Ahead Non Asset Congestion		$ 5,075,832.85		$4,675,837		$ 399,996.13		
13b Real Time Congestion		$ (562.00)		($518)		$ (44.29)		
22b Real Time Non Asset Congestion		$ (9,207.90)		($8,482)		$ (725.62)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 1,508.75		$1,509				
15 Real Time Financial Bilateral Congestion		$ 440.25		$440				
28 Financial Transmission Rights Hourly Allocation		$ (6,623,772.88)		($6,623,773)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (140,934.26)		($140,934)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (739,710.56)		($739,711)				
37 Financial Transmission Guarantee Uplift Amount		$ 755,421.53		$755,422				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 2,446,587.47	-	$1,722,092	-	$ 724,495.54	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 152,832.02		$ 140,788.24		$ 12,043.78		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (200,330.96)		($79,064)		$ (121,267.09)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 178,912.09		$164,813		$ 14,099.00		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (47,021.92)		($27,748)		$ (19,273.51)		
43 Real Time Price Volatility Make Whole Payment		($224,857)		($215,313)		($9,544)		
SUBTOTAL	-	$ (140,465.78)	-	$ (16,523.90)	-	($123,942)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (54,710.46)		($25,497)		$ (29,213.68)		$0
21 Real Time Net Inadvertent Distribution		$ 71,496.69		$71,497				$634
23 Real Time Revenue Neutrality Uplift Amount		$ 868,925.28		$800,450		$ 68,474.82		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 885,711.51	-	$846,450	-	$ 39,261.14	-	$634
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 6,044,899.06		$6,044,899				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (6,528,060.99)		($6,528,061)				
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (290,711.50)		($290,712)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 165,031.72		$165,032				
SUBTOTAL	-	$ (608,841.71)	-	($608,842)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (1,508.75)		($1,509)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,944.46)		($1,944)				
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		$ (440.25)		($440)				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ 48.58		$49				
SUBTOTAL	-	$ (3,844.88)	-	($3,845)	-	$0	-	$0
Total MISO Day 2 Charges	(261,511)	$ (1,346,501.70)	17,605	$ 6,654,826.42	(279,116)	$ (8,001,328.12)	58,850	$ 2,097,895

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 2014	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	78,871	$3,204,847	243,999	$ 8,389,184.85	(165,128)	($5,184,338)		
5a Day Ahead Non Asset Energy	(319,536)	($11,526,418)	(319,536)	($11,526,418)			73,573	$2,632,236
13a Real Time Asset Energy	60,335	$1,277,815	101,382	$2,127,965	(41,047)	($850,150)		
22a Real Time Non Asset Energy	(1,056)	$36,310	(1,056)	$36,310			3,600	$107,060
SUBTOTAL	(181,386)	($7,007,446)	24,789	$ (972,958.77)	(206,175)	($6,034,488)	77,173	$2,739,297
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 4,794,236.59		$4,539,914		$ 254,322.93		
5c Day Ahead Non Asset Loss		$ 1,533,468.53		$1,452,122		$ 81,346.89		
3 Day Ahead Financial Bilateral Transaction Loss		$ 4,148.31		$4,148				
13c Real Time Loss		$ 55,031.63		$52,112		$ 2,919.30		
22c Real Time Non Asset Loss		$ (8,674.53)		($8,214)		$ (460.16)		
14 Real Time Distribution Losses		$ (1,961,143.28)		($1,961,143)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 4,417,067.25	-	$4,078,938	-	$338,129	-	$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)		$ 632,552.65		$618,026		$ 14,526.95		$6,351
19 Real Time Market Administration (Schedule 17)		$ 44,097.88		$40,540		$ 3,557.87		$341
29 Financial Transmission Rights Administration (Schedule 16)		$ 25,647.20		$25,647		$ -		$12,842
33 Day-Ahead Schedule 24 Allocation Amount		$ 68,164.28		$66,631		$ 1,533.31		$689
34 Real -Time Schedule 24 Allocation Amount		$ (31,408.08)		$7,069		$ (38,477.25)		$36
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 739,053.93	-	$757,913	-	$ (18,859.12)	-	$20,260
Congestion & FTRs								
1b Day Ahead Congestion		$ 6,798,706.85		$6,438,052		$ 360,655.35		
5b Day Ahead Non Asset Congestion		$ 615,289.41		$582,650		$ 32,639.65		
13b Real Time Congestion		$ 274,205.42		$259,659		$ 14,545.95		
22b Real Time Non Asset Congestion		$ (76,234.13)		($72,190)		$ (4,044.04)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 7,598.24		$7,598				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (2,774,741.95)		($2,774,742)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (100,868.14)		($100,868)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (375,496.38)		($375,496)				
37 Financial Transmission Guarantee Uplift Amount		$ 483,540.13		$483,540				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 4,851,999.45	-	$4,448,203	-	$ 403,796.91	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 109,833.21		$ 104,006.82		$ 5,826.39		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (122,498.38)		($57,026)		$ (65,472.06)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 147,663.09		$139,830		$ 7,833.18		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (54,840.00)		($40,591)		$ (14,249.16)		
43 Real Time Price Volatility Make Whole Payment		($598,856)		($564,867)		($33,989)		
SUBTOTAL	-	$ (518,697.89)	-	$ (418,647.43)	-	($100,050)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ 7,393.58		$37,081		$ (29,687.34)		$0
21 Real Time Net Inadvertent Distribution		$ (28,411.36)		($28,411)				($302)
23 Real Time Revenue Neutrality Uplift Amount		$ 1,429,445.11		$1,353,616		$ 75,828.69		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 1,408,427.33	-	$1,362,286	-	$ 46,141.35	-	($302)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 6,044,899.06		$6,044,899				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (6,528,060.99)		($6,528,061)				
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (349,320.42)		($349,320)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 165,031.72		$165,032				
SUBTOTAL	-	$ (667,450.63)	-	($667,451)	-	$0	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (7,598.24)		($7,598)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (4,148.31)		($4,148)				
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	-	$ (11,746.55)	-	($11,747)	-	$0	-	$0
Total MISO Day 2 Charges	(181,386)	$ 3,211,206.46	24,789	$ 8,576,536.49	(206,175)	$ (5,365,330.03)	77,173	$ 2,759,254

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 2014	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	(79,580)	$1,100,919	255,580	$ 10,573,186.41	(335,160)	($9,472,267)		
5a Day Ahead Non Asset Energy	(348,237)	($13,501,007)	(348,237)	($13,501,007)			54,719	$1,641,141
13a Real Time Asset Energy	23,691	$1,033,908	77,334	$2,270,258	(53,643)	($1,236,350)		
22a Real Time Non Asset Energy	300	$8,536	300	$8,536			3,600	$107,877
SUBTOTAL	(403,826)	($11,357,644)	(15,023)	$ (649,027.49)	(388,803)	($10,708,617)	58,319	$1,749,018
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,319,822.23		$3,008,058		$ 311,764.70		
5c Day Ahead Non Asset Loss		$ 2,029,696.15		$1,839,087		$ 190,608.88		
3 Day Ahead Financial Bilateral Transaction Loss		$ 5,644.27		$5,644				
13c Real Time Loss		$ (11,887.94)		($10,772)		$ (1,116.40)		
22c Real Time Non Asset Loss		$ (262.50)		($238)		$ (24.65)		
14 Real Time Distribution Losses		$ (1,344,972.09)		($1,344,972)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 3,998,040.12	-	$3,496,808	-	$501,233	-	$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)		$ 549,587.30		$526,591		$ 22,995.82		$3,744
19 Real Time Market Administration (Schedule 17)		$ 39,535.95		$35,844		$ 3,692.07		$253
29 Financial Transmission Rights Administration (Schedule 16)		$ 38,808.88		$38,809		$ -		$13,942
33 Day-Ahead Schedule 24 Allocation Amount		$ 65,081.95		$62,361		$ 2,721.27		$440
34 Real -Time Schedule 24 Allocation Amount		$ (27,169.44)		$2,525		$ (29,694.15)		$30
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 665,844.64	-	$666,130	-	$ (284.99)	-	$18,409
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,592,918.96		$2,349,418		$ 243,501.17		
5b Day Ahead Non Asset Congestion		$ 1,280,300.77		$1,160,068		$ 120,233.12		
13b Real Time Congestion		$ (38,310.70)		($34,713)		$ (3,597.76)		
22b Real Time Non Asset Congestion		$ 337.59		$306		$ 31.70		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (926.26)		($926)				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (3,748,265.03)		($3,748,265)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (181,752.04)		($181,752)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (82,900.03)		($82,900)				
37 Financial Transmission Guarantee Uplift Amount		$ 88,845.34		$88,845				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ (89,751.40)	-	($449,920)	-	$ 360,168.24	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 181,370.20		$ 164,055.80		$ 17,314.40		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (42,131.91)		($26,399)		$ (15,732.48)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 167,304.49		$151,333		$ 15,971.63		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (177,129.60)		($178,494)		$ 1,364.09		
43 Real Time Price Volatility Make Whole Payment		($60,665)		($47,421)		($13,244)		
SUBTOTAL	-	$ 68,748.22	-	$ 63,074.84	-	$5,673	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (211,261.44)		($159,051)		$ (52,210.57)		$0
21 Real Time Net Inadvertent Distribution		$ 8,320.04		$8,320				$75
23 Real Time Revenue Neutrality Uplift Amount		$ 544,351.65		$492,385		$ 51,966.22		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 341,410.25	-	$341,655	-	$ (244.35)	-	$75
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 7,250,896.00		$7,250,896				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (7,412,271.29)		($7,294,918)		$ (117,353.14)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (163,750.35)		($163,750)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 215,785.30		$215,785				
SUBTOTAL	-	$ (109,340.34)	-	$8,013	-	($117,353)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 926.26		$926				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (5,644.27)		($5,644)				
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	-	$ (4,718.01)	-	($4,718)	-	$0	-	$0
Total MISO Day 2 Charges	(403,826)	$ (6,487,410.53)	(15,023)	$ 3,472,014.31	(388,803)	$ (9,959,424.84)	58,319	$ 1,767,502

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 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	133,675	$2,591,925	325,800	$ 7,748,153.14	(192,125)	($5,156,228)		
5a Day Ahead Non Asset Energy	(340,306)	($8,128,583)	(340,306)	($8,128,583)			92,707	$2,631,322
13a Real Time Asset Energy	28,389	$1,448,654	78,872	$2,600,119	(50,483)	($1,151,464)		
22a Real Time Non Asset Energy	316	$8,021	316	$8,021			120	($42)
SUBTOTAL	(177,926)	($4,079,983)	64,682	$ 2,227,709.16	(242,608)	($6,307,693)	92,827	$2,631,280
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 5,018,262.73		$4,713,154		$ 305,108.31		
5c Day Ahead Non Asset Loss		$ (850,409.95)		($798,705)		$ (51,704.57)		
3 Day Ahead Financial Bilateral Transaction Loss		$ 3,961.72		$3,962				
13c Real Time Loss		$ (85,017.45)		($79,848)		$ (5,169.03)		
22c Real Time Non Asset Loss		$ 1,734.88		$1,629		$ 105.48		
14 Real Time Distribution Losses		$ (1,511,371.31)		($1,511,371)				
16 Real Time Financial Bilateral Loss		$ (23.77)		($24)				
SUBTOTAL	-	$ 2,577,136.85	-	$2,328,797	-	$248,340	-	$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)		$ 500,873.36		$488,782		$ 12,091.60		$5,823
19 Real Time Market Administration (Schedule 17)		$ 37,302.32		$34,139		$ 3,163.81		($0)
29 Financial Transmission Rights Administration (Schedule 16)		$ 38,159.60		$38,160		$ -		$16,499
33 Day-Ahead Schedule 24 Allocation Amount		$ 63,799.38		$62,271		$ 1,528.00		$740
34 Real -Time Schedule 24 Allocation Amount		$ (29,413.48)		$5,783		$ (35,196.11)		$0
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 610,721.18	-	$629,134	-	$ (18,412.70)	-	$23,062
Congestion & FTRs								
1b Day Ahead Congestion		$ 3,503,488.11		$3,290,477		$ 213,010.63		
5b Day Ahead Non Asset Congestion		$ 453,878.46		$426,283		$ 27,595.62		
13b Real Time Congestion		$ (292,699.49)		($274,903)		$ (17,796.01)		
22b Real Time Non Asset Congestion		$ (2,336.69)		($2,195)		$ (142.07)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 845.35		$845				
15 Real Time Financial Bilateral Congestion		$ (12.51)		($13)				
28 Financial Transmission Rights Hourly Allocation		$ (3,088,429.08)		($3,088,429)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (187,254.82)		($187,255)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (54,659.01)		($54,659)				
37 Financial Transmission Guarantee Uplift Amount		$ 46,900.17		$46,900				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 379,720.49	-	$157,052	-	$ 222,668.18	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 163,641.43		$ 153,692.10		$ 9,949.33		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (111,103.02)		($65,958)		$ (45,145.06)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 116,402.97		$109,326		$ 7,077.25		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,267.67)		($2,066)		$ 798.19		
43 Real Time Price Volatility Make Whole Payment		($348,515)		($333,310)		($15,205)		
SUBTOTAL	-	$ (180,841.41)	-	$ (138,316.19)	-	($42,525)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (405,509.67)		($310,458)		$ (95,051.51)		$0
21 Real Time Net Inadvertent Distribution		$ (96,680.24)		($96,680)				($914)
23 Real Time Revenue Neutrality Uplift Amount		$ 379,920.53		$356,822		$ 23,099.01		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ (122,269.38)	-	($50,317)	-	$ (71,952.50)	-	($914)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 7,250,896.00		$7,250,896				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (7,412,271.29)		($7,393,103)		$ (19,168.06)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (104,620.47)		($104,620)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 215,789.60		$215,790				
SUBTOTAL	-	$ (50,206.16)	-	($31,038)	-	($19,168)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (845.35)		($845)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (3,961.72)		($3,962)				
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		$ 12.51		$13				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ 23.77		$24				
SUBTOTAL	-	$ (4,770.79)	-	($4,771)	-	$0	-	$0
Total MISO Day 2 Charges	(177,926)	$ (870,492.57)	64,682	$ 5,118,250.05	(242,608)	$ (5,988,742.62)	92,827	$ 2,653,429

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-15-611

Electric Operations - State of Minnesota Part J, Section 5

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

Schedule 7

February 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	211,207	$8,091,356	342,625	$ 12,286,664.84	(131,418)	($4,195,309)		
5a Day Ahead Non Asset Energy	(309,448)	($11,731,614)	(309,448)	($11,731,614)			84,160	$2,939,324
13a Real Time Asset Energy	44,818	$789,095	113,545	$2,532,761	(68,727)	($1,743,666)		
22a Real Time Non Asset Energy	280	($5,530)	280	($5,530)				
SUBTOTAL	(53,143)	($2,856,693)	147,002	$ 3,082,282.03	(200,145)	($5,938,975)	84,160	$2,939,324
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,746,588.94		$3,540,959		$ 205,629.94		
5c Day Ahead Non Asset Loss		$ 1,059,024.79		$1,000,901		$ 58,124.13		
3 Day Ahead Financial Bilateral Transaction Loss		$ 6,378.65		$6,379				
13c Real Time Loss		$ 72,520.67		$68,540		$ 3,980.27		
22c Real Time Non Asset Loss		$ 840.85		$795		$ 46.15		
14 Real Time Distribution Losses		$ (1,785,962.00)		($1,785,962)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 3,099,391.90	-	$2,831,611	-	$267,780	-	$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)		$ 623,735.83		$612,258		$ 11,477.47		$7,262
19 Real Time Market Administration (Schedule 17)		$ 40,413.21		$34,433		$ 5,980.02		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 35,475.84		$35,476		$ -		$20,078
33 Day-Ahead Schedule 24 Allocation Amount		$ 67,939.47		$66,700		$ 1,239.19		$789
34 Real -Time Schedule 24 Allocation Amount		$ (31,611.17)		$5,004		$ (36,614.75)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 735,953.18	-	$753,871	-	$ (17,918.07)	-	$28,130
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,495,521.83		$2,358,556		$ 136,965.65		
5b Day Ahead Non Asset Congestion		$ 1,447,300.89		$1,367,866		$ 79,434.49		
13b Real Time Congestion		$ 298,360.38		$281,985		$ 16,375.38		
22b Real Time Non Asset Congestion		$ 12,085.15		$11,422		$ 663.29		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 4,571.24		$4,571				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (2,638,215.63)		($2,638,216)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (113,847.87)		($113,848)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (71,077.02)		($71,077)				
37 Financial Transmission Guarantee Uplift Amount		$ 67,927.21		$67,927				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 1,502,626.18	-	$1,269,187	-	$ 233,438.82	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 206,399.66		$ 195,071.50		$ 11,328.16		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (100,928.64)		($67,196)		$ (33,732.18)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 154,958.46		$146,454		$ 8,504.83		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (68,367.77)		($62,424)		$ (5,944.00)		
43 Real Time Price Volatility Make Whole Payment		($327,724)		($306,483)		($21,242)		
SUBTOTAL	-	$ (135,662.60)	-	$ (94,577.61)	-	($41,085)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (378,713.36)		($308,708)		$ (70,005.00)		$0
21 Real Time Net Inadvertent Distribution		$ (59,939.70)		($59,940)				($601)
23 Real Time Revenue Neutrality Uplift Amount		$ 716,461.93		$677,139		$ 39,322.71		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 277,808.87	-	$308,491	-	$ (30,682.29)	-	($601)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 7,250,896.00		$7,250,896				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (7,412,271.29)		($7,384,003)		$ (28,268.10)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (165,295.02)		($165,295)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 215,789.60		$215,790				
SUBTOTAL	-	$ (110,880.71)	-	($82,613)	-	($28,268)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (4,571.24)		($4,571)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (6,378.65)		($6,379)				
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	-	$ (10,949.89)	-	($10,950)	-	$0	-	$0
Total MISO Day 2 Charges	(53,143)	$ 2,501,593.69	147,002	$ 8,057,303.11	(200,145)	$ (5,555,709.42)	84,160	$ 2,966,853

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 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	291,509	$10,011,388	440,444	$ 13,415,465.23	(148,935)	($3,404,077)		
5a Day Ahead Non Asset Energy	(338,198)	($9,837,021)	(338,198)	($9,837,021)			93,118	$2,586,607
13a Real Time Asset Energy	22,599	($37,504)	82,126	$1,163,472	(59,527)	($1,200,976)		
22a Real Time Non Asset Energy	310	$6,239	310	$6,239				
SUBTOTAL	(23,780)	$143,102	184,682	$ 4,748,155.24	(208,462)	($4,605,053)	93,118	$2,586,607
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 3,141,039.63		$2,959,946		$ 181,093.93		
5c Day Ahead Non Asset Loss		$ 535,511.28		$504,637		$ 30,874.44		
3 Day Ahead Financial Bilateral Transaction Loss		$ 2,755.65		$2,756				
13c Real Time Loss		$ (27,655.28)		($26,061)		$ (1,594.44)		
22c Real Time Non Asset Loss		$ 8.67		$8		$ 0.50		
14 Real Time Distribution Losses		$ (1,047,242.39)		($1,047,242)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,604,417.56	-	$2,394,043	-	$210,374	-	$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)		$ 704,788.90		$690,518		$ 14,271.21		$8,909
19 Real Time Market Administration (Schedule 17)		$ 51,256.26		$45,542		$ 5,714.35		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 35,653.20		$35,653		$ -		$14,280
33 Day-Ahead Schedule 24 Allocation Amount		$ 71,907.79		$70,476		$ 1,431.59		$888
34 Real -Time Schedule 24 Allocation Amount		$ (32,610.10)		($6,742)		$ (25,868.51)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 830,996.05	-	$835,447	-	$ (4,451.36)	-	$24,077
Congestion & FTRs								
1b Day Ahead Congestion		$ 2,503,187.90		$2,358,869		$ 144,319.14		
5b Day Ahead Non Asset Congestion		$ 183,787.18		$173,191		$ 10,596.09		
13b Real Time Congestion		$ (71,176.63)		($67,073)		$ (4,103.63)		
22b Real Time Non Asset Congestion		$ 66.12		$62		$ 3.81		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 4,855.11		$4,855				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (2,033,457.66)		($2,033,458)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (73,502.00)		($73,502)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 25,507.49		$25,507				
37 Financial Transmission Guarantee Uplift Amount		$ (34,323.72)		($34,324)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 504,943.79	-	$354,128	-	$ 150,815.42	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 473,335.28		$ 446,045.54		$ 27,289.74		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (408,433.12)		($332,955)		$ (75,478.05)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 242,120.87		$228,162		$ 13,959.27		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (487,867.25)		($236,435)		$ (251,432.56)		
43 Real Time Price Volatility Make Whole Payment		($162,063)		($150,057)		($12,006)		
SUBTOTAL	-	$ (342,906.85)	-	$ (45,239.63)	-	($297,667)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (365,421.26)		($296,040)		$ (69,381.57)		$0
21 Real Time Net Inadvertent Distribution		$ 41,702.18		$41,702				$704
23 Real Time Revenue Neutrality Uplift Amount		$ 303,189.66		$285,710		$ 17,480.14		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ (20,529.42)	-	$31,372	-	$ (51,901.43)	-	$704
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 6,666,528.17		$6,666,528				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (6,785,365.96)		($6,769,060)		$ (16,306.18)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (218,926.71)		($218,927)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 293,678.17		$293,678				
SUBTOTAL	-	$ (44,086.33)	-	($27,780)	-	($16,306)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (4,855.11)		($4,855)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (2,755.65)		($2,756)				
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	-	$ (7,610.76)	-	($7,611)	-	$0	-	$0
Total MISO Day 2 Charges	(23,780)	$ 3,668,326.32	184,682	$ 8,282,515.62	(208,462)	$ (4,614,189.30)	93,118	$ 2,611,388

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

Electric Operations - State of Minnesota

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

April 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	618,933	$13,839,801	671,368	$ 14,974,483.32	(52,435)	($1,134,682)		
5a Day Ahead Non Asset Energy	(329,560)	($9,116,033)	(329,560)	($9,116,033)			90,407	$2,237,577
13a Real Time Asset Energy	21,967	$1,181,757	45,144	$1,548,457	(23,177)	($366,700)		
22a Real Time Non Asset Energy	310	$8,502	310	$8,502				
SUBTOTAL	311,650	$5,914,027	387,262	$ 7,415,408.98	(75,612)	($1,501,382)	90,407	$2,237,577
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,544,637.91		$1,508,989		$ 35,648.83		
5c Day Ahead Non Asset Loss		$ 1,353,856.51		$1,322,611		$ 31,245.77		
3 Day Ahead Financial Bilateral Transaction Loss		$ 2,250.67		$2,251				
13c Real Time Loss		$ 45,812.59		$44,755		$ 1,057.31		
22c Real Time Non Asset Loss		$ (1,025.28)		($1,002)		$ (23.66)		
14 Real Time Distribution Losses		$ (925,745.90)		($925,746)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,019,786.50	-	$1,951,858	-	$67,928	-	$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)		$ 517,134.72		$512,791		$ 4,343.43		$7,367
19 Real Time Market Administration (Schedule 17)		$ 38,281.67		$36,364		$ 1,917.32		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 34,623.04		$34,623		$ -		$14,470
33 Day-Ahead Schedule 24 Allocation Amount		$ 62,391.69		$61,857		$ 534.22		$909
34 Real -Time Schedule 24 Allocation Amount		$ (29,955.60)		$4,858		$ (34,813.93)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 622,475.52	-	$650,494	-	$ (28,018.96)	-	$22,746
Congestion & FTRs								
1b Day Ahead Congestion		$ (389,266.03)		($380,282)		$ (8,983.90)		
5b Day Ahead Non Asset Congestion		$ 2,083,502.87		$2,035,418		$ 48,085.34		
13b Real Time Congestion		$ 95,379.26		$93,178		$ 2,201.27		
22b Real Time Non Asset Congestion		$ (1,982.35)		($1,937)		$ (45.75)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 6,827.19		$6,827				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (173,880.77)		($173,881)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (45,114.09)		($45,114)				
32 Financial Transmission Rights Yearly Allocation		$ (780,712.59)		($780,713)				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 888,137.17		$888,137				
37 Financial Transmission Guarantee Uplift Amount		$ (866,657.41)		($866,657)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 816,233.25	-	$774,976	-	$ 41,256.95	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 19,515.91		$ 19,065.50		$ 450.41		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (165,087.62)		($123,190)		$ (41,897.65)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 31,703.22		$30,972		$ 731.68		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (10,022.13)		($8,587)		$ (1,435.18)		
43 Real Time Price Volatility Make Whole Payment		($163,764)		($158,251)		($5,513)		
SUBTOTAL	-	$ (287,654.79)	-	$ (239,990.96)	-	($47,664)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (260,323.94)		($212,714)		$ (47,609.77)		$0
21 Real Time Net Inadvertent Distribution		$ (32,185.36)		($32,185)				($617)
23 Real Time Revenue Neutrality Uplift Amount		$ 414,074.06		$404,518		$ 9,556.45		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 121,564.76	-	$159,618	-	$ (38,053.32)	-	($617)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 6,666,528.17		$6,666,528				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (6,785,365.96)		($6,763,130)		$ (22,235.70)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (216,392.08)		($216,392)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 293,678.17		$293,678				
SUBTOTAL	-	$ (41,551.70)	-	($19,316)	-	($22,236)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (6,827.19)		($6,827)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (2,250.67)		($2,251)				
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	-	$ (9,077.86)	-	($9,078)	-	$0	-	$0
Total MISO Day 2 Charges	311,650	$ 9,155,802.55	387,262	$ 10,683,971.27	(75,612)	$ (1,528,168.72)	90,407	$ 2,259,706

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 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	644,673	$17,252,954	720,768	$ 18,524,662.10	(76,095)	($1,271,709)		
5a Day Ahead Non Asset Energy	(380,424)	($11,077,244)	(380,424)	($11,077,244)			92,296	$2,309,673
13a Real Time Asset Energy	(32,008)	($1,067,565)	18,360	($236,549)	(50,368)	($831,015)		
22a Real Time Non Asset Energy	2,327	$76,959	2,327	$76,959				
SUBTOTAL	234,568	$5,185,104	361,031	$ 7,287,827.42	(126,463)	($2,102,724)	92,296	$2,309,673
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 1,896,380.59		$1,827,046		$ 69,335.05		
5c Day Ahead Non Asset Loss		$ 1,232,148.84		$1,187,099		$ 45,049.56		
3 Day Ahead Financial Bilateral Transaction Loss		$ 1,852.22		$1,852				
13c Real Time Loss		$ 76,484.98		$73,689		$ 2,796.43		
22c Real Time Non Asset Loss		$ (3,761.33)		($3,624)		$ (137.52)		
14 Real Time Distribution Losses		$ (786,313.16)		($786,313)				
16 Real Time Financial Bilateral Loss		$ (1.93)		($2)				
SUBTOTAL	-	$ 2,416,790.21	-	$2,299,747	-	$117,044	-	$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)		$ 510,387.75		$504,552		$ 5,835.93		$7,059
19 Real Time Market Administration (Schedule 17)		$ 40,108.78		$36,233		$ 3,876.18		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 34,200.72		$34,201		$ -		$11,826
33 Day-Ahead Schedule 24 Allocation Amount		$ 62,047.01		$61,337		$ 709.65		$858
34 Real -Time Schedule 24 Allocation Amount		$ (29,960.39)		$5,898		$ (35,858.30)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 616,783.87	-	$642,220	-	$ (25,436.54)	-	$19,743
Congestion & FTRs								
1b Day Ahead Congestion		$ 799,034.88		$769,821		$ 29,214.14		
5b Day Ahead Non Asset Congestion		$ 2,286,302.21		$2,202,711		$ 83,591.28		
13b Real Time Congestion		$ 241,176.99		$232,359		$ 8,817.86		
22b Real Time Non Asset Congestion		$ (19,977.46)		($19,247)		$ (730.41)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ 4,675.74		$4,676				
15 Real Time Financial Bilateral Congestion		$ (8.00)		($8)				
28 Financial Transmission Rights Hourly Allocation		$ (2,568,938.67)		($2,568,939)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (47,991.31)		($47,991)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ (11,782.92)		($11,783)				
37 Financial Transmission Guarantee Uplift Amount		$ 11,782.92		$11,783				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ 694,274.38	-	$573,382	-	$ 120,892.87	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 43,140.27		$ 41,562.98		$ 1,577.29		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (10,305.01)		($14,848)		$ 4,542.82		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 159,942.57		$134,442		$ 25,500.92		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (54,669.10)		($18,803)		$ (35,866.46)		
43 Real Time Price Volatility Make Whole Payment		($135,002)		($131,720)		($3,282)		
SUBTOTAL	-	$ 3,106.64	-	$ 10,634.46	-	($7,528)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (78,037.09)		($13,997)		$ (64,040.02)		$0
21 Real Time Net Inadvertent Distribution		$ (38,015.41)		($38,015)				($511)
23 Real Time Revenue Neutrality Uplift Amount		$ 697,474.62		$691,627		$ 5,847.79		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 581,422.12	-	$639,614	-	$ (58,192.23)	-	($511)
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions		$ 6,666,528.17		$6,666,528				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (6,785,365.96)		($6,761,648)		$ (23,718.08)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (218,818.02)		($218,818)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 293,678.17		$293,678				
SUBTOTAL	-	$ (43,977.64)	-	($20,260)	-	($23,718)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ (4,675.74)		($4,676)				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,852.22)		($1,852)				
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		$ 8.00		$8				
18 Real Time Congestion Rebate on Carve Out Grandfathered		$ 1.93		$2				
SUBTOTAL	-	$ (6,518.03)	-	($6,518)	-	$0	-	$0
Total MISO Day 2 Charges	234,568	$ 9,446,985.14	361,031	$ 11,426,647.25	(126,463)	$ (1,979,662.11)	92,296	$ 2,328,905

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 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	280,556	$8,799,748	410,366	$ 11,773,896.01	(129,810)	($2,974,148)		
5a Day Ahead Non Asset Energy	(378,073)	($11,256,284)	(378,073)	($11,256,284)			90,406	$2,365,574
13a Real Time Asset Energy	47,381	$1,044,920	84,849	$1,837,464	(37,468)	($792,544)		
22a Real Time Non Asset Energy	4,726	($183,721)	4,726	($183,721)				
SUBTOTAL	(45,410)	($1,595,337)	121,868	$ 2,171,355.15	(167,278)	($3,766,692)	90,406	$2,365,574
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss		$ 2,412,016.83		$2,306,254		$ 105,762.71		
5c Day Ahead Non Asset Loss		$ 1,204,680.32		$1,151,857		$ 52,823.12		
3 Day Ahead Financial Bilateral Transaction Loss		$ 1,197.31		$1,197				
13c Real Time Loss		$ 4,286.65		$4,099		$ 187.96		
22c Real Time Non Asset Loss		$ (5,287.17)		($5,055)		$ (231.83)		
14 Real Time Distribution Losses		$ (1,190,722.49)		($1,190,722)				
16 Real Time Financial Bilateral Loss		$ -		$0				
SUBTOTAL	-	$ 2,426,171.45	-	$2,267,629	-	$158,542	-	$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)		$ 583,501.85		$573,608		$ 9,893.81		$6,907
19 Real Time Market Administration (Schedule 17)		$ 39,876.48		$37,048		$ 2,828.56		$0
29 Financial Transmission Rights Administration (Schedule 16)		$ 34,161.28		$34,161		$ -		$8,596
33 Day-Ahead Schedule 24 Allocation Amount		$ 81,719.83		$80,327		$ 1,392.47		$966
34 Real -Time Schedule 24 Allocation Amount		$ (94,321.37)		($6,088)		$ (88,233.67)		
35 Schedule 24 Admin Allocation						$ -		
SUBTOTAL	-	$ 644,938.07	-	$719,057	-	$ (74,118.83)	-	$16,469
Congestion & FTRs								
1b Day Ahead Congestion		$ (143,069.84)		($136,796)		$ (6,273.36)		
5b Day Ahead Non Asset Congestion		$ 1,446,476.67		$1,383,051		$ 63,425.47		
13b Real Time Congestion		$ 3,528.85		$3,374		$ 154.73		
22b Real Time Non Asset Congestion		$ (42,837.66)		($40,959)		$ (1,878.36)		
2 Day Ahead Financial Bilateral Transaction Congestion		$ (1,132.03)		($1,132)				
15 Real Time Financial Bilateral Congestion		$ -		$0				
28 Financial Transmission Rights Hourly Allocation		$ (1,439,393.93)		($1,439,394)		$ -		
30 Financial Transmission Rights Monthly Allocation		$ (50,654.52)		($50,655)				
32 Financial Transmission Rights Yearly Allocation		$ -		$0				
31 Financial Transmission Rights Transaction		$ -		$0				
36 Financial Transmission Rights Full Funding Guarantee Amount		$ 9,151.86		$9,152				
37 Financial Transmission Guarantee Uplift Amount		$ (10,567.73)		($10,568)				
38 Financial Transmission Rights Monthly Transacton Amount		$ -		$0				
SUBTOTAL	-	$ (228,498.33)	-	($283,927)	-	$ 55,428.48	-	$0
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 114,315.22		$ 109,302.70		$ 5,012.52		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (26,220.18)		($16,965)		$ (9,255.55)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 158,932.21		$129,458		$ 29,473.78		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (117,146.13)		($51,336)		$ (65,810.60)		
43 Real Time Price Volatility Make Whole Payment		($169,146)		($163,576)		($5,570)		
SUBTOTAL	-	$ (39,264.67)	-	$ 6,884.78	-	($46,149)	-	$0
Other Charges								
20 Real Time Miscellaneous		$ (37,149.98)		$2,997		$ (40,146.52)		$0
21 Real Time Net Inadvertent Distribution		$ 20,092.04		$20,092				$255
23 Real Time Revenue Neutrality Uplift Amount		$ 672,176.95		$665,208		$ 6,968.90		
26 Real Time Uninstructed Deviation Amount		$ -		$0		$ -		
SUBTOTAL	-	$ 655,119.01	-	$688,297	-	$ (33,177.62)	-	$255
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)		($3,583,891)		$ (4,447.14)		
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (116,560.48)		($116,560)				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue		$ 67,063.94		$67,064				
SUBTOTAL	-	$ (120,835.24)	-	($116,388)	-	($4,447)	-	$0
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered		$ 1,132.03		$1,132				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered		$ (1,197.31)		($1,197)				
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	-	$ (65.28)	-	($65)	-	$0	-	$0
Total MISO Day 2 Charges	(45,410)	$ 1,742,228.00	121,868	$ 5,452,842.76	(167,278)	$ (3,710,614.76)	90,406	$ 2,382,299

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 2014 - June 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	4,087,400	131,195,788	5,775,623	177,461,981	(1,688,223)	(46,266,193)	-	-
5a Day Ahead Non Asset Energy	(4,531,652)	(149,258,521)	(4,531,652)	(149,258,521)	-	-	923,457	27,532,713
13a Real Time Asset Energy	306,223	8,666,580	837,538	21,113,965	(531,315)	(12,447,385)	-	-
22a Real Time Non Asset Energy	37,592	(391,616)	37,592	(391,616)	-	-	22,080	674,267
SUBTOTAL	(100,438)	(9,787,769)	2,119,100	48,925,809	(2,219,538)	(58,713,578)	945,537	28,206,980
Day Ahead & Real Time Energy Loss								
1c Day Ahead Loss	-	36,749,405	-	34,835,273	-	1,914,132	-	-
5c Day Ahead Non Asset Loss	-	15,116,365	-	14,418,340	-	698,025	-	-
3 Day Ahead Financial Bilateral Transaction Loss	-	33,655	-	33,655	-	-	-	-
13c Real Time Loss	-	282,332	-	275,830	-	6,503	-	-
22c Real Time Non Asset Loss	-	(41,258)	-	(39,093)	-	(2,165)	-	-
14 Real Time Distribution Losses	-	(17,168,982)	-	(17,168,982)	-	-	-	-
16 Real Time Financial Bilateral Loss	-	(138)	-	(138)	-	-	-	-
SUBTOTAL	-	34,971,377	-	32,354,883	-	2,616,494	-	-
Virtual Energy								
12 Day Ahead Virtual Energy	-	-	-	-	-	-	-	-
27 Real Time Virtual Energy	-	-	-	-	-	-	-	-
SUBTOTAL	-	-	-	-	-	-	-	-
Schedules 16, 17 & 24								
4 Day Ahead Market Administration (Schedule 17)	-	6,479,548	-	6,355,087	-	124,461	-	68,968
19 Real Time Market Administration (Schedule 17)	-	444,887	-	404,872	-	40,015	-	1,470
29 Financial Transmission Rights Administration (Schedule 16)	-	415,394	-	415,394	-	-	-	171,584
33 Day-Ahead Schedule 24 Allocation Amount	-	815,703	-	800,381	-	15,321	-	8,588
34 Real -Time Schedule 24 Allocation Amount	-	(430,447)	-	29,585	-	(460,032)	-	198
35 Schedule 24 Admin Allocation	-	-	-	-	-	-	-	-
SUBTOTAL	-	7,725,085	-	8,005,319	-	(280,235)	-	250,809
Congestion & FTRs								
1b Day Ahead Congestion	-	28,051,731	-	26,416,688	-	1,635,043	-	-
5b Day Ahead Non Asset Congestion	-	18,875,772	-	17,893,336	-	982,436	-	-
13b Real Time Congestion	-	977,928	-	945,431	-	32,497	-	-
22b Real Time Non Asset Congestion	-	(724,410)	-	(705,119)	-	(19,291)	-	-
2 Day Ahead Financial Bilateral Transaction Congestion	-	36,548	-	36,548	-	-	-	-
15 Real Time Financial Bilateral Congestion	-	564	-	564	-	-	-	-
28 Financial Transmission Rights Hourly Allocation	-	(33,191,732)	-	(33,191,732)	-	-	-	-
30 Financial Transmission Rights Monthly Allocation	-	(1,191,221)	-	(1,191,221)	-	-	-	-
32 Financial Transmission Rights Yearly Allocation	-	(780,713)	-	(780,713)	-	-	-	-
31 Financial Transmission Rights Transaction	-	-	-	-	-	-	-	-
36 Financial Transmission Rights Full Funding Guarantee Amount	-	(820,990)	-	(820,990)	-	-	-	-
37 Financial Transmission Guarantee Uplift Amount	-	961,417	-	961,417	-	-	-	-
38 Financial Transmission Rights Monthly Transacton Amount	-	-	-	-	-	-	-	-
SUBTOTAL	-	12,194,895	-	9,564,210	-	2,630,685	-	-
RSG & Make Whole Payments								
10 Day Ahead Revenue Sufficiency Guarantee Distribution	-	1,953,212	-	1,847,620	-	105,592	-	-
11 Day Ahead Revenue Sufficiency Make Whole Payment	-	(1,396,078)	-	(900,173)	-	(495,905)	-	-
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution	-	1,586,692	-	1,454,201	-	132,490	-	-
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment	-	(1,201,898)	-	818,466	-	(2,020,364)	-	-
43 Real Time Price Volatility Make Whole Payment	-	(3,227,409)	-	(3,089,734)	-	(137,675)	-	-
SUBTOTAL	-	(2,285,481)	-	130,380	-	(2,415,861)	-	-
Other Charges								
20 Real Time Miscellaneous	-	(1,863,558)	-	(1,266,875)	-	(596,683)	-	7,408
21 Real Time Net Inadvertent Distribution	-	(495,310)	-	(495,310)	-	-	-	(4,018)
23 Real Time Revenue Neutrality Uplift Amount	-	8,083,891	-	7,728,681	-	355,210	-	-
26 Real Time Uninstructed Deviation Amount	-	-	-	-	-	-	-	-
SUBTOTAL	-	5,725,024	-	5,966,496	-	(241,473)	-	3,390
Auction Revenue Rights (ARR)								
39 Auction Revenue Rights - FTR Auction Transactions	-	77,938,641	-	77,938,641	-	-	-	-
40 Auction Revenue Rights - Monthly ARR Revenue	-	(81,130,449)	-	(80,898,953)	-	(231,496)	-	-
41 Auction Revenue Rights - ARR Stage 2 Distribution	-	(2,698,422)	-	(2,698,422)	-	-	-	-
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue	-	2,487,130	-	2,487,130	-	-	-	-
SUBTOTAL	-	(3,403,101)	-	(3,171,605)	-	(231,496)	-	-
Grandfathered Charge Types								
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered	-	(36,548)	-	(36,548)	-	-	-	-
7 Day Ahead Loss Rebate on Carve Out-Grandfathered	-	(33,655)	-	(33,655)	-	-	-	-
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	-	(564)	-	(564)	-	-	-	-
18 Real Time Congestion Rebate on Carve Out Grandfathered	-	138	-	138	-	-	-	-
SUBTOTAL	-	(70,628)	-	(70,628)	-	-	-	-
Total MISO Day 2 Charges	(100,438)	45,069,401	2,119,100	101,704,866	(2,219,538)	(56,635,465)	945,537	28,461,179

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 2014 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (137,956.71)	$ -	$ (137,956.71)	$ (103,080.90)
2	Day-Ahead Spinning Reserve Amount	$ (149,004.19)	$ -	$ (149,004.19)	$ (111,335.55)
3	Day-Ahead Supplemental Reserve	$ (50,626.73)	$ -	$ (50,626.73)	$ (37,828.16)
4	Real-Time Regulation Amount (See Note 1)	$ (24,167.14)	$ 92,773.70	$ 68,606.56	$ 51,262.64
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 645.79	$ 76,977.30	$ 77,623.09	$ 57,999.77
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 3,839.85	$ 6,696.83	$ 10,536.68	$ 7,872.98
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 7,883.28		$ 7,883.28	$ 5,890.37
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 817,893.08		$ 817,893.08	$ 611,127.60
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (35,594.95)	$ 642.23	$ (34,952.72)	$ (26,116.58)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 179,667.32	$ (3,241.70)	$ 176,425.62	$ 131,824.77
9	Real Time Net Regulation Adjustment Amount	$ 30,940.29	$ (6,575.18)	$ 24,365.11	$ 18,205.55
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 97,011.07	$ -	$ 97,011.07	$ 72,486.42
11	Real Time Spinnng Reserve Cost Distribution	$ 81,445.50	$ -	$ 81,445.50	$ 60,855.87
12	Real Time Supplemental Reserve Cost Distribution	$ 45,979.79	$ -	$ 45,979.79	$ 34,355.98
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 93,580.19	$ (12,080.37)	$ 81,499.82	$ 60,896.46
14	Real Time Contignecy Reserve Deployment Failure	$ 138.40	$ -	$ 138.40	$ 103.41
	TOTAL MISO ASM CHARGES	**$ 961,674.84**	**$ 155,192.81**	**$ 1,116,867.65**	**$ 834,520.63**

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 2014 Actual					
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (197,900.28)	$ -	$ (197,900.28)	$ (148,288.82)
2	Day-Ahead Spinning Reserve Amount	$ (95,705.77)	$ -	$ (95,705.77)	$ (71,713.37)
3	Day-Ahead Supplemental Reserve	$ (49,420.27)	$ -	$ (49,420.27)	$ (37,031.14)
4	Real-Time Regulation Amount (See Note 1)	$ (76,932.22)	$ 158,024.21	$ 81,091.99	$ 60,763.10
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (320.17)	$ 23,562.62	$ 23,242.45	$ 17,415.82
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 105.90	$ 8,872.10	$ 8,978.00	$ 6,727.31
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 4,558.96		$ 4,558.96	$ 3,416.08
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,683,037.57		$ 1,683,037.57	$ 1,261,118.23
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 82,618.16	$ (1,973.33)	$ 80,644.83	$ 60,428.04
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (88,776.60)	$ 2,120.42	$ (86,656.18)	$ (64,932.41)
9	Real Time Net Regulation Adjustment Amount	$ 27,819.59	$ (2,966.65)	$ 24,852.94	$ 18,622.58
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 94,297.99	$ -	$ 94,297.99	$ 70,658.50
11	Real Time Spinnng Reserve Cost Distribution	$ 86,487.02	$ -	$ 86,487.02	$ 64,805.66
12	Real Time Supplemental Reserve Cost Distribution	$ 38,234.12	$ -	$ 38,234.12	$ 28,649.24
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 99,632.50	$ (6,900.04)	$ 92,732.46	$ 69,485.43
14	Real Time Contignecy Reserve Deployment Failure	$ 1,758.25	$ -	$ 1,758.25	$ 1,317.48
	TOTAL MISO ASM CHARGES	**$ 1,609,494.75**	**$ 180,739.33**	**$ 1,790,234.08**	**$ 1,341,441.74**

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 2014 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (276,212.42)	$ -	$ (276,212.42)	$ (205,983.38)
2	Day-Ahead Spinning Reserve Amount	$ (72,976.10)	$ -	$ (72,976.10)	$ (54,421.39)
3	Day-Ahead Supplemental Reserve	$ (50,529.64)	$ -	$ (50,529.64)	$ (37,682.11)
4	Real-Time Regulation Amount (See Note 1)	$ 60,618.29	$ 114,973.34	$ 175,591.63	$ 130,946.16
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (20,353.68)	$ 49,673.23	$ 29,319.55	$ 21,864.84
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 736.25	$ 6,470.68	$ 7,206.93	$ 5,374.51
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (16,815.79)		$ (16,815.79)	$ (12,540.25)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,471,573.26		$ 1,471,573.26	$ 1,097,414.92
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (90,444.91)	$ 4,011.99	$ (86,432.92)	$ (64,456.71)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 17,616.20	$ (781.43)	$ 16,834.77	$ 12,554.41
9	Real Time Net Regulation Adjustment Amount	$ 7,908.94	$ 934.24	$ 8,843.18	$ 6,594.74
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 100,383.60	$ -	$ 100,383.60	$ 74,860.33
11	Real Time Spinnng Reserve Cost Distribution	$ 88,687.86	$ -	$ 88,687.86	$ 66,138.32
12	Real Time Supplemental Reserve Cost Distribution	$ 44,390.63	$ -	$ 44,390.63	$ 33,103.99
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 89,563.34	$ (14,095.29)	$ 75,468.05	$ 56,279.74
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,354,145.83**	**$ 161,186.76**	**$ 1,515,332.59**	**$ 1,130,048.12**

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 2014 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (310,873.59)	$ -	$ (310,873.59)	$ (228,818.05)
2	Day-Ahead Spinning Reserve Amount	$ (46,681.76)	$ -	$ (46,681.76)	$ (34,360.04)
3	Day-Ahead Supplemental Reserve	$ (56,362.80)	$ -	$ (56,362.80)	$ (41,485.76)
4	Real-Time Regulation Amount (See Note 1)	$ (49,330.84)	$ 212,780.80	$ 163,449.96	$ 120,307.10
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (37,255.54)	$ 36,972.34	$ (283.20)	$ (208.45)
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ (45.14)	$ (883.11)	$ (928.25)	$ (683.24)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (18,516.86)		$ (18,516.86)	$ (13,629.31)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,449,010.34		$ 2,449,010.34	$ 1,802,590.48
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (142,933.57)	$ 11,263.74	$ (131,669.83)	$ (96,915.38)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 40,194.66	$ (3,167.50)	$ 37,027.16	$ 27,253.79
9	Real Time Net Regulation Adjustment Amount	$ (962.51)	$ (2,115.62)	$ (3,078.13)	$ (2,265.65)
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 119,361.97	$ -	$ 119,361.97	$ 87,856.20
11	Real Time Spinnng Reserve Cost Distribution	$ 126,349.39	$ -	$ 126,349.39	$ 92,999.28
12	Real Time Supplemental Reserve Cost Distribution	$ 80,725.44	$ -	$ 80,725.44	$ 59,417.84
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 132,236.87	$ (30,218.04)	$ 102,018.83	$ 75,090.81
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 2,284,916.06**	**$ 224,632.61**	**$ 2,509,548.67**	**$ 1,847,149.63**

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 2014 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (267,961.62)	$ -	$ (267,961.62)	$ (194,380.26)
2	Day-Ahead Spinning Reserve Amount	$ (51,613.80)	$ -	$ (51,613.80)	$ (37,440.82)
3	Day-Ahead Supplemental Reserve	$ (30,387.12)	$ -	$ (30,387.12)	$ (22,042.92)
4	Real-Time Regulation Amount (See Note 1)	$ 1,431.01	$ 183,631.51	$ 185,062.52	$ 134,244.98
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (31,119.99)	$ 33,722.73	$ 2,602.74	$ 1,888.04
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ (98.56)	$ 433.85	$ 335.29	$ 243.22
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (42,481.82)		$ (42,481.82)	$ (30,816.46)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 4,006,506.43		$ 4,006,506.43	$ 2,906,333.26
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (191,628.28)	$ 10,165.43	$ (181,462.85)	$ (131,633.76)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (48,682.21)	$ 2,582.48	$ (46,099.73)	$ (33,440.90)
9	Real Time Net Regulation Adjustment Amount	$ 3,556.21	$ 329.11	$ 3,885.32	$ 2,818.42
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 140,158.14	$ -	$ 140,158.14	$ 101,671.19
11	Real Time Spinnng Reserve Cost Distribution	$ 129,521.16	$ -	$ 129,521.16	$ 93,955.09
12	Real Time Supplemental Reserve Cost Distribution	$ 34,227.49	$ -	$ 34,227.49	$ 24,828.74
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 94,600.53	$ (20,137.48)	$ 74,463.05	$ 54,015.75
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 3,746,027.57**	**$ 210,727.62**	**$ 3,956,755.19**	**$ 2,870,243.55**

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 2014 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (58,184.63)	$ -	$ (58,184.63)	$ (42,010.49)
2	Day-Ahead Spinning Reserve Amount	$ (31,933.06)	$ -	$ (31,933.06)	$ (23,056.32)
3	Day-Ahead Supplemental Reserve	$ (25,164.02)	$ -	$ (25,164.02)	$ (18,168.94)
4	Real-Time Regulation Amount (See Note 1)	$ (32,060.87)	$ 4,205.93	$ (27,854.94)	$ (20,111.84)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (7,383.69)	$ 10,326.58	$ 2,942.89	$ 2,124.83
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 126.13	$ 860.54	$ 986.67	$ 712.40
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (20,399.43)		$ (20,399.43)	$ (14,728.81)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 4,963,544.80		$ 4,963,544.80	$ 3,583,780.99
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 20,096.96	$ (1,887.31)	$ 18,209.65	$ 13,147.74
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 22,631.69	$ (2,125.34)	$ 20,506.35	$ 14,806.00
9	Real Time Net Regulation Adjustment Amount	$ 3,463.20	$ (2,571.86)	$ 891.34	$ 643.57
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 93,004.04	$ -	$ 93,004.04	$ 67,150.82
11	Real Time Spinnng Reserve Cost Distribution	$ 67,214.02	$ -	$ 67,214.02	$ 48,529.90
12	Real Time Supplemental Reserve Cost Distribution	$ 23,938.61	$ -	$ 23,938.61	$ 17,284.17
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 50,494.55	$ (22,418.79)	$ 28,075.76	$ 20,271.27
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 5,069,388.30**	**$ (13,610.25)**	**$ 5,055,778.05**	**$ 3,650,375.28**

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 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (52,138.62)	$ -	$ (52,138.62)	$ (37,508.41)
2	Day-Ahead Spinning Reserve Amount	$ (94,663.06)	$ -	$ (94,663.06)	$ (68,100.40)
3	Day-Ahead Supplemental Reserve	$ (30,650.87)	$ -	$ (30,650.87)	$ (22,050.17)
4	Real-Time Regulation Amount (See Note 1)	$ 10,736.61	$ 1,250.43	$ 11,987.04	$ 8,623.45
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 7,712.52	$ 44,830.04	$ 52,542.56	$ 37,799.00
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ (3,863.61)	$ 9,278.27	$ 5,414.66	$ 3,895.29
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (22,436.29)		$ (22,436.29)	$ (16,140.62)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 3,064,031.95		$ 3,064,031.95	$ 2,204,257.91
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 159,062.03	$ (9,670.91)	$ 149,391.12	$ 107,471.65
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 12,139.90	$ (738.10)	$ 11,401.80	$ 8,202.43
9	Real Time Net Regulation Adjustment Amount	$ 1,170.48	$ (794.72)	$ 375.76	$ 270.32
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 80,868.66	$ -	$ 80,868.66	$ 58,176.74
11	Real Time Spinnng Reserve Cost Distribution	$ 66,431.35	$ -	$ 66,431.35	$ 47,790.57
12	Real Time Supplemental Reserve Cost Distribution	$ 19,211.25	$ -	$ 19,211.25	$ 13,820.53
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 22,746.18	$ (1,036.99)	$ 21,709.19	$ 15,617.54
14	Real Time Contignecy Reserve Deployment Failure	$ 985.06	$ -	$ 985.06	$ 708.65
	TOTAL MISO ASM CHARGES	**$ 3,241,343.54**	**$ 43,118.02**	**$ 3,284,461.56**	**$ 2,362,834.50**

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

		System	Intersystem	Retail	Minnesota Retail
	February 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (114,510.61)	$ -	$ (114,510.61)	$ (82,028.99)
2	Day-Ahead Spinning Reserve Amount	$ (97,635.22)	$ -	$ (97,635.22)	$ (69,940.40)
3	Day-Ahead Supplemental Reserve	$ (45,228.22)	$ -	$ (45,228.22)	$ (32,398.96)
4	Real-Time Regulation Amount (See Note 1)	$ 367.07	$ 27,363.07	$ 27,730.14	$ 19,864.32
5	Real-Time Spinning Reserve Amount (See Note 1)	$ 7,438.18	$ 39,877.66	$ 47,315.84	$ 33,894.42
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 310.18	$ 6,029.61	$ 6,339.79	$ 4,541.47
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (24,390.77)		$ (24,390.77)	$ (17,472.18)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (549,938.30)		$ (549,938.30)	$ (393,945.01)
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (173,397.46)	$ 9,516.85	$ (163,880.61)	$ (117,394.90)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (9,957.34)	$ 546.50	$ (9,410.84)	$ (6,741.40)
9	Real Time Net Regulation Adjustment Amount	$ 3,679.08	$ (597.60)	$ 3,081.48	$ 2,207.40
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 95,425.93	$ -	$ 95,425.93	$ 68,357.79
11	Real Time Spinnng Reserve Cost Distribution	$ 72,504.33	$ -	$ 72,504.33	$ 51,938.04
12	Real Time Supplemental Reserve Cost Distribution	$ 35,309.03	$ -	$ 35,309.03	$ 25,293.41
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 40,938.82	$ (7,218.58)	$ 33,720.24	$ 24,155.29
14	Real Time Contignecy Reserve Deployment Failure	$ 413.49	$ -	$ 413.49	$ 296.20
	TOTAL MISO ASM CHARGES	**$ (758,671.81)**	**$ 75,517.51**	**$ (683,154.30)**	**$ (489,373.49)**

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 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (130,903.49)	$ -	$ (130,903.49)	$ (93,976.71)
2	Day-Ahead Spinning Reserve Amount	$ (98,272.30)	$ -	$ (98,272.30)	$ (70,550.50)
3	Day-Ahead Supplemental Reserve	$ (43,519.15)	$ -	$ (43,519.15)	$ (31,242.76)
4	Real-Time Regulation Amount (See Note 1)	$ 11,127.94	$ 39,490.55	$ 50,618.49	$ 36,339.44
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (31,184.12)	$ 74,256.39	$ 43,072.27	$ 30,921.94
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 4,314.57	$ 8,863.29	$ 13,177.86	$ 9,460.50
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (4,310.19)		$ (4,310.19)	$ (3,094.32)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ (582,516.36)		$ (582,516.36)	$ (418,193.36)
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 159,775.76	$ (9,211.73)	$ 150,564.03	$ 108,091.17
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 65,368.86	$ (3,768.79)	$ 61,600.07	$ 44,223.21
9	Real Time Net Regulation Adjustment Amount	$ 1,857.42	$ 10.95	$ 1,868.37	$ 1,341.32
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 110,887.50	$ -	$ 110,887.50	$ 79,607.06
11	Real Time Spinnng Reserve Cost Distribution	$ 95,591.82	$ -	$ 95,591.82	$ 68,626.17
12	Real Time Supplemental Reserve Cost Distribution	$ 31,873.53	$ -	$ 31,873.53	$ 22,882.27
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 26,423.44	$ (3,507.37)	$ 22,916.07	$ 16,451.64
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ (383,484.77)**	**$ 106,133.29**	**$ (277,351.48)**	**$ (199,112.94)**

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 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (21,215.78)	$ -	$ (21,215.78)	$ (15,558.78)
2	Day-Ahead Spinning Reserve Amount	$ (35,190.13)	$ -	$ (35,190.13)	$ (25,806.99)
3	Day-Ahead Supplemental Reserve	$ (924.39)	$ -	$ (924.39)	$ (677.91)
4	Real-Time Regulation Amount (See Note 1)	$ 7,133.13	$ 156.66	$ 7,289.79	$ 5,346.03
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (11,102.96)	$ 3,755.83	$ (7,347.13)	$ (5,388.08)
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ (195.21)	$ (1,077.32)	$ (1,272.53)	$ (933.22)
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (6,193.04)		$ (6,193.04)	$ (4,541.72)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,313,000.23		$ 2,313,000.23	$ 1,696,259.16
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (45,895.38)	$ 1,059.22	$ (44,836.16)	$ (32,880.99)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (3,394.65)	$ 78.35	$ (3,316.30)	$ (2,432.04)
9	Real Time Net Regulation Adjustment Amount	$ 2,160.32	$ (0.68)	$ 2,159.64	$ 1,583.79
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 65,854.61	$ -	$ 65,854.61	$ 48,295.06
11	Real Time Spinnng Reserve Cost Distribution	$ 80,949.94	$ -	$ 80,949.94	$ 59,365.35
12	Real Time Supplemental Reserve Cost Distribution	$ 26,712.24	$ -	$ 26,712.24	$ 19,589.66
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 28,394.15	$ (4,124.76)	$ 24,269.39	$ 17,798.17
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 2,400,093.08**	**$ (152.70)**	**$ 2,399,940.38**	**$ 1,760,017.48**

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 2015 Actual				
Procurement Charges					
1	Day-Ahead Regulation Amount	$ (56,858.51)	$ -	$ (56,858.51)	$ (41,915.10)
2	Day-Ahead Spinning Reserve Amount	$ (67,270.35)	$ -	$ (67,270.35)	$ (49,590.52)
3	Day-Ahead Supplemental Reserve	$ (22,283.52)	$ -	$ (22,283.52)	$ (16,427.02)
4	Real-Time Regulation Amount (See Note 1)	$ (743.76)	$ 4,915.10	$ 4,171.34	$ 3,075.04
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (18,636.83)	$ 33,449.56	$ 14,812.73	$ 10,919.68
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 95.63	$ 277.81	$ 373.44	$ 275.29
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ 5,611.04		$ 5,611.04	$ 4,136.36
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 2,252,860.17		$ 2,252,860.17	$ 1,660,768.98
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ (346,471.44)	$ 12,667.61	$ (333,803.83)	$ (246,074.32)
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ (88,322.22)	$ 3,229.22	$ (85,093.00)	$ (62,729.07)
9	Real Time Net Regulation Adjustment Amount	$ 2,489.74	$ (428.99)	$ 2,060.75	$ 1,519.15
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 105,657.96	$ -	$ 105,657.96	$ 77,889.19
11	Real Time Spinnng Reserve Cost Distribution	$ 82,982.00	$ -	$ 82,982.00	$ 61,172.87
12	Real Time Supplemental Reserve Cost Distribution	$ 28,283.38	$ -	$ 28,283.38	$ 20,850.01
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 19,291.98	$ (1,524.59)	$ 17,767.39	$ 13,097.81
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -
	TOTAL MISO ASM CHARGES	**$ 1,896,685.27**	**$ 52,585.72**	**$ 1,949,270.99**	**$ 1,436,968.36**

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	$ (19,151.44)	$ -	$ (19,151.44)	$ (14,249.45)
2	Day-Ahead Spinning Reserve Amount	$ (81,505.40)	$ -	$ (81,505.40)	$ (60,643.33)
3	Day-Ahead Supplemental Reserve	$ (34,668.56)	$ -	$ (34,668.56)	$ (25,794.82)
4	Real-Time Regulation Amount (See Note 1)	$ (51,309.33)	$ 27,225.04	$ (24,084.29)	$ (17,919.69)
5	Real-Time Spinning Reserve Amount (See Note 1)	$ (14,297.15)	$ 53,827.14	$ 39,529.99	$ 29,411.92
6	Real-Time Supplemental Reserve Amount. (See Note 1)	$ 7,144.73	$ 2,215.19	$ 9,359.92	$ 6,964.16
Resource Energy Charges					
7a	Real Time Excessive Energy Amount	$ (15,797.47)		$ (15,797.47)	$ (11,753.96)
7b	Real Time Excessive Energy Congestion	$ -		$ -	$ -
7c	Real Time Excessive Energy Loss	$ -		$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 1,627,778.51		$ 1,627,778.51	$ 1,211,133.32
8b	Real Time Non Excessive Energy Congestion (See Note 2)	$ 179,638.54	$ (7,876.84)	$ 171,761.70	$ 127,797.68
8c	Real Time Non Excessive Energy Loss (See Note 2)	$ 97,692.18	$ (4,283.63)	$ 93,408.55	$ 69,499.75
9	Real Time Net Regulation Adjustment Amount	$ 6,446.31	$ (1,481.85)	$ 4,964.46	$ 3,693.76
Cost Distribution Charges					
10	Real Time Regulation Reserve Cost Distribution Amount	$ 95,964.27	$ -	$ 95,964.27	$ 71,401.31
11	Real Time Spinnng Reserve Cost Distribution	$ 108,094.63	$ -	$ 108,094.63	$ 80,426.79
12	Real Time Supplemental Reserve Cost Distribution	$ 32,194.85	$ -	$ 32,194.85	$ 23,954.28
Penalty Charges					
13	Real Time Excessive/Dificient Energy Deployment	$ 19,002.33	$ (3,382.02)	$ 15,620.31	$ 11,622.15
14	Real Time Contignecy Reserve Deployment Failure	$ 4,995.65	$ -	$ 4,995.65	$ 3,716.97
	TOTAL MISO ASM CHARGES	**$ 1,962,222.65**	**$ 66,243.03**	**$ 2,028,465.68**	**$ 1,509,260.85**

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.

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

		July 14	August 14	September 14	1st Qt	October 14	November 14	December 14	2nd Qt	January 15	February 15	March 15	3rd Qt	April 15	May 15	June 15	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	(137,956.71)	(197,900.28)	(276,212.42)	(612,069.41)	(310,873.59)	(267,961.62)	(58,184.63)	(637,019.84)	(52,138.62)	(114,510.61)	(130,903.49)	(297,552.72)	(21,215.78)	(56,858.51)	(19,151.44)	(97,225.73)	(1,643,867.70)
4	Real-Time Regulation Amount	(24,167.14)	(76,932.22)	60,618.29	(40,481.07)	(49,330.84)	1,431.01	(32,060.87)	(79,960.70)	10,736.61	367.07	11,127.94	22,231.62	7,133.13	(743.76)	(51,309.33)	(44,919.96)	(143,130.11)
10	Real Time Regulation Reserve Cost Distribution Amou	97,011.07	94,297.99	100,383.60	291,692.66	119,361.97	140,158.14	93,004.04	352,524.15	80,868.66	95,425.93	110,887.50	287,182.09	65,854.61	105,657.96	95,964.27	267,476.84	1,198,875.74
	SUBTOTAL	(65,112.78)	(180,534.51)	(115,210.53)	(360,857.82)	(240,842.46)	(126,372.47)	2,758.54	(364,456.39)	39,466.65	(18,717.61)	(8,888.05)	11,860.99	51,771.96	48,055.69	25,503.50	125,331.15	(588,122.07)
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	(149,004.19)	(95,705.77)	(72,976.10)	(317,686.06)	(46,681.76)	(51,613.80)	(31,933.06)	(130,228.62)	(94,663.06)	(97,635.22)	(98,272.30)	(290,570.58)	(35,190.13)	(67,270.35)	(81,505.40)	(183,965.88)	(922,451.14)
5	Real-Time Spinning Reserve Amount	645.79	(320.17)	(20,353.68)	(20,028.06)	(37,255.54)	(31,119.99)	(7,383.69)	(75,759.22)	7,712.52	7,438.18	(31,184.12)	(16,033.42)	(11,102.96)	(18,636.83)	(14,297.15)	(44,036.94)	(155,857.64)
11	Real Time Spinnng Reserve Cost Distribution	81,445.50	86,487.02	88,687.86	256,620.38	126,349.39	129,521.16	67,214.02	323,084.57	66,431.35	72,504.33	95,591.82	234,527.50	80,949.94	82,982.00	108,094.63	272,026.57	1,086,259.02
	SUBTOTAL	(66,912.90)	(9,538.92)	(4,641.92)	(81,093.74)	42,412.09	46,787.37	27,897.27	117,096.73	(20,519.19)	(17,692.71)	(33,864.60)	(72,076.50)	34,656.85	(2,925.18)	12,292.08	44,023.75	7,950.24
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	(50,626.73)	(49,420.27)	(50,529.64)	(150,576.64)	(56,362.80)	(30,387.12)	(25,164.02)	(111,913.94)	(30,650.87)	(45,228.22)	(43,519.15)	(119,398.24)	(924.39)	(22,283.52)	(34,668.56)	(57,876.47)	(439,765.29)
6	Real-Time Supplemental Reserve Amount.	3,839.85	105.90	736.25	4,682.00	(45.14)	(98.56)	126.13	(17.57)	(3,863.61)	310.18	4,314.57	761.14	(195.21)	95.63	7,144.73	7,045.15	12,470.72
12	Real Time Supplemental Reserve Cost Distribution	45,979.79	38,234.12	44,390.63	128,604.54	80,725.44	34,227.49	23,938.61	138,891.54	19,211.25	35,309.03	31,873.53	86,393.81	26,712.24	28,283.38	32,194.85	87,190.47	441,080.36
	SUBTOTAL	(807.09)	(11,080.25)	(5,402.76)	(17,290.10)	24,317.50	3,741.81	(1,099.28)	26,960.03	(15,303.23)	(9,609.01)	(7,331.05)	(32,243.29)	25,592.64	6,095.49	4,671.02	36,359.15	13,785.79
Other Charges																		
14	Real Time Contignecy Reserve Deployment Failure	138.40	1,758.25	-	1,896.65	-	-	-	-	985.06	413.49	-	1,398.55	-	-	4,995.65	4,995.65	8,290.85
13	Real Time Excessive/Dificient Energy Deployment	93,580.19	99,632.50	89,563.34	282,776.03	132,236.87	94,600.53	50,494.55	277,331.95	22,746.18	40,938.82	26,423.44	90,108.44	28,394.15	19,291.98	19,002.33	66,688.46	716,904.88
9	Real Time Net Regulation Adjustment Amount	30,940.29	27,819.59	7,908.94	66,668.82	(962.51)	3,556.21	3,463.20	6,056.90	1,170.48	3,679.08	1,857.42	6,706.98	2,160.32	2,489.74	6,446.31	11,096.37	90,529.07
	SUBTOTAL	124,658.88	129,210.34	97,472.28	351,341.50	131,274.36	98,156.74	53,957.75	283,388.85	24,901.72	45,031.39	28,280.86	98,213.97	30,554.47	21,781.72	30,444.29	82,780.48	815,724.80
	TOTAL MISO ASM CHARGES	(8,173.89)	(71,943.34)	(27,782.93)	(107,900.16)	(42,838.51)	22,313.45	83,514.28	62,989.22	28,545.95	(987.94)	(21,802.84)	5,755.17	142,575.92	73,007.72	72,910.89	288,494.53	249,338.76
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	7,883.28	4,558.96	(16,815.79)	(4,373.55)	(18,516.86)	(42,481.82)	(20,399.43)	(81,398.11)	(22,436.29)	(24,390.77)	(4,310.19)	(51,137.25)	(6,193.04)	5,611.04	(15,797.47)	(16,379.47)	(153,288.38)
7b	Real Time Excessive Energy Congestion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7c	Real Time Excessive Energy Loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8a	Real Time Non Excessive Energy Amount	817,893.08	1,683,037.57	1,471,573.26	3,972,503.91	2,449,010.34	4,006,506.43	4,963,544.80	11,419,061.57	3,064,031.95	(549,938.30)	(582,516.36)	1,931,577.29	2,313,000.23	2,252,860.17	1,627,778.51	6,193,638.91	23,516,781.68
8b	Real Time Non Excessive Energy Congestion	(35,594.95)	82,618.16	(90,444.91)	(43,421.70)	(142,933.57)	(191,628.28)	20,096.96	(314,464.89)	159,062.03	(173,397.46)	159,775.76	145,440.33	(45,895.38)	(346,471.44)	179,638.54	(212,728.28)	(425,174.54)
8c	Real Time Non Excessive Energy Loss	179,667.32	(88,776.60)	17,616.20	108,506.92	40,194.66	(48,682.21)	22,631.69	14,144.14	12,139.90	(9,957.34)	65,368.86	67,551.42	(3,394.65)	(88,322.22)	97,692.18	5,975.31	196,177.79
	SUBTOTAL	969,848.73	1,681,438.09	1,381,928.76	4,033,215.58	2,327,754.57	3,723,714.12	4,985,874.02	11,037,342.71	3,212,797.59	(757,683.87)	(361,681.93)	2,093,431.79	2,257,517.16	1,823,677.55	1,889,311.76	5,970,506.47	23,134,496.55
	GRAND TOTAL MISO ASM CHARGES	961,674.84	1,609,494.75	1,354,145.83	3,925,315.42	2,284,916.06	3,746,027.57	5,069,388.30	11,100,331.93	3,241,343.54	(758,671.81)	(383,484.77)	2,099,186.96	2,400,093.08	1,896,685.27	1,962,222.65	6,259,001.00	23,383,835.31

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

		July 14	August 14	September 14	1st Qt	October 14	November 14	December 14	2nd Qt	January 15	February 15	March 15	3rd Qt	April 15	May 15	June 15	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Real-Time Regulation Amount	$ 92,773.70	$ 158,024.21	$ 114,973.34	$ 365,771.25	$ 212,780.80	$ 183,631.51	$ 4,205.93	$ 400,618.24	$ 1,250.43	$ 27,363.07	$ 39,490.55	$ 68,104.05	$ 156.66	$ 4,915.10	$ 27,225.04	$ 32,296.80	$ 866,790.34
10	Real Time Regulation Reserve Cost Distribution Amou	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 92,773.70	$ 158,024.21	$ 114,973.34	$ 365,771.25	$ 212,780.80	$ 183,631.51	$ 4,205.93	$ 400,618.24	$ 1,250.43	$ 27,363.07	$ 39,490.55	$ 68,104.05	$ 156.66	$ 4,915.10	$ 27,225.04	$ 32,296.80	$ 866,790.34
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Real-Time Spinning Reserve Amount	$ 76,977.30	$ 23,562.62	$ 49,673.23	$ 150,213.15	$ 36,972.34	$ 33,722.73	$ 10,326.58	$ 81,021.65	$ 44,830.04	$ 39,877.66	$ 74,256.39	$ 158,964.09	$ 3,755.83	$ 33,449.56	$ 53,827.14	$ 91,032.53	$ 481,231.42
11	Real Time Spinnng Reserve Cost Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 76,977.30	$ 23,562.62	$ 49,673.23	$ 150,213.15	$ 36,972.34	$ 33,722.73	$ 10,326.58	$ 81,021.65	$ 44,830.04	$ 39,877.66	$ 74,256.39	$ 158,964.09	$ 3,755.83	$ 33,449.56	$ 53,827.14	$ 91,032.53	$ 481,231.42
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Real-Time Supplemental Reserve Amount.	$ 6,696.83	$ 8,872.10	$ 6,470.68	$ 22,039.61	$ (883.11)	$ 433.85	$ 860.54	$ 411.28	$ 9,278.27	$ 6,029.61	$ 8,863.29	$ 24,171.17	$ (1,077.32)	$ 277.81	$ 2,215.19	$ 1,415.68	$ 48,037.74
12	Real Time Supplemental Reserve Cost Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	SUBTOTAL	$ 6,696.83	$ 8,872.10	$ 6,470.68	$ 22,039.61	$ (883.11)	$ 433.85	$ 860.54	$ 411.28	$ 9,278.27	$ 6,029.61	$ 8,863.29	$ 24,171.17	$ (1,077.32)	$ 277.81	$ 2,215.19	$ 1,415.68	$ 48,037.74
Other Charges																		
14	Real Time Contignecy Reserve Deployment Failure	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Real Time Excessive/Dificient Energy Deployment	$ (12,080.37)	$ (6,900.04)	$ (14,095.29)	$ (33,075.70)	$ (30,218.04)	$ (20,137.48)	$ (22,418.79)	$ (72,774.31)	$ (1,036.99)	$ (7,218.58)	$ (3,507.37)	$ (11,762.94)	$ (4,124.76)	$ (1,524.59)	$ (3,382.02)	$ (9,031.37)	$ (126,644.32)
9	Real Time Net Regulation Adjustment Amount	$ (6,575.18)	$ (2,966.65)	$ 934.24	$ (8,607.59)	$ (2,115.62)	$ 329.11	$ (2,571.86)	$ (4,358.37)	$ (794.72)	$ (597.60)	$ 10.95	$ (1,381.37)	$ (0.68)	$ (428.99)	$ (1,481.85)	$ (1,911.52)	$ (16,258.85)
	SUBTOTAL	$ (18,655.55)	$ (9,866.69)	$ (13,161.05)	$ (41,683.29)	$ (32,333.66)	$ (19,808.37)	$ (24,990.65)	$ (77,132.68)	$ (1,831.71)	$ (7,816.18)	$ (3,496.42)	$ (13,144.31)	$ (4,125.44)	$ (1,953.58)	$ (4,863.87)	$ (10,942.89)	$ (142,903.17)
	TOTAL MISO ASM CHARGES	$ 157,792.28	$ 180,592.24	$ 157,956.20	$ 496,340.72	$ 216,536.37	$ 197,979.72	$ (9,597.60)	$ 404,918.49	$ 53,527.03	$ 65,454.16	$ 119,113.81	$ 238,095.00	$ (1,290.27)	$ 36,688.89	$ 78,403.50	$ 113,802.12	$ 1,253,156.33
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	$ 642.23	$ (1,973.33)	$ 4,011.99	$ 2,680.89	$ 11,263.74	$ 10,165.43	$ (1,887.31)	$ 19,541.86	$ (9,670.91)	$ 9,516.85	$ (9,211.73)	$ (9,365.79)	$ 1,059.22	$ 12,667.61	$ (7,876.84)	$ 5,850.00	$ 18,706.96
8c	Real Time Non Excessive Energy Loss	$ (3,241.70)	$ 2,120.42	$ (781.43)	$ (1,902.70)	$ (3,167.50)	$ 2,582.48	$ (2,125.34)	$ (2,710.37)	$ (738.10)	$ 546.50	$ (3,768.79)	$ (3,960.38)	$ 78.35	$ 3,229.22	$ (4,283.63)	$ (976.07)	$ (9,549.52)
	SUBTOTAL	$ (2,599.47)	$ 147.09	$ 3,230.56	$ 778.19	$ 8,096.24	$ 12,747.90	$ (4,012.65)	$ 16,831.50	$ (10,409.01)	$ 10,063.35	$ (12,980.52)	$ (13,326.18)	$ 1,137.57	$ 15,896.83	$ (12,160.47)	$ 4,873.93	$ 9,157.44
	GRAND TOTAL MISO ASM CHARGES	$ 155,192.81	$ 180,739.33	$ 161,186.76	$ 497,118.91	$ 224,632.61	$ 210,727.62	$ (13,610.25)	$ 421,749.99	$ 43,118.02	$ 75,517.51	$ 106,133.29	$ 224,768.82	$ (152.70)	$ 52,585.72	$ 66,243.03	$ 118,676.05	$ 1,262,313.77

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

		July 14	August 14	September 14	1st Qt	October 14	November 14	December 14	2nd Qt	January 15	February 15	March 15	3rd Qt	April 15	May 15	June 15	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (137,956.71)	$ (197,900.28)	$ (276,212.42)	$ (612,069.41)	$ (310,873.59)	$ (267,961.62)	$ (58,184.63)	$ (637,019.84)	$ (52,138.62)	$ (114,510.61)	$ (130,903.49)	$ (297,552.72)	$ (21,215.78)	$ (56,858.51)	$ (19,151.44)	$ (97,225.73)	$ (1,643,867.70)
4	Real-Time Regulation Amount	$ 68,606.56	$ 81,091.99	$ 175,591.63	$ 325,290.18	$ 163,449.96	$ 185,062.52	$ (27,854.94)	$ 320,657.54	$ 11,987.04	$ 27,730.14	$ 50,618.49	$ 90,335.67	$ 7,289.79	$ 4,171.34	$ (24,084.29)	$ (12,623.16)	$ 723,660.23
10	Real Time Regulation Reserve Cost Distribution Amou	$ 97,011.07	$ 94,297.99	$ 100,383.60	$ 291,692.66	$ 119,361.97	$ 140,158.14	$ 93,004.04	$ 352,524.15	$ 80,868.66	$ 95,425.93	$ 110,887.50	$ 287,182.09	$ 65,854.61	$ 105,657.96	$ 95,964.27	$ 267,476.84	$ 1,198,875.74
	SUBTOTAL	$ 27,660.92	$ (22,510.30)	$ (237.19)	$ 4,913.43	$ (28,061.66)	$ 57,259.04	$ 6,964.47	$ 36,161.85	$ 40,717.08	$ 8,645.46	$ 30,602.50	$ 79,965.04	$ 51,928.62	$ 52,970.79	$ 52,728.54	$ 157,627.95	$ 278,668.27
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (149,004.19)	$ (95,705.77)	$ (72,976.10)	$ (317,686.06)	$ (46,681.76)	$ (51,613.80)	$ (31,933.06)	$ (130,228.62)	$ (94,663.06)	$ (97,635.22)	$ (98,272.30)	$ (290,570.58)	$ (35,190.13)	$ (67,270.35)	$ (81,505.40)	$ (183,965.88)	$ (922,451.14)
5	Real-Time Spinning Reserve Amount	$ 77,623.09	$ 23,242.45	$ 29,319.55	$ 130,185.09	$ (283.20)	$ 2,602.74	$ 2,942.89	$ 5,262.43	$ 52,542.56	$ 47,315.84	$ 43,072.27	$ 142,930.67	$ (7,347.13)	$ 14,812.73	$ 39,529.99	$ 46,995.59	$ 325,373.78
11	Real Time Spinnng Reserve Cost Distribution	$ 81,445.50	$ 86,487.02	$ 88,687.86	$ 256,620.38	$ 126,349.39	$ 129,521.16	$ 67,214.02	$ 323,084.57	$ 66,431.35	$ 72,504.33	$ 95,591.82	$ 234,527.50	$ 80,949.94	$ 82,982.00	$ 108,094.63	$ 272,026.57	$ 1,086,259.02
	SUBTOTAL	$ 10,064.40	$ 14,023.70	$ 45,031.31	$ 69,119.41	$ 79,384.43	$ 80,510.10	$ 38,223.85	$ 198,118.38	$ 24,310.85	$ 22,184.95	$ 40,391.79	$ 86,887.59	$ 38,412.68	$ 30,524.38	$ 66,119.22	$ 135,056.28	$ 489,181.66
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (50,626.73)	$ (49,420.27)	$ (50,529.64)	$ (150,576.64)	$ (56,362.80)	$ (30,387.12)	$ (25,164.02)	$ (111,913.94)	$ (30,650.87)	$ (45,228.22)	$ (43,519.15)	$ (119,398.24)	$ (924.39)	$ (22,283.52)	$ (34,668.56)	$ (57,876.47)	$ (439,765.29)
6	Real-Time Supplemental Reserve Amount.	$ 10,536.68	$ 8,978.00	$ 7,206.93	$ 26,721.61	$ (928.25)	$ 335.29	$ 986.67	$ 393.71	$ 5,414.66	$ 6,339.79	$ 13,177.86	$ 24,932.31	$ (1,272.53)	$ 373.44	$ 9,359.92	$ 8,460.83	$ 60,508.46
12	Real Time Supplemental Reserve Cost Distribution	$ 45,979.79	$ 38,234.12	$ 44,390.63	$ 128,604.54	$ 80,725.44	$ 34,227.49	$ 23,938.61	$ 138,891.54	$ 19,211.25	$ 35,309.03	$ 31,873.53	$ 86,393.81	$ 26,712.24	$ 28,283.38	$ 32,194.85	$ 87,190.47	$ 441,080.36
	SUBTOTAL	$ 5,889.74	$ (2,208.15)	$ 1,067.92	$ 4,749.51	$ 23,434.39	$ 4,175.66	$ (238.74)	$ 27,371.31	$ (6,024.96)	$ (3,579.40)	$ 1,532.24	$ (8,072.12)	$ 24,515.32	$ 6,373.30	$ 6,886.21	$ 37,774.83	$ 61,823.53
Other Charges																		
13	Real Time Excessive/Dificient Energy Deployment	$ 138.40	$ 1,758.25	$ -	$ 1,896.65	$ -	$ -	$ -	$ -	$ 985.06	$ 413.49	$ -	$ 1,398.55	$ -	$ -	$ 4,995.65	$ 4,995.65	$ 8,290.85
14	Real Time Contignecy Reserve Deployment Failure	$ 81,499.82	$ 92,732.46	$ 75,468.05	$ 249,700.33	$ 102,018.83	$ 74,463.05	$ 28,075.76	$ 204,557.64	$ 21,709.19	$ 33,720.24	$ 22,916.07	$ 78,345.50	$ 24,269.39	$ 17,767.39	$ 15,620.31	$ 57,657.09	$ 590,260.56
9	Real Time Net Regulation Adjustment Amount	$ 24,365.11	$ 24,852.94	$ 8,843.18	$ 58,061.23	$ (3,078.13)	$ 3,885.32	$ 891.34	$ 1,698.53	$ 375.76	$ 3,081.48	$ 1,868.37	$ 5,325.61	$ 2,159.64	$ 2,060.75	$ 4,964.46	$ 9,184.85	$ 74,270.22
	SUBTOTAL	$ 106,003.33	$ 119,343.65	$ 84,311.23	$ 309,658.21	$ 98,940.70	$ 78,348.37	$ 28,967.10	$ 206,256.17	$ 23,070.01	$ 37,215.21	$ 24,784.44	$ 85,069.66	$ 26,429.03	$ 19,828.14	$ 25,580.42	$ 71,837.59	$ 672,821.63
	TOTAL MISO ASM CHARGES	$ 149,618.39	$ 108,648.90	$ 130,173.27	$ 388,440.56	$ 173,697.86	$ 220,293.17	$ 73,916.68	$ 467,907.71	$ 82,072.98	$ 64,466.22	$ 97,310.97	$ 243,850.17	$ 141,285.65	$ 109,696.61	$ 151,314.39	$ 402,296.65	$ 1,502,495.09
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ 7,883.28	$ 4,558.96	$ (16,815.79)	$ (4,373.55)	$ (18,516.86)	$ (42,481.82)	$ (20,399.43)	$ (81,398.11)	$ (22,436.29)	$ (24,390.77)	$ (4,310.19)	$ (51,137.25)	$ (6,193.04)	$ 5,611.04	$ (15,797.47)	$ (16,379.47)	$ (153,288.38)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 817,893.08	$ 1,683,037.57	$ 1,471,573.26	$ 3,972,503.91	$ 2,449,010.34	$ 4,006,506.43	$ 4,963,544.80	$ 11,419,061.57	$ 3,064,031.95	$ (549,938.30)	$ (582,516.36)	$ 1,931,577.29	$ 2,313,000.23	$ 2,252,860.17	$ 1,627,778.51	$ 6,193,638.91	$ 23,516,781.68
8b	Real Time Non Excessive Energy Congestion	$ (34,952.72)	$ 80,644.83	$ (86,432.92)	$ (40,740.81)	$ (131,669.83)	$ (181,462.85)	$ 18,209.65	$ (294,923.03)	$ 149,391.12	$ (163,880.61)	$ 150,564.03	$ 136,074.54	$ (44,836.16)	$ (333,803.83)	$ 171,761.70	$ (206,878.28)	$ (406,467.58)
8c	Real Time Non Excessive Energy Loss	$ 176,425.62	$ (86,656.18)	$ 16,834.77	$ 106,604.22	$ 37,027.16	$ (46,099.73)	$ 20,506.35	$ 11,433.77	$ 11,401.80	$ (9,410.84)	$ 61,600.07	$ 63,591.04	$ (3,316.30)	$ (85,093.00)	$ 93,408.55	$ 4,999.24	$ 186,628.27
	SUBTOTAL	$ 967,249.26	$ 1,681,585.18	$ 1,385,159.32	$ 4,033,993.77	$ 2,335,850.81	$ 3,736,462.02	$ 4,981,861.37	$ 11,054,174.21	$ 3,202,388.58	$ (747,620.52)	$ (374,662.45)	$ 2,080,105.61	$ 2,258,654.73	$ 1,839,574.38	$ 1,877,151.29	$ 5,975,380.40	$ 23,143,653.99
	GRAND TOTAL MISO ASM CHARGES	$ 1,116,867.65	$ 1,790,234.08	$ 1,515,332.59	$ 4,422,434.33	$ 2,509,548.67	$ 3,956,755.19	$ 5,055,778.05	$ 11,522,081.92	$ 3,284,461.56	$ (683,154.30)	$ (277,351.48)	$ 2,323,955.78	$ 2,399,940.38	$ 1,949,270.99	$ 2,028,465.68	$ 6,377,677.05	$ 24,646,149.08

Northern States Power Company

Docket No. E999/AA-15-611

Part J, Section 5

Schedule 12

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

		July 14	August 14	September 14	1st Qt	October 14	November 14	December 14	2nd Qt	January 15	February 15	March 15	3rd Qt	April 15	May 15	June 15	4th Qt	YTD
Regulation																		
1	Day-Ahead Regulation Amount	$ (103,080.90)	$ (148,288.82)	$ (205,983.38)	$ (457,353.09)	$ (228,818.05)	$ (194,380.26)	$ (42,010.49)	$ (465,208.81)	$ (37,508.41)	$ (82,028.99)	$ (93,976.71)	$ (213,514.11)	$ (15,558.78)	$ (41,915.10)	$ (14,249.45)	$ (71,723.32)	$ (1,207,799.33)
4	Real-Time Regulation Amount	$ 51,262.64	$ 60,763.10	$ 130,946.16	$ 242,971.91	$ 120,307.10	$ 134,244.98	$ (20,111.84)	$ 234,440.24	$ 8,623.45	$ 19,864.32	$ 36,339.44	$ 64,827.21	$ 5,346.03	$ 3,075.04	$ (17,919.69)	$ (9,498.62)	$ 532,740.74
10	Real Time Regulation Reserve Cost Distribution Amou	$ 72,486.42	$ 70,658.50	$ 74,860.33	$ 218,005.25	$ 87,856.20	$ 101,671.19	$ 67,150.82	$ 256,678.21	$ 58,176.74	$ 68,357.79	$ 79,607.06	$ 206,141.59	$ 48,295.06	$ 77,889.19	$ 71,401.31	$ 197,585.57	$ 878,410.63
	SUBTOTAL	$ 20,668.17	$ (16,867.21)	$ (176.88)	$ 3,624.07	$ (20,654.74)	$ 41,535.90	$ 5,028.49	$ 25,909.65	$ 29,291.78	$ 6,193.12	$ 21,969.79	$ 57,454.69	$ 38,082.31	$ 39,049.14	$ 39,232.18	$ 116,363.62	$ 203,352.04
Spinning Reserve																		
2	Day-Ahead Spinning Reserve Amount	$ (111,335.55)	$ (71,713.37)	$ (54,421.39)	$ (237,470.30)	$ (34,360.04)	$ (37,440.82)	$ (23,056.32)	$ (94,857.19)	$ (68,100.40)	$ (69,940.40)	$ (70,550.50)	$ (208,591.31)	$ (25,806.99)	$ (49,590.52)	$ (60,643.33)	$ (136,040.84)	$ (676,959.64)
5	Real-Time Spinning Reserve Amount	$ 57,999.77	$ 17,415.82	$ 21,864.84	$ 97,280.43	$ (208.45)	$ 1,888.04	$ 2,124.83	$ 3,804.41	$ 37,799.00	$ 33,894.42	$ 30,921.94	$ 102,615.36	$ (5,388.08)	$ 10,919.68	$ 29,411.92	$ 34,943.52	$ 238,643.73
11	Real Time Spinnng Reserve Cost Distribution	$ 60,855.87	$ 64,805.66	$ 66,138.32	$ 191,799.84	$ 92,999.28	$ 93,955.09	$ 48,529.90	$ 235,484.27	$ 47,790.57	$ 51,938.04	$ 68,626.17	$ 168,354.78	$ 59,365.35	$ 61,172.87	$ 80,426.79	$ 200,965.02	$ 796,603.91
	SUBTOTAL	$ 7,520.09	$ 10,508.11	$ 33,581.77	$ 51,609.97	$ 58,430.79	$ 58,402.30	$ 27,598.40	$ 144,431.49	$ 17,489.17	$ 15,892.06	$ 28,997.60	$ 62,378.83	$ 28,170.28	$ 22,502.04	$ 49,195.38	$ 99,867.70	$ 358,288.00
Supplemental Reserve																		
3	Day-Ahead Supplemental Reserve	$ (37,828.16)	$ (37,031.14)	$ (37,682.11)	$ (112,541.41)	$ (41,485.76)	$ (22,042.92)	$ (18,168.94)	$ (81,697.61)	$ (22,050.17)	$ (32,398.96)	$ (31,242.76)	$ (85,691.89)	$ (677.91)	$ (16,427.02)	$ (25,794.82)	$ (42,899.75)	$ (322,830.67)
6	Real-Time Supplemental Reserve Amount.	$ 7,872.98	$ 6,727.31	$ 5,374.51	$ 19,974.81	$ (683.24)	$ 243.22	$ 712.40	$ 272.38	$ 3,895.29	$ 4,541.47	$ 9,460.50	$ 17,897.26	$ (933.22)	$ 275.29	$ 6,964.16	$ 6,306.23	$ 44,450.68
12	Real Time Supplemental Reserve Cost Distribution	$ 34,355.98	$ 28,649.24	$ 33,103.99	$ 96,109.20	$ 59,417.84	$ 24,828.74	$ 17,284.17	$ 101,530.75	$ 13,820.53	$ 25,293.41	$ 22,882.27	$ 61,996.22	$ 19,589.66	$ 20,850.01	$ 23,954.28	$ 64,393.94	$ 324,030.11
	SUBTOTAL	$ 4,400.80	$ (1,654.59)	$ 796.39	$ 3,542.60	$ 17,248.85	$ 3,029.04	$ (172.38)	$ 20,105.51	$ (4,334.34)	$ (2,564.08)	$ 1,100.01	$ (5,798.42)	$ 17,978.53	$ 4,698.28	$ 5,123.62	$ 27,800.43	$ 45,650.13
Other Charges																		
14	Real Time Contignecy Reserve Deployment Failure	$ 103.41	$ 1,317.48	$ -	$ 1,420.89	$ -	$ -	$ -	$ -	$ 708.65	$ 296.20	$ -	$ 1,004.85	$ -	$ -	$ 3,716.97	$ 3,716.97	$ 6,142.71
13	Real Time Excessive/Dificient Energy Deployment	$ 60,896.46	$ 69,485.43	$ 56,279.74	$ 186,661.63	$ 75,090.81	$ 54,015.75	$ 20,271.27	$ 149,377.83	$ 15,617.54	$ 24,155.29	$ 16,451.64	$ 56,224.47	$ 17,798.17	$ 13,097.81	$ 11,622.15	$ 42,518.12	$ 434,782.06
9	Real Time Net Regulation Adjustment Amount	$ 18,205.55	$ 18,622.58	$ 6,594.74	$ 43,422.86	$ (2,265.65)	$ 2,818.42	$ 643.57	$ 1,196.34	$ 270.32	$ 2,207.40	$ 1,341.32	$ 3,819.04	$ 1,583.79	$ 1,519.15	$ 3,693.76	$ 6,796.70	$ 55,234.94
	SUBTOTAL	$ 79,205.41	$ 89,425.49	$ 62,874.48	$ 231,505.38	$ 72,825.16	$ 56,834.17	$ 20,914.84	$ 150,574.17	$ 16,596.51	$ 26,658.89	$ 17,792.96	$ 61,048.36	$ 19,381.96	$ 14,616.96	$ 19,032.87	$ 53,031.79	$ 496,159.70
	TOTAL MISO ASM CHARGES	$ 111,794.47	$ 81,411.79	$ 97,075.76	$ 290,282.03	$ 127,850.06	$ 159,801.41	$ 53,369.36	$ 341,020.82	$ 59,043.12	$ 46,179.99	$ 69,860.36	$ 175,083.47	$ 103,613.08	$ 80,866.42	$ 112,584.05	$ 297,063.55	$ 1,103,449.86
Resource Energy Charges NOT INCLUDED IN Minnesota Power FORMAT																		
7a	Real Time Excessive Energy Amount	$ 5,890.37	$ 3,416.08	$ (12,540.25)	$ (3,233.81)	$ (13,629.31)	$ (30,816.46)	$ (14,728.81)	$ (59,174.57)	$ (16,140.62)	$ (17,472.18)	$ (3,094.32)	$ (36,707.12)	$ (4,541.72)	$ 4,136.36	$ (11,753.96)	$ (12,159.32)	$ (111,274.82)
7b	Real Time Excessive Energy Congestion	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7c	Real Time Excessive Energy Loss	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8a	Real Time Non Excessive Energy Amount	$ 611,127.60	$ 1,261,118.23	$ 1,097,414.92	$ 2,969,660.75	$ 1,802,590.48	$ 2,906,333.26	$ 3,583,780.99	$ 8,292,704.73	$ 2,204,257.91	$ (393,945.01)	$ (418,193.36)	$ 1,392,119.55	$ 1,696,259.16	$ 1,660,768.98	$ 1,211,133.32	$ 4,568,161.45	$ 17,222,646.49
8b	Real Time Non Excessive Energy Congestion	$ (26,116.58)	$ 60,428.04	$ (64,456.71)	$ (30,145.25)	$ (96,915.38)	$ (131,633.76)	$ 13,147.74	$ (215,401.41)	$ 107,471.65	$ (117,394.90)	$ 108,091.17	$ 98,167.92	$ (32,880.99)	$ (246,074.32)	$ 127,797.68	$ (151,157.63)	$ (298,536.37)
8c	Real Time Non Excessive Energy Loss	$ 131,824.77	$ (64,932.41)	$ 12,554.41	$ 79,446.77	$ 27,253.79	$ (33,440.90)	$ 14,806.00	$ 8,618.89	$ 8,202.43	$ (6,741.40)	$ 44,223.21	$ 45,684.24	$ (2,432.04)	$ (62,729.07)	$ 69,499.75	$ 4,338.65	$ 138,088.54
	SUBTOTAL	$ 722,726.15	$ 1,260,029.94	$ 1,032,972.37	$ 3,015,728.46	$ 1,719,299.58	$ 2,710,442.14	$ 3,597,005.92	$ 8,026,747.64	$ 2,303,791.37	$ (535,553.48)	$ (268,973.30)	$ 1,499,264.59	$ 1,656,404.40	$ 1,356,101.95	$ 1,396,676.80	$ 4,409,183.15	$ 16,950,923.84
	GRAND TOTAL MISO ASM CHARGES	$ 834,520.63	$ 1,341,441.74	$ 1,130,048.12	$ 3,306,010.48	$ 1,847,149.63	$ 2,870,243.55	$ 3,650,375.28	$ 8,367,768.46	$ 2,362,834.50	$ (489,373.49)	$ (199,112.94)	$ 1,674,348.06	$ 1,760,017.48	$ 1,436,968.36	$ 1,509,260.85	$ 4,706,246.69	$ 18,054,373.71

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

July 2014	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		$ (137,956.71)		$ (137,956.71)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (149,004.19)		$ (149,004.19)		$ -		
3 Day-Ahead Supplemental Reserve		$ (50,626.73)		$ (50,626.73)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (24,167.14)		$ 68,606.56		$ (92,773.70)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 645.79		$ 77,623.09		$ (76,977.30)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 3,839.85		$ 10,536.68		$ (6,696.83)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,246)	$ 7,883.28	(2,246)	$ 7,883.28				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	61,175	$ 817,893.08	61,175	$ 817,893.08				
8b Real Time Non Excessive Energy Congestion		$ (35,594.95)		$ (34,952.72)		$ (642.23)		
8c Real Time Non Excessive Energy Loss		$ 179,667.32		$ 176,425.62		$ 3,241.70		
9 Real Time Net Regulation Adjustment Amount		$ 30,940.29		$ 24,365.11		$ 6,575.18		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 97,011.07		$ 97,011.07		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 81,445.50		$ 81,445.50		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 45,979.79		$ 45,979.79		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 93,580.19		$ 81,499.82		$ 12,080.37		
14 Real Time Contignecy Reserve Deployment Failure		$ 138.40		$ 138.40		$ -		
TOTAL MISO ASM CHARGES	**58,928**	**$ 961,674.84**	**58,928**	**$ 1,116,867.65**		**$ (155,192.81)**		**$ -**

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 2014	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		$ (197,900.28)		$ (197,900.28)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (95,705.77)		$ (95,705.77)		$ -		
3 Day-Ahead Supplemental Reserve		$ (49,420.27)		$ (49,420.27)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (76,932.22)		$ 81,091.99		$ (158,024.21)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (320.17)		$ 23,242.45		$ (23,562.62)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 105.90		$ 8,978.00		$ (8,872.10)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,299)	$ 4,558.96	(2,299)	$ 4,558.96				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	35,159	$ 1,683,037.57	35,159	$ 1,683,037.57				
8b Real Time Non Excessive Energy Congestion		$ 82,618.16		$ 80,644.83		$ 1,973.33		
8c Real Time Non Excessive Energy Loss		$ (88,776.60)		$ (86,656.18)		$ (2,120.42)		
9 Real Time Net Regulation Adjustment Amount		$ 27,819.59		$ 24,852.94		$ 2,966.65		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 94,297.99		$ 94,297.99		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 86,487.02		$ 86,487.02		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 38,234.12		$ 38,234.12		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 99,632.50		$ 92,732.46		$ 6,900.04		
14 Real Time Contignecy Reserve Deployment Failure		$ 1,758.25		$ 1,758.25		$ -		
TOTAL MISO ASM CHARGES	**32,860**	**$ 1,609,494.75**	**32,860**	**$ 1,790,234.08**		**$ (180,739.33)**		**$ -**

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.

September 2014	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		$ (276,212.42)		$ (276,212.42)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (72,976.10)		$ (72,976.10)		$ -		
3 Day-Ahead Supplemental Reserve		$ (50,529.64)		$ (50,529.64)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 60,618.29		$ 175,591.63		$ (114,973.34)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (20,353.68)		$ 29,319.55		$ (49,673.23)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 736.25		$ 7,206.93		$ (6,470.68)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,035)	$ (16,815.79)	(1,035)	$ (16,815.79)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	65,824	$ 1,471,573.26	65,824	$ 1,471,573.26				
8b Real Time Non Excessive Energy Congestion		$ (90,444.91)		$ (86,432.92)		$ (4,011.99)		
8c Real Time Non Excessive Energy Loss		$ 17,616.20		$ 16,834.77		$ 781.43		
9 Real Time Net Regulation Adjustment Amount		$ 7,908.94		$ 8,843.18		$ (934.24)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 100,383.60		$ 100,383.60		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 88,687.86		$ 88,687.86		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 44,390.63		$ 44,390.63		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 89,563.34		$ 75,468.05		$ 14,095.29		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**64,789**	**$ 1,354,145.83**	**64,789**	**$ 1,515,332.59**		**$ (161,186.76)**		**$ -**

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 2014	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		$ (310,873.59)		$ (310,873.59)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (46,681.76)		$ (46,681.76)		$ -		
3 Day-Ahead Supplemental Reserve		$ (56,362.80)		$ (56,362.80)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (49,330.84)		$ 163,449.96		$ (212,780.80)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (37,255.54)		$ (283.20)		$ (36,972.34)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (45.14)		$ (928.25)		$ 883.11		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(134)	$ (18,516.86)	(134)	$ (18,516.86)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	108,119	$ 2,449,010.34	108,119	$ 2,449,010.34				
8b Real Time Non Excessive Energy Congestion		$ (142,933.57)		$ (131,669.83)		$ (11,263.74)		
8c Real Time Non Excessive Energy Loss		$ 40,194.66		$ 37,027.16		$ 3,167.50		
9 Real Time Net Regulation Adjustment Amount		$ (962.51)		$ (3,078.13)		$ 2,115.62		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 119,361.97		$ 119,361.97		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 126,349.39		$ 126,349.39		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 80,725.44		$ 80,725.44		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 132,236.87		$ 102,018.83		$ 30,218.04		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**107,985**	**$ 2,284,916.06**	**107,985**	**$ 2,509,548.67**		**$ (224,632.61)**		**$ -**

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 - NEW FORMAT

November 2014	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		$ (267,961.62)		$ (267,961.62)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (51,613.80)		$ (51,613.80)		$ -		
3 Day-Ahead Supplemental Reserve		$ (30,387.12)		$ (30,387.12)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 1,431.01		$ 185,062.52		$ (183,631.51)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (31,119.99)		$ 2,602.74		$ (33,722.73)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (98.56)		$ 335.29		$ (433.85)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,166)	$ (42,481.82)	(1,166)	$ (42,481.82)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	145,520	$ 4,006,506.43	145,520	$ 4,006,506.43				
8b Real Time Non Excessive Energy Congestion		$ (191,628.28)		$ (181,462.85)		$ (10,165.43)		
8c Real Time Non Excessive Energy Loss		$ (48,682.21)		$ (46,099.73)		$ (2,582.48)		
9 Real Time Net Regulation Adjustment Amount		$ 3,556.21		$ 3,885.32		$ (329.11)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 140,158.14		$ 140,158.14		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 129,521.16		$ 129,521.16		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 34,227.49		$ 34,227.49		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 94,600.53		$ 74,463.05		$ 20,137.48		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**144,354**	**$ 3,746,027.57**	**144,354**	**$ 3,956,755.19**		**$ (210,727.62)**		**$ -**

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

Electric Operations - State of Minnesota

MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

December 2014	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		$ (58,184.63)		$ (58,184.63)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (31,933.06)		$ (31,933.06)		$ -		
3 Day-Ahead Supplemental Reserve		$ (25,164.02)		$ (25,164.02)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (32,060.87)		$ (27,854.94)		$ (4,205.93)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (7,383.69)		$ 2,942.89		$ (10,326.58)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 126.13		$ 986.67		$ (860.54)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(3,138)	$ (20,399.43)	(3,138)	$ (20,399.43)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	153,758	$ 4,963,544.80	153,758	$ 4,963,544.80				
8b Real Time Non Excessive Energy Congestion		$ 20,096.96		$ 18,209.65		$ 1,887.31		
8c Real Time Non Excessive Energy Loss		$ 22,631.69		$ 20,506.35		$ 2,125.34		
9 Real Time Net Regulation Adjustment Amount		$ 3,463.20		$ 891.34		$ 2,571.86		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 93,004.04		$ 93,004.04		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 67,214.02		$ 67,214.02		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 23,938.61		$ 23,938.61		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 50,494.55		$ 28,075.76		$ 22,418.79		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**150,620**	**$ 5,069,388.30**	**150,620**	**$ 5,055,778.05**		**$ 13,610.25**		**$ -**

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 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		$ (52,138.62)		$ (52,138.62)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (94,663.06)		$ (94,663.06)		$ -		
3 Day-Ahead Supplemental Reserve		$ (30,650.87)		$ (30,650.87)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 10,736.61		$ 11,987.04		$ (1,250.43)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 7,712.52		$ 52,542.56		$ (44,830.04)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (3,863.61)		$ 5,414.66		$ (9,278.27)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,317)	$ (22,436.29)	(1,317)	$ (22,436.29)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	122,598	$ 3,064,031.95	122,598	$ 3,064,031.95				
8b Real Time Non Excessive Energy Congestion		$ 159,062.03		$ 149,391.12		$ 9,670.91		
8c Real Time Non Excessive Energy Loss		$ 12,139.90		$ 11,401.80		$ 738.10		
9 Real Time Net Regulation Adjustment Amount		$ 1,170.48		$ 375.76		$ 794.72		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 80,868.66		$ 80,868.66		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 66,431.35		$ 66,431.35		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 19,211.25		$ 19,211.25		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 22,746.18		$ 21,709.19		$ 1,036.99		
14 Real Time Contignecy Reserve Deployment Failure		$ 985.06		$ 985.06		$ -		
TOTAL MISO ASM CHARGES	**121,281**	**$ 3,241,343.54**	**121,281**	**$ 3,284,461.56**		**$ (43,118.02)**		**$ -**

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 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		$ (114,510.61)		$ (114,510.61)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (97,635.22)		$ (97,635.22)		$ -		
3 Day-Ahead Supplemental Reserve		$ (45,228.22)		$ (45,228.22)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 367.07		$ 27,730.14		$ (27,363.07)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ 7,438.18		$ 47,315.84		$ (39,877.66)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 310.18		$ 6,339.79		$ (6,029.61)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,221)	$ (24,390.77)	(1,221)	$ (24,390.77)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	(39,532)	$ (549,938.30)	(39,532)	$ (549,938.30)				
8b Real Time Non Excessive Energy Congestion		$ (173,397.46)		$ (163,880.61)		$ (9,516.85)		
8c Real Time Non Excessive Energy Loss		$ (9,957.34)		$ (9,410.84)		$ (546.50)		
9 Real Time Net Regulation Adjustment Amount		$ 3,679.08		$ 3,081.48		$ 597.60		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 95,425.93		$ 95,425.93		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 72,504.33		$ 72,504.33		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 35,309.03		$ 35,309.03		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 40,938.82		$ 33,720.24		$ 7,218.58		
14 Real Time Contignecy Reserve Deployment Failure		$ 413.49		$ 413.49		$ -		
TOTAL MISO ASM CHARGES	**(40,753)**	**$ (758,671.81)**	**(40,753)**	**$ (683,154.30)**		**$ (75,517.51)**		**$ -**

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.

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MISO ASM MARKET SETTLEMENT BY CATEGORIES - NEW FORMAT

March 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		$ (130,903.49)		$ (130,903.49)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (98,272.30)		$ (98,272.30)		$ -		
3 Day-Ahead Supplemental Reserve		$ (43,519.15)		$ (43,519.15)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 11,127.94		$ 50,618.49		$ (39,490.55)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (31,184.12)		$ 43,072.27		$ (74,256.39)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 4,314.57		$ 13,177.86		$ (8,863.29)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(9,128)	$ (4,310.19)	(9,128)	$ (4,310.19)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	17,059	$ (582,516.36)	17,059	$ (582,516.36)				
8b Real Time Non Excessive Energy Congestion		$ 159,775.76		$ 150,564.03		$ 9,211.73		
8c Real Time Non Excessive Energy Loss		$ 65,368.86		$ 61,600.07		$ 3,768.79		
9 Real Time Net Regulation Adjustment Amount		$ 1,857.42		$ 1,868.37		$ (10.95)		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 110,887.50		$ 110,887.50		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 95,591.82		$ 95,591.82		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 31,873.53		$ 31,873.53		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 26,423.44		$ 22,916.07		$ 3,507.37		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**7,931**	**$ (383,484.77)**	**7,931**	**$ (277,351.48)**		**$ (106,133.29)**		**$ -**

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 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		$ (21,215.78)		$ (21,215.78)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (35,190.13)		$ (35,190.13)		$ -		
3 Day-Ahead Supplemental Reserve		$ (924.39)		$ (924.39)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ 7,133.13		$ 7,289.79		$ (156.66)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (11,102.96)		$ (7,347.13)		$ (3,755.83)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (195.21)		$ (1,272.53)		$ 1,077.32		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	4,391	$ (6,193.04)	4,391	$ (6,193.04)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	68,325	$ 2,313,000.23	68,325	$ 2,313,000.23				
8b Real Time Non Excessive Energy Congestion		$ (45,895.38)		$ (44,836.16)		$ (1,059.22)		
8c Real Time Non Excessive Energy Loss		$ (3,394.65)		$ (3,316.30)		$ (78.35)		
9 Real Time Net Regulation Adjustment Amount		$ 2,160.32		$ 2,159.64		$ 0.68		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 65,854.61		$ 65,854.61		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 80,949.94		$ 80,949.94		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 26,712.24		$ 26,712.24		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 28,394.15		$ 24,269.39		$ 4,124.76		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**72,716**	**$ 2,400,093.08**	**72,716**	**$ 2,399,940.38**		**$ 152.70**		**$ -**

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 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		$ (56,858.51)		$ (56,858.51)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (67,270.35)		$ (67,270.35)		$ -		
3 Day-Ahead Supplemental Reserve		$ (22,283.52)		$ (22,283.52)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (743.76)		$ 4,171.34		$ (4,915.10)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (18,636.83)		$ 14,812.73		$ (33,449.56)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 95.63		$ 373.44		$ (277.81)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(1,217)	$ 5,611.04	(1,217)	$ 5,611.04				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	136,274	$ 2,252,860.17	136,274	$ 2,252,860.17				
8b Real Time Non Excessive Energy Congestion		$ (346,471.44)		$ (333,803.83)		$ (12,667.61)		
8c Real Time Non Excessive Energy Loss		$ (88,322.22)		$ (85,093.00)		$ (3,229.22)		
9 Real Time Net Regulation Adjustment Amount		$ 2,489.74		$ 2,060.75		$ 428.99		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 105,657.96		$ 105,657.96		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 82,982.00		$ 82,982.00		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 28,283.38		$ 28,283.38		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 19,291.98		$ 17,767.39		$ 1,524.59		
14 Real Time Contignecy Reserve Deployment Failure		$ -		$ -		$ -		
TOTAL MISO ASM CHARGES	**135,057**	**$ 1,896,685.27**	**135,057**	**$ 1,949,270.99**		**$ (52,585.72)**		**$ -**

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

June 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		$ (19,151.44)		$ (19,151.44)		$ -		
2 Day-Ahead Spinning Reserve Amount		$ (81,505.40)		$ (81,505.40)		$ -		
3 Day-Ahead Supplemental Reserve		$ (34,668.56)		$ (34,668.56)		$ -		
4 Real-Time Regulation Amount (See Note 1)		$ (51,309.33)		$ (24,084.29)		$ (27,225.04)		
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (14,297.15)		$ 39,529.99		$ (53,827.14)		
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 7,144.73		$ 9,359.92		$ (2,215.19)		
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(2,548)	$ (15,797.47)	(2,548)	$ (15,797.47)				
7b Real Time Excessive Energy Congestion		$ -		$ -				
7c Real Time Excessive Energy Loss		$ -		$ -				
8a Real Time Non Excessive Energy Amount	59,624	$ 1,627,778.51	59,624	$ 1,627,778.51				
8b Real Time Non Excessive Energy Congestion		$ 179,638.54		$ 171,761.70		$ 7,876.84		
8c Real Time Non Excessive Energy Loss		$ 97,692.18		$ 93,408.55		$ 4,283.63		
9 Real Time Net Regulation Adjustment Amount		$ 6,446.31		$ 4,964.46		$ 1,481.85		
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount		$ 95,964.27		$ 95,964.27		$ -		
11 Real Time Spinnng Reserve Cost Distribution		$ 108,094.63		$ 108,094.63		$ -		
12 Real Time Supplemental Reserve Cost Distribution		$ 32,194.85		$ 32,194.85		$ -		
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment		$ 19,002.33		$ 15,620.31		$ 3,382.02		
14 Real Time Contignecy Reserve Deployment Failure		$ 4,995.65		$ 4,995.65		$ -		
TOTAL MISO ASM CHARGES	**57,076**	**$ 1,962,222.65**	**57,076**	**$ 2,028,465.68**		**$ (66,243.03)**		**$ -**

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 2014 - June 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	-	$ (1,643,867.70)	-	$ (1,643,867.70)	-	$ -	-	$ -
2 Day-Ahead Spinning Reserve Amount	-	$ (922,451.14)	-	$ (922,451.14)	-	$ -	-	$ -
3 Day-Ahead Supplemental Reserve	-	$ (439,765.29)	-	$ (439,765.29)	-	$ -	-	$ -
4 Real-Time Regulation Amount	-	$ (143,130.11)	-	$ 723,660.23	-	$ (866,790.34)	-	$ -
5 Real-Time Spinning Reserve Amount	-	$ (155,857.64)	-	$ 325,373.78	-	$ (481,231.42)	-	$ -
6 Real-Time Supplemental Reserve Amount.	-	$ 12,470.72	-	$ 60,508.46	-	$ (48,037.74)	-	$ -
Resource Energy Charges								
7a Real Time Excessive Energy Amount	(21,058)	$ (153,288.38)	(21,058)	$ (153,288.38)	-	$ -	-	$ -
7b Real Time Excessive Energy Congestion	-	$ -	-	$ -	-	$ -	-	$ -
7c Real Time Excessive Energy Loss	-	$ -	-	$ -	-	$ -	-	$ -
8a Real Time Non Excessive Energy Amount	933,903	$ 23,516,781.68	933,903	$ 23,516,781.68	-	$ -	-	$ -
8b Real Time Non Excessive Energy Congestion	-	$ (425,174.54)	-	$ (406,467.58)	-	$ (18,706.96)	-	$ -
8c Real Time Non Excessive Energy Loss	-	$ 196,177.79	-	$ 186,628.27	-	$ 9,549.52	-	$ -
9 Real Time Net Regulation Adjustment Amount	-	$ 90,529.07	-	$ 74,270.22	-	$ 16,258.85	-	$ -
Cost Distribution Charges								
10 Real Time Regulation Reserve Cost Distribution Amount	-	$ 1,198,875.74	-	$ 1,198,875.74	-	$ -	-	$ -
11 Real Time Spinnng Reserve Cost Distribution	-	$ 1,086,259.02	-	$ 1,086,259.02	-	$ -	-	$ -
12 Real Time Supplemental Reserve Cost Distribution	-	$ 441,080.36	-	$ 441,080.36	-	$ -	-	$ -
Penalty Charges								
13 Real Time Excessive/Dificient Energy Deployment	-	$ 716,904.88	-	$ 590,260.56	-	$ 126,644.32	-	$ -
14 Real Time Contignecy Reserve Deployment Failure	-	$ 8,290.85	-	$ 8,290.85	-	$ -	-	$ -
	-	$ -	-	$ -	-	$ -	-	$ -
TOTAL MISO ASM CHARGES	**912,844**	**$ 23,383,835.31**	**912,844**	**$ 24,646,149.08**	**-**	**$ (1,262,313.77)**	**-**	**$ -**

Total

MISO ASM

A. Overall Market Performance to Date

During the 2014-2015 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 2014 State of the Market Report, "The MISO energy and ancillary service markets generally performed competitively in 2014. Conduct of suppliers was broadly consistent with expectations for a workably competitive market."[1] The Market Monitor also noted, "Energy prices in the first quarter of 2014 averaged $53.02 per MWh, over 80 percent higher than in the first quarter of 2013. Energy prices in the last three quarters averaged $35.29 per MWh, just 6 percent higher than the same period in 2013." These market prices closely followed natural gas prices during 2014, for which the report observed, "The first quarter exhibited extremely cold weather and tight natural gas market conditions caused by the 'polar vortex.' The rest of the year was characterized by mild weather and historically-low natural gas prices, leading to less extreme system conditions and less volatile market outcomes, especially in the summer months. As a result, the market outcomes varied considerably throughout the year."

B. Estimated Market Benefits

1. *Benefits Calculation*

The comparison of NSP's participation in the MISO ASM market to an alternative scenario where NSP must self supply ancillary services will always result in benefits to NSP and its ratepayers. Ancillary services are always supplied by the most economical set of resources within MISO, including periods where NSP sells excess to the market. The alternative for NSP is to self-supply ancillary services from a restricted number of NSP resources and never sell excess to the market. The results of the ASM benefit analysis continue to show an overall benefit for the 2014-2015 AAA reporting period, and are provided in the table on the following page.

[1] https://www.misoenergy.org/Library/Repository/Report/IMM/2014%20State%20of%20the%20Market%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 2014	(59,791,923)	(60,255,865)	463,942	111,011	17,904	335,026
Aug 2014	(68,994,406)	(69,563,614)	569,208	138,348	18,186	412,674
Sep 2014	(52,233,809)	(53,251,550)	1,017,741	89,433	17,585	910,724
Total Q3 2014	(181,020,138)	(183,071,029)	2,050,891	338,792	53,675	1,658,424
Oct 2014	(62,066,686)	(62,460,574)	393,888	111,744	19,949	262,195
Nov 2014	(56,686,452)	(57,672,820)	986,368	100,061	25,621	860,686
Dec 2014	(66,428,750)	(67,580,714)	1,151,964	58,240	23,404	1,070,320
Total Q4 2014	(185,181,888)	(187,714,108)	2,532,220	270,046	68,973	2,193,201
Jan 2015	(61,468,479)	(61,933,805)	465,326	23,155	20,924	421,246
Feb 2015	(59,288,017)	(59,660,498)	372,481	45,301	26,366	300,814
Mar 2015	(53,237,835)	(54,672,501)	1,434,666	32,032	28,903	1,373,731
Total Q1 2015	(173,994,331)	(176,266,804)	2,272,473	100,489	76,192	2,095,791
Apr 2015	(35,840,967)	(36,596,641)	755,674	25,869	18,679	711,126
May 2015	(39,458,099)	(39,879,880)	421,781	21,036	18,305	382,440
Jun 2015	(55,567,170)	(56,074,619)	507,449	33,953	24,567	448,929
Total Q2 2015	(130,866,236)	(132,551,140)	1,684,904	80,858	61,551	1,542,495
Total	(671,062,593)	(679,603,081)	8,540,488	790,185	260,391	7,489,911

The Company estimates the ASM resulted in total NSP System savings of approximately $7.5 million for the 2014-15 reporting period. The Minnesota jurisdictional allocation of the savings is approximately 75 percent, or $5.6 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 EDEDC amounts assessed to each NSP System resource by month during the reporting period.

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

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

The ASM benefit calculation is a measure of the extent to which the Company has struck the *appropriate balance* between too much or too little flexibility being offered to

MISO. For the 2014-2015 AAA reporting period, the net benefit for the Company was approximately $7.5 million,[2] while the amount incurred in EDEDC was $696,947. The $7.5 million in gross benefits would not have been achievable if the Company had been offering ramp rates for its units that would have all but eliminated the chance of incurring an EDEDC.

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

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 2014 through June 2015, EDEDC amounts declined by $671,984 as compared to the 2014 AAA period, ending June 30, 2014.

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.

[2] The $7.5 million in ASM benefits calculated by the Company for 2014 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.

Part J, Section 6, Schedule 3 shows NSP incurred a total of $4,996 in CRDFC during the 2014-2015 AAA reporting period. NSP carries reserves on units with Automatic Generation Control (AGC) and units without AGC. For units without AGC, a phone call to the facility is required to deploy the reserves, adding to the time from receiving the signal and deployment. When deploying a large amount of reserves on many facilities, that action requires many more steps and time becomes critical. Additionally, MISO must meet Disturbance Control Standards within 15 minutes but does not always provide market participants the remaining time between the deployment signal and the end of the 15-minute timeframe to deploy reserves. Instead, MISO holds participants to a 10-minute response regardless if MISO has 15 minutes to meet the standard or less than 10 minutes.

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

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

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

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.

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

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
7/1/2014	(1,552,640)	(1,565,114)	12,474	0.80%	0	44	7	4,950	-1	495	11,928
7/2/2014	(1,631,913)	(1,643,876)	11,963	0.73%	0	105	-115	4,859	17	488	11,486
7/3/2014	(1,663,354)	(1,673,929)	10,575	0.63%	0	151	-106	4,932	295	523	10,008
7/4/2014	(1,478,447)	(1,491,311)	12,864	0.86%	0	10	-92	4,800	-37	476	12,470
7/5/2014	(1,479,375)	(1,492,964)	13,589	0.91%	0	865	-226	4,846	-27	482	12,469
7/6/2014	(1,594,067)	(1,608,178)	14,111	0.88%	0	1,929	897	5,016	163	518	10,767
7/7/2014	(2,769,552)	(2,801,420)	31,868	1.14%	0	8,485	6,642	6,670	499	717	16,024
7/8/2014	(1,791,375)	(1,800,864)	9,489	0.53%	0	4,092	-302	5,274	120	539	5,159
7/9/2014	(2,189,783)	(2,198,529)	8,746	0.40%	0	4,581	1,155	5,498	140	564	2,446
7/10/2014	(1,759,363)	(1,768,795)	9,432	0.53%	0	3,277	68	5,202	286	549	5,538
7/11/2014	(1,962,910)	(1,969,334)	6,424	0.33%	0	2,668	234	5,430	163	559	2,963
7/12/2014	(1,943,755)	(1,955,433)	11,678	0.60%	0	4,686	1,063	5,416	230	565	5,364
7/13/2014	(1,551,050)	(1,565,032)	13,982	0.89%	0	1,908	5	4,774	73	485	11,584
7/14/2014	(1,689,930)	(1,688,292)	-1,638	-0.10%	0	38	-60	4,843	75	492	-2,108
7/15/2014	(1,582,502)	(1,602,818)	20,316	1.27%	0	41	-112	4,832	5	484	19,904
7/16/2014	(1,701,380)	(1,711,515)	10,135	0.59%	0	1,899	-30	5,069	104	517	7,748
7/17/2014	(1,942,291)	(1,979,739)	37,448	1.89%	0	2,346	110	5,687	113	580	34,412
7/18/2014	(2,005,425)	(2,017,590)	12,165	0.60%	0	3,216	-255	5,899	285	618	8,585
7/19/2014	(1,613,721)	(1,627,058)	13,337	0.82%	0	3,831	-206	5,392	175	557	9,155
7/20/2014	(1,664,899)	(1,726,570)	61,671	3.57%	0	1,909	92	5,522	157	568	59,102
7/21/2014	(2,936,762)	(2,898,435)	-38,327	-1.32%	0	2,519	2,430	7,334	418	775	-44,052
7/22/2014	(2,611,915)	(2,594,348)	-17,567	-0.68%	0	2,275	656	7,091	320	741	-21,239
7/23/2014	(2,294,137)	(2,295,100)	963	0.04%	0	3,320	94	6,386	146	653	-3,104
7/24/2014	(2,061,160)	(2,059,880)	-1,280	-0.06%	0	1,409	6,346	6,018	707	673	-9,707
7/25/2014	(2,433,699)	(2,439,912)	6,213	0.25%	0	5,849	4,026	6,672	645	732	-4,394
7/26/2014	(2,477,591)	(2,477,008)	-583	-0.02%	0	9,534	1,979	6,612	504	712	-12,808
7/27/2014	(1,460,501)	(1,473,662)	13,161	0.89%	0	376	-264	4,850	52	490	12,559
7/28/2014	(2,000,967)	(2,032,929)	31,962	1.57%	0	5,579	849	5,867	92	596	24,938
7/29/2014	(2,013,435)	(2,091,929)	78,494	3.75%	0	3,415	345	5,853	113	597	74,137
7/30/2014	(1,875,914)	(1,939,860)	63,946	3.30%	0	3,174	788	5,597	-25	557	59,427
7/31/2014	(2,058,110)	(2,064,441)	6,331	0.31%	0	1,130	332	5,938	104	604	4,264
8/1/2014	(2,541,240)	(2,542,552)	1,312	0.05%	0	3,051	167	5,960	207	617	-2,522
8/2/2014	(2,187,001)	(2,182,056)	-4,945	-0.23%	0	2,427	877	5,527	222	575	-8,824
8/3/2014	(2,178,223)	(2,172,540)	-5,683	-0.26%	0	4,039	2,281	5,505	210	571	-12,574
8/4/2014	(2,577,839)	(2,589,605)	11,766	0.45%	0	2,540	949	6,115	300	642	7,635
8/5/2014	(2,470,964)	(2,470,634)	-330	-0.01%	0	3,341	1,574	5,986	253	624	-5,869
8/6/2014	(2,048,045)	(2,081,757)	33,712	1.62%	0	4,447	3,047	5,536	205	574	25,644
8/7/2014	(2,172,155)	(2,172,703)	548	0.03%	0	4,874	2,130	5,656	133	579	-7,035
8/8/2014	(2,101,524)	(2,106,045)	4,521	0.21%	0	2,817	1,371	5,562	60	562	-229
8/9/2014	(2,248,069)	(2,255,214)	7,145	0.32%	0	6,423	2,307	5,663	149	581	-2,166

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
8/10/2014	(2,066,417)	(2,064,144)	-2,273	-0.11%	0	4,902	2,295	5,414	126	554	-10,024
8/11/2014	(2,304,738)	(2,313,246)	8,508	0.37%	0	3,141	-1,519	5,870	510	638	6,248
8/12/2014	(1,800,673)	(1,851,723)	51,050	2.76%	0	913	-219	5,105	59	516	49,840
8/13/2014	(2,267,213)	(2,297,737)	30,524	1.33%	0	5,325	1,321	5,665	170	583	23,295
8/14/2014	(2,050,200)	(2,159,806)	109,606	5.07%	0	3,378	1,093	5,399	52	545	104,590
8/15/2014	(1,790,922)	(1,834,753)	43,831	2.39%	0	864	-5	5,128	11	514	42,458
8/16/2014	(1,987,536)	(1,982,783)	-4,753	-0.24%	0	2,661	1,940	5,290	108	540	-9,895
8/17/2014	(1,734,918)	(1,795,409)	60,491	3.37%	0	1,958	-99	4,926	88	501	58,131
8/18/2014	(2,411,753)	(2,399,856)	-11,897	-0.50%	0	1,980	150	5,903	152	606	-14,633
8/19/2014	(2,468,450)	(2,468,750)	300	0.01%	0	1,396	68	6,029	299	633	-1,796
8/20/2014	(2,672,592)	(2,670,015)	-2,577	-0.10%	0	2,689	434	6,279	282	656	-6,356
8/21/2014	(2,670,420)	(2,670,102)	-318	-0.01%	0	1,486	230	6,306	269	658	-2,691
8/22/2014	(2,871,923)	(2,863,780)	-8,143	-0.28%	0	2,644	1,253	6,561	449	701	-12,741
8/23/2014	(1,735,247)	(1,781,665)	46,418	2.61%	0	1,869	-122	5,081	79	516	44,155
8/24/2014	(2,202,764)	(2,182,074)	-20,690	-0.95%	0	2,284	1,875	5,629	119	575	-25,424
8/25/2014	(2,555,651)	(2,528,554)	-27,097	-1.07%	0	3,284	-399	5,953	497	645	-30,628
8/26/2014	(2,509,097)	(2,640,220)	131,123	4.97%	0	3,748	1,651	6,065	536	660	125,064
8/27/2014	(2,162,863)	(2,162,574)	-289	-0.01%	0	8,138	3,600	5,428	483	591	-12,618
8/28/2014	(2,060,021)	(2,107,473)	47,452	2.25%	0	7,234	3,036	5,490	109	560	36,622
8/29/2014	(2,498,374)	(2,499,337)	963	0.04%	0	5,644	554	6,000	160	616	-5,851
8/30/2014	(2,028,101)	(2,074,411)	46,310	2.23%	0	2,959	1,092	5,411	79	549	41,710
8/31/2014	(1,619,473)	(1,642,096)	22,623	1.38%	0	3,038	-77	4,858	186	504	19,158
9/1/2014	(1,938,423)	(1,978,660)	40,237	2.03%	0	9,151	3,860	5,910	471	638	26,587
9/2/2014	(2,097,843)	(2,135,579)	37,736	1.77%	0	1,396	2,241	6,023	685	671	33,428
9/3/2014	(2,082,787)	(2,089,967)	7,180	0.34%	0	295	-1,205	6,366	527	689	7,400
9/4/2014	(1,906,833)	(1,934,231)	27,398	1.42%	0	1,622	1,329	6,074	105	618	23,829
9/5/2014	(2,239,266)	(2,234,947)	-4,319	-0.19%	0	7,666	-1,714	6,492	442	693	-10,965
9/6/2014	(1,804,339)	(1,851,994)	47,655	2.57%	0	4,071	94	5,875	163	604	42,886
9/7/2014	(1,644,940)	(1,698,608)	53,668	3.16%	0	7,407	1,051	5,542	45	559	44,651
9/8/2014	(1,968,488)	(1,979,381)	10,893	0.55%	0	3,916	-911	6,175	434	661	7,227
9/9/2014	(1,910,904)	(1,937,688)	26,784	1.38%	0	702	-70	5,880	414	629	25,523
9/10/2014	(1,365,461)	(1,379,088)	13,627	0.99%	0	144	-138	4,884	75	496	13,125
9/11/2014	(1,534,705)	(1,599,499)	64,794	4.05%	0	605	-8	5,210	113	532	63,665
9/12/2014	(1,563,556)	(1,634,948)	71,392	4.37%	0	508	-5	5,266	-8	526	70,363
9/13/2014	(1,220,182)	(1,234,018)	13,836	1.12%	0	3,271	69	4,317	252	457	10,039
9/14/2014	(1,443,275)	(1,491,394)	48,119	3.23%	0	3,682	164	4,988	407	539	43,734
9/15/2014	(1,666,161)	(1,679,766)	13,605	0.81%	0	1,552	-183	5,165	41	521	11,716
9/16/2014	(1,753,381)	(1,771,281)	17,900	1.01%	0	1,754	-356	5,248	202	545	15,957
9/17/2014	(1,794,190)	(1,810,754)	16,564	0.91%	0	5,151	1,041	5,679	590	627	9,745
9/18/2014	(1,504,157)	(1,577,806)	73,649	4.67%	0	853	-814	5,231	471	570	73,039

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
9/19/2014	(1,403,539)	(1,453,954)	50,415	3.47%	0	78	0	5,212	641	585	49,751
9/20/2014	(1,344,549)	(1,382,721)	38,172	2.76%	0	1,037	317	4,877	277	515	36,303
9/21/2014	(1,364,228)	(1,382,640)	18,412	1.33%	0	976	-594	4,937	540	548	17,483
9/22/2014	(1,502,133)	(1,583,143)	81,010	5.12%	0	1,816	-190	5,150	427	558	78,826
9/23/2014	(1,619,177)	(1,690,432)	71,255	4.22%	0	2,050	-141	5,256	348	560	68,786
9/24/2014	(1,898,142)	(1,918,464)	20,322	1.06%	0	277	-128	5,697	344	604	19,569
9/25/2014	(2,087,126)	(2,132,012)	44,886	2.11%	0	2,395	152	6,077	242	632	41,707
9/26/2014	(2,149,366)	(2,180,758)	31,392	1.44%	0	6,018	922	6,149	398	655	23,797
9/27/2014	(1,925,710)	(1,931,247)	5,537	0.29%	0	8,531	883	5,748	208	596	-4,473
9/28/2014	(2,007,214)	(2,046,072)	38,858	1.90%	0	3,213	397	5,825	115	594	34,654
9/29/2014	(2,145,387)	(2,204,465)	59,078	2.68%	0	1,948	-435	6,036	664	670	56,895
9/30/2014	(1,348,347)	(1,326,033)	-22,314	-1.68%	0	2,219	-500	4,601	325	493	-24,525
10/1/2014	(2,067,502)	(2,093,726)	26,224	1.25%	0	1,299	-475	6,262	1,064	733	24,668
10/2/2014	(1,916,707)	(1,941,709)	25,002	1.29%	0	2,209	621	5,860	1,022	688	21,484
10/3/2014	(1,407,117)	(1,411,416)	4,299	0.30%	0	2,397	-154	5,329	756	608	1,447
10/4/2014	(1,401,104)	(1,455,770)	54,666	3.76%	0	4,368	-68	5,040	295	534	49,833
10/5/2014	(1,512,594)	(1,555,050)	42,456	2.73%	0	3,658	-496	5,137	400	554	38,740
10/6/2014	(1,820,321)	(1,829,137)	8,816	0.48%	0	5,099	-333	5,724	335	606	3,444
10/7/2014	(1,869,392)	(1,886,640)	17,248	0.91%	0	2,383	-710	5,809	540	635	14,940
10/8/2014	(2,015,806)	(2,019,809)	4,003	0.20%	0	832	-185	5,563	491	605	2,751
10/9/2014	(1,885,701)	(1,888,835)	3,134	0.17%	0	1,092	571	5,103	570	567	904
10/10/2014	(2,000,529)	(1,983,211)	-17,318	-0.87%	0	1,772	33	5,717	238	595	-19,719
10/11/2014	(1,808,275)	(1,799,420)	-8,855	-0.49%	0	3,602	166	5,463	279	574	-13,198
10/12/2014	(1,180,962)	(1,250,495)	69,533	5.56%	0	2,978	-193	4,278	304	458	66,290
10/13/2014	(2,246,999)	(2,238,193)	-8,806	-0.39%	0	3,099	269	6,209	590	680	-12,854
10/14/2014	(2,215,798)	(2,233,231)	17,433	0.78%	0	1,762	-797	6,259	544	680	15,787
10/15/2014	(2,489,515)	(2,482,077)	-7,438	-0.30%	0	3,419	71	6,609	810	742	-11,670
10/16/2014	(2,011,496)	(2,034,032)	22,536	1.11%	0	3,369	301	6,131	750	688	18,177
10/17/2014	(1,405,490)	(1,459,475)	53,985	3.70%	0	700	88	4,958	889	585	52,612
10/18/2014	(2,214,718)	(2,192,996)	-21,722	-0.99%	0	4,951	530	6,067	273	634	-27,837
10/19/2014	(1,766,641)	(1,777,308)	10,667	0.60%	0	4,674	-150	5,417	617	603	5,539
10/20/2014	(2,456,676)	(2,455,802)	-874	-0.04%	0	8,186	-592	6,379	302	668	-9,137
10/21/2014	(2,540,088)	(2,504,989)	-35,099	-1.40%	0	8,646	-2,567	6,803	342	714	-41,893
10/22/2014	(2,454,658)	(2,479,920)	25,262	1.02%	0	3,462	786	6,745	638	738	20,276
10/23/2014	(2,741,540)	(2,712,565)	-28,975	-1.07%	0	5,311	303	7,319	578	790	-35,378
10/24/2014	(2,169,317)	(2,171,287)	1,970	0.09%	0	11,048	1,610	6,345	453	680	-11,368
10/25/2014	(2,071,232)	(2,067,051)	-4,181	-0.20%	0	4,385	-834	6,112	445	656	-8,388
10/26/2014	(1,305,430)	(1,351,485)	46,055	3.41%	0	3,652	76	4,597	316	491	41,836
10/27/2014	(2,315,132)	(2,312,380)	-2,752	-0.12%	0	8,301	864	6,577	362	694	-12,611
10/28/2014	(2,002,880)	(2,048,484)	45,604	2.23%	0	2,755	-456	6,260	263	652	42,653

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
10/29/2014	(2,419,519)	(2,433,573)	14,054	0.58%	0	2,611	-544	6,863	422	728	11,258
10/30/2014	(2,175,858)	(2,173,778)	-2,080	-0.10%	0	1,382	-615	6,578	328	691	-3,538
10/31/2014	(2,177,689)	(2,216,730)	39,041	1.76%	0	1,855	-637	6,328	432	676	37,147
11/1/2014	(1,455,455)	(1,526,088)	70,633	4.63%	0	1,667	634	6,364	779	714	67,618
11/2/2014	(1,255,321)	(1,283,971)	28,650	2.23%	0	2,312	-22	5,778	555	633	25,727
11/3/2014	(1,461,268)	(1,514,680)	53,412	3.53%	0	2,165	616	6,295	474	677	49,954
11/4/2014	(1,771,461)	(1,816,756)	45,295	2.49%	0	4,311	1,174	7,044	782	783	39,027
11/5/2014	(1,636,612)	(1,635,312)	-1,300	-0.08%	0	4,753	768	6,813	613	743	-7,564
11/6/2014	(2,080,410)	(2,051,293)	-29,117	-1.42%	0	5,205	734	7,430	720	815	-35,871
11/7/2014	(1,487,769)	(1,508,234)	20,465	1.36%	0	2,883	-766	6,390	705	710	17,638
11/8/2014	(1,521,287)	(1,623,567)	102,280	6.30%	0	1,922	35	6,896	1,001	790	99,533
11/9/2014	(2,125,530)	(2,078,944)	-46,586	-2.24%	0	1,005	127	7,977	650	863	-48,581
11/10/2014	(2,227,506)	(2,255,535)	28,029	1.24%	0	681	-385	8,761	1,282	1,004	26,729
11/11/2014	(1,659,550)	(1,712,739)	53,189	3.11%	0	1,206	-315	7,394	597	799	51,499
11/12/2014	(1,774,603)	(1,823,978)	49,375	2.71%	0	2,739	2,868	7,551	557	811	42,957
11/13/2014	(2,707,284)	(2,711,137)	3,853	0.14%	0	4,731	-111	9,589	868	1,046	-1,813
11/14/2014	(3,042,110)	(3,015,183)	-26,927	-0.89%	0	1,749	602	10,468	404	1,087	-30,365
11/15/2014	(2,584,448)	(2,611,838)	27,390	1.05%	0	3,077	-378	9,411	439	985	23,706
11/16/2014	(1,390,617)	(1,415,214)	24,597	1.74%	0	3,410	0	6,744	410	715	20,471
11/17/2014	(1,335,604)	(1,405,540)	69,936	4.98%	0	2,651	-486	6,588	349	694	67,077
11/18/2014	(2,601,868)	(2,570,215)	-31,653	-1.23%	0	6,936	-984	9,104	711	982	-38,586
11/19/2014	(1,901,896)	(1,915,026)	13,130	0.69%	0	6,191	-306	7,951	896	885	6,360
11/20/2014	(2,822,400)	(2,817,868)	-4,532	-0.16%	0	2,363	407	9,426	420	985	-8,287
11/21/2014	(2,076,627)	(2,126,156)	49,529	2.33%	0	4,630	446	8,342	688	903	43,550
11/22/2014	(1,432,596)	(1,491,112)	58,516	3.92%	0	3,338	-366	6,730	690	742	54,801
11/23/2014	(1,371,668)	(1,416,275)	44,607	3.15%	0	5,758	226	6,854	1,377	823	37,800
11/24/2014	(1,665,113)	(1,744,614)	79,501	4.56%	0	4,540	-23	7,798	1,277	908	74,077
11/25/2014	(2,271,605)	(2,325,799)	54,194	2.33%	0	1,712	171	9,455	472	993	51,318
11/26/2014	(1,930,146)	(1,980,713)	50,567	2.55%	0	163	-22	8,992	105	910	49,517
11/27/2014	(1,843,351)	(1,889,883)	46,532	2.46%	0	1,216	72	8,586	622	921	44,324
11/28/2014	(1,789,771)	(1,838,288)	48,517	2.64%	0	2,887	-44	8,533	374	891	44,783
11/29/2014	(1,846,952)	(1,914,280)	67,328	3.52%	0	4,747	-122	8,689	970	966	61,738
11/30/2014	(1,615,624)	(1,652,582)	36,958	2.24%	0	4,506	54	7,981	489	847	31,551
12/1/2014	(2,375,154)	(2,416,399)	41,245	1.71%	0	2,633	30	7,591	230	782	37,799
12/2/2014	(1,947,068)	(2,003,643)	56,575	2.82%	0	4,353	234	7,106	341	745	51,244
12/3/2014	(2,358,043)	(2,373,202)	15,159	0.64%	0	3,767	78	7,584	427	801	10,512
12/4/2014	(2,019,233)	(2,056,723)	37,490	1.82%	0	297	68	7,366	254	762	36,363
12/5/2014	(2,721,828)	(2,784,935)	63,107	2.27%	0	8,616	1,658	8,577	181	876	51,957
12/6/2014	(2,387,083)	(2,474,555)	87,472	3.53%	0	934	-21	7,984	560	854	85,704
12/7/2014	(1,529,061)	(1,534,009)	4,948	0.32%	0	3,814	-44	6,147	401	655	522

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
12/8/2014	(1,763,422)	(1,816,855)	53,433	2.94%	0	695	81	6,844	65	691	51,966
12/9/2014	(3,100,342)	(2,961,685)	-138,657	-4.68%	0	660	343	8,580	299	888	-140,547
12/10/2014	(2,584,123)	(2,608,429)	24,306	0.93%	0	727	12	8,098	585	868	22,699
12/11/2014	(2,441,824)	(2,453,038)	11,214	0.46%	0	294	37	7,552	172	772	10,111
12/12/2014	(2,179,964)	(2,225,215)	45,251	2.03%	0	1,523	-11	7,073	576	765	42,975
12/13/2014	(1,572,993)	(1,623,961)	50,968	3.14%	0	3,285	-83	5,835	416	625	47,141
12/14/2014	(1,424,623)	(1,465,802)	41,179	2.81%	0	2,977	159	5,270	299	557	37,486
12/15/2014	(1,587,433)	(1,625,652)	38,219	2.35%	0	351	137	5,739	456	619	37,111
12/16/2014	(2,300,406)	(2,344,680)	44,274	1.89%	0	506	82	6,740	1,105	785	42,902
12/17/2014	(2,729,995)	(2,760,695)	30,700	1.11%	0	451	100	7,848	706	855	29,294
12/18/2014	(2,774,957)	(2,873,394)	98,437	3.43%	0	2,570	185	8,246	507	875	94,807
12/19/2014	(2,733,387)	(2,814,136)	80,749	2.87%	0	1,872	589	8,231	422	865	77,423
12/20/2014	(2,341,221)	(2,366,942)	25,721	1.09%	0	879	18	7,373	456	783	24,041
12/21/2014	(1,502,731)	(1,541,304)	38,573	2.50%	0	1,740	14	5,557	544	610	36,209
12/22/2014	(2,117,116)	(2,160,698)	43,582	2.02%	0	364	26	6,736	341	708	42,484
12/23/2014	(1,923,507)	(1,954,158)	30,651	1.57%	0	999	-2	6,536	499	703	28,951
12/24/2014	(1,717,205)	(1,721,651)	4,446	0.26%	0	1,089	17	5,912	473	639	2,702
12/25/2014	(1,292,819)	(1,292,990)	171	0.01%	0	922	181	4,774	396	517	-1,449
12/26/2014	(1,905,177)	(1,939,750)	34,573	1.78%	0	1,025	36	6,401	351	675	32,837
12/27/2014	(1,926,410)	(1,963,671)	37,261	1.90%	0	1,048	52	6,503	632	713	35,448
12/28/2014	(2,359,388)	(2,408,144)	48,756	2.02%	0	1,382	350	7,853	325	818	46,206
12/29/2014	(2,506,718)	(2,581,624)	74,906	2.90%	0	1,077	560	8,701	510	921	72,348
12/30/2014	(2,622,187)	(2,701,688)	79,501	2.94%	0	1,449	342	9,067	450	952	76,758
12/31/2014	(1,683,332)	(1,731,086)	47,754	2.76%	0	712	3	6,626	609	723	46,316
1/1/2015	(1,610,687)	(1,640,402)	29,715	1.81%	0	205	-7	5,648	406	605	28,912
1/2/2015	(1,975,648)	(1,948,928)	-26,720	-1.37%	0	366	-5	6,149	622	677	-27,758
1/3/2015	(1,614,059)	(1,619,000)	4,941	0.31%	0	183	-8	5,400	356	576	4,190
1/4/2015	(1,532,892)	(1,569,952)	37,060	2.36%	0	193	128	5,465	178	564	36,175
1/5/2015	(2,885,299)	(2,908,943)	23,644	0.81%	0	93	2	8,037	867	890	22,658
1/6/2015	(2,143,914)	(2,161,221)	17,307	0.80%	0	174	64	6,897	1,078	798	16,272
1/7/2015	(2,379,312)	(2,428,021)	48,709	2.01%	0	270	38	6,838	310	715	47,686
1/8/2015	(1,659,838)	(1,719,562)	59,724	3.47%	0	9,693	-80	5,706	380	609	49,502
1/9/2015	(2,086,900)	(2,084,153)	-2,747	-0.13%	0	31	0	6,520	528	705	-3,483
1/10/2015	(1,828,752)	(1,866,276)	37,524	2.01%	0	39	0	5,899	678	658	36,828
1/11/2015	(2,458,006)	(2,412,157)	-45,849	-1.90%	0	602	84	7,313	310	762	-47,297
1/12/2015	(2,648,080)	(2,698,466)	50,386	1.87%	0	523	32	7,718	222	794	49,037
1/13/2015	(2,703,708)	(2,701,274)	-2,434	-0.09%	0	814	-34	8,018	638	866	-4,079
1/14/2015	(2,517,183)	(2,545,212)	28,029	1.10%	0	77	127	7,338	353	769	27,056
1/15/2015	(1,948,822)	(2,017,118)	68,296	3.39%	0	415	11	6,260	264	652	67,217
1/16/2015	(2,096,456)	(2,086,452)	-10,004	-0.48%	0	539	3	6,669	782	745	-11,290

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

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
1/17/2015	(1,123,029)	(1,120,789)	-2,240	-0.20%	0	352	16	4,410	71	448	-3,056
1/18/2015	(1,882,885)	(1,892,882)	9,997	0.53%	0	913	-5	5,763	790	655	8,433
1/19/2015	(2,145,242)	(2,136,546)	-8,696	-0.41%	0	837	20	6,742	865	761	-10,313
1/20/2015	(2,036,482)	(2,072,159)	35,677	1.72%	0	347	11	6,358	197	655	34,664
1/21/2015	(2,388,298)	(2,413,889)	25,591	1.06%	0	271	-3	7,079	166	724	24,599
1/22/2015	(2,057,831)	(2,088,280)	30,449	1.46%	0	88	1	6,550	321	687	29,673
1/23/2015	(1,485,049)	(1,494,570)	9,521	0.64%	0	538	8	5,196	367	556	8,419
1/24/2015	(1,486,845)	(1,508,812)	21,967	1.46%	0	278	38	5,222	513	573	21,078
1/25/2015	(1,609,664)	(1,606,772)	-2,892	-0.18%	0	97	68	5,469	432	590	-3,647
1/26/2015	(1,549,261)	(1,562,097)	12,836	0.82%	0	1,752	-175	5,407	590	600	10,659
1/27/2015	(2,326,170)	(2,370,437)	44,267	1.87%	0	1,520	17	6,993	1,457	845	41,885
1/28/2015	(1,756,520)	(1,728,874)	-27,646	-1.60%	0	637	20	5,434	565	600	-28,904
1/29/2015	(1,361,235)	(1,360,728)	-507	-0.04%	0	203	0	4,615	545	516	-1,226
1/30/2015	(2,149,797)	(2,156,653)	6,856	0.32%	0	329	62	6,223	557	678	5,787
1/31/2015	(2,020,615)	(2,013,180)	-7,435	-0.37%	0	368	-26	6,152	347	650	-8,427
2/1/2015	(1,566,047)	(1,567,737)	1,690	0.11%	0	97	0	6,979	807	779	815
2/2/2015	(2,350,856)	(2,363,208)	12,352	0.52%	0	25	-9	9,262	477	974	11,362
2/3/2015	(2,291,980)	(2,263,960)	-28,020	-1.24%	0	200	354	9,155	639	979	-29,553
2/4/2015	(1,971,770)	(1,970,549)	-1,221	-0.06%	0	157	-13	8,141	625	877	-2,242
2/5/2015	(1,944,754)	(1,974,266)	29,512	1.49%	0	208	2	8,194	858	905	28,396
2/6/2015	(2,119,666)	(2,126,156)	6,490	0.31%	0	361	108	8,630	743	937	5,085
2/7/2015	(1,751,501)	(1,747,481)	-4,020	-0.23%	0	242	0	7,467	687	815	-5,078
2/8/2015	(1,822,873)	(1,835,468)	12,595	0.69%	0	325	-6	7,776	1,195	897	11,379
2/9/2015	(2,068,889)	(2,062,761)	-6,128	-0.30%	0	116	54	8,551	417	897	-7,195
2/10/2015	(1,983,979)	(1,961,344)	-22,635	-1.15%	0	2,771	23	8,586	792	938	-26,366
2/11/2015	(1,548,101)	(1,553,336)	5,235	0.34%	0	479	18	7,026	695	772	3,967
2/12/2015	(2,266,984)	(2,286,753)	19,769	0.86%	0	82	60	8,904	658	956	18,670
2/13/2015	(1,796,390)	(1,785,041)	-11,349	-0.64%	0	622	24	7,882	837	872	-12,867
2/14/2015	(1,819,624)	(1,840,418)	20,794	1.13%	0	195	17	8,405	176	858	19,724
2/15/2015	(2,133,213)	(2,125,767)	-7,446	-0.35%	0	515	0	9,307	428	974	-8,935
2/16/2015	(2,485,725)	(2,441,830)	-43,895	-1.80%	0	1,286	556	10,482	1,012	1,149	-46,887
2/17/2015	(2,057,460)	(2,091,677)	34,217	1.64%	0	2,580	3	9,281	845	1,013	30,621
2/18/2015	(2,236,129)	(2,295,364)	59,235	2.58%	0	2,732	761	9,597	401	1,000	54,742
2/19/2015	(3,145,417)	(3,279,306)	133,889	4.08%	0	2,792	685	11,017	643	1,166	129,246
2/20/2015	(2,231,538)	(2,351,878)	120,340	5.12%	0	5,460	163	9,757	457	1,021	113,696
2/21/2015	(1,337,358)	(1,358,003)	20,645	1.52%	0	5,810	-102	7,192	568	776	14,161
2/22/2015	(1,699,619)	(1,740,992)	41,373	2.38%	0	2,579	454	7,979	380	836	37,504
2/23/2015	(2,559,212)	(2,497,530)	-61,682	-2.47%	0	4,140	-127	9,681	780	1,046	-66,741
2/24/2015	(1,963,539)	(1,900,705)	-62,834	-3.31%	0	2,555	441	8,487	986	947	-66,777
2/25/2015	(2,842,396)	(2,791,077)	-51,319	-1.84%	0	2,872	23	9,824	1,125	1,095	-55,309

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2/26/2015	(2,719,045)	(2,771,805)	52,760	1.90%	0	1,535	199	9,418	484	990	50,036
2/27/2015	(3,181,800)	(3,240,552)	58,752	1.81%	0	140	82	10,405	662	1,107	57,423
2/28/2015	(1,392,152)	(1,435,534)	43,382	3.02%	0	580	77	7,391	500	789	41,936
3/1/2015	(1,607,426)	(1,620,098)	12,672	0.78%	0	662	75	8,820	363	918	11,016
3/2/2015	(2,113,295)	(2,049,899)	-63,396	-3.09%	0	449	23	10,360	356	1,072	-64,939
3/3/2015	(1,902,012)	(1,901,608)	-404	-0.02%	0	1,209	-108	9,353	697	1,005	-2,510
3/4/2015	(2,268,165)	(2,303,593)	35,428	1.54%	0	691	0	10,041	262	1,030	33,707
3/5/2015	(2,897,995)	(2,906,865)	8,870	0.31%	0	2,682	-212	11,476	2,111	1,359	5,041
3/6/2015	(2,154,021)	(2,195,352)	41,331	1.88%	0	5,003	1,715	8,716	972	969	33,644
3/7/2015	(1,414,639)	(1,422,642)	8,003	0.56%	0	278	-1	7,201	898	810	6,916
3/8/2015	(1,752,310)	(1,753,353)	1,043	0.06%	0	1,634	-69	8,601	498	910	-1,432
3/9/2015	(1,798,517)	(1,799,528)	1,011	0.06%	0	1,080	-85	9,103	1,227	1,033	-1,017
3/10/2015	(1,973,878)	(2,044,393)	70,515	3.45%	0	1,067	3	8,153	433	859	68,587
3/11/2015	(1,976,267)	(2,120,268)	144,001	6.79%	0	1,225	-8	8,361	541	890	141,894
3/12/2015	(1,822,587)	(1,884,151)	61,564	3.27%	0	2,104	0	8,025	367	839	58,621
3/13/2015	(1,565,467)	(1,635,240)	69,773	4.27%	0	967	105	7,537	706	824	67,877
3/14/2015	(1,459,165)	(1,481,163)	21,998	1.49%	0	590	8	7,562	550	811	20,589
3/15/2015	(953,515)	(1,005,079)	51,564	5.13%	0	108	0	6,111	352	646	50,809
3/16/2015	(1,125,879)	(1,156,980)	31,101	2.69%	0	203	-49	6,604	433	704	30,243
3/17/2015	(1,645,819)	(1,917,141)	271,322	14.15%	0	145	-7	7,535	2,103	964	270,220
3/18/2015	(1,881,343)	(2,000,599)	119,256	5.96%	0	572	-1	9,333	478	981	117,704
3/19/2015	(1,752,489)	(1,776,118)	23,629	1.33%	0	1,183	17	8,681	1,742	1,042	21,386
3/20/2015	(1,792,712)	(1,814,677)	21,965	1.21%	0	187	8	9,419	371	979	20,791
3/21/2015	(1,635,410)	(1,691,618)	56,208	3.32%	0	1,040	17	8,636	479	912	54,240
3/22/2015	(1,144,499)	(1,188,854)	44,355	3.73%	0	75	1	6,759	417	718	43,562
3/23/2015	(1,869,723)	(1,995,887)	126,164	6.32%	0	1,239	144	9,279	583	986	123,795
3/24/2015	(1,710,075)	(1,720,223)	10,148	0.59%	0	551	66	9,025	1,198	1,022	8,509
3/25/2015	(1,625,443)	(1,646,771)	21,328	1.30%	0	509	37	8,885	895	978	19,804
3/26/2015	(1,869,639)	(1,892,090)	22,451	1.19%	0	903	-6	9,857	352	1,021	20,534
3/27/2015	(1,961,244)	(1,958,469)	-2,775	-0.14%	0	852	21	10,251	1,165	1,142	-4,789
3/28/2015	(1,447,088)	(1,456,600)	9,512	0.65%	0	933	72	8,574	485	906	7,601
3/29/2015	(910,011)	(1,036,729)	126,718	12.22%	0	38	1	6,635	91	673	126,006
3/30/2015	(1,494,825)	(1,540,365)	45,540	2.96%	0	450	-59	8,504	602	911	44,239
3/31/2015	(1,712,377)	(1,756,148)	43,771	2.49%	0	1,549	147	9,538	366	990	41,084
4/1/2015	(901,052)	(940,354)	39,301	4.18%	0	246	15	5,671	-19	565	38,476
4/2/2015	(1,001,742)	(1,041,655)	39,913	3.83%	0	101	5	5,990	265	625	39,181
4/3/2015	(1,556,816)	(1,561,606)	4,790	0.31%	0	200	1	7,593	1,242	884	3,706
4/4/2015	(1,238,308)	(1,271,853)	33,545	2.64%	0	302	-4	6,404	985	739	32,508
4/5/2015	(1,082,509)	(1,118,397)	35,888	3.21%	0	99	3	5,687	521	621	35,166
4/6/2015	(1,573,442)	(1,588,598)	15,156	0.95%	0	1,756	-126	7,599	467	807	12,719

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
4/7/2015	(1,413,287)	(1,471,426)	58,139	3.95%	0	1,147	291	7,218	372	759	55,942
4/8/2015	(1,728,953)	(1,710,181)	-18,772	-1.10%	0	877	218	7,863	787	865	-20,732
4/9/2015	(1,229,159)	(1,265,136)	35,977	2.84%	0	2,635	236	6,397	614	701	32,405
4/10/2015	(1,442,580)	(1,476,284)	33,704	2.28%	0	932	54	6,652	799	745	31,972
4/11/2015	(954,960)	(977,146)	22,186	2.27%	0	28	-5	4,828	954	578	21,585
4/12/2015	(558,868)	(590,771)	31,903	5.40%	0	70	-21	3,339	250	359	31,495
4/13/2015	(1,188,218)	(1,212,913)	24,695	2.04%	0	992	82	5,379	396	577	23,044
4/14/2015	(1,302,616)	(1,292,165)	-10,451	-0.81%	0	721	-63	5,881	569	645	-11,754
4/15/2015	(1,009,506)	(1,058,256)	48,750	4.61%	0	260	90	4,931	482	541	47,859
4/16/2015	(1,590,014)	(1,625,126)	35,112	2.16%	0	1,333	349	6,553	253	681	32,750
4/17/2015	(1,522,413)	(1,523,586)	1,173	0.08%	0	2,181	582	6,720	317	704	-2,293
4/18/2015	(825,689)	(843,936)	18,247	2.16%	0	1,288	55	4,447	480	493	16,411
4/19/2015	(716,469)	(721,197)	4,728	0.66%	0	1,811	-28	3,966	374	434	2,511
4/20/2015	(810,553)	(850,209)	39,655	4.66%	0	148	63	4,399	422	482	38,963
4/21/2015	(816,847)	(877,484)	60,637	6.91%	0	299	43	4,421	307	473	59,822
4/22/2015	(1,214,247)	(1,246,769)	32,522	2.61%	0	567	-327	5,555	317	587	31,695
4/23/2015	(1,605,614)	(1,602,607)	-3,007	-0.19%	0	1,158	234	6,655	285	694	-5,093
4/24/2015	(990,047)	(1,009,933)	19,886	1.97%	0	544	-19	4,870	461	533	18,828
4/25/2015	(799,528)	(798,446)	-1,081	-0.14%	0	98	-1	4,169	525	469	-1,648
4/26/2015	(1,175,644)	(1,198,072)	22,428	1.87%	0	21	0	5,190	330	552	21,855
4/27/2015	(1,485,116)	(1,494,170)	9,054	0.61%	0	1,592	250	6,274	188	646	6,566
4/28/2015	(1,432,112)	(1,505,460)	73,348	4.87%	0	823	377	6,336	477	681	71,466
4/29/2015	(1,367,898)	(1,395,780)	27,882	2.00%	0	601	-44	6,108	174	628	26,696
4/30/2015	(1,306,760)	(1,327,126)	20,366	1.53%	0	868	-138	5,862	240	610	19,025
5/1/2015	(1,102,893)	(1,182,605)	79,712	6.74%	0	1,344	53	4,811	224	503	77,812
5/2/2015	(921,226)	(955,107)	33,881	3.55%	0	2,256	-201	4,183	755	494	31,332
5/3/2015	(634,140)	(665,534)	31,394	4.72%	0	61	3	3,326	329	366	30,964
5/4/2015	(1,329,648)	(1,340,013)	10,365	0.77%	0	26	214	5,000	409	541	9,584
5/5/2015	(1,311,305)	(1,340,412)	29,107	2.17%	0	71	0	5,098	558	566	28,470
5/6/2015	(1,300,261)	(1,334,189)	33,928	2.54%	0	524	63	5,175	1,341	652	32,689
5/7/2015	(1,352,440)	(1,391,575)	39,135	2.81%	0	213	25	5,351	1,052	640	38,256
5/8/2015	(1,777,873)	(1,716,485)	-61,388	-3.58%	0	411	311	6,278	1,176	745	-62,856
5/9/2015	(1,482,862)	(1,466,157)	-16,705	-1.14%	0	364	1	5,859	659	652	-17,722
5/10/2015	(982,018)	(982,012)	-5	0.00%	0	325	-3	4,301	319	462	-788
5/11/2015	(1,253,817)	(1,271,115)	17,298	1.36%	0	379	2	5,465	1,206	667	16,249
5/12/2015	(1,399,332)	(1,417,268)	17,936	1.27%	0	84	0	6,152	94	625	17,227
5/13/2015	(1,207,062)	(1,212,202)	5,140	0.42%	0	73	-17	5,502	252	575	4,508
5/14/2015	(1,262,499)	(1,250,363)	-12,136	-0.97%	0	48	0	5,612	171	578	-12,762
5/15/2015	(1,473,914)	(1,456,534)	-17,380	-1.19%	0	1,590	1,001	6,024	762	679	-20,650
5/16/2015	(1,230,575)	(1,230,365)	-210	-0.02%	0	1,014	-31	5,660	470	613	-1,806

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
5/17/2015	(1,068,591)	(1,076,468)	7,877	0.73%	0	961	-45	5,118	458	558	6,403
5/18/2015	(1,257,292)	(1,292,590)	35,298	2.73%	0	1,355	-119	5,845	309	615	33,447
5/19/2015	(1,376,228)	(1,400,586)	24,358	1.74%	0	651	240	5,719	159	588	22,880
5/20/2015	(1,771,568)	(1,832,501)	60,933	3.33%	0	698	354	6,924	212	714	59,167
5/21/2015	(1,362,994)	(1,387,026)	24,032	1.73%	0	329	-26	5,879	794	667	23,062
5/22/2015	(1,511,507)	(1,524,654)	13,147	0.86%	0	562	87	6,145	54	620	11,878
5/23/2015	(1,076,165)	(1,079,167)	3,002	0.28%	0	598	-7	4,781	291	507	1,904
5/24/2015	(970,024)	(976,118)	6,094	0.62%	0	331	-2	4,453	348	480	5,285
5/25/2015	(919,190)	(956,755)	37,565	3.93%	0	176	-30	4,651	106	476	36,943
5/26/2015	(1,679,792)	(1,690,078)	10,286	0.61%	0	1,196	170	6,603	127	673	8,247
5/27/2015	(1,731,983)	(1,719,290)	-12,693	-0.74%	0	1,186	5	7,030	795	782	-14,666
5/28/2015	(1,136,972)	(1,154,994)	18,022	1.56%	0	117	2	5,537	317	585	17,317
5/29/2015	(1,276,136)	(1,273,303)	-2,833	-0.22%	0	292	-66	5,333	332	567	-3,626
5/30/2015	(1,176,348)	(1,175,960)	-388	-0.03%	0	926	-83	5,201	502	570	-1,802
5/31/2015	(1,121,445)	(1,128,454)	7,009	0.62%	0	1,015	-46	4,939	515	545	5,494
6/1/2015	(1,201,106)	(1,233,553)	32,447	2.63%	0	46	6	5,244	1,403	665	31,730
6/2/2015	(1,205,326)	(1,221,685)	16,359	1.34%	0	592	-23	5,141	569	571	15,219
6/3/2015	(1,584,986)	(1,594,172)	9,186	0.58%	0	432	-48	6,026	733	676	8,126
6/4/2015	(1,845,600)	(1,843,232)	-2,368	-0.13%	4,996	174	-1	7,038	758	780	-8,316
6/5/2015	(1,868,219)	(1,888,222)	20,003	1.06%	0	628	172	7,729	915	864	18,339
6/6/2015	(1,223,868)	(1,222,807)	-1,061	-0.09%	0	5	3	6,009	160	617	-1,686
6/7/2015	(1,553,174)	(1,577,395)	24,221	1.54%	0	92	8	7,075	931	801	23,320
6/8/2015	(2,039,898)	(2,056,708)	16,810	0.82%	0	287	143	8,071	571	864	15,516
6/9/2015	(2,162,929)	(2,181,204)	18,275	0.84%	0	1,090	36	8,496	648	914	16,234
6/10/2015	(2,216,804)	(2,228,329)	11,525	0.52%	0	3,837	3,525	8,561	682	924	3,239
6/11/2015	(1,533,765)	(1,543,425)	9,660	0.63%	0	204	20	6,683	673	736	8,700
6/12/2015	(1,826,932)	(1,846,405)	19,473	1.05%	0	696	32	7,216	412	763	17,982
6/13/2015	(1,704,315)	(1,730,714)	26,399	1.53%	0	221	-582	6,979	735	771	25,989
6/14/2015	(1,984,362)	(1,988,328)	3,966	0.20%	0	339	598	7,858	901	876	2,153
6/15/2015	(2,136,837)	(2,162,280)	25,443	1.18%	0	2,006	-663	8,987	1,109	1,010	23,090
6/16/2015	(1,631,783)	(1,631,670)	-113	-0.01%	0	471	1,683	7,191	290	748	-3,015
6/17/2015	(1,540,184)	(1,558,702)	18,518	1.19%	0	14	0	6,891	408	730	17,774
6/18/2015	(1,729,181)	(1,730,145)	964	0.06%	0	86	26	7,193	580	777	76
6/19/2015	(1,860,498)	(1,895,986)	35,488	1.87%	0	88	-4	7,869	440	831	34,574
6/20/2015	(1,440,194)	(1,455,963)	15,769	1.08%	0	43	0	6,776	177	695	15,031
6/21/2015	(1,861,650)	(1,863,907)	2,257	0.12%	0	177	-7	7,648	134	778	1,309
6/22/2015	(1,909,653)	(1,932,386)	22,733	1.18%	0	430	-46	8,297	313	861	21,488
6/23/2015	(2,369,843)	(2,391,390)	21,547	0.90%	0	1,509	395	9,317	207	952	18,690
6/24/2015	(2,305,947)	(2,314,361)	8,414	0.36%	0	468	254	9,308	315	962	6,730
6/25/2015	(2,308,072)	(2,321,948)	13,876	0.60%	0	987	418	9,409	85	949	11,521

Date	ASM Market Run Cost	Self Schedule Run Cost	ASM Market Savings	Savings %	Reserve Depl Failure Charge	Excessive/ Deficient Energy Charge	Net Regulation Adjust Charge	DA Admin	RT Admin	ASM Admin (10.00%)	Net Savings
6/26/2015	(2,126,284)	(2,143,502)	17,218	0.80%	0	593	65	8,860	85	895	15,666
6/27/2015	(2,043,734)	(2,060,965)	17,231	0.84%	0	2,678	452	8,573	126	870	13,230
6/28/2015	(1,628,686)	(1,666,322)	37,636	2.26%	0	613	108	7,427	91	752	36,164
6/29/2015	(2,272,918)	(2,292,345)	19,427	0.85%	0	2,172	717	9,127	203	933	15,604
6/30/2015	(2,450,422)	(2,496,568)	46,146	1.85%	0	531	162	9,635	384	1,002	44,451
Total	**(671,062,593)**	**(679,603,081)**	**8,540,488**	**1.40%**	**4,996**	**696,947**	**88,242**	**2,431,283**	**172,629**	**260,391**	**7,489,911**

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

Excessive Deficient Energy Deployment Charge by NSP Resource

LOCATION	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
Anson_G2	$ 4	$ 15	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 13	$ 4	$ -
Anson_G3	$ 175	$ 121	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	$ -	$ 0
Anson_G4	$ -	$ 4	$ 307	$ 244	$ -	$ -	$ -	$ -	$ -	$ 161	$ -	$ 26
Blk_Dog_G3	$ -	$ -	$ -	$ 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blk_Dog_G4	$ 14	$ 7	$ 3	$ 11	$ -	$ -	$ 5	$ -	$ 13	$ -	$ -	$ -
Blk_Dog_G52	$ 3,096	$ 3,649	$ 1,150	$ 24,439	$ 1,843	$ 8,707	$ 3,125	$ 7,698	$ 4,609	$ 4,785	$ 1,362	$ 6,977
Blue_Lk_G1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Blue_Lk_G7	$ 540	$ 122	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ 16
Blue_Lk_G8	$ 196	$ 551	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 63
Canon_Falls1	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	$ 8	$ -	$ -	$ -	$ -
Canon_Falls2	$ 173	$ 11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,066
CC Highbridge1	$ 670	$ 3,382	$ 407	$ 2,614	$ 1,275	$ 2,513	$ 118	$ 480	$ 3,918	$ 1,413	$ 55	$ 599
CC Highbridge2	$ 2,615	$ 7,351	$ 3,077	$ 9,403	$ 2,703	$ 835	$ 52	$ 120	$ 1,125	$ 651	$ 202	$ 168
CC Mankato	$ 941	$ 241	$ 25	$ 465	$ 135	$ 44	$ 16	$ 97	$ 1,512	$ 3,979	$ 2,795	$ 4,162
CCRiverside1	$ 12,944	$ 30,831	$ 16,910	$ 16,467	$ 9,244	$ 5,348	$ 154	$ 5,060	$ 2,656	$ 916	$ 705	$ 1,153
CCRiverside2	$ 11,732	$ 20,459	$ 12,101	$ 16,265	$ 9,415	$ 6,129	$ 554	$ 7,176	$ 1,456	$ 3,813	$ 1,897	$ 1,425
French_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
French_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_1	$ 10	$ -	$ -	$ 1	$ -	$ -	$ -	$ 4	$ -	$ -	$ -	$ -
InvrHils_2	$ -	$ -	$ 2	$ -	$ -	$ -	$ -	$ 2	$ -	$ -	$ -	$ -
InvrHils_3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -
InvrHils_5	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
InvrHils_6	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19	$ -	$ -	$ -
King_G1	$ 624	$ 502	$ 1,393	$ 697	$ 1,235	$ 207	$ 87	$ 274	$ 1,163	$ -	$ 1,121	$ 239
LSPower_1	$ 14	$ 589	$ 8	$ 55	$ 2,384	$ -	$ -	$ 1,237	$ 338	$ 2,683	$ 1,004	$ 1,643
Monticello_1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	$ 20
NSP.NOBLES_TR	$ 89	$ 38	$ 55	$ 85	$ 107	$ 17	$ 52	$ 25	$ 67	$ 71	$ 51	$ 48
NSP.NOBLES_TR2	$ 88	$ 36	$ 52	$ 109	$ 112	$ 26	$ 60	$ 19	$ 60	$ 69	$ 52	$ 51
PR_ISLD_1	$ -	$ -	$ -	$ 18	$ -	$ 26	$ 13	$ 20	$ -	$ -	$ 13	$ 15
PR_ISLD_2	$ -	$ -	$ 82	$ -	$ -	$ -	$ -	$ -	$ 25	$ 26	$ -	$ -
SHERC3	$ 5,227	$ 2,804	$ 5,451	$ 468	$ 15,759	$ 17,800	$ 10,485	$ 6,929	$ 6,746	$ 3,220	$ 4,871	$ 997
SHERCO_G1	$ 23,975	$ 19,047	$ 25,058	$ 24,807	$ 26,090	$ 7,126	$ 4,606	$ 628	$ -	$ -	$ 2,946	$ 1,372
SHERCO_G2	$ 21,151	$ 15,661	$ 17,841	$ 18,986	$ 23,151	$ 4,201	$ 3,371	$ 11,619	$ 6,371	$ 1,797	$ 1,867	$ 1,268
Wheaton_1	$ 260	$ 10	$ 13	$ -	$ 1,788	$ -	$ -	$ -	$ -	$ 2	$ -	$ 43
Wheaton_2	$ 25	$ 5	$ 257	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	$ 148	$ 69
Wheaton_3	$ -	$ 9	$ -	$ -	$ -	$ -	$ -	$ 1	$ 6	$ -	$ 1	$ 18
Wheaton_4	$ 4	$ 6	$ 24	$ 14	$ 134	$ -	$ -	$ -	$ 16	$ -	$ 2	$ 13
Wheaton_5	$ -	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wheaton_6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wi Grand Meadow	$ 63	$ 42	$ 88	$ 95	$ 79	$ 31	$ 50	$ 59	$ 66	$ 84	$ 78	$ 56
Totals	**$ 84,662**	**$ 105,494**	**$ 84,303**	**$ 115,260**	**$ 95,455**	**$ 53,011**	**$ 22,747**	**$ 41,455**	**$ 30,177**	**$ 23,697**	**$ 19,179**	**$ 21,507**

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

Contigency Reserve Deployment Failure Charges by NSP Resource

LOCATION	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
SHERCO_G2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,996
Totals	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,996**

Northern States Power Company
Electric Operations - State of Minnesota

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

July 2014	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(42,046)	($718,219.88)									14,236	$ 471,186.57		
5a Day Ahead Non Asset Energy			55,839	$ 1,775,869.63					(1,440)	$ 328,802.62	(1,846)	$ (438,068.96)		
13a Real Time Asset Energy	(29,227)	($1,225,059.68)			2,140	$59,657.59	481	$ 14,350.02			(2,090)	$ (78,791.14)		
22a Real Time Non Asset Energy			3,720	$ 108,410.20					2	$ 79.10				
Accrual (no detail)					117	$2,932.49	3	$ 83.37	(116)	$ (2,802.89)	1,065	$ (4,893.67)		
Prior Month's reversals					(283)	($8,486.52)	(102)	$ (2,753.77)	188	$ 5,930.06	(1,396)	$ 5,255.44		
Prior Month's reversals (counterparty not available)					(2,506)	$ (83,563.13)								
SUBTOTAL	(71,273)	($1,943,279.56)	59,559	$1,884,279.83	(532)	($29,459.57)	382	$11,679.62	(1,366)	$332,008.89	9,970	($45,311.76)	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 41,173.52												
5c Day Ahead Non Asset Loss		$ 47,076.74												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ 700.74												
22c Real Time Non Asset Loss		$ (125.46)												
14 Real Time Distribution Losses						$ (1,201.06)		$ (175.13)				$ (5,981.34)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 88,825.54				$ (1,201.06)		$ (175.13)		$ -		$ (5,981.34)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 2,446.62		$ 3,448.88						$ 287.48		$ 2,480.81		
19 Real Time Market Administration (Schedule 17)		$ 1,961.39		$ 230.64		$ 141.09		$ 30.76		$ 0.14		$ 151.95		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 17,883.12										
33 Day-Ahead Schedule 24 Allocation Amount		$ 309.86		$ 452.72						$ 34.66		$ 320.41		
34 Real -Time Schedule 24 Allocation Amount		$ (27,656.78)		$ 29.76		$ 18.41		$ 2.15		$ 0.02		$ 19.43		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (2,072.42)								
SUBTOTAL		$ (22,938.91)		$ 22,045.12		$ (1,912.92)		$ 32.91		$ 322.30		$ 2,972.60		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ 30,250.62												
5b Day Ahead Non Asset Congestion		$ 25,500.57												
13b Real Time Congestion		$ 3.42												
22b Real Time Non Asset Congestion		$ (7,448.28)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation														
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount														
37 Financial Transmission Guarantee Uplift Amount														
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$ 48,306.33												
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 1,899.19						$ 0.39				$ 558.49		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (60,961.22)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ (2,289.82)				$ 341.77		$ 87.16		$ 2.82		$ 497.99		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,576,097.42)												
43 Real Time Price Volatility Make Whole Payment		$ (6,962.59)												
SUBTOTAL		$ (1,644,411.86)				$ 341.77		$ 87.55		$ 2.82		$ 1,056.48		$ -
Other Charges														
20 Real Time Miscellaneous		$ (33,840.59)		$ -		$ (43.32)		$ (7.29)		$ (148.42)		$ (236.87)		
21 Real Time Net Inadvertent Distribution				$ 417.77		$ 55.02		$ 11.90		$ 331.90		$ 739.82		
23 Real Time Revenue Neutrality Uplift Amount		$ 11,751.51				$ 314.74		$ 63.35				$ 1,735.96		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ (22,089.08)		$ 417.77		$ 326.44		$ 67.96		$ 183.48		$ 2,238.91		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (2,011.37)				$ -		$ (5,641.49)		
40 Auction Revenue Rights - Monthly ARR Revenue														
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (219.19)				$ -		$ (2,001.09)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ 0.00				$ 573.42
SUBTOTAL						$ (2,230.56)				$ 0.00		$ (7,642.58)		$ 573.42
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(71,273)	$ (3,495,587.53)	59,559	$ 1,906,742.72	(532)	$ (34,135.90)	382	$ 11,692.91	(1,366)	$ 332,517.49	9,970	$ (52,667.69)	-	$ 573.42

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 - INTERSYSTEM **NOTE 1**

August 2014	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(62,408)	($2,310,446.12)									12,750	$ 413,925.47		
5a Day Ahead Non Asset Energy			55,508	$ 1,830,821.55					(1,342)	$ 303,942.99	(1,265)	$ (389,260.30)		
13a Real Time Asset Energy	(37,009)	($995,163.05)			1,853	$53,564.73	463	$ 14,888.12			(1,410)	$ (51,977.63)		
22a Real Time Non Asset Energy			3,720	$ 112,341.20										
Accrual (no detail)					213	$6,513.38	66	$ 1,914.03	(152)	$ (4,730.18)	1,414	$ 2,157.41		
Prior Month's reversals					(117)	($2,986.61)	(3)	$ (84.24)	116	$ 2,890.15	(1,065)	$ 4,718.15		
Prior Month's reversals (counterparty not available)					(1,657)	$ (50,226.83)								
SUBTOTAL	(99,417)	($3,305,609.17)	59,228	$1,943,162.75	292	$6,864.67	526	$16,717.91	(1,378)	$302,102.96	10,425	($20,436.90)	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 78,638.91												
5c Day Ahead Non Asset Loss		$ 38,147.99												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ 2,011.02												
22c Real Time Non Asset Loss		$ (50.13)												
14 Real Time Distribution Losses						$ (1,506.31)		$ (253.28)				$ (7,911.64)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 118,747.79				$ (1,506.31)		$ (253.28)		$ -		$ (7,911.64)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 3,281.51		$ 3,022.32						$ 219.31		$ 1,976.92		
19 Real Time Market Administration (Schedule 17)		$ 2,084.34		$ 200.88		$ 105.11		$ 28.36				$ 101.48		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 13,434.16										
33 Day-Ahead Schedule 24 Allocation Amount		$ 525.72		$ 475.68						$ 26.89		$ 295.31		
34 Real -Time Schedule 24 Allocation Amount		$ (36,483.13)		$ 29.76		$ 16.07		$ 2.13				$ 14.18		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (342.00)								
SUBTOTAL		$ (30,591.56)		$ 17,162.80		$ (220.82)		$ 30.49		$ 246.20		$ 2,387.89		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ 16,542.89												
5b Day Ahead Non Asset Congestion		$ 27,461.92												
13b Real Time Congestion		$ 5,614.30												
22b Real Time Non Asset Congestion		$ (3,070.98)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation														
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount														
37 Financial Transmission Guarantee Uplift Amount														
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$ 46,548.12												
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 4,799.25						$ 0.08				$ 499.35		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (6,378.39)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 4,839.17				$ 930.24		$ 172.41		$ (0.08)		$ 826.38		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (9,337.52)												
43 Real Time Price Volatility Make Whole Payment		$ (13,038.13)												
SUBTOTAL		$ (19,115.61)				$ 930.24		$ 172.49		$ (0.08)		$ 1,325.73		$ -
Other Charges														
20 Real Time Miscellaneous		$ (36,163.70)		$ 7,407.65		$ (8.61)		$ (3.24)		$ (133.94)		$ (85.95)		
21 Real Time Net Inadvertent Distribution				$ (2,969.48)		$ (77.50)		$ (17.44)		$ (481.38)		$ (1,071.13)		
23 Real Time Revenue Neutrality Uplift Amount		$ 20,391.36				$ 495.19		$ 105.27				$ 2,846.54		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ (15,772.34)		$ 4,438.17		$ 409.08		$ 84.59		$ (615.32)		$ 1,689.46		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (2,011.37)				$ -		$ (5,641.49)		
40 Auction Revenue Rights - Monthly ARR Revenue														
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (220.93)				$ -		$ (2,001.09)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 573.42
SUBTOTAL						$ (2,232.30)				$ -		$ (7,642.58)		$ 573.42
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(99,417)	$ (3,205,792.77)	59,228	$ 1,964,763.72	292	$ 4,244.56	526	$ 16,752.20	(1,378)	$ 301,733.76	10,425	$ (30,588.04)	-	$ 573.42

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

Northern States Power Company
Electric Operations - State of Minnesota
MISO DAY 2 MARKET SETTLEMENT BY CATEGORIES - INTERSYSTEM **NOTE 1**

September 2014	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(114,596)	($2,635,689.84)									11,980	$394,185.12		
5a Day Ahead Non Asset Energy			85,595	$2,645,141.85					(1,325)	$284,693.67	(486)	$(337,642.91)		
13a Real Time Asset Energy	(39,590)	($915,685.05)			1,731	$46,136.68	426	$12,580.98			(1,216)	$(38,803.85)		
22a Real Time Non Asset Energy			3,600	$96,155.45										
Accrual (no detail)					290	$7,299.80	(8)	$(201.21)	(175)	$(4,116.28)	1,557	$2,784.13		
Prior Month's reversals					(213)	($6,464.62)	(66)	$(1,904.20)	152	$4,831.19	(1,414)	$(2,448.54)		
Prior Month's reversals (counterparty not available)					(2,549)	$(85,346.33)								
SUBTOTAL	(154,186)	($3,551,374.89)	89,195	$2,741,297.30	(741)	($38,374.47)	352	$10,475.57	(1,348)	$285,408.58	10,420	$18,073.95	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$118,691.52												
5c Day Ahead Non Asset Loss		$60,744.72												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$2,077.04												
22c Real Time Non Asset Loss		$26.00												
14 Real Time Distribution Losses						$(917.68)		$(178.93)				$(5,083.58)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$181,539.28				$(917.68)		$(178.93)		$ -		$(5,083.58)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$7,142.39		$5,331.84						$216.95		$1,950.61		
19 Real Time Market Administration (Schedule 17)		$2,458.68		$223.20		$100.48		$25.24				$79.55		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$14,879.04										
33 Day-Ahead Schedule 24 Allocation Amount		$1,156.98		$864.16						$34.17		$313.80		
34 Real -Time Schedule 24 Allocation Amount		$(38,499.06)		$36.00		$16.47		$1.90				$12.63		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$724.61								
SUBTOTAL		$(27,741.01)		$21,334.24		$841.56		$27.14		$251.12		$2,356.59		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$150,571.23												
5b Day Ahead Non Asset Congestion		$63,876.28												
13b Real Time Congestion		$10,325.75												
22b Real Time Non Asset Congestion		$(1,904.60)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation														
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount														
37 Financial Transmission Guarantee Uplift Amount														
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$222,868.66												
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$8,101.43										$630.55		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$(25,127.91)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$6,789.43				$745.42		$186.57		$0.04		$597.12		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$(43,079.66)												
43 Real Time Price Volatility Make Whole Payment		$1,920.18												
SUBTOTAL		$(51,396.54)				$745.42		$186.57		$0.04		$1,227.67		$ -
Other Charges														
20 Real Time Miscellaneous		$(29,332.67)				$(14.69)		$(3.53)		$(141.18)		$(91.91)		
21 Real Time Net Inadvertent Distribution				$(189.85)		$(15.17)		$(3.50)		$(100.69)		$(217.61)		
23 Real Time Revenue Neutrality Uplift Amount		$24,522.45				$229.25		$48.63				$1,481.42		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$(4,810.22)		$(189.85)		$199.39		$41.60		$(241.87)		$1,171.90		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$(1,993.15)				$ -		$(6,146.03)		
40 Auction Revenue Rights - Monthly ARR Revenue														
41 Auction Revenue Rights - ARR Stage 2 Distribution						$(139.76)				$ -		$(1,060.08)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$480.56
SUBTOTAL						$(2,132.91)				$ -		$(7,206.11)		$480.56
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(154,186)	$(3,230,914.71)	89,195	$2,762,441.69	(741)	$(39,638.69)	352	$10,551.95	(1,348)	$285,417.87	10,420	$10,540.42	-	$480.56

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 - INTERSYSTEM **NOTE 1**

October 2014	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(238,067)	($7,809,079.49)									10,382	$ 382,101.40		
5a Day Ahead Non Asset Energy			55,130	$ 1,937,424.56					(1,125)	$ 288,728.92	(517)	$ (334,046.01)		
13a Real Time Asset Energy	(41,049)	($1,138,611.97)			1,661	$40,571.64	406	$ 13,795.23			(759)	$ (29,223.43)		
22a Real Time Non Asset Energy			3,720	$ 142,464.10					6	$ 112.73				
Accrual (no detail)					198	$5,034.33	(13)	$ (384.26)	(206)	$ (4,859.53)	1,835	$ 3,972.87		
Prior Month's reversals					(290)	($7,241.09)	8	$ 214.99	175	$ 4,251.51	(1,557)	$ (2,592.06)		
Prior Month's reversals (counterparty not available)					(1,092)	$ (32,742.76)								
SUBTOTAL	(279,116)	($8,947,691.46)	58,850	$2,079,888.66	477	$5,622.12	401	$13,625.96	(1,150)	$288,233.63	9,384	$20,212.77	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 206,961.63												
5c Day Ahead Non Asset Loss		$ 113,686.89												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ (1,347.67)												
22c Real Time Non Asset Loss		$ (1,289.68)												
14 Real Time Distribution Losses						$ (878.29)		$ (160.79)				$ (4,905.72)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 318,011.17				$ (878.29)		$ (160.79)		$ -		$ (4,905.72)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 16,154.42		$ 3,743.20						$ 138.99		$ 1,961.78		
19 Real Time Market Administration (Schedule 17)		$ 2,780.16		$ 221.53		$ 111.55		$ 26.10		$ 0.42		$ 64.81		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 12,854.48										
33 Day-Ahead Schedule 24 Allocation Amount		$ 2,239.02		$ 516.00						$ 24.30		$ 281.10		
34 Real -Time Schedule 24 Allocation Amount		$ (32,636.22)		$ 37.20		$ 14.66		$ 2.71		$ 0.06		$ 9.44		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (908.19)								
SUBTOTAL		$ (11,462.62)		$ 17,372.41		$ (781.98)		$ 28.81		$ 163.77		$ 2,317.13		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ 325,269.32												
5b Day Ahead Non Asset Congestion		$ 399,996.13												
13b Real Time Congestion		$ (44.29)												
22b Real Time Non Asset Congestion		$ (725.62)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation														
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount														
37 Financial Transmission Guarantee Uplift Amount														
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$ 724,495.54												
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 12,043.78										$ 553.71		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (121,267.09)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 14,099.00				$ 783.61		$ 265.31		$ 4.54		$ 416.50		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (19,273.51)												
43 Real Time Price Volatility Make Whole Payment		$ (9,544.06)												
SUBTOTAL		$ (123,941.88)				$ 783.61		$ 265.31		$ 4.54		$ 970.21		$ -
Other Charges														
20 Real Time Miscellaneous		$ (29,213.68)				$ (15.70)		$ (3.98)		$ (124.15)		$ (91.84)		
21 Real Time Net Inadvertent Distribution				$ 634.09		$ 11.93		$ 3.05		$ 84.20		$ 165.30		
23 Real Time Revenue Neutrality Uplift Amount		$ 68,474.82				$ 444.45		$ 119.40				$ 2,599.28		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ 39,261.14		$ 634.09		$ 440.68		$ 118.47		$ (39.95)		$ 2,672.74		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (1,993.15)				$ -		$ (6,146.03)		
40 Auction Revenue Rights - Monthly ARR Revenue														
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (105.84)				$ -		$ (1,060.08)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 480.55
SUBTOTAL						$ (2,098.99)				$ -		$ (7,206.11)		$ 480.55
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(279,116)	$ (8,001,328.12)	58,850	$ 2,097,895.16	477	$ 3,087.15	401	$ 13,877.76	(1,150)	$ 288,361.99	9,384	$ 14,061.02	-	$ 480.55

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

Docket No. E999/AA-15-611
Part J, Section 7
Schedule 1

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

November 2014	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(165,128)	($5,184,337.83)									12,183	$ 453,943.85		
5a Day Ahead Non Asset Energy			73,573	$ 2,632,236.31					(1,707)	$ 331,263.86	(1,213)	$ (416,279.65)		
13a Real Time Asset Energy	(41,047)	($850,149.83)			2,096	$52,911.67	375	$ 11,499.88			(856)	$ (29,491.21)		
22a Real Time Non Asset Energy			3,600	$ 107,060.45										
Accrual (no detail)					513	$13,085.74	(16)	$ (446.16)	(293)	$ (6,898.84)	1,711	$ 3,776.27		
Prior Month's reversals					(198)	($4,878.55)	13	$ 439.11	206	$ 5,044.04	(1,835)	$ (3,699.96)		
Prior Month's reversals (counterparty not available)					(1,958)	$ (74,510.77)								
SUBTOTAL	(206,175)	($6,034,487.66)	77,173	$2,739,296.76	453	($13,391.91)	372	$11,492.83	(1,794)	$329,409.06	9,990	$8,249.30	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 254,322.93												
5c Day Ahead Non Asset Loss		$ 81,346.89												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ 2,919.30												
22c Real Time Non Asset Loss		$ (460.16)												
14 Real Time Distribution Losses						$ (1,357.89)		$ (180.08)				$ (6,196.12)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 338,128.95				$ (1,357.89)		$ (180.08)		$ -		$ (6,196.12)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 14,526.95		$ 6,351.20						$ 219.03		$ 2,743.39		
19 Real Time Market Administration (Schedule 17)		$ 3,557.87		$ 341.03		$ 168.77		$ 32.59				$ 98.38		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 12,842.24										
33 Day-Ahead Schedule 24 Allocation Amount		$ 1,533.31		$ 689.04						$ 32.31		$ 313.32		
34 Real -Time Schedule 24 Allocation Amount		$ (38,477.25)		$ 36.00		$ 20.22		$ 1.77				$ 11.25		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (899.57)								
SUBTOTAL		$ (18,859.12)		$ 20,259.51		$ (710.58)		$ 34.36		$ 251.34		$ 3,166.34		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ 360,655.35												
5b Day Ahead Non Asset Congestion		$ 32,639.65												
13b Real Time Congestion		$ 14,545.95												
22b Real Time Non Asset Congestion		$ (4,044.04)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation														
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount														
37 Financial Transmission Guarantee Uplift Amount														
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$ 403,796.91												
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 5,826.39										$ 475.25		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (65,472.06)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 7,833.18				$ 691.17		$ 150.46				$ 405.92		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (14,249.16)												
43 Real Time Price Volatility Make Whole Payment		$ (33,988.81)												
SUBTOTAL		$ (100,050.46)				$ 691.17		$ 150.46		$ -		$ 881.17		$ -
Other Charges														
20 Real Time Miscellaneous		$ (29,687.34)		$ -		$ (16.14)		$ (3.41)		$ 103.77		$ (89.98)		
21 Real Time Net Inadvertent Distribution				$ (301.83)		$ (2.02)		$ (0.50)		$ (9.25)		$ (27.18)		
23 Real Time Revenue Neutrality Uplift Amount		$ 75,828.69				$ 720.48		$ 146.20				$ 3,853.83		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ 46,141.35		$ (301.83)		$ 702.32		$ 142.29		$ 94.52		$ 3,736.67		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (1,993.15)				$ -		$ (6,146.03)		
40 Auction Revenue Rights - Monthly ARR Revenue														
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (330.46)				$ -		$ (1,057.15)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 480.55
SUBTOTAL						$ (2,323.61)				$ -		$ (7,203.18)		$ 480.55
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(206,175)	$ (5,365,330.03)	77,173	$ 2,759,254.44	453	$ (16,390.50)	372	$ 11,639.86	(1,794)	$ 329,754.92	9,990	$ 2,634.18	-	$ 480.55

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 - INTERSYSTEM **NOTE 1**

December 2014	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(335,160)	($9,472,266.95)									14,885	$ 495,411.73		
5a Day Ahead Non Asset Energy			54,719	$ 1,641,140.72					11,586	$ 362,878.35	(14,885)	$ (460,884.07)		
13a Real Time Asset Energy	(53,643)	($1,236,349.57)			2,451	$73,946.41	372	$ 11,649.99			(873)	$ (30,692.95)		
22a Real Time Non Asset Energy			3,600	$ 107,877.25										
Accrual (no detail)					479	$14,557.86	20	$ 595.43	(103)	$ (2,781.43)	956	$ (1,951.49)		
Prior Month's reversals					(513)	($12,973.58)	16	$ 482.92	293	$ 7,103.12	(1,711)	$ (3,244.25)		
Prior Month's reversals (counterparty not available)					(2,896)	$ (111,268.01)								
SUBTOTAL	(388,803)	($10,708,616.52)	58,319	$1,749,017.97	(479)	($35,737.32)	408	$12,728.34	11,776	$367,200.04	(1,629)	($1,361.03)	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 311,764.70												
5c Day Ahead Non Asset Loss		$ 190,608.88												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ (1,116.40)												
22c Real Time Non Asset Loss		$ (24.65)												
14 Real Time Distribution Losses						$ (1,368.94)		$ (177.25)				$ (6,740.42)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 501,232.54				$ (1,368.94)		$ (177.25)		$ -		$ (6,740.42)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 22,995.82		$ 3,744.08						$ 404.48		$ 3,003.02		
19 Real Time Market Administration (Schedule 17)		$ 3,692.07		$ 252.96		$ 186.96		$ 28.42				$ 121.82		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 13,941.84		$ (8.81)				$ -		$ 43.37		
33 Day-Ahead Schedule 24 Allocation Amount		$ 2,721.27		$ 439.92						$ 42.60		$ 345.39		
34 Real -Time Schedule 24 Allocation Amount		$ (29,694.15)		$ 29.76		$ 20.44		$ 0.12				$ 14.01		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (2,144.71)								
SUBTOTAL		$ (284.99)		$ 18,408.56		$ (1,946.12)		$ 28.54		$ 447.08		$ 3,527.61		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ 243,501.17												
5b Day Ahead Non Asset Congestion		$ 120,233.12												
13b Real Time Congestion		$ (3,597.76)												
22b Real Time Non Asset Congestion		$ 31.70												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation						$ (11.74)				$ -		$ 25.07		
30 Financial Transmission Rights Monthly Allocation						$ 95.28				$ -		$ (95.28)		
32 Financial Transmission Rights Yearly Allocation						$ 15.83						$ (15.83)		
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount						$ (258.18)				$ -		$ 96.01		
37 Financial Transmission Guarantee Uplift Amount						$ 234.76				$ -		$ (72.59)		
38 Financial Transmission Rights Monthly Transacton Amount						$ -						$ 13,289.92		
SUBTOTAL		$ 360,168.24				$ 75.95				$ -		$ 13,227.30		
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 17,314.40				$ 39.33						$ 612.18		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (15,732.48)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 15,971.63				$ 1,262.41		$ 186.50		$ 9.68		$ 703.25		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ 1,364.09												
43 Real Time Price Volatility Make Whole Payment		$ (13,244.26)												
SUBTOTAL		$ 5,673.38				$ 1,301.74		$ 186.50		$ 9.68		$ 1,315.43		$ -
Other Charges														
20 Real Time Miscellaneous		$ (52,210.57)		$ -		$ (82.60)		$ (13.41)		$ 95.47		$ (46.19)		
21 Real Time Net Inadvertent Distribution				$ 75.45		$ 1.66		$ (0.06)		$ 5.10		$ 8.49		
23 Real Time Revenue Neutrality Uplift Amount		$ 51,966.22				$ 621.63		$ 76.38				$ 3,725.99		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ (244.35)		$ 75.45		$ 540.69		$ 62.91		$ 100.57		$ 3,688.29		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (2,888.33)				$ -		$ (6,658.98)		
40 Auction Revenue Rights - Monthly ARR Revenue		$ (117,353.14)												
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (337.96)				$ -		$ (908.52)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 635.96
SUBTOTAL						$ (3,226.29)				$ -		$ (7,567.50)		$ 635.96
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(388,803)	$ (9,842,071.70)	58,319	$ 1,767,501.98	(479)	$ (40,360.29)	408	$ 12,829.04	11,776	$ 367,757.37	(1,629)	$ 6,089.68	-	$ 635.96

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

Northern States Power Company

Electric Operations - State of Minnesota

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

January 2015	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(192,125)	($5,156,228.15)									13,981	$ 385,786.23		
5a Day Ahead Non Asset Energy			92,707	$ 2,631,322.18					(1,814)	$ 304,060.59	(426)	$ (361,416.73)		
13a Real Time Asset Energy	(50,483)	($1,151,464.36)			2,927	$75,542.34	420	$ 10,380.87			(399)	$ (6,841.15)		
22a Real Time Non Asset Energy			120	$ (41.75)					19	$ 257.02				
Accrual (no detail)					109	$2,734.56	61	$ 1,492.32	(228)	$ (5,505.80)	1,875	$ 2,863.70		
Prior Month's reversals					(479)	($14,511.20)	(20)	$ (583.40)	103	$ 2,872.75	(956)	$ 2,079.86		
Prior Month's reversals (counterparty not available)					(1,640)	$ (44,097.11)								
SUBTOTAL	(242,608)	($6,307,692.51)	92,827	$2,631,280.43	917	$19,668.59	461	$11,289.79	(1,920)	$301,684.56	14,075	$22,471.91	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 305,108.31												
5c Day Ahead Non Asset Loss		$ (51,704.57)												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ (5,169.03)												
22c Real Time Non Asset Loss		$ 105.48												
14 Real Time Distribution Losses						$ (1,452.69)		$ (147.52)				$ (5,967.21)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 248,340.19				$ (1,452.69)		$ (147.52)		$ -		$ (5,967.21)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 12,091.60		$ 5,823.36						$ 244.68		$ 2,555.34		
19 Real Time Market Administration (Schedule 17)		$ 3,163.81		$ (0.00)		$ 191.11		$ 25.11		$ 1.24		$ 75.80		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 16,498.72		$ 8.37				$ -		$ 20.43		
33 Day-Ahead Schedule 24 Allocation Amount		$ 1,528.00		$ 740.16						$ 28.65		$ 319.58		
34 Real -Time Schedule 24 Allocation Amount		$ (35,196.11)		$ -		$ 20.68		$ 1.65		$ 0.19		$ 9.21		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (558.55)								
SUBTOTAL		$ (18,412.70)		$ 23,062.24		$ (338.39)		$ 26.76		$ 274.76		$ 2,980.36		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ 213,010.63												
5b Day Ahead Non Asset Congestion		$ 27,595.62												
13b Real Time Congestion		$ (17,796.01)												
22b Real Time Non Asset Congestion		$ (142.07)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation						$ 916.78				$ -		$ (1,659.88)		
30 Financial Transmission Rights Monthly Allocation						$ 6.69				$ -		$ (101.97)		
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount						$ 4.59				$ -		$ 5.39		
37 Financial Transmission Guarantee Uplift Amount						$ 5.38				$ -		$ (9.58)		
38 Financial Transmission Rights Monthly Transacton Amount						$ -				$ -		$ 5,467.60		
SUBTOTAL		$ 222,668.18				$ 933.44				$ -		$ 3,701.56		
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 9,949.33				$ 9.67		$ 0.85				$ 501.00		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (45,145.06)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 7,077.25				$ 749.05		$ 116.60				$ 308.99		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ 798.19												
43 Real Time Price Volatility Make Whole Payment		$ (15,204.93)												
SUBTOTAL		$ (42,525.22)				$ 758.72		$ 117.45		$ -		$ 809.99		$ -
Other Charges														
20 Real Time Miscellaneous		$ (95,051.51)		$ -		$ (117.16)		$ (26.61)		$ (365.48)		$ (175.55)		
21 Real Time Net Inadvertent Distribution				$ (913.75)		$ (23.70)		$ (3.85)		$ (135.64)		$ (262.86)		
23 Real Time Revenue Neutrality Uplift Amount		$ 23,099.01				$ 334.17		$ 25.23				$ 1,441.91		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ (71,952.50)		$ (913.75)		$ 193.31		$ (5.23)		$ (501.12)		$ 1,003.50		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (2,888.33)				$ -		$ (6,658.98)		
40 Auction Revenue Rights - Monthly ARR Revenue		$ (19,168.06)												
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ 135.79				$ -		$ (910.41)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 635.97
SUBTOTAL		$ (19,168.06)				$ (2,752.54)				$ -		$ (7,569.39)		$ 635.97
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(242,608)	$ (5,988,742.62)	92,827	$ 2,653,428.92	917	$ 17,010.44	461	$ 11,281.25	(1,920)	$ 301,458.20	14,075	$ 17,430.72	-	$ 635.97

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 - INTERSYSTEM **NOTE 1**

February 2015

Posting Account Description	ASSET BASED MWh	ASSET BASED Net Cost	OTHER (NSPT) MWh	OTHER (NSPT) Net Cost
Day Ahead & Real Time Energy				
1a Day Ahead Asset Energy	(131,418)	($4,195,309)		
5a Day Ahead Non Asset Energy			84,160	$ 2,939,324.27
13a Real Time Asset Energy	(68,727)	($1,743,666)		
22a Real Time Non Asset Energy				
Accrual (no detail)				
Prior Month's reversals				
Prior Month's reversals (counterparty not available)				
SUBTOTAL	(200,145)	($5,938,975.27)	84,160	$2,939,324.27
Day Ahead & Real Time Energy Loss				
1c Day Ahead Loss		$ 205,629.94		
5c Day Ahead Non Asset Loss		$ 58,124.13		
3 Day Ahead Financial Bilateral Transaction Loss				
13c Real Time Loss		$ 3,980.27		
22c Real Time Non Asset Loss		$ 46.15		
14 Real Time Distribution Losses				
16 Real Time Financial Bilateral Loss				
SUBTOTAL		$ 267,780.48		
Virtual Energy				
12 Day Ahead Virtual Energy				
27 Real Time Virtual Energy				
SUBTOTAL				
Schedules 16, 17 & 24				
4 Day Ahead Market Administration (Schedule 17)		$ 11,477.47		$ 7,262.40
19 Real Time Market Administration (Schedule 17)		$ 5,980.02		$ -
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 20,078.24
33 Day-Ahead Schedule 24 Allocation Amount		$ 1,239.19		$ 789.12
34 Real -Time Schedule 24 Allocation Amount		$ (36,614.75)		
35 Schedule 24 Admin Allocation		$ -		
Prior Month's reversals (counterparty not available)				
SUBTOTAL		$ (17,918.07)		$ 28,129.76
Congestion & FTRs				
1b Day Ahead Congestion		$ 136,965.65		
5b Day Ahead Non Asset Congestion		$ 79,434.49		
13b Real Time Congestion		$ 16,375.38		
22b Real Time Non Asset Congestion		$ 663.29		
2 Day Ahead Financial Bilateral Transaction Congestion				
15 Real Time Financial Bilateral Congestion				
28 Financial Transmission Rights Hourly Allocation				
30 Financial Transmission Rights Monthly Allocation				
32 Financial Transmission Rights Yearly Allocation				
31 Financial Transmission Rights Transaction				
36 Financial Transmission Rights Full Funding Guarantee Amount				
37 Financial Transmission Guarantee Uplift Amount				
38 Financial Transmission Rights Monthly Transacton Amount				
SUBTOTAL		$ 233,438.82		
RSG & Make Whole Payments				
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 11,328.16		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (33,732.18)		
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 8,504.83		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (5,944.00)		
43 Real Time Price Volatility Make Whole Payment		$ (21,241.80)		
SUBTOTAL		$ (41,084.99)		
Other Charges				
20 Real Time Miscellaneous		$ (70,005.00)		$ -
21 Real Time Net Inadvertent Distribution				$ (601.48)
23 Real Time Revenue Neutrality Uplift Amount		$ 39,322.71		
26 Real Time Uninstructed Deviation Amount				
SUBTOTAL		$ (30,682.29)		$ (601.48)
Auction Revenue Rights (ARR)				
39 Auction Revenue Rights - FTR Auction Transactions				
40 Auction Revenue Rights - Monthly ARR Revenue		$ (28,268.10)		
41 Auction Revenue Rights - ARR Stage 2 Distribution				
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue				
SUBTOTAL		$ (28,268.10)		
Grandfathered Charge Types				
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered				
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				
Total MISO Day 2 Charges	(200,145)	$ (5,555,709.42)	84,160	$ 2,966,852.55

Posting Account Description	CITY OF ADA MWh	CITY OF ADA Net Cost	CITY OF KASOTA MWh	CITY OF KASOTA Net Cost	WAPA MWh	WAPA Net Cost
Day Ahead & Real Time Energy						
1a Day Ahead Asset Energy						
5a Day Ahead Non Asset Energy					(1,680)	$ 301,419.29
13a Real Time Asset Energy	2,992	$78,495.76	417	$ 10,733.59		
22a Real Time Non Asset Energy						
Accrual (no detail)	366	$10,360.13	62	$ 1,724.17	(196)	$ (4,806.52)
Prior Month's reversals	(109)	($2,753.25)	(61)	$ (1,485.57)	228	$ 5,644.88
Prior Month's reversals (counterparty not available)	(3,126)	$ (77,807.48)				
SUBTOTAL	123	$8,295.16	418	$10,972.19	(1,648)	$302,257.65
Day Ahead & Real Time Energy Loss						
1c Day Ahead Loss						
5c Day Ahead Non Asset Loss						
3 Day Ahead Financial Bilateral Transaction Loss						
13c Real Time Loss						
22c Real Time Non Asset Loss						
14 Real Time Distribution Losses		$ (1,763.14)		$ (177.24)		
16 Real Time Financial Bilateral Loss						
SUBTOTAL		$ (1,763.14)		$ (177.24)		$ -
Virtual Energy						
12 Day Ahead Virtual Energy						
27 Real Time Virtual Energy						
SUBTOTAL						
Schedules 16, 17 & 24						
4 Day Ahead Market Administration (Schedule 17)						$ 274.80
19 Real Time Market Administration (Schedule 17)		$ 225.85		$ 32.16		
29 Financial Transmission Rights Administration (Schedule 16)						$ 9.60
33 Day-Ahead Schedule 24 Allocation Amount						$ 37.83
34 Real -Time Schedule 24 Allocation Amount		$ 26.26		$ 0.31		
35 Schedule 24 Admin Allocation						
Prior Month's reversals (counterparty not available)		$ 530.91				
SUBTOTAL		$ 783.02		$ 32.47		$ 322.23
Congestion & FTRs						
1b Day Ahead Congestion						
5b Day Ahead Non Asset Congestion						
13b Real Time Congestion						
22b Real Time Non Asset Congestion						
2 Day Ahead Financial Bilateral Transaction Congestion						
15 Real Time Financial Bilateral Congestion						
28 Financial Transmission Rights Hourly Allocation						$ (1,319.21)
30 Financial Transmission Rights Monthly Allocation						$ (101.97)
32 Financial Transmission Rights Yearly Allocation						
31 Financial Transmission Rights Transaction						
36 Financial Transmission Rights Full Funding Guarantee Amount						$ 5.54
37 Financial Transmission Guarantee Uplift Amount						$ (9.70)
38 Financial Transmission Rights Monthly Transacton Amount						
SUBTOTAL						$ (1,425.34)
RSG & Make Whole Payments						
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 9.67		$ 0.85		
11 Day Ahead Revenue Sufficiency Make Whole Payment						
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 746.54		$ 125.24		$ (0.09)
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment						
43 Real Time Price Volatility Make Whole Payment						
SUBTOTAL		$ 756.21		$ 126.09		$ (0.09)
Other Charges						
20 Real Time Miscellaneous		$ (185.96)		$ (31.83)		$ (130.32)
21 Real Time Net Inadvertent Distribution		$ (23.72)		$ (3.71)		$ (127.81)
23 Real Time Revenue Neutrality Uplift Amount		$ 555.67		$ 86.95		
26 Real Time Uninstructed Deviation Amount						
SUBTOTAL		$ 345.99		$ 51.41		$ (258.13)
Auction Revenue Rights (ARR)						
39 Auction Revenue Rights - FTR Auction Transactions		$ (2,888.33)				$ -
40 Auction Revenue Rights - Monthly ARR Revenue						
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (111.72)				$ -
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue						$ -
SUBTOTAL		$ (3,000.05)				$ -
Grandfathered Charge Types						
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered						
7 Day Ahead Loss Rebate on Carve Out-Grandfathered						
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						
Total MISO Day 2 Charges	123	$ 5,417.19	418	$ 11,004.92	(1,648)	$ 300,896.32

Posting Account Description	DLP MWh	DLP Net Cost	NSPX MWh	NSPX Net Cost
Day Ahead & Real Time Energy				
1a Day Ahead Asset Energy	13,395	$ 379,899.22		
5a Day Ahead Non Asset Energy	(201)	$ (346,392.25)		
13a Real Time Asset Energy	(149)	$ 3,481.23		
22a Real Time Non Asset Energy				
Accrual (no detail)	1,899	$ 10,031.73		
Prior Month's reversals	(1,875)	$ (3,101.81)		
Prior Month's reversals (counterparty not available)				
SUBTOTAL	13,069	$43,918.12	-	$0.00
Day Ahead & Real Time Energy Loss				
1c Day Ahead Loss				
5c Day Ahead Non Asset Loss				
3 Day Ahead Financial Bilateral Transaction Loss				
13c Real Time Loss				
22c Real Time Non Asset Loss				
14 Real Time Distribution Losses		$ (7,000.79)		
16 Real Time Financial Bilateral Loss				
SUBTOTAL		$ (7,000.79)		$ -
Virtual Energy				
12 Day Ahead Virtual Energy				
27 Real Time Virtual Energy				
SUBTOTAL				
Schedules 16, 17 & 24				
4 Day Ahead Market Administration (Schedule 17)		$ 2,894.75		
19 Real Time Market Administration (Schedule 17)		$ 100.03		
29 Financial Transmission Rights Administration (Schedule 16)				
33 Day-Ahead Schedule 24 Allocation Amount		$ 328.85		
34 Real -Time Schedule 24 Allocation Amount		$ 11.39		
35 Schedule 24 Admin Allocation				
Prior Month's reversals (counterparty not available)				
SUBTOTAL		$ 3,335.02		$ -
Congestion & FTRs				
1b Day Ahead Congestion				
5b Day Ahead Non Asset Congestion				
13b Real Time Congestion				
22b Real Time Non Asset Congestion				
2 Day Ahead Financial Bilateral Transaction Congestion				
15 Real Time Financial Bilateral Congestion				
28 Financial Transmission Rights Hourly Allocation				
30 Financial Transmission Rights Monthly Allocation				
32 Financial Transmission Rights Yearly Allocation				
31 Financial Transmission Rights Transaction				
36 Financial Transmission Rights Full Funding Guarantee Amount				
37 Financial Transmission Guarantee Uplift Amount				
38 Financial Transmission Rights Monthly Transacton Amount				
SUBTOTAL				
RSG & Make Whole Payments				
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 540.37		
11 Day Ahead Revenue Sufficiency Make Whole Payment				
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 406.65		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment				
43 Real Time Price Volatility Make Whole Payment				
SUBTOTAL		$ 947.02		$ -
Other Charges				
20 Real Time Miscellaneous		$ (243.82)		
21 Real Time Net Inadvertent Distribution		$ (244.49)		
23 Real Time Revenue Neutrality Uplift Amount		$ 2,386.47		
26 Real Time Uninstructed Deviation Amount				
SUBTOTAL		$ 1,898.16		$ -
Auction Revenue Rights (ARR)				
39 Auction Revenue Rights - FTR Auction Transactions		$ (6,658.98)		
40 Auction Revenue Rights - Monthly ARR Revenue				
41 Auction Revenue Rights - ARR Stage 2 Distribution		$ (910.41)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue				$ 635.97
SUBTOTAL		$ (7,569.39)		$ 635.97
Grandfathered Charge Types				
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered				
7 Day Ahead Loss Rebate on Carve Out-Grandfathered				
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				
Total MISO Day 2 Charges	13,069	$ 35,528.14	-	$ 635.97

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 - INTERSYSTEM **NOTE 1**

March 2015			NON-ASSET BASED											
	ASSET BASED		OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(148,935)	($3,404,077)									13,059	$ 414,279.85		
5a Day Ahead Non Asset Energy			93,118	$ 2,586,607.32					(1,660)	$ 315,386.12	(476)	$ (371,479.23)		
13a Real Time Asset Energy	(59,527)	($1,200,976)			2,540	$67,658.75	489	$ 12,723.33			394	$ 24,218.97		
22a Real Time Non Asset Energy														
Accrual (no detail)					190	$4,500.95	5	$ 154.62	(220)	$ (4,214.67)	1,768	$ 5,262.59		
Prior Month's reversals					(366)	($10,365.12)	(62)	$ (1,707.24)	196	$ 4,982.93	(1,899)	$ (10,199.71)		
Prior Month's reversals (counterparty not available)					(3,531)	$ (133,193.08)								
SUBTOTAL	(208,462)	($4,605,052.96)	93,118	$2,586,607.32	(1,167)	($71,398.50)	432	$11,170.71	(1,684)	$316,154.38	12,846	$62,082.47	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 181,093.93												
5c Day Ahead Non Asset Loss		$ 30,874.44												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ (1,594.44)												
22c Real Time Non Asset Loss		$ 0.50												
14 Real Time Distribution Losses						$ (1,436.93)		$ (217.79)				$ (7,745.18)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 210,374.43				$ (1,436.93)		$ (217.79)		$ -		$ (7,745.18)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 14,271.21		$ 8,908.56						$ 407.48		$ 3,296.74		
19 Real Time Market Administration (Schedule 17)		$ 5,714.35		$ -		$ 238.33		$ 46.86				$ 130.07		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 14,280.48										
33 Day-Ahead Schedule 24 Allocation Amount		$ 1,431.59		$ 887.52						$ 45.35		$ 338.65		
34 Real -Time Schedule 24 Allocation Amount		$ (25,868.51)				$ 27.66		$ 2.31				$ 13.15		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (224.26)								
SUBTOTAL		$ (4,451.36)		$ 24,076.56		$ 41.73		$ 49.17		$ 452.83		$ 3,778.61		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ 144,319.14												
5b Day Ahead Non Asset Congestion		$ 10,596.09												
13b Real Time Congestion		$ (4,103.63)												
22b Real Time Non Asset Congestion		$ 3.81												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation										$ 0.10				
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount										$ (0.10)				
37 Financial Transmission Guarantee Uplift Amount										$ 0.09				
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$ 150,815.42								$ 0.09				
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 27,289.74				$ 0.97		$ 0.08				$ 1,461.99		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (75,478.05)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 13,959.27				$ 2,128.43		$ 376.84		$ 0.46		$ 1,086.89		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (251,432.56)												
43 Real Time Price Volatility Make Whole Payment		$ (12,005.62)												
SUBTOTAL		$ (297,667.22)				$ 2,129.40		$ 376.92		$ 0.46		$ 2,548.88		$ -
Other Charges														
20 Real Time Miscellaneous		$ (69,381.57)		$ -		$ (220.65)		$ (35.36)		$ (141.18)		$ (765.92)		
21 Real Time Net Inadvertent Distribution				$ (601.48)		$ 5.48		$ 0.84		$ 26.08		$ 40.38		
23 Real Time Revenue Neutrality Uplift Amount		$ 17,480.14				$ 400.36		$ 82.44				$ 2,070.59		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ (51,901.43)		$ (601.48)		$ 185.19		$ 47.92		$ (115.10)		$ 1,345.05		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (1,892.86)				$ -		$ (8,082.84)		
40 Auction Revenue Rights - Monthly ARR Revenue		$ (16,306.18)												
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (130.12)				$ -		$ (1,165.08)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 863.03
SUBTOTAL		$ (16,306.18)				$ (2,022.98)				$ -		$ (9,247.92)		$ 863.03
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(208,462)	$ (4,614,189.30)	93,118	$ 2,610,082.40	(1,167)	$ (72,502.09)	432	$ 11,426.93	(1,684)	$ 316,492.66	12,846	$ 52,761.91	-	$ 863.03

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 - INTERSYSTEM **NOTE 1**

April 2015			NON-ASSET BASED											
	ASSET BASED		OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(52,435)	($1,134,682)									9,772	$ 225,328.97		
5a Day Ahead Non Asset Energy			90,407	$ 2,237,577.04					(1,244)	$ 180,138.20	(307)	$ (210,209.53)		
13a Real Time Asset Energy	(23,177)	($366,700)			2,190	$47,003.93	393	$ 8,165.28			(400)	$ (9,602.55)		
22a Real Time Non Asset Energy														
Accrual (no detail)					(227)	($4,287.91)	(53)	$ (961.07)	(112)	$ (1,813.09)	1,031	$ 1,136.54		
Prior Month's reversals					(190)	($4,256.77)	(5)	$ (109.48)	220	$ 4,444.01	(1,768)	$ (4,759.70)		
Prior Month's reversals (counterparty not available)					(1,290)	$ (32,542.65)								
SUBTOTAL	(75,612)	($1,501,382.11)	90,407	$2,237,577.04	483	$5,916.60	335	$7,094.73	(1,136)	$182,769.12	8,328	$1,893.73	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 35,648.83												
5c Day Ahead Non Asset Loss		$ 31,245.77												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ 1,057.31												
22c Real Time Non Asset Loss		$ (23.66)												
14 Real Time Distribution Losses						$ (694.12)		$ (91.70)				$ (2,643.32)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 67,928.25				$ (694.12)		$ (91.70)		$ -		$ (2,643.32)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 4,343.43		$ 7,366.88						$ 275.09		$ 2,341.22		
19 Real Time Market Administration (Schedule 17)		$ 1,917.32		$ -		$ 185.71		$ 32.14				$ 69.92		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 14,469.92										
33 Day-Ahead Schedule 24 Allocation Amount		$ 534.22		$ 909.12						$ 25.79		$ 272.69		
34 Real -Time Schedule 24 Allocation Amount		$ (34,813.93)				$ 20.57		$ 2.12				$ 7.89		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (1,813.13)								
SUBTOTAL		$ (28,018.96)		$ 22,745.92		$ (1,606.85)		$ 34.26		$ 300.88		$ 2,691.72		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ (8,983.90)												
5b Day Ahead Non Asset Congestion		$ 48,085.34												
13b Real Time Congestion		$ 2,201.27												
22b Real Time Non Asset Congestion		$ (45.75)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation														
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation										$ (15.83)				
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount										$ 15.83				
37 Financial Transmission Guarantee Uplift Amount										$ 1.80				
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$ 41,256.95								$ 1.80				
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 450.41										$ 296.39		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (41,897.65)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 731.68				$ 706.94		$ 86.80				$ 334.03		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (1,435.18)												
43 Real Time Price Volatility Make Whole Payment		$ (5,513.09)												
SUBTOTAL		$ (47,663.83)				$ 706.94		$ 86.80		$ -		$ 630.42		$ -
Other Charges														
20 Real Time Miscellaneous		$ (47,609.77)		$ -		$ (29.90)		$ (5.61)		$ (123.08)		$ (158.51)		
21 Real Time Net Inadvertent Distribution				$ (617.13)		$ (6.02)		$ (1.04)		$ (21.16)		$ (43.33)		
23 Real Time Revenue Neutrality Uplift Amount		$ 9,556.45				$ 288.39		$ 43.27				$ 1,226.81		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ (38,053.32)		$ (617.13)		$ 252.47		$ 36.62		$ (144.24)		$ 1,024.97		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (1,892.86)				$ -		$ (8,082.84)		
40 Auction Revenue Rights - Monthly ARR Revenue		$ (22,235.70)												
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (105.97)				$ -		$ (1,165.08)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 863.03
SUBTOTAL		$ (22,235.70)				$ (1,998.83)				$ -		$ (9,247.92)		$ 863.03
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(75,612)	$ (1,528,168.72)	90,407	$ 2,259,705.83	483	$ 2,576.21	335	$ 7,160.71	(1,136)	$ 182,927.56	8,328	$ (5,650.40)	-	$ 863.03

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 - INTERSYSTEM **NOTE 1**

May 2015	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(76,095)	($1,271,709)									10,213	$ 241,906.89		
5a Day Ahead Non Asset Energy			92,296	$ 2,309,673.37					(1,306)	$ 181,512.88	(397)	$ (215,298.13)		
13a Real Time Asset Energy	(50,368)	($831,015)			1,839	$36,126.79	363	$ 6,274.55	4	$ 47.74	(502)	$ (12,624.37)		
22a Real Time Non Asset Energy														
Accrual (no detail)					(1)	$165.73	(41)	$ (639.45)	(177)	$ (3,045.35)	1,498	$ 3,416.17		
Prior Month's reversals					227	$4,347.27	53	$ 971.53	112	$ 1,901.71	(1,031)	$ (938.54)		
Prior Month's reversals (counterparty not available)					(1,903)	$ (42,694.28)								
SUBTOTAL	(126,463)	($2,102,723.83)	92,296	$2,309,673.37	162	($2,054.49)	375	$6,606.63	(1,367)	$180,416.98	9,781	$16,462.02	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 69,335.05												
5c Day Ahead Non Asset Loss		$ 45,049.56												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ 2,796.43												
22c Real Time Non Asset Loss		$ (137.52)												
14 Real Time Distribution Losses						$ (521.35)		$ (82.41)				$ (2,895.48)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 117,043.52				$ (521.35)		$ (82.41)		$ -		$ (2,895.48)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 5,835.93		$ 7,058.56						$ 243.02		$ 2,226.14		
19 Real Time Market Administration (Schedule 17)		$ 3,876.18		$ -		$ 140.20		$ 27.28		$ 0.32		$ 70.10		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 11,826.00										
33 Day-Ahead Schedule 24 Allocation Amount		$ 709.65		$ 858.00						$ 29.92		$ 271.45		
34 Real -Time Schedule 24 Allocation Amount		$ (35,858.30)				$ 17.64		$ 0.84		$ 0.04		$ 8.59		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (538.88)								
SUBTOTAL		$ (25,436.54)		$ 19,742.56		$ (381.04)		$ 28.12		$ 273.30		$ 2,576.28		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ 29,214.14												
5b Day Ahead Non Asset Congestion		$ 83,591.28												
13b Real Time Congestion		$ 8,817.86												
22b Real Time Non Asset Congestion		$ (730.41)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation														
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount														
37 Financial Transmission Guarantee Uplift Amount														
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$ 120,892.87								$ -				
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 1,577.29										$ (3.19)		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ 4,542.82												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 25,500.92				$ 747.81		$ 105.09				$ 262.10		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (35,866.46)												
43 Real Time Price Volatility Make Whole Payment		$ (3,282.38)												
SUBTOTAL		$ (7,527.82)				$ 747.81		$ 105.09		$ -		$ 258.91		$ -
Other Charges														
20 Real Time Miscellaneous		$ (64,040.02)		$ -		$ 7.02		$ 1.09		$ (138.44)		$ (124.24)		
21 Real Time Net Inadvertent Distribution				$ (510.79)		$ (11.40)		$ (2.23)		$ (53.76)		$ (104.55)		
23 Real Time Revenue Neutrality Uplift Amount		$ 5,847.79				$ 296.66		$ 57.31				$ 1,475.93		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ (58,192.23)		$ (510.79)		$ 292.28		$ 56.17		$ (192.20)		$ 1,247.14		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ (1,892.86)						$ (8,082.84)		
40 Auction Revenue Rights - Monthly ARR Revenue		$ (23,718.08)												
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (114.50)				0		$ (1,167.40)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 863.03
SUBTOTAL		$ (23,718.08)				$ (2,007.36)				$ -		$ (9,250.24)		$ 863.03
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(126,463)	$ (1,979,662.11)	92,296	$ 2,328,905.14	162	$ (3,924.15)	375	$ 6,713.60	(1,367)	$ 180,498.08	9,781	$ 8,398.63	-	$ 863.03

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 - INTERSYSTEM **NOTE 1**

June 2015	ASSET BASED		NON-ASSET BASED											
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP		NSPX	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Day Ahead & Real Time Energy														
1a Day Ahead Asset Energy	(129,810)	($2,974,148)									11,439	$ 289,453.69		
5a Day Ahead Non Asset Energy			90,406	$ 2,365,574.32					(1,405)	$ 195,833.03	(847)	$ (248,292.92)		
13a Real Time Asset Energy	(37,468)	($792,544)			1,503	$33,187.86	395	$ 8,573.72			(1,093)	$ (29,955.98)		
22a Real Time Non Asset Energy														
Accrual (no detail)					252	$5,988.48	(15)	$ (300.78)	(179)	$ (3,867.83)	1,426	$ 1,532.23		
Prior Month's reversals					1	$18.72	41	$ 671.80	177	$ 3,172.80	(1,498)	$ (3,019.91)		
Prior Month's reversals (counterparty not available)					(2,529)	$ (57,045.37)								
SUBTOTAL	(167,278)	($3,766,692.16)	90,406	$2,365,574.32	(773)	($17,850.31)	421	$8,944.74	(1,407)	$195,138.00	9,428	$9,717.11	-	$0.00
Day Ahead & Real Time Energy Loss														
1c Day Ahead Loss		$ 105,762.71												
5c Day Ahead Non Asset Loss		$ 52,823.12												
3 Day Ahead Financial Bilateral Transaction Loss														
13c Real Time Loss		$ 187.96												
22c Real Time Non Asset Loss		$ (231.83)												
14 Real Time Distribution Losses						$ (364.05)		$ (121.58)				$ (3,491.89)		
16 Real Time Financial Bilateral Loss														
SUBTOTAL		$ 158,541.96				$ (364.05)		$ (121.58)		$ -		$ (3,491.89)		$ -
Virtual Energy														
12 Day Ahead Virtual Energy														
27 Real Time Virtual Energy														
SUBTOTAL														
Schedules 16, 17 & 24														
4 Day Ahead Market Administration (Schedule 17)		$ 9,893.81		$ 6,907.04						$ 517.22		$ 2,149.03		
19 Real Time Market Administration (Schedule 17)		$ 2,828.56		$ -		$ 115.16		$ 31.27				$ 101.01		
29 Financial Transmission Rights Administration (Schedule 16)		$ -		$ 8,595.84		$ 5.52						$ 44.16		
33 Day-Ahead Schedule 24 Allocation Amount		$ 1,392.47		$ 966.24						$ 65.35		$ 288.41		
34 Real -Time Schedule 24 Allocation Amount		$ (88,233.67)				$ 14.50		$ 0.66				$ 13.36		
35 Schedule 24 Admin Allocation		$ -												
Prior Month's reversals (counterparty not available)						$ (1,894.48)								
SUBTOTAL		$ (74,118.83)		$ 16,469.12		$ (1,759.30)		$ 31.93		$ 582.57		$ 2,595.97		$ -
Congestion & FTRs														
1b Day Ahead Congestion		$ (6,273.36)												
5b Day Ahead Non Asset Congestion		$ 63,425.47												
13b Real Time Congestion		$ 154.73												
22b Real Time Non Asset Congestion		$ (1,878.36)												
2 Day Ahead Financial Bilateral Transaction Congestion														
15 Real Time Financial Bilateral Congestion														
28 Financial Transmission Rights Hourly Allocation						$ 101.37						$ (1,950.65)		
30 Financial Transmission Rights Monthly Allocation														
32 Financial Transmission Rights Yearly Allocation														
31 Financial Transmission Rights Transaction														
36 Financial Transmission Rights Full Funding Guarantee Amount						$ (12.12)						$ (40.46)		
37 Financial Transmission Guarantee Uplift Amount						$ 12.12						$ 40.46		
38 Financial Transmission Rights Monthly Transacton Amount														
SUBTOTAL		$ 55,428.48				$ 101.37				$ -		$ (1,950.65)		$ -
RSG & Make Whole Payments														
10 Day Ahead Revenue Sufficiency Guarantee Distribution		$ 5,012.52										$ 308.36		
11 Day Ahead Revenue Sufficiency Make Whole Payment		$ (9,255.55)												
24 Real Time Revenue Sufficiency Guarantee First Pass Distribution		$ 29,473.78				$ 825.92		$ 185.07				$ 698.00		
25 Real Time Revenue Sufficiency Guarantee Make Whole Payment		$ (65,810.60)												
43 Real Time Price Volatility Make Whole Payment		$ (5,569.60)												
SUBTOTAL		$ (46,149.45)				$ 825.92		$ 185.07		$ -		$ 1,006.36		$ -
Other Charges														
20 Real Time Miscellaneous		$ (40,146.52)		$ -		$ (1.77)		$ (0.96)		$ (129.91)		$ (133.54)		
21 Real Time Net Inadvertent Distribution				$ 255.36		$ 4.39		$ 1.07		$ 16.50		$ 31.22		
23 Real Time Revenue Neutrality Uplift Amount		$ 6,968.90				$ 395.18		$ 83.74				$ 2,332.81		
26 Real Time Uninstructed Deviation Amount														
SUBTOTAL		$ (33,177.62)		$ 255.36		$ 397.80		$ 83.85		$ (113.41)		$ 2,230.49		$ -
Auction Revenue Rights (ARR)														
39 Auction Revenue Rights - FTR Auction Transactions						$ 0.00				$ 0.00		$ (34.56)		
40 Auction Revenue Rights - Monthly ARR Revenue		$ (4,447.14)												
41 Auction Revenue Rights - ARR Stage 2 Distribution						$ (96.10)				$ -		$ (918.83)		
42 Auction Revenue Rights - Monthly Infeasible ARR Revenue										$ -				$ 200.91
SUBTOTAL		$ (4,447.14)				$ (96.10)				$ 0.00		$ (953.39)		$ 200.91
Grandfathered Charge Types														
6 Day Ahead Congestion Rebate on Carve Out-Grandfathered														
7 Day Ahead Loss Rebate on Carve Out-Grandfathered														
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														
Total MISO Day 2 Charges	(167,278)	$ (3,710,614.76)	90,406	$ 2,382,298.80	(773)	$ (18,744.67)	421	$ 9,124.01	(1,407)	$ 195,607.16	9,428	$ 9,154.00	-	$ 200.91

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

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

July 2014	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (92,773.70)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (76,977.30)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (6,696.83)										
Resource Energy Charges												
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		$ (642.23)										
8c Real Time Non Excessive Energy Loss		$ 3,241.70										
9 Real Time Net Regulation Adjustment Amount		$ 6,575.18										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 57.97		$ 12.25				$ 316.77
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 50.92		$ 10.04				$ 278.81
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 26.83		$ 4.64				$ 141.13
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 12,080.37										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	**-**	**$ (155,192.81)**	**-**	**$ -**		**$ 135.72**		**$ 26.93**		**$ -**		**$ 736.71**

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

August 2014	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (158,024.21)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (23,562.62)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (8,872.10)										
Resource Energy Charges												
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		$ 1,973.33										
8c Real Time Non Excessive Energy Loss		$ (2,120.42)										
9 Real Time Net Regulation Adjustment Amount		$ 2,966.65										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 43.02		$ 10.76				$ 264.92
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 38.91		$ 8.89				$ 228.02
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 17.76		$ 3.41				$ 107.58
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 6,900.04										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	**-**	**$ (180,739.33)**	**-**	**$ -**		**$ 99.69**		**$ 23.06**		**$ -**		**$ 600.52**

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

September 2014	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (114,973.34)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (49,673.23)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (6,470.68)										
Resource Energy Charges												
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		$ (4,011.99)										
8c Real Time Non Excessive Energy Loss		$ 781.43										
9 Real Time Net Regulation Adjustment Amount		$ (934.24)										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 46.21		$ 10.99				$ 278.69
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 44.27		$ 9.83				$ 263.92
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 20.80		$ 3.20				$ 132.06
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 14,095.29										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	**-**	**$ (161,186.76)**	**-**	**$ -**		**$ 111.28**		**$ 24.02**		**$ -**		**$ 674.67**

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
Electric Operations - State of Minnesota

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

October 2014	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (212,780.80)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (36,972.34)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 883.11										
Resource Energy Charges												
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		$ (11,263.74)										
8c Real Time Non Excessive Energy Loss		$ 3,167.50										
9 Real Time Net Regulation Adjustment Amount		$ 2,115.62										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 56.59		$ 14.66				$ 331.29
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 56.47		$ 15.42				$ 338.87
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 33.95		$ 7.72				$ 208.06
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 30,218.04										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	-	$ (224,632.61)	-	$ -		$ 147.01		$ 37.80		$ -		$ 878.22

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

November 2014	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (183,631.51)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (33,722.73)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (433.85)										
Resource Energy Charges												
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		$ (10,165.43)										
8c Real Time Non Excessive Energy Loss		$ (2,582.48)										
9 Real Time Net Regulation Adjustment Amount		$ (329.11)										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 80.68		$ 15.31				$ 445.93
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 75.65		$ 14.72				$ 430.20
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 27.63		$ 5.33				$ 163.84
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 20,137.48										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	-	$ (210,727.62)	-	$ -		$ 183.96		$ 35.36		$ -		$ 1,039.97

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

December 2014	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (4,205.93)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (10,326.58)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (860.54)										
Resource Energy Charges												
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		$ 1,887.31										
8c Real Time Non Excessive Energy Loss		$ 2,125.34										
9 Real Time Net Regulation Adjustment Amount		$ 2,571.86										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 73.91		$ 10.74				$ 436.74
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 59.72		$ 7.41				$ 359.15
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 20.29		$ (0.24)				$ 119.77
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 22,418.79										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	**-**	**$ 13,610.25**	**-**	**$ -**		**$ 153.92**		**$ 17.91**		**$ -**		**$ 915.66**

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.

Northern States Power Company
Electric Operations - State of Minnesota

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

January 2015	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (1,250.43)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (44,830.04)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (9,278.27)										
Resource Energy Charges												
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		$ 9,670.91										
8c Real Time Non Excessive Energy Loss		$ 738.10										
9 Real Time Net Regulation Adjustment Amount		$ 794.72										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 66.40		$ 9.21				$ 298.39
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 54.20		$ 7.05				$ 245.44
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 18.17		$ 0.52				$ 75.88
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 1,036.99										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	**-**	**$ (43,118.02)**	**-**	**$ -**		**$ 138.77**		**$ 16.78**		**$ -**		**$ 619.71**

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

February 2015			NON-ASSET BASED									
	ASSET BASED		OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (27,363.07)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (39,877.66)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (6,029.61)										
Resource Energy Charges												
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		$ (9,516.85)										
8c Real Time Non Excessive Energy Loss		$ (546.50)										
9 Real Time Net Regulation Adjustment Amount		$ 597.60										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 61.45		$ 9.07				$ 271.78
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 50.52		$ 6.93				$ 234.67
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 22.12		$ 0.57				$ 102.65
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 7,218.58										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	-	$ (75,517.51)	-	$ -		$ 134.09		$ 16.57		$ -		$ 609.10

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
Electric Operations - State of Minnesota

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

March 2015	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**	**MWh**	**Net Cost**
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (39,490.55)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (74,256.39)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (8,863.29)										
Resource Energy Charges												
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		$ 9,211.73										
8c Real Time Non Excessive Energy Loss		$ 3,768.79										
9 Real Time Net Regulation Adjustment Amount		$ (10.95)										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 80.10		$ 14.87				$ 417.94
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 73.66		$ 12.70				$ 375.58
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 28.11		$ 2.38				$ 139.02
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 3,507.37										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	**-**	**$ (106,133.29)**	**-**	**$ -**		**$ 181.87**		**$ 29.95**		**$ -**		**$ 932.54**

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

April 2015	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (156.66)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (3,755.83)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ 1,077.32										
Resource Energy Charges												
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		$ (1,059.22)										
8c Real Time Non Excessive Energy Loss		$ (78.35)										
9 Real Time Net Regulation Adjustment Amount		$ 0.68										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 58.79		$ 10.07				$ 241.86
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 55.97		$ 7.31				$ 224.38
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 18.78		$ 0.53				$ 78.40
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 4,124.76										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	-	$ 152.70	-	$ -		$ 133.54		$ 17.91		$ -		$ 544.64

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

May 2015	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (4,915.10)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (33,449.56)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (277.81)										
Resource Energy Charges												
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		$ (12,667.61)										
8c Real Time Non Excessive Energy Loss		$ (3,229.22)										
9 Real Time Net Regulation Adjustment Amount		$ 428.99										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 58.27		$ 11.02				$ 302.31
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 45.18		$ 7.23				$ 233.78
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 15.87		$ 0.93				$ 81.68
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 1,524.59										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	-	$ (52,585.72)	-	$ -		$ 119.32		$ 19.18		$ -		$ 617.77

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

June 2015	ASSET BASED		NON-ASSET BASED									
			OTHER (NSPT)		CITY OF ADA		CITY OF KASOTA		WAPA		DLP	
Posting Account Description	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost	MWh	Net Cost
Procurement Charges												
1 Day-Ahead Regulation Amount		$ -										
2 Day-Ahead Spinning Reserve Amount		$ -										
3 Day-Ahead Supplemental Reserve		$ -										
4 Real-Time Regulation Amount (See Note 1)		$ (27,225.04)										
5 Real-Time Spinning Reserve Amount (See Note 1)		$ (53,827.14)										
6 Real-Time Supplemental Reserve Amount. (See Note 1)		$ (2,215.19)										
Resource Energy Charges												
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		$ 7,876.84										
8c Real Time Non Excessive Energy Loss		$ 4,283.63										
9 Real Time Net Regulation Adjustment Amount		$ 1,481.85										
Cost Distribution Charges												
10 Real Time Regulation Reserve Cost Distribution Amount		$ -				$ 42.17		$ 10.39				$ 277.18
11 Real Time Spinnng Reserve Cost Distribution		$ -				$ 46.13		$ 10.35				$ 284.14
12 Real Time Supplemental Reserve Cost Distribution		$ -				$ 12.62		$ 1.19				$ 82.95
Penalty Charges												
13 Real Time Excessive/Dificient Energy Deployment		$ 3,382.02										
14 Real Time Contignecy Reserve Deployment Failure		$ -										
TOTAL MISO ASM CHARGES	**-**	**$ (66,243.03)**	**-**	**$ -**		**$ 100.92**		**$ 21.93**		**$ -**		**$ 644.27**

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.

Annual Automatic Adjustment Report

Docket No. E999/AA-15-611

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 June 2015 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.

			Energy Allocation Ratios		87.5707%	87.5394%
			Demand Allocation Ratios		87.6729%	87.5284%
			NSP Minnesota Company Totals		**Minnesota Jurisdictional Totals ***	
FERC Account Description		**Allocation Method**	**2014 Test Year Totals - Based on 2014 Budget**	**2014 Actuals**	**2014 Test Year Totals - Based on 2014 Budget**	**2014 Actuals**
510	Stm Maint Super&Eng	Energy	$ 1,937,824	$ 2,884,282	$ 1,696,966	$ 2,524,883
511	Stm Maint of Structures	Demand	$ 3,529,078	$ 8,080,769	$ 3,094,045	$ 7,072,967
512	Stm Maint of Boiler Plt	Energy	$ 43,843,815	$ 41,795,530	$ 38,394,335	$ 36,587,556
513	Stm Maint of Elec Plant	Energy	$ 5,526,058	$ 7,364,749	$ 4,839,208	$ 6,447,057
514	Stm Maint of Misc Stm Plt	Demand	$ 15,973,376	$ 15,094,294	$ 14,004,322	$ 13,211,794
528	Nuc Maint Super & Eng	Energy	$ 12,650,239	$ 12,742,279	$ 11,077,903	$ 11,154,515
529	Nuc Maint of Structures	Demand	$ 54,945	$ 646,661	$ 48,172	$ 566,012
530	Nuc Mtc of React Plt Equip	Energy	$ 46,683,386	$ 39,220,988	$ 40,880,968	$ 34,333,817
531	Nuc Maint of Elect Plant	Energy	$ 11,578,433	$ 19,309,350	$ 10,139,314	$ 16,903,289
532	Nuc Mtc of Misc Nuc Plant	Demand	$ 35,343,585	$ 40,951,887	$ 30,986,746	$ 35,844,531
541	Hydro Mtc Super& Eng	Energy	$ 5,319	$ 22,674	$ 4,658	$ 19,848
542	Hyd Maint of Structures	Demand	$ -	$ 122,787	$ -	$ 107,473
543	Hydro Mtc Resv, Dams	Demand	$ 60,000	$ 107,611	$ 52,604	$ 94,190
544	Hyd Maint of Elec Plant	Energy	$ 92,839	$ 37,579	$ 81,300	$ 32,897
545	Hyd Mt Misc Hyd Plnt Mjr	Demand	$ 52,280	$ 1,643	$ 45,835	$ 1,438
551	Oth Maint Super & Eng	Demand	$ 458,691	$ 633,108	$ 402,148	$ 554,150
552	Oth Maint of Structures	Demand	$ 2,083,508	$ 3,903,252	$ 1,826,672	$ 3,416,454
553	Oth Mtc of Gen & Ele Plant	Demand	$ 10,608,955	$ 11,816,311	$ 9,301,179	$ 10,342,628
554	Oth Mtc Misc Gen Plt Mjr	Demand	$ 3,203,235	$ 2,370,029	$ 2,808,369	$ 2,074,449
Production Maintenance Expense Totals			**$ 193,685,565**	**$ 207,105,781**	**$ 169,684,742**	**$ 181,289,948**

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

	Generation Maintenance O&M Costs
2014 Test Year	$ 193,685,565
2014 Actual	$ 207,105,781

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.*

<u>Company Report</u>

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 in to 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 mitigate poor 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.

An example of sharing best practices among our fleet of plants is our overhaul management group. To better streamline planned power plant outages, we have partnered with a boiler inspection contractor to thoroughly identify a prioritized repair scope of work for our boilers not only at Sherco but also at the King plant. Identifying the critical path for boiler repair generally drives outage 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 plant, we monitor boiler weld completion rates in order to project a finish date and subsequent unit startup.

[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.

Human Performance

A recent 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 grassroots 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 last half of 2014, we experienced a significant decrease in the number and types of 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.

We have focused the 2014-15 QA/QC program oversight efforts on contractor/supplier performance during plant overhauls and projects. Comprehensive overhaul quality plans are developed for each plant overhaul which includes aggressive oversight for supplier repairs of plant equipment as well as independent inspection of the contractors performing the plant equipment/component installation activities. The results of contractor/supplier performance for plant overhauls in the NSP region for the first half of 2015 have improved. Plant overhaul schedules were met, with 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.

Cases where equipment or services did not meet contract requirements were dealt with using our Non-Conformance Report (NCR) process for recovering costs from Suppliers/Contractors. The Minnesota region Unplanned Outage Rate performance metric as a key performance indicator (KPI) is projecting top quartile performance relative to our industry peers.

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 2014-15 we continued implementing 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 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: WITH TRADE SECRET DATA EXCISED

Summary of Power Purchase Agreement Off-Setting Revenues (July 1, 2014 - June 30, 2015)

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 2014	Yes	September 2014	E002/AA-14-0746	Energy Production Credit
			October 2014	Yes	December 2014	E002/AA-14-0995	Energy Production Credit
			January 2015	Yes	March 2015	E002/AA-15-0188	Energy Production Credit
			April 2015	Yes	June 2015	E002/AA-15-0513	Energy Production Credit
Odell	E003/M-13-603		November 2014	Yes	January 2015	E002/AA-14-1070	Delay Damages for not meeting COD
			December 2014	Yes	February 2015	E002/AA-15-0116	Delay Damages for not meeting COD
MN Power Laurentian	E002/M-09-913		August 2014	Yes	October 2014	E002/AA-14-0845	Estoppel Agreement
			October 2014	Yes	December 2014	E002/AA-14-0995	Estoppel Agreement
			November 2014	Yes	January 2015	E002/AA-14-1070	Estoppel Agreement
			January 2015	Yes	March 2015	E002/AA-15-0188	Estoppel Agreement
			April 2015	Yes	June 2015	E002/AA-15-0513	Estoppel Agreement
			May 2015	Yes	July 2015	E002/AA-15-0638	Estoppel Agreement
			June 2015	Yes	August 2015	E002/AA-15-0718	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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JULY 2014									
Black.Dog.3	Forced	First Superheater Leaks	07/19/2014	07/24/2014	Unit 3 Boiler Tubes	Boiler Tube Rupture - Primary Superheat Section		Two similar events for this unit occurred during this reporting period.	This unit is past end of life and is scheduled for retirement in April 2015. Much of the boiler is thinned due to normal operation (sootblower erosion and flyash erosion). A survey was completed to measure the tube wall thickness and any thin tubes were replaced or shielded for protection from future erosion.
Black.Dog.4	Forced	First Superheater Leaks	07/18/2014	07/20/2014	Unit 4 Boiler Tubes	Boiler Tube Rupture - Primary Superheat Section		One similar event for this unit occurred during this reporting period.	This unit is past end of life and is scheduled for retirement in April 2015. Much of the boiler is thinned due to normal operation (sootblower erosion and flyash erosion). A survey was completed to measure the tube wall thickness and any thin tubes were replaced or shielded for protection from future erosion.
Black.Dog.4	Forced	First Reheater Leaks	07/20/2014	07/25/2014	Unit 4 Boiler Tubes	Boiler Tube Rupture - Reheat Superheat Section		One similar event for this unit occurred during this reporting period.	This event is a continuation of the 7/18 event. This unit is past end of life and is scheduled for retirement in April 2015. Much of the boiler is thinned due to normal operation (sootblower erosion and flyash erosion). A survey was completed to measure the tube wall thickness and any thin tubes were replaced or shielded for protection from future erosion.
AUGUST 2014									
Black.Dog.4	Forced	Other Miscellaneous Condensing System Problems	08/24/2014	08/29/2014	U4 Condenser	Unit was derated for degraded condenser performance. Condenser fouling (biological and non biological reduction in heat transfer) coupled with high river temperatures caused condenser vacuum issues which limited load generation due to condenser absolute limits (which could cause damage to steam turbine blades).		No similar failures were reported during this reporting period	Condenser fouling and resultant cleaning is a semiannual reoccurring issue. Online mechanical and chemical cleaning is used to improve condenser performance during high river temperatures, but is less effective than offline cleaning (enter condenser and manually clean with scrapers). For this derate, the frequency of the online mechanical cleaning and chemical addition was increased to improve the performance of the unit in the short term until the unit could be taken offline for a regularly scheduled fall outage, at which time an offline cleaning would be performed.
Sherburne.2	Forced	Operator Error	08/25/2014	08/27/2014	This event was initially coded as condenser tube leaks, but further investigation showed that this was due to human error. This error resulted in recycle water (brackish water) being introduced into the primary system causing a chemistry excursion which based on chemistry data was believed to be a condenser tube leak.	Operations and Engineering were investigating a suspected leak in a scrubber module reheater. Past practice has been to use the high pressure deaerator water to confirm reheater leak location. Operations was hesitant to do that in this particular instance due to concerns that it would cause a stack opacity transient. Operations hooked up a hose between an unlabeled pipe connection and the reheater vent connection. Operations and Engineering believed this to be well water (clean water), but in actuality was recycle pond water which is used for other service duties in the scrubbers. Following the leak check, the water was drained but draining was terminated prior to removing all the water. When the reheater was placed back in service, this water was returned to the deaerator, in to the condensate and feedwater, and into the boiler causing the chemistry transient.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	Procedure has been developed to provide guidance to Operations when checking for scrubber module reheater leaks including performing flushing prior to placing it back in service. Water system piping connections in the scrubber building have been labeled.
Black.Dog.3	Forced	First Superheater Leaks	08/19/2014	08/23/2014	Unit 3 Boiler Tubes	Boiler Tube Rupture - Primary Superheat Section		Two Similar events for this unit occurred during this reporting period.	This unit is past end of life and is scheduled for retirement in April 2015. Additional thickness surveys were completed to measure the tube wall thickness and any thin tubes were replaced or shielded for protection from future erosion.
Red.Wing.2	Forced	First Superheater Leaks	08/07/2014	08/13/2014	Unit 2 Superheat Tubes	Unit 2 Superheat tube leak		There was one other similar event during this reporting period (July 1, 2014 - June 30, 2015).	Inspected all superheat tubes for wall loss and repaired as necessary. Performed capital project in March 2015 to perform a partial pendent replacement, which included the front 9 tubes of the western 18 pendents.

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SEPTEMBER 2014									
Allen.S.King.1	Forced/Derate	Feedwater Pump/drive Lube Oil System	09/01/2014	09/03/2014	12 Boiler Feed Pump Main lube oil pump	Turbine driven 12 Boiler Feed Pump Main Lube oil pump failed the monthly swap of pumps test causing the boiler feed pump to trip		No instance prior to this event.	12 Boiler Feed Pump Main Lube oil pump was rebuilt. Testing and swap of oil pumps is done monthly to test the capacity of each pump.
Monticello.1	Forced	Reactor Coolant/recirculating Pump Motors	09/14/2014	09/21/2014	Faulty volt/hertz potentiometer	In the period of time immediately prior to this derate Monticello was operating at approximately 88% power due to power ascension testing limits associated with the Extended Power Uprate Project. On September 14 power was further reduced due to one of the two recirculation pumps that push water through the reactor tripping due to a faulty volt/hertz potentiometer. With only one recirculation pump operating the amount of steam that can be produced is limited. The length of time of this derate was due to the need to replace the faulty volt/hertz potentiometer and to implement the ensuing plan to restart the recirculation pump.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	An Equipment Cause Evaluation was done to evaluate the recirculation pump lockout and why the potentiometer caused the lockout condition. The faulty volt/hertz potentiometer was replaced.
Monticello.1	Forced/Derate	Circulating Water Pump Motors	09/21/2014	09/30/2014	Circulating water pump motor	On September 21 as Monticello was at approximately 81% power, as it was ascending to 88% power following the derate that began on September 14, one of the two circulating water pumps tripped unexpectedly. Because operation of both circulating water pumps is required to support plant operation at higher power levels, operators performed a rapid power reduction from 81% to 63% to stabilize condenser vacuum. The length of time of this derate was due to the need to ship the motor offsite to be rewound.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	Prior to this failure Monticello had been relying on visual inspections and electrical testing to assess the condition of the circulating pump motors. An Equipment Cause Evaluation (ECE) was done. During inspection of the motor as part of the ECE it was determined that a stator winding fault had occurred on the circulating pump motor. This motor was original plant equipment and failure was due to the overall service life of the insulation being reached. The motor was rewound and replaced. An Extent of Condition review was completed on other large motors that are nomally operating during plant operation and recommended actions to prevent age related winding failure have been identified.
Prairie.Island.1	Forced/Derate	Circulating Water Pumps	09/01/2014	09/02/2014	Resistance Temperature Detector (RTD)	An RTD on a circulating water pump motor failed causing a high temperature indication to the operators. The operators, by procedure, removed the motor from service resulting in one of two of the circulating water pumps to be running. With one circulating pump out of service the unit had to be downpowered until the RTD was repaired.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	The faulty RTD was replaced and the circulating water pump was returned to service.
Black.Dog.4	Forced	Second Reheater Leaks	09/20/2014	09/21/2014	Unit 4 Boiler Tubes	Boiler Tube Rupture - Secondary Superheat Section		One Similar event for this unit occurred during this reporting period.	This unit is past end of life and is scheduled for retirement in April 2015. Along with additional thickness surveys / repairs / shielding, boiler pressures and temperatures were reduced in an effort to reduce the stress on the unit. These reductions resulted in reduced energy output, but allowed for operation thru retirement in April of 2015 without another tube leak.
OCTOBER 2014									
Allen.S.King.1	Derate (17 MW)	Feedwater Pump	10/30/2014	10/31/2014	12 Boiler Feed Pump	Turbine driven 12 Boiler Feed Pump removed from service due to high vibrations and temperatures of outboard pump bearing. Suspected alignment of pump and/or bearing as well as a rotating assembly balance issue. Electric driven, 11 boiler feed water pump was put in service but has a smaller capacity resulting in derate		No instance prior to this event.	Outboard bearing inspected and pump alignment verified. Vibration specialist contacted to perform analysis upon return of pump. Specialist recommended a balance weight should be fabricated and installed at the next opportunity.
Monticello.1	Forced/Derate	Circulating Water Pump Motors	10/01/2014	10/31/2014	Continuation of derate beginning on 09/21/2014.	Continuation of derate beginning on 09/21/2014. See explanation above.		Continuation of derate beginning on 09/21/2014. See explanation above.	Continuation of derate beginning on 09/21/2014. See explanation above.
Black.Dog.3	Forced	Second Reheater Leaks	10/02/2014	10/08/2014	Unit 3 Boiler Tubes	Boiler Tube Rupture - Secondary Superheat Section		Two Similar events for this unit occurred during this reporting period.	This unit is past end of life and is scheduled for retirement in April 2015. Along with additional thickness surveys / repairs / shielding, boiler pressures and temperatures were reduced in an effort to reduce the stress on the unit. These reductions resulted in reduced energy output, but allowed for operation thru retirement in April of 2015 without another tube leak.

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Sherburne.2	Forced	Main Steam Relief/safety Valves	10/01/2014	10/03/2014	Main Steam Relief Valve (HP RV 2001)	The Unit experienced a trip from full load on 9/24/14 due to a breaker trip which caused this relief valve and the two other superheat relief valves to lift. When the unit was placed back on-line and steam pressure was building with the load increase, this valve lifted prematurely twice and could not be reset on-line.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	We are planning to change to a different style of valve from the current Crosby valves to Consolidated valves in 2019, which we expect to alleviate future issues. We have changed relief valve servicing contractors due to this outage. We will also do a full inspection on all of the superheat relief valves in 2016.
Sherburne.3	Forced	Second Superheater Leaks	10/17/2014	10/22/2014	Finishing Superheat - One initial leak site, which caused collateral damage on multiple tubes. A total of nine tube replacements were made.	Tube leak occurred in finishing superheat in October of 2014, two and a half days after unit startup. Root cause was short term overheating stress rupture. The lower mills were not available during the initial startup as a result of a failure of a programmable logic controller. This resulted in the superheat section of the boiler being hotter than normal during low steam flow conditions.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	The finishing superheat is original plant equipment and is nearing end of life. Sectional replacement is planned for 2017. Motor control center programmable logic controller replacement is also planned for 2017. Procedures have been compensatorily revised to prevent a cold start up of the unit without management approval if these lower mills are not available.
Wheaton.4G	Maintenance	Gas Turbine - Boroscope Inspection	10/04/2014	10/14/2014	This was a scheduled maintenance outage.	Turbine boroscope inspection was completed during planned overhaul.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	This was a scheduled maintenance outage.
Willmarth.1	Forced	Emergency Generator Trip Devices	10/01/2014	10/07/2014	Mechanical overspeed trip mechanism	Upon removal of trip it was tested on test bench. After it failed to trip at a consistant RPM it was determined that it needed to be sent for internal inspection. The overspeed mechanism was sent to Power Plant Services to inspect the internal components. Their inspection revealed that there was excessive wear (Flat spots)on the governor weight where it actuates the Spindle collar.		There were no other events associated with this forced outage.	A new manufactured overspeed mechanism was purchased and installed in January 2015.
NOVEMBER 2014									
Allen.S.King.1	Forced/Derate	Feedwater Pump	11/03/2014	11/05/2014	12 Boiler Feed Pump	Turbine driven 12 Boiler Feed Pump removed from service due to high vibrations and temperatures of outboard pump bearing. Electric driven 11 boiler feed water pump has a smaller capacity resulting in derate.		One prior event noted above on 10/30/14.	12 Boiler Feed Pump has balance weight installed the week of 11/4/2014 to reduce vibrations.
Allen.S.King.1	Forced/Derate	Feedwater Pump	11/07/2014	11/14/2014	12 Boiler Feed Pump	Turbine driven 12 Boiler Feed Pump removed from service due to high vibrations, high bearing temperatures and bypass leak of recirculation valve. Electric driven 11 boiler feed water pump was put in service but has a smaller capacity resulting in derate.		Two prior events, noted above on 10/30/14 and 11/3/14.	Contacted pump specialist consulted in regards to recirc line bypass leak and the impact to pump vibration which resulted in repairing leak on 12 boiler feed pump recirculation valve flange.
Monticello.1	Forced/Derate	Circulating Water Pump Motors	11/01/2014	11/15/2014	Continuation of derate beginning on 09/21/2014.	Continuation of derate beginning on 09/21/2014. See explanation above.		Continuation of derate beginning on 09/21/2014. See explanation above.	Continuation of derate beginning on 09/21/2014. See explanation above.
Sherburne.2	Forced	Pulverizer Motors And Drives	11/01/2014	11/10/2014	23 Coal Mill main vertical shaft thrust bearing failure.	Mill tripped on low lube oil pressure due to metal shavings plugging up the lube oil filter. Inspection revealed the lower bearing housing oil return lines on both the main and intermediate vertical shafts were not piped back to the sump as originally designed. This was an undocumented modification which occured at some time in the life of the plant. Oil impurities collected in the lower bearing housing due to no flow conditions as a result of this incorrect piping leading to the eventual failure of the bearing.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	The oil return piping was routed back to the sump to be consistent with original design. All other mills on Units 1 and 2 were inspected for similar piping configuration and the other instances found will be corrected during each applicable mill overhaul. Mills are inspected prior to overhauls to determine major gearbox preventative maintenance schedules along with regular lube oil sampling.
Blue.Lake.8	Forced	Main Transformer	11/10/2014	11/22/2014	Unit 8 Generator Step Up Transformer	High Voltage Bushing Oil Leak		Leak was being monitored and was scheduled to be completed during the planned maintenance cycle.	Work was rescheduled for December due to worker availability.

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DECEMBER 2014									
Allen.S.King.1	Forced/Derate	Feedwater Pump	12/01/2014	12/31/2014	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. 12 boiler feedwater pump could not be disassembled at this time due time due to lack of positive isolation against 4500 psi, 300F water. Pump was worked during the spring 2015 plant outage, at that time it was discovered that the inlet pump volute had cracked open due to cyclic fatigue initiating a crack at an internal stress riser. The inlet volute is internal to the pump, guiding the inlet water source through the first of 5 stages of impellers within the pump.		Yes, noted above on 10/30/14, 11/3/14, and 11/7/14.	Pump was removed from service, the pump could not be repaired at this time due to isolation valve leakage making it unsafe to perform the work. In addition, we are pursuing various pump manufacturerers about redesigning the pump to reduce/remove the cyclic fatigue issues and stress risers throughout the pump element.
Blue.Lake.7	Forced	Gas Turbine - Fuel Piping And Valves	12/17/2014	12/19/2014	U7 Fuel Gas Isolation Valve	This was a brand new isolation valve that leaked through and did not hold pressure.		None the Equipment was brand new.	Vendor replaced the leaking valve with a new tested valve, no issues since.
Blue.Lake.8	Forced	Main Transformer	12/09/2014	12/19/2014	Unit 8 Generator Step Up Transformer	High Voltage Bushing Oil Leak		Leak was being monitored and was scheduled to be completed during the planned maintenance cycle.	Oil Leak was repaired. No issues have occurred since.
Prairie.Island.1	Forced	Reactor Coolant/recirculating Pumps	12/10/2014	12/27/2014	Reactor Coolant Pump Seal	During the fall 2014 refueling outage reactor coolant pump seals of a new design were installed in the two reactor coolant pumps on Unit 1. This was a first of a kind modification installed to meet regulatory requirements from Fukushima Accident. Following installation of the new seals degradation of the seals was trended resulting in plant being shutdown on December 10 to troubleshoot and replace the seals. The cause was determined to be foreign material in the reactor coolant pump seals as a result of fabrication activities associated with the seal bypass line during installation of the new seals that was causing the seal to wear unexpectantly.		No similar events prior to occurrence during the reporting period (July 1, 2014 to December 10, 2014).	Failure of the new design was entered into the plant's Corrective Action Program (CAP). Under the CAP program causual evaluations are performed to understand why the seals failed and to identify corrective actions to prevent recurrence. In addition, because this was a new design, other plants who are planning on installing the new seals wanted to ensure this failure and its remedy were thoroughly understood. As a result, Prairie Island had assistance not only from the seal vendor but from multiple experts throughout the industry. Collectively it was decided to remove the foreign material and replace the seals.
Red.Wing.2	Forced	Induced Draft Fan Motors And Drives	12/08/2014	12/11/2014	Unit 2 Over Fired Air Fan Variable Frequency Drive Unit	Unit 2 Over Fired Air Fan Variable Frequency Drive unit failed		No similar events during this reporting period (July 1, 2014 - June 30, 2015).	The failed variable frequency drive was repaired and returned to service.
Red.Wing.2	Forced	First Superheater Leaks	12/20/2014	12/24/2014	Unit 2 Superheat Tubes	Unit 2 Superheat tube leak		There was one other similar event during this reporting period (July 1, 2014 - June 30, 2015). The other event occurred in August 2014.	Inspected all superheat tubes for wall loss and repaired as necessary. Performed capital project in March 2015 to perform a partial pendent replacement, which included the front 9 tubes of the western 18 pendents.

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JANUARY 2015									
Sherburne.1	Forced	Pulverizer Mill Classifiers	01/22/2015	01/25/2015	13 Coal Mill Dynamic Classifier labrynth seal failure.	The addition of dynamic classifiers is a capital project to comply with environmental regulations for NOX reduction. A temporary corrosion protective coating was applied to the machined surfaces of various parts. This material was not removed prior to assembly which prevented the metal surfaces from mating properly. This likely started two failure mechanisms. The first failure mechanism was that the additional material decreased the clearance in the labyrinth seal which caused a "rub" once the drive assembly heated up. The second failure mechanism is that the socket head cap screws that hold the drive pulley would have become loose once the protective coating became less viscous under higher temperatures. The socket head cap screws had been modified during assembly to compensate for the counter bores being too shallow by facing off the underside of the head and removing the fillet radius to get them to sit below flush. These screws also were manufactured with the flaw of having had the hole drilled too deep into the head prior to being broached. The combination of the machining on the cap and the drilling prior to broaching the socket created an intersection where the cross-sectional area of the cap screw was reduced; this weakened the cap screws causing five of the eight to fail. The heads broke off three and the other two broke from the additional load placed upon them. Three remained intact but two of these had some stripped threads and all were loose. This was a contractor performance issue.		Similar event on 1/26/2015	Classifier was disassembled down to the bearing, parts were cleaned and re-assembled with all new fasteners, Loctite and lock washers. A non conformance report was initiated for all issues identified on this project to hold the supplier accountable. All charges for parts and labor will be back charged to the supplier. All identified defects were corrected by the supplier on unshipped dynamic classifiers and all dynamic classifiers already installed or on site have been inspected and identified defects repaired.
Sherburne.1	Forced	Pulverizer Mill Classifiers	01/26/2015	01/28/2015	13 Coal Mill Dynamic Classifier labrynth seal failure.	The addition of dynamic classifiers is a capital project to comply with environmental regulations for NOX reduction. This classifier was disassembled again and found that the same bolts for the drive pulley as referenced in the above event had all worked loose even with the Loctite and lock washers and torqued to 100 ft/lbs per supplier recommendation. Most of the counter bores in the drive pulley were found to be shallow so spacers were not flat on the bottom causing the screws to work loose. It was also discovered .030 of vertical run-out in the bearing. Also the lower grease seal was found to be installed upside down. This was a contractor performance issue.		Similar event on 1/22/2015	The spacer that the bearing attaches to bearing was modified to achieve .005 run-out, bearings were replaced, the stationary labrynth seal was shimmed to get it parallel to the rotating seal to maintain clearance of at least .090. The counter bores in the drive pulley were recut. Lower grease seal was re-installed in the correct configuration. A non conformance report was initiated for all issues identified on this project to hold the supplier accountable. All charges for parts and labor will be back charged to the supplier. All identified defects were corrected by the supplier on unshipped dynamic classifiers and all dynamic classifiers already installed or on site have been inspected and identified defects repaired.
Allen.S.King.1	Forced	Exciter Commutator And Brushes	01/06/2015	01/07/2015	Generator Exciter	Exciter/Generator ground fault detection system alarmed as a result of an oil film across insulated surfaces. The oil was drawn through the bearing oil seal and liberated into a fine mist and distributed throughout the exciter housing due to the speed of the exciter shaft and ventilation system within the housing. The oil allowed fine particles of carbon from exciter brush wear to collect resulting in the ground fault detection alarm. Root cause(s): lower pressure within the exciter encloser vs the bearing oil system due to accumulation of dust and other materials on the exciter enclosure filters.		No instance prior to this event.	All surfaces and equipment were cleaned, removing oil residual and carbon dust. Preventative maintenance practices for filter change outs was increased. New insulating materials were ordered to have on hand in the event the oil had penetrated the existing insulators.

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Allen.S.King.1	Forced	Exciter Commutator And Brushes	01/16/2015	01/18/2015	Generator Exciter	Exciter/Generator ground fault detection system alarmed as a result of an oil film across insulated surfaces. The oil was leaching out from under insulating material as well as through the oil seal. The oil surfaces allowed carbon dust to build up resulting in the ground fault detection alarm. Root cause(s): Bearing oil seal clearance was excessive and dust had migrated into the seal grooves allowing small amounts of oil to migrate past seal. Oil from the first event noted above had gotten wicked under the insulated surfaces due to small gaps between mating surfaces, this oil leached out from under the surfaces during equipment operation.		One other instance noted above on 1/6/15.	All surfaces were cleaned, equipment disassembled, and new insulting materials were installed.. Bearing oil seal was disassembled, cleaned and installed to proper tolerance. We are working with the OEM and our technical resources team to develop an improved bearing oil seal design for installation in a future planned outage.
Black.Dog.3	Forced	Generator Rotor Collector Rings	01/14/2015	01/15/2015	Unit 3 Generator Rotor Collector Rings	Long term generator collector ring wear caused rotor vibration requiring an outage and repair		No similar failures were reported during this reporting period	This unit is past end of life and is scheduled for retirement in April 2015. The collector ring has required frequent offline grinding to bring vibration down and prolong life. However, only so much material can be removed before replacement of the ring assembly would be required , at a significant cost, lead time, and outage duration for installation. Due to vibration and proximity to the retirement in April, the ring was hand stoned, rather than ground, and the unit was returned to service.
Black.Dog.3	Forced	Generator Brushes And Brush Rigging	01/19/2015	01/23/2015	Unit 3 Generator Rotor Collector Rings	Long term generator collector ring wear caused rotor vibration requiring an outage and repair		Continuation of event on 1/14/2015	Continuation of 1/14/15 event. Following hand stoning and return to service, collector ring current distribution was uneven. The unit was taken offline and additional stoning was performed, along with installing new brush rigging and brushes. The unit was returned to service without issue and operated without incident through retirement in April 2015.
BD25.CC	Forced	Other Exciter Problems	01/04/2015	01/06/2015	Unit 52 Generator Exciter Breaker	Exciter breaker failed to close on startup		No similar failures were reported during this reporting period	The breaker failed due to the auxillary switch found slightly out of adjustment. This prevented the breaker from latching as designed. The auxillary switch actuating lever was adjusted, the breaker was tested repeatedly and did not fail. Our Preventative Maintenance Procedures were reviewed to make sure this switch adjustment/verification step was included and found that it was properly included. This appeared to be an isolated incident so no further actions were necessary.
Prairie.Island.1	Forced	Reactor Coolant/recirculating Pumps	01/26/2015	01/31/2015	Reactor Coolant Pump Seal	Following plant startup on December 27 degradation of the newly replaced reactor coolant pump seals was experienced. The cause was determined to be foreign material in the reactor coolant pump seals causing the seal to wear unexpectantly.		A similar event occurred during the reporting period on December 10, 2014 (see above).	As described above, failure of the seal was entered into the plant's corrective action program and industry experts were gathered to understand why removal of the foreign material had not adequately addressed the problem. It was identified that the new seal design was susceptible to much smaller particles of foreign material than had been previously experienced with other seals. To further remove the potential for foreign material contamination the seals and associated piping were flushed with approximately 37,000 gallons of clean water and the seals were replaced.
FEBRUARY 2015									
Black.Dog.3	Forced	Air Heater (regenerative)	02/24/2015	02/27/2015	Unit 3 Air Heater (regenerative)	Air Heater Drive Coupling failure		No similar failures were reported during this reporting period	This unit is past end of life and is scheduled for retirement in April 2015. The Air Heater Drive Coupling failed from normal operational wear. The coupling was replaced and the unit operated without issue through retirement in April 2015.
Prairie.Island.1	Forced	Reactor Coolant/recirculating Pumps	02/01/2015	02/12/2015	Continuation of outage beginning on 01/26/2015. See explanation above.	Continuation of outage beginning on 01/26/2015. See explanation above.		Continuation of outage beginning on 01/26/2015. See explanation above.	Continuation of outage beginning on 01/26/2015. See explanation above.

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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
MARCH 2015									
Prairie.Island.1	Forced	Heater Drain Pumps	03/05/2015	03/06/2015	Fuse on the Heater Drain Tank Level indicator	The heater drain tanks locked out on a low Heater Drain Tank Level indication causing a power transient and a down power to 95% for 30 hours. The cause of the low level indication was a failed fuse.		The fuse had been replaced due to low voltage on November 13, 2014.	The fuse was replaced. Past experience has demonstrated that a four-year replacement frequency is adequate for preventive maintenance. It was concluded that this instance was a premature part failure.
Black.Dog.4	Forced	Boiler Water Condition (not Feedwater Water Quality)	03/13/2015	03/15/2015	Unit 4 Water Condition	Contamination of makeup water required cleanup before starting unit up		No similar failures were reported during this reporting period	Common makeup water tanks were contaminated from a water softener malfunction. A unit startup was attempted once the makeup water quality was acceptable, but soon showed that water quality was deteriorating again and the unit start was aborted.
Black.Dog.4	Forced	Boiler Water Condition (not Feedwater Water Quality)	03/16/2015	03/23/2015	Unit 4 Water Condition	Contamination of makeup water required cleanup before starting unit up		Continuation of event on 3/13/2015	The unit was held out pending improved makeup water quality following contamination from a softener malfunction. The softener system design was changed to prevent future contamination.
Prairie.Island.2	Forced	Instrument Air Valves	03/05/2015	03/25/2015	Solenoid on containment isolation valve in instrument air line going into containment	Failure of the solenoid caused a containment isolation valve in the instrument air line supplying systems inside of containment to fail in the closed position causing instrument air to be unavailable inside containment. As a result normal means of cooling equipment inside of containment were not available and we had to switch to alternate methods. The alternate method requires Pressurizer level to be maintained by diverting Pressurizer level to the Pressurizer Relief Tank. The Pressurizer Relief Tank rupture disc ruptured which released steam inside of containment causing a false fire alarm in Unit 2 Containment. Because the fire alarm was inside containment and it could not be validated within 15 minutes an Unusual Event was declared. The loss of instrument air to the reactor vessel ventilation systems required us to shut down the plant.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	The faulty solenoid valve was replaced and an extent of condition assessment was performed on both units at Prairie Island. All similar solenoid valves were replaced.
APRIL 2015									
HBR CC 1x1	Forced	Other Gas Turbine Combustor Problems	04/14/2015	04/17/2015	U7/U8 Combustion systems	Various derates as a result of combustion dynamics issues creating unstable unit firing.		Numerous other instances of combustion dynamics and tuning related issues occurred during this reporting period.	Each occurrence was managed by interface with MHPSA (Mitsubishi/Hitachi Power Systems Americas) Remote Monitoring Center (RMC). The RMC provided combustion tuning changes to address the instability issues. In addition, combustion and turbine modifications were completed during the U7 Hot Gas Path Overhaul in May 2015 to address equipment issues contributing to combustion instability. U8 is scheduled for a portion of these same modifications in the October 2015 overhaul as well as the scheduled 2018 Hot Gas Path Overhaul.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Northern States Power Company - Minnesota
Unit Outage Information
2015 AAA Reporting Period: July 1, 2014 - June 30, 2015

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
Prairie.Island.1	Forced	Reactor Coolant/recirculating Pumps	04/07/2015	04/30/2015	Reactor Coolant Pump Seal	Following startup on February 12 degradation of the newly replaced reactor coolant pump seals was experienced. The cause was determined to be foreign material in the reactor coolant pump seals causing the seal to wear unexpectantly.		Similar events occurred during this reporting period on December 10, 2014 and January 26, 2014.	As described above, failure of the seal was entered into the plant's corrective action program and industry experts were gathered to understand why flushing with clean water had not remedied the issue. It was identified that the new seal design continued to be susceptible to smaller particles of foreign material than had been previously experienced with other seals. A two-step approach was identified to remedy the issue: 1) A new "frothing flush" method was used to remove much finer particles of foreign material; and 2) A modification was made to the 3rd stage of the 3-stage seal reducing its susceptibility to foreign material. The seals were replaced and have been performing well. The new reactor coolant pump seals with the modification developed at Prairie Island is now being utilized by other utilities to ensure that foreign material from normal operations do not degrade the reactor coolant pump seals.
Prairie.Island.2	Forced	Other Feedwater System Problems	04/03/2015	04/04/2015	Feedwater Pump Pressure Switch	Mechanical failure of a pressure switch due to pressure fluctuations within the system.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	The pressure switch was replaced and snubbers were installed to reduce flow fluctuations that caused internal wear in the switch.
MAY 2015									
French.Is.2	Maintenance	Minor Boiler Overhaul (less Than 720 Hours)	05/15/2015	05/21/2015		This was a maintenance outage for periodic cleaning and inspection.		One similar event for French Island Unit 1 in June 2015	RDF fuel causes boiler fouling. We believe we are cleaning at appropriate intervals.
Prairie.Island.1	Forced	Reactor Coolant/recirculating Pumps	05/01/2015	05/09/2015	Continuation of outage beginning on 04/07/2015. See explanation above	Continuation of outage beginning on 04/07/2015. See explanation above.		Continuation of outage beginning on 04/07/2015. See explanation above.	Continuatin of outage beginning on 04/07/2015. See explanation above.
JUNE 2015									
Sherburne.2	Forced	Automatic Turbine Control Systems - Mechanical	06/15/2015	06/22/2015	Load reference signal from the turbine control system to the coordinated control system	Load reference signal input to the coordinated control system had drifted due to age preventing turbine control valve number four from opening past 42% open.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	The load reference signal was adjusted to allow full open on the control valve. Turbine controls are becoming obsolete. New turbine controls will be installed in 2016.
French.Is.1	Maintenance	Minor Boiler Overhaul (less Than 720 Hours)	06/03/2015	06/12/2015		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.
Prairie.Island.1	Forced	Condensate/hotwell Pump Motor	06/01/2015	06/03/2015	Number 11 Condensate Pump	The number 11 condensate pump locked out resulting in an unplanned reactor trip. The pump locked out due to degradation of the insulation in the motor windings.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	Degradation of the insulation was caused by voids in the windings. The motor was rewound and tested using a new process to ensure the voids were not present.
Prairie.Island.2	Forced	Ip Turbine Bearings	06/07/2015	06/13/2015	Turbine Lube Oil Sump	Unit 2 Reactor automatically tripped while operating at 100 percent power due to an automatic Turbine trip due to low bearing oil pressure. The low oil bearing pressure was due to a broken weld at the connection of the main oil pump discharge to the high presure seal oil supply diverting the flow of oil.		No similar events during this reporting period (July 1, 2014 to June 30, 2015).	The weld was part of original plant equipment. It was repaired and other welds in the tank were inspected.

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, 2014	July, 2014
Network Resource	ICAP (Summer)	UCAP (Summer)	ICAP (summer)	UCAP (summer)
NSP.ALDRIHERC	34	23	34	23
NSP.ANSON2	93	83	97	89
NSP.ANSON3	93	76	96	85
NSP.ANSON4	149	144	153	147
NSP.BAYFRN	67	64	69	37
NSP.BIGFALL_A	4	3	7	3
NSP.BLKDO3	NA	NA	83	67
NSP.BLKDO4	NA	NA	152	120
NSP.CC.BLKD52	285	247	281	197
NSP.BLUEL1	39	35	40	38
NSP.BLUEL2	39	39	40	40
NSP.BLUEL3	38	38	39	39
NSP.BLUEL4	41	41	45	45
NSP.BLUE_LK7	154	154	152	149
NSP.BLUE_LK8	155	150	153	145
NSP.CANFLSG1	179	157	157	157
NSP.CANFLSG2	179	155	157	155
NSP.CEDARFAL	3	2	9	3
NSP.CHEMOLSPO	262	235	243	235
NSP.CHPFAL	9	7	23	4
NSP.CORNEL1	15	11	31	11
NSP.FIBROMIN1	55	47	55	53
NSP.FRENCH1	16	15	15	0
NSP.FRENCH2			16	7
NSP.FRENCH4	61	56	61	57
NSP.GDMEADOW	101	14	100	14
NSP.GRANCT1	13	9	14	13
NSP.GRANCT2	14	12	14	14
NSP.GRANCT3	14	12	14	13
NSP.GRANCT4	13	11	13	12
NSP.HENNIPIN1	5	4	11	0
NSP.CC.HIBRDG	544	515	541	522
NSP.HOLCOM	15	11	34	12
NSP.INVRHL1	48	41	49	41
NSP.INVRHL2	48	46	47	45
NSP.INVRHL3	48	44	48	44
NSP.INVRHL4	48	40	48	42
NSP.INVRHL5	47	41	47	42
NSP.INVRHL6	48	39	47	42
NSP.JIMFL	24	18	52	18
NSP.KEYCIT	49	45	37	34
NSP.KING1	541	519	542	516
NSP.CC.MANKATO	357	277	299	277
NSP.MENOMOA	2	2	5	1
NSP.MNMETHANE	5	1	5	2
NSP.MNTCEL1	624	608	557	528
NSP.NOBLES	201	34	200	34
NSP.PINEBEND	12	5	7	5

	2016-2030 Resource Plan	2016-2030 Resource Plan	July, 2014	July, 2014
Network Resource	ICAP (Summer)	UCAP (Summer)	ICAP (summer)	UCAP (summer)
NSP.PKFLSFLAM	13	11	14	11
NSP.PRISL	1,038	1,035	1040	1027
NSP.RAPIDA1	5	3	6	3
NSP.REDWIN1	21	20	10	8
NSP.REDWIN2			11	8
NSP.CC.RIVRSD	470	443	462	435
NSP.SHAKOBIO1	12	12	12	12
NSP.SHERCO1	709	694	709	698
NSP.SHERCO2	694	667	693	675
NSP.SHERC3	527	515	492	469
NSP.SPGSPG1 (St. Paul Co-Gen)	25	25	25	25
NSP.STCLOUD1	9	7	8	7
NSP.STCRO	15	11	15	25
NSP.WHEATO1	46	40	49	43
NSP.WHEATO2	55	48	57	45
NSP.WHEATO3	46	42	48	40
NSP.WHEATO4	47	45	49	41
NSP.WHEATO5	53	42	58	42
NSP.WHEATO6	51	31	54	45
NSP.WILMAR1	19	17	11	7
NSP.WILMAR2			12	8
NSP.WISSOT	17	12	38	13
MHEB (500 MW System Purchase)	500	489	500	490
MHEB (200 MW Diversity Exchange)	200	342	200	200
MHEB (150 MW Diversity Exchange)	150		150	150
Laurentian Energy Authority	35	32	35	35
DPC - Flambeau Hydro	1		0	1
MPC - Coyote #1	100	95	100	95
Wind Aggregate PPA's	1,393	181	1363	177
Total	11,041	8,988	11,159	9,009

Note: Excelsior Tech was mothballed during this reporting period.

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-14	Coal JDE Object 614000	Mar-14	Spring Coal Survey Adjustment correction to Black Dog Plant	$674,226	Yes
Aug-14	None				
Sep-14	None				
Oct-14	Long Term (JDE Object 632000)	Various Time Period and Refund Included in December 2014 Fuel Cost Charges	A settlement was received from Alliant Energy for $6.4M to reimburse NSP for overpaying MISO for the energy poriton of an overstatement of load volumes. This was offset by a payment to WAPA for unmetered volumes on past invoices. Commission granted variance to proceed with the net refund with interest to Minnesota ratepayers (Docket No. E002/M-14-614, dated Novemer 24, 2014).	($5,650,409)	Yes
Nov-14	None				
Dec-14	Coal JDE Object 614000	Oct-14	Fall Coal Survey Adjustment impacting Sherco Plant	($1,735,487)	Yes
Jan-15	Long Term JDE Object 632000	2014	Annual true-up for Fibrominn Ash pass through charge	$1,133,341	Yes
Feb-15	Long Term JDE Object 632000	2014	Annual true-up for Fibrominn Ash pass through charge	$2,634,653	Yes
Mar-15	Fossil Fuel-Oil JDE Object 612000	Mar-15	Remibursement from the insurance companies for the excess fuel oil that was consumed during the startup of Sherco 3 following repairs	($503,486)	Yes
Apr-15	None				
May-15	None				
Jun-15	Coal JDE Object 614000	Mar-15	Spring Coal Survey Adjustment impacting Sherco Plant	$1,449,983	Yes
Jun-15	Long Term IPP JDE Object 632000	May-15	Fibrominn estiamted accrual for Transportation Pass-Through costs was much higher than actual invoice paid.	($1,165,894)	Yes
Jun-15	Wind JDE Object 634000	Oct 2014 - Feb 2015	Courtenay Wind Farm - reversal of prior months estimated accrual for delay damanges.	$604,000	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 2013 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	Total MWs awarded in Day-Ahead Markets (Positive for Loads, negative for Generators). **This field is TRADE SECRET**.
NativeMW	MWs assigned to Native. **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 2014	
[TRADE SECRET BEGINS		Peak	Peak Off
			TRADE SECRET ENDS]

Generation Node	Load Node	Fall 2014	
[TRADE SECRET BEGINS		Peak	Peak Off
			TRADE SECRET ENDS]

Generation Node	Load Node	Winter 2014-2015	
[TRADE SECRET BEGINS		Peak	Peak Off
			TRADE SECRET ENDS]

Generation Node	Load Node	Spring 2015	
[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 2013 and 2014 compared to the amounts built into base rates for the 2014 test year approved in Docket No. E002/GR-13-868. The table shows State of Minnesota jurisdictional amounts.

2013 Actual	2014 Actual	Two-Year Average	2014 Test Year as filed
$13,907,388	$13,404,416	$13,655,902	$15,291,479

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

*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.)	Minimum (p.u.)	Maximum (p.u.)	Minimum (p.u.)
	Pre Contingent		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.

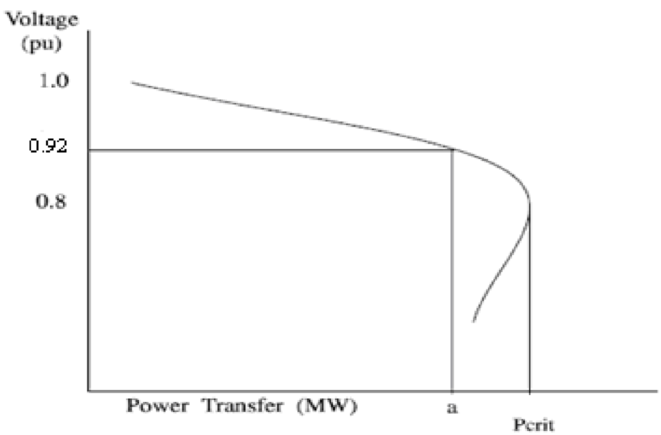

Figure 4.1

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
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4.0 VERSION HISTORY

Effective Date	Version Number	Supercedes	Change
	1.0	n/a	Initial version

TABLE OF CONTENTS

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:

[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-15-611

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-15-611

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
John Tuma	Commissioner
Betsy Wergin	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-15-611

On September 1, 2015, 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, 2015 involving the following MPUC Rules:

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

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

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

Xcel Energy
Regulatory Administration
414 Nicollet Mall
Minneapolis, Minnesota 55401

CERTIFICATE OF SERVICE

I, SaGonna Thompson, 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-12-961; E002/GR-13-868; E999/AA-14-579; AND MISCELLANEOUS ELECTRIC

Dated this 1st day of September 2015

/s/

____
SaGonna Thompson

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