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Fergus Falls, Minnesota 56538-0496
218 739-8200
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August 31, 2015

PUBLIC DOCUMENT – TRADE SECRET DATA HAS BEEN EXCISED

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: Otter Tail Power Company
2015 Annual Automatic Adjustment of Charges Report - Electric
Minnesota Rules 7825.2800 – 7825.2840
Docket No. E999/AA-15-___

Dear Mr. Wolf:

Otter Tail Power Company ("Otter Tail") hereby submits to the Minnesota Public Utilities Commission ("Commission") its annual report pursuant to Minnesota Rules 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges.

Attachment P to this response contains the hourly information requested in an Access file format (Attachment PtoAAA_2014-2015_NONPUBLIC.accdb). *This attachment will be provided separately on a cd as it is not in a format that can be electronically filed.*

Various portions and attachments to this filing contain information that Otter Tail considers trade secret. Otter Tail believes this filing comports with the Commission's Notice relating to Revised Procedures for Handling Trade Secret and Privileged Data, pursuant to Minn. Rule part 7829.0500. As required by the revised procedures, a statement providing the justification for excising the trade secret data follows this letter.

If you have any questions regarding this filing, please contact me at 218-739-8279 or at stommerdahl@otpco.com.

Sincerely,

/s/ STUART TOMMERDAHL
Stuart Tommerdahl
Manager, Regulatory Administration

Enclosures
By electronic filing
c: Service List

STATEMENT REGARDING JUSTIFICATION FOR EXCISING TRADE SECRET INFORMATION

Please note that Otter Tail Power Company has marked the following portions of this filing with the caption **NONPUBLIC DOCUMENT – CONTAINS TRADE SECRET DATA**, according to Minn. Stat. Sec. 13.37, subd. 1(b). This statute protects certain "government data," as that term is defined at Minn. Stat. Sec. 13.02, subd. 7, from being disclosed by an administrative agency to the public.

- Rule 7825.2810 Subpart 1.B. Monthly Cost Components by Fuel-Type (Part E Section 2 Attachment C-2);
- Wind Curtailment Summary Report (Part E Section 9 Attachment F);
- Paragraphs 7.A.1. a) and b) of reporting requirements from Passing MISO Day 2 Costs Through Fuel Clause Order in Docket No. E-017/M-05-284 (Part E Section 10);
- MISO Module E Data (Part E Section 10 Attachment G);
- Forecast for 2016 (Part E Section 10 Attachment H);
- Net Intersystem and Total columns of the monthly Detail of MISO Day 2 Charges by Charge Group (Part E Section 10 Attachment I-1);
- Annual Five-Year Projection Report (Part G);
- Compliance Report in Docket No. E017/M-06-1332 (Part H Section 1);
- Non Asset Based columns of the Detail of MISO Day 2 Charges by Retail, Asset Based and Non Asset Based (Part H Section 3 Attachment K);
- Otter Tail's Forced Outage Information Change in Energy Costs Column (Part H Section 5 Attachment M);
- Otter Tail's Generation Deliverability Results for MISO Planning Year 2014/2015 (Part H Section 5 Attachment N);
- Comparison of Otter Tail's MISO Generation Deliverability Results and Otter Tail's current Integrated Resource Plan (Part H Section 5 Attachment O);
- Hourly information in an Access file format (Part H Section 7 Attachment P); and
- Portion of reply to 20. b.i. through c.iii. of MN PUC Order Acting on Electric Utilities' Annual Reports, Requiring Refund of Certain Curtailment Costs, and Requiring Additional Filings in 2010/2011 Annual Automatic Adjustment Reports Docket No. E999/AA-11-792 (Part H Section 7).

The information being supplied in this filing is considered to be a "compilation" of data that (1) was supplied by Otter Tail Power Company, (2) is the subject of reasonable efforts by Otter Tail Power Company to maintain its secrecy, and (3) derives independent economic value, actual or potential, from not being generally known to or accessible to the public.

It is Otter Tail Power Company's understanding that marking the filing in this manner is consistent with the revised procedures for handling trade secret and privileged data, as announced in the joint memorandum of the Office of Energy Security and Public Utilities Commission dated August 18, 1999 and which became effective September 1, 1999.

Date prepared: August 31, 2015

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's Annual Automatic Adjustment of Charges Report	Docket No. E999/AA-15-___ **PETITION OF OTTER TAIL POWER COMPANY**

I. INTRODUCTION

Otter Tail Power Company ("Otter Tail" or "the Company") submits this Annual Report as required in Minn. Rules 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges (AAA) for electric utilities for the period of July 1, 2014 to June 30, 2015.

II. GENERAL FILING INFORMATION

Pursuant to Minn. Rule 7829.1300, subp. 4, Otter Tail provides the following general information.

A. Name, Address, and Telephone Number of Utility.

Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8200

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

Cary Stephenson
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8956
cstephenson@otpco.com

C. Date of Filing.

Consistent with the filing requirement in Minn. Rule 7825.2840, the date of this filing is August 31, 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. Rules 7825.2800 through 7825.2840.

E. Title of Utility Employee Responsible for Filing.

Stuart Tommerdahl
Manager, Regulatory Administration
Otter Tail Power Company
215 South Cascade Street
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III. DESCRIPTION OF FILING

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

7825.2800 Annual Report: Policies and Actions

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

Section 1 Fuel Procurement Practices
Section 2 Fuel Utilization
Section 3 Procurement of Transportation Services
Section 4 Conservation Improvement Programs
Section 5 Compliance Report as Requirement by Order in
Docket E017/PA-01-1391

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 the prior year of July 1, 2014 to June 30, 2015. It includes the following:

Section 1 Subpart 1.A. Commission Approved Base Cost of Fuel
Section 2 and 3 Subpart 1.B. and 1.C. Billing Adjustment Amounts
Section 4 Subpart 1.D. Total Cost of Fuel Delivered to Customers
Section 5 Subpart 1.E. Revenue Collected from Customer for Energy Delivered
Section 6 and 7 Subpart 1.F and 1.G. The Amount of Refunds
Section 8 Compliance Report as Ordered in Docket No. E017/M-03-30
Section 9 Compliance Report as Ordered in Docket No. E017/M-03-970
Section 10 Passing MISO Day 2 Costs Through Fuel Clause Order in Docket No. E017/M-05-284

7825.2820 Annual Auditor's Report

Part F contains the Independent Auditor's Report for the period of July 1, 2014 to June 30, 2015.

7825.2830 Annual Five-Year Projection

Part G contains a monthly five-year projection of fuel cost by energy source marked as Trade Secret.

Additional Reporting Requirements

Part H includes reporting items from other dockets pertaining to the fuel clause.

7825.2830 Notice of Reports Availability

Part I contains the Notice of Reports Availability, Certificate of Service, and Service Lists.

IV. ACKNOWLEDGEMENT OF DEPARTMENT'S RECOMMENDATION TO END ONE COMPLIANCE OBLIGATION

An annual compliance report was required in the Order in Docket No. E017/M-06-1332. This report pertains to one particular customer and compares the rate they are currently on to an alternative rate available to the customer. Otter Tail questioned the need to continue filing this report and requested in Docket No. E999/AA-14-579 ("AA-14-579") the Commission give consideration to ending this compliance report in future annual automatic adjustment filings. This report is found in Part H, Section 1 of this annual filing. In the Department's Comments dated May 19, 2015 in AA-14-579, the Department recommends the Commission approve the removal of this requirement. Otter Tail is submitting the information for 2014/2015 while awaiting the Commission approval.

V. CONCLUSION

Otter Tail respectfully requests that the Commission approve the enclosed annual automatic adjustment of charges report.

Dated: August 31, 2015

Respectfully submitted,

OTTER TAIL POWER COMPANY

By: */s/ STUART TOMMERDAHL*

Stuart Tommerdahl
Manager, Regulatory Administration
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LIST OF ATTACHMENTS

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-___

PART D - RULE 7825.2800 POLICIES AND ACTIONS

RULE 7825.2800 ANNUAL REPORTS - POLICIES AND ACTIONS

Otter Tail Power Company ("Otter Tail") has one main policy with regard to energy purchases and fuel consumption, as well as dispatching procedures. Under this main policy are also several other policies that pertain to our main policy. These policies are identified first, and then later explained with the procedures used to implement these policies.

1. The total cost for energy purchases and fuel cost of generation to Otter Tail customers will be minimized, while at the same time operating the electrical system in a safe and reliable manner within the NERC, MISO, and MRO guidelines.

2. Otter Tail generating facilities will be economically dispatched within the operating constraints of the units. This economic dispatch is provided by the Midwest ISO ("MISO") energy market as of April 1, 2005.

These policies involve the following procedures:

1. We state that we wish to minimize the total cost of purchases and fuel cost of generation, because a decrease in cost of one area may cause an increase in cost in the other area. As long as net savings are possible in the overall costs and the system is operated within guidelines, generation and/or energy transactions will be adjusted to affect those savings. In the long term (seasonally), computer software is used to analyze the effect of making long-term energy purchases in order to reduce overall costs. If savings can be realized by making long-term purchases, we will make such a purchase. In the short-term, the MISO energy market will automatically complete short-term energy purchases—displacing higher cost company generation.

2. Otter Tail units are dispatched by the MISO energy market according to their offer parameters relative to the offer parameters of all other units within the MISO footprint. Operating constraints are communicated to MISO, and they must be closely followed. Where Otter Tail retail load serving is concerned Otter Tail Power Services' personnel are instructed to follow the guidelines stated above.

Rule 7825.2800 Annual Report: Policies and Actions (Continued)

FUEL PROCUREMENT PRACTICES

COAL

Otter Tail's policy for the procurement of fuel for the Big Stone Plant and Coyote Station is to use a competitive bidding process. A complete evaluation of all bids received is performed and supplier(s) are selected based on achieving the lowest cost to Otter Tail commensurate with adequate reliability of supply, environmental compliance and compatibility with boiler equipment.

Otter Tail has commitments for approximately 100% of the expected coal needs in 2016 and approximately 90% of the expected coal needs for 2017. The balance of the plant’s coal needs will be procured at a future time.

The Big Stone Plant in South Dakota has commitments for about 100% of the expected coal needs in 2016 and 85% in 2017. The balance of the plant’s coal needs will be procured at a future time.

The Coyote Station in North Dakota burns lignite from an adjacent mine. This lignite is supplied under a contract with Dakota Westmoreland Corporation. This contract expires in 2016. Following an evaluation of alternatives in October 2012, the Coyote Station owners, including Otter Tail, entered into a lignite sales agreement (“LSA”) with Coyote Creek Mining Company, L.L.C. (“CCMC”), a subsidiary of The North American Coal Corporation, for the purchase of coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040.

Otter Tail is currently evaluating a contract for the supply of fuel to the Hoot Lake Plant that would not require a minimum tonnage, but rather allow for greater flexibility of coal use should the Hoot Lake facility not operate significantly between 2016 – 2020 due to the dispatch cost of the plant relative to market prices within the MISO market. The coal being considered is known to operate well in the Hoot Lake boilers as well as the pollution control equipment installed to meet the Federal Environmental Protection Agencies Mercury & Air Toxics Standards (“MATS”) rule.

Otter Tail notes that due to rail service issues experienced not only by Otter Tail, but rail customers across the country during calendar year 2014, coal conservation measures were implemented by the joint owners at Big Stone Plant for a period of time in late 2013 and parts of calendar year 2014. Otter Tail provided a lengthy discussion on the issue in Reply Comments submitted in last year’s AAA Docket 14-579 on June 19, 2015. These conservation measures continued from July thru November of 2014 and lifted beginning December 2014. No further conservation measures have been needed since that time. Otter Tail estimates the incremental cost of power during the July to November timeframe to be roughly $1.02 million (System), with Otter Tail’s share being approximately 50% of that amount during the 2014/2015 AAA reporting period.

Rule 7825.2800 Annual Report: Policies and Actions (Continued)

FUEL PROCUREMENT PRACTICES

OIL

Otter Tail's policy for the purchase of fuel oil requires a competitive bidding process wherein inquiries are provided to several suppliers and the lowest cost bidder selected after an evaluation process.

OTHER FUELS

Otter Tail purchases natural gas for the Solway unit from competitive suppliers. Since the unit is operated as a peaking facility, the need for gas is intermittent, and long-term supply arrangements have not been utilized. Gas is generally purchased on a day-ahead basis using firm transfer capability. The unit is located on the Great Lakes pipeline.

Rule 7825.2800 Annual Report: Policies and Actions (Continued)

FUEL UTILIZATION

1. The steam plants operated by Otter Tail are equipped with oxygen probes that indicate and record the readings in the flue gas at the boiler exit. The readings are used by the plant control systems and monitored by the operators to maintain levels that are efficient and safe. The operators at Big Stone, Coyote, and Hoot Lake have numerous tools to monitor and control the air flow to keep the plant running at its optimum efficiency.

2. In general, Otter Tail has established the following policies with regard to periodic maintenance of its steam-electric generating facilities:

   (a) Partial inspections of turbines are performed once every three to six years. A partial inspection includes such items as cleaning and inspecting of all valves, measuring and recording tolerances, inspecting the governor mechanism, inspecting couplings and bushings, valve actuators, as well as the repair when issues are found.

   (b) Partial inspections of generators are performed on a three- to six-year interval. The inspection includes cleaning and numerous electrical tests recommended by the original equipment manufacturer (“OEM”). The "megger" resistance readings of the generator stator and rotor windings, the exciter field leads, rotor winding, and other critical points are performed during these inspections.

   (c) Complete inspections of the turbines are performed at approximately 6 – 10 year intervals, including lifting of covers and rotors, checking blade clearances, inspection of control valves, bearings, lube oil systems, and bleeder line nonreturn valves. The blades will generally be tested for cracks with the magnaflux system, and coupling alignment is checked. Major turbine overhauls are performed on 6 - 10 year intervals, per manufacturer recommendations.

   (d) Complete inspection of generators are performed at approximately 10-year intervals, including removal of the rotor and complete cleaning. All electrical and mechanical components are checked and tested and all clearances confirmed. "Megger" resistance tests and Doble power factor tests are performed.

   (e) Complete cleaning and inspection of boiler parts is performed on a one- to three-year basis. Boiler sections are repaired/rebuilt on a scheduled basis, and on an as-needed basis as determined by inspection. Typical work includes repairing erosion and corrosion damage, supports, tube shields, etc. In addition, all instrumentation is inspected, cleaned and adjusted on an annual basis, as well as all plant auxiliary systems. Boiler maintenance is performed on an as-needed basis, with some level of repair performed annually. Major work is scheduled to coincide with longer outages, approximately every 3 - 5 years.

Rule 7825.2800 Annual Report: Policies and Actions (Continued)

FUEL UTILIZATION (Continued)

3. All coal received at Big Stone Plant and Hoot Lake Plant is weighed by certified scales at the mine when loaded onto trains, and freight billings are also based on weight at the mine. The quality of coal received is determined by sampling trains as they are loaded and daily sampling at the plants with analysis by a contract laboratory.

   All coal received at Coyote is transported over a conveyor from the mine and weighed at both the mine and the plant on electronic scales. The plant scale is used for billing purposes. Coal samples are taken from the conveyor on a daily basis and analyzed by a contract laboratory.

4. Company policy is to retain fuel inventories at all of its electric generating stations in the following amounts:

   Hoot Lake Plant – 20 days
   Big Stone Plant - 30 days
   Coyote Station - 20 days
   Combustion Turbine Plants – 3 – 6 days

Rule 7825.2800 Annual Report: Policies and Actions (Continued)

PROCUREMENT OF TRANSPORTATION SERVICES

1. Hoot Lake Plant of Fergus Falls receives sub bituminous coal supply by a unit train consisting of cars leased by the plant. The locomotives are provided by Burlington Northern Santa Fe Railroad (BNSF) and the cars are switched at Dilworth, Minnesota. The locomotives used from Dilworth to Hoot Lake Plant are owned by Otter Tail Valley Railroad.

   Transportation services are provided under the terms of a common carrier rate between the BNSF and Otter Tail. The rate is effective until December 31, 2015.

2. Big Stone Plant at Big Stone City, South Dakota, receives its coal by a unit train consisting of cars leased by the Big Stone Plant co-owners. Locomotives are supplied by BNSF Railroad.

   Transportation services are provided under the terms of a common carrier rate between the BNSF and the co-owners of the Big Stone Plant. The rate is effective until December 31, 2015.

CONSERVATION IMPROVEMENT PROGRAMS

(Refer to separate filing for Conservation Projects as per filing under Minn. Stat. 216B.241)

OTTER TAIL POWER COMPANY'S COMPLIANCE REPORT AS REQUIRED BY ORDER IN DOCKET E017/PA-01-1391

As ordered in Docket No. E017/PA-01-1391, issued May 9, 2002 (In The Matter of Otter Tail Power Company's Petition for Approval of Transfer of Operational Control of Transmission Facilities to the Midwest Independent System Operator) Otter Tail submits the following compliance report with its Annual Automatic Adjustment of Charges report (AAA) filed under Minnesota Rules part 7825.2800.

For convenience, the conditions are listed with the same numbering system as the order in Docket No. E017/PA-01-1391 used.

3) **Report as part of its Annual Automatic Adjustment of Charges report (AAA) filed under Minnesota Rules part 7825.2800, the following:**

   a) **The Schedule 10 administrative charges paid to the MISO under the MISO tariff, and**

      The following has been paid for the 12-month periods July through June: (2002)(Jan-July) $412,778.58; (2003) $559,511.58; (2004) $678,052.33; (2004/2005) $756,138.54 and (2005/2006) $681,930.21; (2006/2007) $737,285.53; (2007/2008) $702,790.26; (2008/2009) $894,057.20; (2009/2010) $881,371.12; (2010/2011) $906,659.07; (2011/2012) $999,053.00; (2012/2013) $1,026,112.24; (2013/2014) $980,378.43; (2014/2015) $1,119,924.97

      Attachment A provides the monthly breakdown for 2014/2015.

   b) **Any amount of MISO administrative charge deferred by the MISO for later recovery.**

      We are not aware of any new deferrals.

5) **Do the following:**

   c) **Report to the Commission, in Otter Tail Power's annual AAA report, each instance where the MISO directed Otter Tail Power to curtail Otter Tail Power's owned generation, for reliability reasons, that resulted in an interruption of firm retail electric service to Otter Tail Power's retail customers in Minnesota.**

      There were no instances to report for this period.

   d) **Report to the Commission in Otter Tail Power's annual AAA report each instance where the 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 Otter Tail Power's retail customers in Minnesota.**

      There were no instances to report for this period.

8) **Do the following:**

b) **Report in its AAA report on changes to MISO tariffs that may ultimately affect the rates of retail customers in Minnesota, and on Otter Tail Power's efforts to minimize MISO transmission service costs.**

The potential effects on the rates of retail customers in Minnesota are not a simple item to estimate. In situations where MISO membership has declined, the administrative adder has trended upward. As MISO expands its membership, the administrative adder has trended downward. Otter Tail has voiced its concerns when and where appropriate.

As we did at the Midcontinent Area Power Pool ("MAPP"), Otter Tail has employees involved on many of the committees at MISO. Because Otter Tail is relatively small, it has found being involved is the best way to impact the decisions made by organizations such as MISO.

The sensitive economies of the small towns we serve are impacted by our rates and as such we are always looking for ways to maintain our low rates.

c) **Submit in its AAA reports an annual analysis of how the transfer of operational control to the MISO has affected Otter Tail Power's overall transmission costs and revenues and its overall energy costs for retail customers, including –**

i) **an analysis of how MISO membership has affected Otter Tail Power's ability to use its own generating sources when they are the least-cost power source and**

MISO membership has not impacted Otter Tail's ability to use its own generating resources when they are the least-cost power source.

ii) **Otter Tail Power's ability to access low-cost power on the wholesale market for its retail customers.**

The introduction of the MISO Locational Marginal Price ("LMP") market on April 1, 2005 has made wholesale purchased power readily available. During many periods, Otter Tail has been able to buy energy at prices below our baseload generation cost—allowing us to back down baseload units. While there have been times when importing energy from outside MISO has been difficult, it has not presented a significant problem in serving retail load.

d) Report in its AAA report each instance where the MISO directed Otter Tail Power to redispatch Otter Tail Power'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 Commission discontinued this requirement in their February 6, 2008, Order in Docket No. E017/M-05-284.

OTTER TAIL POWER COMPANY
MISO SCHEDULE 10 CHARGE SUMMARY
July 2014 to June 2015

	A	B	C	D Col. (A+B) x C	E
MONTH	**SCHEDULE 10 CHARGE MISO Cost Adder (System Use)**	**SCHEDULE 10 Adjustment from Previous Month (System Use)**	**D2 (transmission) Allocator from Docket E017/GR-10-239**	**MN Share of SCHEDULE 10 CHARGE MISO Cost Adder**	**SCHEDULE 10 CHARGE FERC MISO Cost Adder (Non-System Use*)**
JUL 2014	$61,982.30	$0.00	47.889095%	$29,682.76	$25,044.97
AUG 2014	$41,999.01	$0.00	47.889095%	$20,112.95	$23,028.60
SEP 2014	$49,679.88	$0.00	47.889095%	$23,791.24	$20,642.67
OCT 2014	$62,340.98	$0.00	47.889095%	$29,854.53	$24,400.02
NOV 2014	$73,776.04	$0.00	47.889095%	$35,330.68	$28,058.12
DEC 2014	$81,791.11	$0.00	47.889095%	$39,169.02	$31,479.76
JAN 2015	$83,763.25	$0.00	47.889095%	$40,113.46	$32,395.92
FEB 2015	$75,404.96	$0.00	47.889095%	$36,110.75	$28,117.54
MAR 2015	$92,264.23	$0.00	47.889095%	$44,184.50	$30,649.08
APR 2015	$61,223.29	$0.00	47.889095%	$29,319.28	$22,220.70
MAY 2015	$54,446.87	$0.00	47.889095%	$26,074.11	$21,872.53
JUN 2015	$70,467.51	$0.00	47.889095%	$33,746.25	$22,875.63
TOTALS	$809,139.43	$0.00	47.889095%	$387,489.55	$310,785.54

*Non-system use is not allocated to MN.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-___

PART E - RULE 7825.2810 AUTOMATIC ADJUSTMENT CHARGES

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

RULE 7825.2810 ANNUAL REPORT - AUTOMATIC ADJUSTMENT CHARGES

PERIOD: July 1, 2014 - June 30, 2015

Rule 7825.2810 Subpart 1.A. Commission Approved Base Cost of Fuel

Refer to Energy Adjustment Rider – Electric Rate Schedule - Section 13.01 (Part E Section 1 Attachment B) - approved April 25, 2011, in Docket No. E017/GR-10-239.

Rule 7825.2810 Subpart 1.B. Billing Adjustment Amounts

Per the Office of Energy Security's March 31, 2008 letter, Otter Tail provides the following Attachments with a break down by primary energy source:

1. (Part E Section 2 Attachment C) - kWh Sales by Primary Energy Source for the period of July 2014 to June 2015
2. (Part E Section 2 Attachment C-1) - Energy Cost by Primary Energy Source
3. (Part E Section 2 Attachment C-2) - Monthly Cost Components from January 2001 to present which includes the cost of delivered coal by plant, natural gas, oil and wholesale purchases without Revenue Sufficiency Guarantee ("RSG") and Revenue Neutrality Uplift ("RNU") charges (marked as Trade Secret).

Otter Tail will continue to provide the information it has for several years, which include the (14) monthly cost of energy calculation worksheets as shown in Part E Section 2 Attachment D for the months ending May 2014 through June 2015.

Rule 7825.2810 Subpart 1.C. Billing Adjustment Amounts, By Gas Supplier

Does not apply.

Rule 7825.2810 Subpart 1.D. The Total Cost of Fuel Delivered to Customers

Date	Amount (System)
July-14	$7,796,086
August	$8,850,866
September	$6,929,539
October	$7,986,032
November	$8,758,410
December	$13,773,720
January-15	$12,940,272
February	$11,789,838
March	$11,303,821
April	$7,882,234
May	$7,235,793
June	$7,429,209
Total	$112,675,820

Total kWh Sales – System = 4,588,130,226
Total kWh Sales Subject to COE – Minnesota = 2,317,615,842
Percent of Minnesota Sales to System
(2,317,615,842 / 4,588,130,226) = 0.505132969
Fuel Costs Allocated to Minnesota: ($112,675,820) x 0.505132969 = $56,916,271

Rule 7825.2810 Subpart 1.E. Revenue Collected From Customers for Energy Delivered

Revenue does not include the collection of true-up during July 2014 – June 2015 in the amount of $1,496,545:

Date	Amount (System)
July-14	($35,553)
August	($35,957)
September	$139,621
October	$139,675
November	$150,017
December	$167,469
January-15	$187,286
February	$186,419
March	$171,449
April	$155,906
May	$133,950
June	$136,263
Total	$1,496,545

Recovery From FCA	Recovery From Fuel Base	Total Adj. Recovery	Actual Fuel Cost	Total Over/(Under) Recovery
$4,471,302	[1]$53,682,936	$58,154,238	$56,916,271	[2]$1,237,967

Rule 7825.2810 Subpart 1.F. The Amount of Supplier Refunds Received

None

Rule 7825.2810 Subpart 1.G. The Amount of Refunds Credited to Customers

There was not a refund for the true-up period of September 2014-June 2015. The result was a collection of $1,568,054 for the same time period.

[1] Recovery from fuel base cost:

Total Minnesota kWh Sales July 2014 – June 2015	2,317,615,842
Minnesota Base Cost	x $0.023163
Amount Recovered From Base Cost	$ 53,682,936

[2] Refer to attached July 31, 2015, true-up implementation filing (Part E Section 8 Attachment E)

ENERGY ADJUSTMENT RIDER

DESCRIPTION	RATE CODE
Energy Adjustment Rider	31-540

N
N
N

RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General Rules and Regulations govern use of this rider. N N

There shall be added to or deducted from the monthly bill the amount per Kilowatt-Hour (rounded to the nearest 0.001¢) that the average cost of energy is above or below 2.3163¢ per Kilowatt-Hour. The average cost of energy shall be based upon the cost of energy during the two months immediately preceding the month when the cost of energy is calculated, divided by all Kilowatt-Hour sales exclusive of intersystem sales for the same two-month period. The applicable adjustment will be applied to each Customer's bill beginning with cycle 1 of the calendar month following the month when the adjustment is calculated. The cost of energy shall be determined as follows: C CR C C C C

1. The cost of fuel, as recorded in Account 151, used in the Company's generating plants.

2. The energy cost of purchased power included in Account 555 when such energy is purchased on an economic dispatch basis, exclusive of Capacity or Demand charges. C

3. The net energy cost of purchases from a qualifying facility, as that term is defined in 18 C.F.R. Part 292 and Minn. Rule 7835.0100, Subp. 19, as amended, whether or not those purchases occur on an economic dispatch basis, and all fuel and purchased energy expenses incurred by the Company over the duration of any Commission-approved contract, as provided for by Minnesota Statutes, Section 216B.1645, except any such expense identified in 216B.1645, subd. 1(1), and subd. 1(2) to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691. C C C C C

4. All Midwest ISO (MISO) costs and revenues associated with retail sales that have been authorized by the Commission to flow through this Energy Adjustment Rider and excluding MISO costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders. N N N N

5. Renewable energy purchased for the Tail*Winds* program is not included in the cost of energy adjustment calculation.

6. The actual identifiable fuel costs associated with energy purchased for reasons other than in 2 and 3 above.

7. Less the fuel-related costs recovered through intersystem sales.

8. Less a credit for asset-based margins: revenues minus costs from asset-based wholesale energy and MISO ancillary services market ("ASM") transactions (excluding ancillary services net revenues derived through OTP's FERC-approved Control Area Services Operations Tariff) shall be credited to the cost of energy. The revenues for this calculation are those received from sales of excess generation; the costs are the fuel costs (as defined in FERC Account 501) and energy costs (including MISO costs that are booked to FERC Account 555) and any transmission costs incurred that are required to make such sales. **N N N N N N N**

In addition there shall be an annual true-up for any amount collected over or under the actual cost of energy for the twelve months ending June 30 of each year as reported in the Annual Automatic Adjustment report filed according to Minnesota Rule 7825.2810. The annual true-up shall be based on a historic twelve-month period and shall be applied to the subsequent twelve months. The annual true-up will be effective on billings beginning September 1 of the current year through August 31 of the following year, when a new true-up rate will be calculated and applied. In years when the over- or under-recovery amount is small (a rate rounded to less than 0.001¢), an annual true-up rate shall not apply.

The annual true-up rate shall be calculated as follows. The over- or under-recovery amount as shown in the current year Annual Automatic Adjustment report will be divided by the Minnesota Kilowatt-Hours subject to the fuel adjustment clause from the same report. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) that will be applied to Customers' bills in the same manner as the monthly cost of energy adjustment. **C C C**

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply and by any Voluntary Rate Riders selected by the Customer, unless otherwise noted in this schedule. See Sections 12.00, 13.00 and 14.00 of the Minnesota electric rates for the matrices of riders. **N N N N**

Otter Tail Power Company
kWh SALES BY PRIMARY ENERGY SOURCE *
* Utilizes kWh input
Docket No E,999/DI-07-1582

Line No.	Based on Period Ending	Jun-14	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	COAL	179,139,033	210,336,607	234,408,418	204,297,312	230,401,380	234,514,661	217,828,951	252,757,559	221,274,885	121,700,199	80,086,456	53,104,528	48,988,166
2	BIOMASS	0	0	0	0	0	0	0	0	0	0	0	0	0
3	HYDRO	1,943,516	1,564,995	1,287,992	1,249,193	1,493,092	1,545,159	1,614,168	1,661,981	1,308,609	1,699,581	1,493,809	1,419,543	1,681,033
4	GAS	1,494,058	(70,087)	2,736,673	(804,793)	2,413,123	344,463	(171,410)	46,455	1,063,452	663,893	96,910	147,438	1,795
5	WIND	36,060,031	32,480,961	20,020,805	40,183,308	53,807,125	53,230,333	29,322,943	47,987,859	39,521,985	50,700,483	45,470,546	44,508,297	25,964,018
6	FUEL OIL	0	99,576	(57,166)	0	67,926	0	47,681	1,775	1,796	1,737	0	75,652	90,623
7	UNKNOWN	144,834,957	99,941,065	119,993,734	89,463,526	91,675,169	113,301,643	246,300,048	185,628,396	185,435,206	241,292,359	213,124,222	212,214,111	233,947,537
8	1-MONTH TOTAL	363,471,595	344,353,117	378,390,456	334,388,546	379,857,815	402,936,259	494,942,381	488,084,025	448,605,933	416,058,252	340,271,943	311,469,569	310,673,172

Starting February 27, 2015 Big Stone Plant is down for air-quality control system (AQCS) installation. The Plant itself is scheduled to be back on-line late summer 2015.

Coyote Plant experienced an "A" boiler feed pump fire in December 2014 and since then has been running at a reduced load.

Hoot Lake Plant has periodically been off-line for economic reasons January - June 2015.

Otter Tail Power Company
ENERGY COST BY PRIMARY ENERGY SOURCE
Docket No E999/DI-07-1582

Line No.		Based on Period Ending	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15
	FUEL COSTS BY ENERGY TYPE:													
1	GENERATION	COAL	$4,485,944	$4,975,916	$4,505,898	$5,066,680	$5,083,648	$5,158,448	$5,724,764	$4,981,114	$2,723,453	$1,726,918	$1,008,732	$931,423
2		BIOMASS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3		HYDRO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4		GAS	($5,609)	$119,193	($41,570)	$99,467	$39,615	($13,235)	$9,482	$226,435	($9,224)	$1,125	$4,484	($2)
5		WIND	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6		FUEL OIL	$240,221	$154,441	$96,225	$28,122	$0	$19,522	$33,028	$58	$26,051	$23,436	$93,330	$68,956
7		UNKNOWN	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	PURCHASES	COAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	NET	BIOMASS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10		HYDRO	$403,410	$615,383	($143,080)	$439,943	$792,716	$1,894,608	$2,469,294	$2,018,334	$2,412,411	$1,529,274	$1,483,099	$1,344,920
11		GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12		WIND	$634,969	$623,447	$630,178	$1,274,582	$1,338,319	$1,040,509	$928,369	$1,001,625	$994,247	$1,320,536	$961,119	$588,306
13		SOLAR	$355	$382	$306	$330	$363	$116	$122	$202	$350	$432	$539	$519
14		FUEL OIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15		UNKNOWN	$2,036,797	$2,362,104	$1,881,581	$1,076,908	$1,503,750	$5,673,753	$3,775,214	$3,562,069	$5,156,531	$3,280,512	$3,684,490	$4,495,086
16		1-MONTH TOTAL	$7,796,086	$8,850,866	$6,929,539	$7,986,032	$8,758,410	$13,773,720	$12,940,272	$11,789,838	$11,303,821	$7,882,234	$7,235,793	$7,429,209
17	RETAIL KWH SALES	1-MONTH TOTAL	335,166,718	339,857,126	338,014,061	336,316,513	372,231,288	440,129,087	488,130,203	472,853,269	441,505,169	384,728,785	320,774,919	318,423,088
18	ACTUAL COST (cents/kWh)		2.32603	2.60429	2.05007	2.37456	2.35295	3.12947	2.65099	2.49334	2.56029	2.04878	2.25572	2.33313
	ONE-MONTH COST DISTRIBUTION BY ENERGY TYPE:													
19	GENERATION	COAL	1.33842	1.46412	1.33305	1.50652	1.36572	1.17203	1.17279	1.05342	0.61686	0.44887	0.31447	0.29251
20		BIOMASS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
21		HYDRO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
22		GAS	-0.00167	0.03507	-0.01230	0.02958	0.01064	-0.00301	0.00194	0.04789	-0.00209	0.00029	0.00140	0.00000
23		WIND	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
24		FUEL OIL	0.07167	0.04544	0.02847	0.00836	0.00000	0.00444	0.00677	0.00001	0.00590	0.00609	0.02910	0.02166
25		UNKNOWN	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
26	PURCHASES	COAL	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
27		BIOMASS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
28		HYDRO	0.12036	0.18107	-0.04233	0.13081	0.21296	0.43047	0.50587	0.42684	0.54641	0.39749	0.46235	0.42237
29		GAS	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
30		WIND	0.18945	0.18344	0.18644	0.37898	0.35954	0.23641	0.19019	0.21183	0.22519	0.34324	0.29962	0.18476
31		SOLAR	0.00011	0.00011	0.00009	0.00010	0.00010	0.00003	0.00003	0.00004	0.00008	0.00011	0.00017	0.00016
32		FUEL OIL	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
33		UNKNOWN	0.60770	0.69503	0.55666	0.32021	0.40398	1.28911	0.77340	0.75331	1.16794	0.85268	1.14862	1.41167
34	ACTUAL COST (cents/kWh)		2.32603	2.60429	2.05007	2.37456	2.35295	3.12947	2.65099	2.49334	2.56029	2.04878	2.25572	2.33313

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Response to cost per Mbtu request from Burl Haar Letter of March 31, 2008 - Docket No E,999/DI-07-1582
Source of data: OTP Fuel cost per Million Btus for steam plants, January 2001 to present

MONTHLY COST COMPONENTS BY FUEL TYPE

	January	February	March	April	May	June	July	August	September	October	November	December
Cost of delivered coal by plant (1)												
	[TRADE SECRET DATA BEGINS											
2001 Big Stone cost per Mbtu												
2002 Big Stone cost per Mbtu												
2003 Big Stone cost per Mbtu												
2004 Big Stone cost per Mbtu												
2005 Big Stone cost per Mbtu												
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2014 Big Stone cost per Mbtu												
2015 Big Stone cost per Mbtu												
2001 Coyote cost per Mbtu												
2002 Coyote cost per Mbtu												
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2014 Hoot Lake cost per Mbtu												
2015 Hoot Lake cost per Mbtu												
											. . . TRADE SECRET DATA ENDS]	

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Source of data: OTP Fuel cost per Million Btus for steam plants, January 2001 to present

MONTHLY COST COMPONENTS BY FUEL TYPE

	January	February	March	April	May	June	July	August	September	October	November	December
Cost of delivered natural gas												
	[TRADE SECRET DATA BEGINS											
2003 Solway Plant cost per Mbtu												
2004 Solway Plant cost per Mbtu												
2005 Solway Plant cost per Mbtu												
2006 Solway Plant cost per Mbtu												
2007 Solway Plant cost per Mbtu												
2008 Solway Plant cost per Mbtu												
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2011 Solway Plant cost per Mbtu												
2012 Solway Plant cost per Mbtu												
2013 Solway Plant cost per Mbtu												
2014 Solway Plant cost per Mbtu												
2015 Solway Plant cost per Mbtu												
												. . . TRADE SECRET DATA ENDS]
Cost of delivered nuclear fuel - not applicable												
Cost of delivered oil												
2001 IC Plants and FF Control Ctr diesel, $/Mbtu	6.57	6.64	6.43	6.36	6.57	6.43	6.29	6.29	6.50	6.36	6.14	6.07
2002 IC Plants and FF Control Ctr diesel, $/Mbtu	6.00	9.07	6.14	0.00	6.14	10.64	6.14	7.43	6.64	6.43	7.64	6.43
2003 IC Plants and FF Control Ctr diesel, $/Mbtu	6.43	6.86	7.36	10.43	2.71	6.93	6.64	7.07	6.93	7.14	7.00	6.93
2004 IC Plants and FF Control Ctr diesel, $/Mbtu	6.86	7.14	6.86	6.86	6.93	7.07	7.50	7.50	7.29	7.43	7.50	7.93
2005 IC Plants and FF Control Ctr diesel, $/Mbtu	7.93	7.93	7.93	9.93	9.93	10.79	11.43	12.00	11.29	12.29	12.86	13.43
2006 IC Plants and FF Control Ctr diesel, $/Mbtu	12.86	13.14	12.93	13.29	13.29	14.07	13.21	17.14	15.36	16.00	15.79	15.93
2007 IC Plants and FF Control Ctr diesel, $/Mbtu	15.79	15.07	15.07	15.21	15.43	15.50	15.86	15.43	16.07	16.00	16.07	16.07
2008 IC Plants and FF Control Ctr diesel, $/Mbtu	16.36	16.71	16.79	16.71	0	15.14	18.07	16.50	12.64	17.50	13.79	17.00
2009 IC Plants and FF Control Ctr diesel, $/Mbtu	13.57	0.00	0.00	12.64	15.36	0.00	0.00	16.79	16.07	16.07	15.79	15.79
2010 IC Plants and FF Control Ctr diesel, $/Mbtu	16.07	12.64	15.86	16.21	16.00	16.00	0.00	16.14	16.29	16.29	16.21	17.21
2011 IC Plants and FF Control Ctr diesel, $/Mbtu	17.29	17.29	16.93	0.00	17.00	16.29	13.57	21.21	20.21	17.43	20.21	17.29
2012 IC Plants and FF Control Ctr diesel, $/Mbtu	17.29	17.29	20.57	20.57	20.57	19.86	19.93	20.93	14.29	22.07	17.93	22.21
2013 IC Plants and FF Control Ctr diesel, $/Mbtu	19.71	0.00	19.36	17.86	0.00	17.79	0.00	21.36	17.86	17.79	19.00	22.07
2014 IC Plants and FF Control Ctr diesel, $/Mbtu	21.21	22.14	20.07	19.07	22.14	19.93	21.00	0.00	22.29	19.93	0.00	19.93
2015 IC Plants and FF Control Ctr diesel, $/Mbtu	19.93	21.64	22.14	14.29	20.50	21.14	0.00	0.00	0.00	0.00	0.00	0.00
Cost of wholesale purchases ($/MWh) without RSG or RNU charges (2)												
2001 Purchased Power	23.60	21.34	26.56	23.63	26.63	25.02	32.00	30.79	35.17	25.80	19.55	29.65
2002 Purchased Power	28.01	31.19	28.19	28.65	47.04	30.61	30.99	29.49	25.27	24.17	31.94	28.92
2003 Purchased Power	29.45	32.70	43.26	33.70	33.45	34.17	32.59	25.98	25.77	31.16	21.00	37.37
2004 Purchased Power	36.62	40.15	23.88	34.22	41.15	38.44	45.39	41.77	38.79	35.56	34.57	36.66
2005 Purchased Power	39.17	40.07	38.05	17.35	23.54	21.48	11.86	16.72	11.48	14.35	11.13	28.17
2006 Purchased Power	32.43	53.34	49.82	36.19	43.46	50.81	128.29	58.97	65.01	52.14	61.35	42.55
2007 Purchased Power	38.64	82.81	55.89	64.08	56.05	59.22	46.31	41.13	47.17	44.61	53.65	63.58
2008 Purchased Power	61.28	74.56	69.65	68.19	39.65	49.85	57.12	52.07	42.47	45.91	49.02	52.47
2009 Purchased Power	59.90	59.86	32.18	26.22	34.01	32.41	32.04	38.92	37.51	44.60	36.69	41.36
2010 Purchased Power	58.11	57.90	49.57	49.04	37.80	33.02	37.69	41.60	40.25	39.47	28.31	33.43
2011 Purchased Power	35.68	35.89	31.89	32.53	38.17	84.70	12.52	48.38	35.39	31.31	26.86	32.18
2012 Purchased Power	31.08	30.72	30.75	25.00	29.55	34.91	38.41	45.41	38.95	28.64	30.13	31.64
2013 Purchased Power	33.82	32.37	31.50	36.33	35.14	30.56	36.22	38.82	47.32	31.31	31.04	39.19
2014 Purchased Power	39.32	48.75	49.66	27.76	48.69	33.97	32.60	29.36	28.60	33.58	33.55	34.85
2015 Purchased Power	38.50	35.43	35.23	28.46	28.50	27.05	0.00	0.00	0.00	0.00	0.00	0.00

(1) Effective July 2008 fuel oil burned for generation is included
(2) Is not retail

EFFECTIVE 7/2/2014
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MAY 31, 2014
FOR BILLINGS TO BE EFFECTIVE JULY 2, 2014

Line No.	ENERGY COSTS	(A) 2014 Apr	(B) 2014 May	(C) Total This Period
1	Plant Generation	$ 4,435,611	$ 4,038,790	$ 8,474,401
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 2,307,341	$ 5,096,871	$ 7,404,212
3	Purchased Power	$ 1,349,453	$ 1,240,563	$ 2,590,016
4	Wind Curtailment	$ 24,386	$ 281,969	$ 306,355
5	Less: MISO ASM (Rev) Cost	$ (13,053)	$ (27,218)	$ (40,272)
6	Less: Intersystem Sales (Rev) Cost	$ (462,281)	$ (406,694)	$ (868,974)
7	Less: Asset Based Margins (Rev) Cost	$ (266,055)	$ (216,495)	$ (482,550)
8	Total Cost of Fuel	$ 7,375,402	10,007,786	$ 17,383,188
	KWH SALES			
9	Total Sales of Electricity	447,477,969	405,532,188	853,010,157
10	Less Inter-System Sales	(38,232,708)	(56,790,867)	(95,023,575)
11	Total kWh	409,245,261	348,741,321	757,986,582
12	Cost per KWH		0.022933	
13	Base Cost		0.023163	
14	Annual True-Up Factor		-0.0002	
15	Energy Adjustment per kWh		(0.00043)	

kWh Information For The Billing Month of: May 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	172,596,249	kWh
2	Non-Energy Adjustment Rider Sales	151,300	kWh
3	Total	172,747,549	kWh
	Non-Minnesota Sales		
4	Sales for Resale	222,425	kWh
5	Total Sales of Electricity (ND and SD)	175,771,347	kWh
6	Inter-System Sales	56,790,867	kWh
	Total kWh Sales	405,532,188	kWh

EFFECTIVE 8/1/2014

CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JUNE 30, 2014
FOR BILLINGS TO BE EFFECTIVE AUGUST 1, 2014

Line No.	ENERGY COSTS		(A) 2014 May		(B) 2014 June		(C) Total This Period
1	Plant Generation	$	4,038,790	$	4,128,719	$	8,167,509
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	5,096,871	$	3,890,249	$	8,987,120
3	Purchased Power	$	1,240,563	$	1,308,075	$	2,548,639
4	Wind Curtailment	$	281,969	$	(105,007)	$	176,962
5	Less: MISO ASM (Rev) Cost	$	(27,218)	$	3,389	$	(23,830)
6	Less: Intersystem Sales (Rev) Cost	$	(406,694)	$	(287,134)	$	(693,828)
7	Less: Asset Based Margins (Rev) Cost	$	(216,495)	$	(74,489)	$	(290,984)
8	Total Cost of Fuel	$	10,007,786		8,863,803	$	18,871,588

	KWH SALES			
9	Total Sales of Electricity	405,532,188	371,893,264	777,425,452
10	Less Inter-System Sales	(56,790,867)	(46,349,857)	(103,140,724)
11	Total kWh	348,741,321	325,543,407	674,284,728

12	Cost per KWH	0.027988
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0002
15	Energy Adjustment per kWh	0.00462

kWh Information For The Billing Month of: June 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	169,304,676	kWh
2	Non-Energy Adjustment Rider Sales	105,531	kWh
3	Total	169,410,207	kWh
	Non-Minnesota Sales		
4	Sales for Resale	207,884	kWh
5	Total Sales of Electricity (ND and SD)	155,925,316	kWh
6	Inter-System Sales	46,349,857	kWh
	Total kWh Sales	371,893,264	kWh

EFFECTIVE 9/2/2014

CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JULY 31, 2014
FOR BILLINGS TO BE EFFECTIVE SEPTEMBER 2, 2014

Line No.	ENERGY COSTS		(A) 2014 June		(B) 2014 July		(C) Total This Period
1	Plant Generation	$	4,128,719	$	5,203,813	$	9,332,532
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,890,249	$	2,251,882	$	6,142,131
3	Purchased Power	$	1,308,075	$	1,049,534	$	2,357,609
4	Wind Curtailment	$	(105,007)	$	(10,047)	$	(115,054)
5	Less: MISO ASM (Rev) Cost	$	3,389	$	1,052	$	4,440
6	Less: Intersystem Sales (Rev) Cost	$	(287,134)	$	(484,011)	$	(771,145)
7	Less: Asset Based Margins (Rev) Cost	$	(74,489)	$	(216,137)	$	(290,626)
8	Total Cost of Fuel	$	8,863,803		7,796,086	$	16,659,888
	KWH SALES						
9	Total Sales of Electricity		371,893,264		375,625,759		747,519,023
10	Less Inter-System Sales		(46,349,857)		(40,459,041)		(86,808,898)
11	Total kWh		325,543,407		335,166,718		660,710,125

Line		
12	Cost per KWH	0.025215
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00285

kWh Information For The Billing Month of: July 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	177,763,469	kWh
2	Non-Energy Adjustment Rider Sales	140,185	kWh
3	Total	177,903,654	kWh
	Non-Minnesota Sales		
4	Sales for Resale	158,046	kWh
5	Total Sales of Electricity (ND and SD)	157,105,018	kWh
6	Inter-System Sales	40,459,041	kWh
	Total kWh Sales	375,625,759	kWh

EFFECTIVE 10/2/2014
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING AUGUST 31, 2014
FOR BILLINGS TO BE EFFECTIVE OCTOBER 2, 2014

Line No.	ENERGY COSTS		(A) 2014 July		(B) 2014 August		(C) Total This Period
1	Plant Generation	$	5,203,813	$	5,391,495	$	10,595,308
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	2,251,882	$	2,420,886	$	4,672,768
3	Purchased Power	$	1,049,534	$	1,244,926	$	2,294,460
4	Wind Curtailment	$	(10,047)	$	6,327	$	(3,721)
5	Less: MISO ASM (Rev) Cost	$	1,052	$	(5,093)	$	(4,041)
6	Less: Intersystem Sales (Rev) Cost	$	(484,011)	$	(153,985)	$	(637,996)
7	Less: Asset Based Margins (Rev) Cost	$	(216,137)	$	(53,689)	$	(269,826)
8	Total Cost of Fuel	$	7,796,086		8,850,866	$	16,646,952
	KWH SALES						
9	Total Sales of Electricity		375,625,759		352,064,370		727,690,129
10	Less Inter-System Sales		(40,459,041)		(12,207,244)		(52,666,285)
11	Total kWh		335,166,718		339,857,126		675,023,844

12	Cost per KWH	0.024661
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00230

kWh Information For The Billing Month of: August 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	179,784,084	kWh
2	Non-Energy Adjustment Rider Sales	132,609	kWh
3	Total	179,916,693	kWh
	Non-Minnesota Sales		
4	Sales for Resale	252,790	kWh
5	Total Sales of Electricity (ND and SD)	159,687,643	kWh
6	Inter-System Sales	12,207,244	kWh
	Total kWh Sales	352,064,370	kWh

EFFECTIVE 11/3/2014
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING SEPTEMBER 30, 2014
FOR BILLINGS TO BE EFFECTIVE NOVEMBER 3, 2014

Line No.	ENERGY COSTS			(A) 2014 August		(B) 2014 September		(C) Total This Period
1	Plant Generation		$	5,391,495	$	5,137,797	$	10,529,292
2	MISO Day 2 Charges (not Schedule 16 & 17)		$	2,420,886	$	2,142,557	$	4,563,443
3	Purchased Power		$	1,244,926	$	518,721	$	1,763,647
4	Wind Curtailment		$	6,327	$	(31,316)	$	(24,990)
5	Less: MISO ASM (Rev) Cost		$	(5,093)	$	(22,485)	$	(27,578)
6	Less: Intersystem Sales (Rev) Cost		$	(153,985)	$	(577,242)	$	(731,228)
7	Less: Asset Based Margins (Rev) Cost		$	(53,689)	$	(238,493)	$	(292,182)
8		Total Cost of Fuel	$	8,850,867		6,929,539	$	15,780,406
	KWH SALES							
9	Total Sales of Electricity			352,064,370		366,079,838		718,144,208
10	Less Inter-System Sales			(12,207,244)		(28,065,777)		(40,273,021)
11		Total kWh		339,857,126		338,014,061		677,871,187
12		Cost per KWH				0.023279		
13		Base Cost				0.023163		
14		Annual True-Up Factor				0.0008		
15		Energy Adjustment per kWh				0.00092		

kWh Information For The Billing Month of: September 2014

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	174,526,179	kWh
2	Non-Energy Adjustment Rider Sales	134,730	kWh
3	Total	174,660,909	kWh
	Non-Minnesota Sales		
4	Sales for Resale	249,294	kWh
5	Total Sales of Electricity (ND and SD)	163,103,858	kWh
6	Inter-System Sales	28,065,777	kWh
	Total kWh Sales	366,079,838	kWh

EFFECTIVE 12/1/2014
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING OCTOBER 31, 2014
FOR BILLINGS TO BE EFFECTIVE DECEMBER 1, 2014

Line No.	ENERGY COSTS		(A) 2014 September		(B) 2014 October		(C) Total This Period
1	Plant Generation	$	5,137,797	$	5,873,229	$	11,011,026
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	2,142,557	$	1,486,840	$	3,629,397
3	Purchased Power	$	518,721	$	1,699,463	$	2,218,184
4	Wind Curtailment	$	(31,316)	$	15,392	$	(15,924)
5	Less: MISO ASM (Rev) Cost	$	(22,485)	$	(24,146)	$	(46,631)
6	Less: Intersystem Sales (Rev) Cost	$	(577,242)	$	(678,959)	$	(1,256,201)
7	Less: Asset Based Margins (Rev) Cost	$	(238,493)	$	(385,787)	$	(624,279)
8	Total Cost of Fuel	$	6,929,539		7,986,032	$	14,915,571
	KWH SALES						
9	Total Sales of Electricity		366,079,838		369,893,650		735,973,488
10	Less Inter-System Sales		(28,065,777)		(33,577,137)		(61,642,914)
11	Total kWh		338,014,061		336,316,513		674,330,574

12	Cost per KWH	0.022119
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	(0.00024)

kWh Information For The Billing Month of: October 2014

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	174,593,713	kWh
2	Non-Energy Adjustment Rider Sales	138,835	kWh
3	Total	174,732,548	kWh
	Non-Minnesota Sales		
4	Sales for Resale	288,845	kWh
5	Total Sales of Electricity (ND and SD)	161,295,120	kWh
6	Inter-System Sales	33,577,137	kWh
	Total kWh Sales	369,893,650	kWh

EFFECTIVE 1/2/2015

CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING NOVEMBER 30, 2014
FOR BILLINGS TO BE EFFECTIVE JANUARY 2, 2015

Line No.	ENERGY COSTS		(A) 2014 October		(B) 2014 November		(C) Total This Period
1	Plant Generation	$	5,873,229	$	5,934,820	$	11,808,049
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	1,486,840	$	1,818,556	$	3,305,396
3	Purchased Power	$	1,699,463	$	2,118,439	$	3,817,902
4	Wind Curtailment	$	15,392	$	12,958	$	28,350
5	Less: MISO ASM (Rev) Cost	$	(24,146)	$	(32,960)	$	(57,107)
6	Less: Intersystem Sales (Rev) Cost	$	(678,959)	$	(811,558)	$	(1,490,517)
7	Less: Asset Based Margins (Rev) Cost	$	(385,787)	$	(281,846)	$	(667,632)
8	Total Cost of Fuel	$	7,986,032		8,758,410	$	16,744,441

Line No.	KWH SALES			
9	Total Sales of Electricity	369,893,650	408,084,122	777,977,772
10	Less Inter-System Sales	(33,577,137)	(35,852,834)	(69,429,971)
11	Total kWh	336,316,513	372,231,288	708,547,801

12	Cost per KWH	0.023632
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00127

kWh Information For The Billing Month of: November 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	187,520,821	kWh
2	Non-Energy Adjustment Rider Sales	187,698	kWh
3	Total	187,708,519	kWh
	Non-Minnesota Sales		
4	Sales for Resale	367,205	kWh
5	Total Sales of Electricity (ND and SD)	184,155,564	kWh
6	Inter-System Sales	35,852,834	kWh
	Total kWh Sales	408,084,122	kWh

EFFECTIVE 2/2/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING DECEMBER 31, 2014
FOR BILLINGS TO BE EFFECTIVE FEBRUARY 2, 2015

Line No.	ENERGY COSTS		(A) 2014 November		(B) 2014 December		(C) Total This Period
1	Plant Generation	$	5,934,820	$	5,500,877	$	11,435,697
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	1,818,556	$	5,804,312	$	7,622,867
3	Purchased Power	$	2,118,439	$	2,894,939	$	5,013,378
4	Wind Curtailment	$	12,958	$	40,294	$	53,253
5	Less: MISO ASM (Rev) Cost	$	(32,960)	$	(8,227)	$	(41,187)
6	Less: Intersystem Sales (Rev) Cost	$	(811,558)	$	(336,143)	$	(1,147,700)
7	Less: Asset Based Margins (Rev) Cost	$	(281,846)	$	(122,332)	$	(404,178)
8	Total Cost of Fuel	$	8,758,410		13,773,720	$	22,532,130
	KWH SALES						
9	Total Sales of Electricity		408,084,122		453,613,745		861,697,867
10	Less Inter-System Sales		(35,852,834)		(13,484,658)		(49,337,492)
11	Total kWh		372,231,288		440,129,087		812,360,375

12	Cost per KWH	0.027737
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00537

kWh Information For The Billing Month of: December 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	209,336,030	kWh
2	Non-Energy Adjustment Rider Sales	143,031	kWh
3	Total	209,479,061	kWh
	Non-Minnesota Sales		
4	Sales for Resale	560,555	kWh
5	Total Sales of Electricity (ND and SD)	230,089,471	kWh
6	Inter-System Sales	13,484,658	kWh
	Total kWh Sales	453,613,745	kWh

EFFECTIVE 3/3/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JANUARY 31, 2015
FOR BILLINGS TO BE EFFECTIVE MARCH 3, 2015

Line No.	ENERGY COSTS	(A) 2014 December	(B) 2015 January	(C) Total This Period
1	Plant Generation	$ 5,500,877	$ 5,941,448	$ 11,442,325
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 5,804,312	$ 3,817,366	$ 9,621,678
3	Purchased Power	$ 2,894,939	$ 3,362,622	$ 6,257,561
4	Wind Curtailment	$ 40,294	$ 35,163	$ 75,457
5	Less: MISO ASM (Rev) Cost	$ (8,227)	$ (1,963)	$ (10,191)
6	Less: Intersystem Sales (Rev) Cost	$ (336,143)	$ (174,174)	$ (510,317)
7	Less: Asset Based Margins (Rev) Cost	$ (122,332)	$ (40,189)	$ (162,520)
8	Total Cost of Fuel	$ 13,773,720	12,940,272	$ 26,713,993
	KWH SALES			
9	Total Sales of Electricity	453,613,745	496,692,693	950,306,438
10	Less Inter-System Sales	(13,484,658)	(8,562,490)	(22,047,148)
11	Total kWh	440,129,087	488,130,203	928,259,290

12	Cost per KWH	0.028779
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00642

kWh Information For The Billing Month of: January 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	234,107,076	kWh
2	Non-Energy Adjustment Rider Sales	212,906	kWh
3	Total	234,319,982	kWh
	Non-Minnesota Sales		
4	Sales for Resale	455,729	kWh
5	Total Sales of Electricity (ND and SD)	253,354,492	kWh
6	Inter-System Sales	8,562,490	kWh
	Total kWh Sales	496,692,693	kWh

EFFECTIVE 4/2/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING FEBRUARY 28, 2015
FOR BILLINGS TO BE EFFECTIVE APRIL 2, 2015

Line No.	ENERGY COSTS		(A) 2015 January		(B) 2015 February		(C) Total This Period
1	Plant Generation	$	5,941,448	$	5,562,027	$	11,503,475
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,817,366	$	3,652,476	$	7,469,842
3	Purchased Power	$	3,362,622	$	3,011,453	$	6,374,075
4	Wind Curtailment	$	35,163	$	8,708	$	43,871
5	Less: MISO ASM (Rev) Cost	$	(1,963)	$	9,166	$	7,202
6	Less: Intersystem Sales (Rev) Cost	$	(174,174)	$	(354,419)	$	(528,594)
7	Less: Asset Based Margins (Rev) Cost	$	(40,189)	$	(99,573)	$	(139,762)
8	Total Cost of Fuel	$	12,940,272		11,789,838	$	24,730,110

Line No.	KWH SALES			
9	Total Sales of Electricity	496,692,693	491,182,428	987,875,121
10	Less Inter-System Sales	(8,562,490)	(18,329,159)	(26,891,649)
11	Total kWh	488,130,203	472,853,269	960,983,472

12	Cost per KWH	0.025734
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00337

kWh Information For The Billing Month of: February 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	233,024,161	kWh
2	Non-Energy Adjustment Rider Sales	205,803	kWh
3	Total	233,229,964	kWh
	Non-Minnesota Sales		
4	Sales for Resale	520,855	kWh
5	Total Sales of Electricity (ND and SD)	239,102,450	kWh
6	Inter-System Sales	18,329,159	kWh
	Total kWh Sales	491,182,428	kWh

EFFECTIVE 5/1/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MARCH 31, 2015
FOR BILLINGS TO BE EFFECTIVE MAY 1, 2015

Line No.	ENERGY COSTS		(A) 2015 February		(B) 2015 March		(C) Total This Period
1	Plant Generation	$	5,562,027	$	2,942,415	$	8,504,442
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,652,476	$	5,263,326	$	8,915,802
3	Purchased Power	$	3,011,453	$	3,411,677	$	6,423,130
4	Wind Curtailment	$	8,708	$	(4,669)	$	4,039
5	Less: MISO ASM (Rev) Cost	$	9,166	$	(3,110)	$	6,056
6	Less: Intersystem Sales (Rev) Cost	$	(354,419)	$	(202,135)	$	(556,555)
7	Less: Asset Based Margins (Rev) Cost	$	(99,573)	$	(103,684)	$	(203,257)
8	Total Cost of Fuel	$	11,789,838		11,303,821	$	23,093,658
	KWH SALES						
9	Total Sales of Electricity		491,182,428		449,319,717		940,502,145
10	Less Inter-System Sales		(18,329,159)		(7,814,548)		(26,143,707)
11	Total kWh		472,853,269		441,505,169		914,358,438
12	Cost per KWH				0.025257		
13	Base Cost				0.023163		
14	Annual True-Up Factor				0.0008		
15	Energy Adjustment per kWh				0.00289		

kWh Information For The Billing Month of: March 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	214,310,960	kWh
2	Non-Energy Adjustment Rider Sales	238,938	kWh
3	Total	214,549,898	kWh
	Non-Minnesota Sales		
4	Sales for Resale	414,841	kWh
5	Total Sales of Electricity (ND and SD)	226,540,430	kWh
6	Inter-System Sales	7,814,548	kWh
	Total kWh Sales	449,319,717	kWh

EFFECTIVE 6/2/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING APRIL 30, 2015
FOR BILLINGS TO BE EFFECTIVE JUNE 2, 2015

Line No.	ENERGY COSTS	(A) 2015 March	(B) 2015 April	(C) Total This Period
1	Plant Generation	$ 2,942,415	$ 1,816,504	$ 4,758,919
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 5,263,326	$ 3,273,673	$ 8,536,999
3	Purchased Power	$ 3,411,677	$ 2,829,312	$ 6,240,989
4	Wind Curtailment	$ (4,669)	$ 20,929	$ 16,260
5	Less: MISO ASM (Rev) Cost	$ (3,110)	$ 10,188	$ 7,078
6	Less: Intersystem Sales (Rev) Cost	$ (202,135)	$ (65,024)	$ (267,159)
7	Less: Asset Based Margins (Rev) Cost	$ (103,684)	$ (3,347)	$ (107,031)
8	Total Cost of Fuel	$ 11,303,821	7,882,234	$ 19,186,055
	KWH SALES			
9	Total Sales of Electricity	449,319,717	387,742,266	837,061,983
10	Less Inter-System Sales	(7,814,548)	(3,013,481)	(10,828,029)
11	Total kWh	441,505,169	384,728,785	826,233,954

12	Cost per KWH	0.023221
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00086

kWh Information For The Billing Month of: April 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	194,882,267	kWh
2	Non-Energy Adjustment Rider Sales	208,519	kWh
3	Total	195,090,786	kWh
	Non-Minnesota Sales		
4	Sales for Resale	277,387	kWh
5	Total Sales of Electricity (ND and SD)	189,360,612	kWh
6	Inter-System Sales	3,013,481	kWh
	Total kWh Sales	387,742,266	kWh

EFFECTIVE 7/2/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MAY 31, 2015
FOR BILLINGS TO BE EFFECTIVE JULY 2, 2015

Line No.	ENERGY COSTS		(A) 2015 April		(B) 2015 May		(C) Total This Period
1	Plant Generation	$	1,816,504	$	1,186,652	$	3,003,156
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,273,673	$	3,671,352	$	6,945,026
3	Purchased Power	$	2,829,312	$	2,440,165	$	5,269,477
4	Wind Curtailment	$	20,929	$	4,592	$	25,521
5	Less: MISO ASM (Rev) Cost	$	10,188	$	13,085	$	23,273
6	Less: Intersystem Sales (Rev) Cost	$	(65,024)	$	(80,107)	$	(145,131)
7	Less: Asset Based Margins (Rev) Cost	$	(3,347)	$	54	$	(3,294)
8	Total Cost of Fuel	$	7,882,234	$	7,235,793	$	15,118,028
	KWH SALES						
9	Total Sales of Electricity		387,742,266		323,946,707		711,688,973
10	Less Inter-System Sales		(3,013,481)		(3,171,788)		(6,185,269)
11	Total kWh		384,728,785		320,774,919		705,503,704

Line		
12	Cost per KWH	0.021429
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	(0.00093)

kWh Information For The Billing Month of: May 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	167,437,726	kWh
2	Non-Energy Adjustment Rider Sales	147,894	kWh
3	Total	167,585,620	kWh
	Non-Minnesota Sales		
4	Sales for Resale	202,247	kWh
5	Total Sales of Electricity (ND and SD)	152,987,052	kWh
6	Inter-System Sales	3,171,788	kWh
	Total kWh Sales	323,946,707	kWh

EFFECTIVE 8/3/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JUNE 30, 2015
FOR BILLINGS TO BE EFFECTIVE AUGUST 3, 2015

Line No.	ENERGY COSTS		(A) 2015 May		(B) 2015 June		(C) Total This Period
1	Plant Generation	$	1,186,652	$	1,027,126	$	2,213,778
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,671,352	$	4,480,717	$	8,152,070
3	Purchased Power	$	2,440,165	$	1,933,630	$	4,373,795
4	Wind Curtailment	$	4,592	$	115	$	4,707
5	Less: MISO ASM (Rev) Cost	$	13,085	$	15,050	$	28,135
6	Less: Intersystem Sales (Rev) Cost	$	(80,107)	$	(26,749)	$	(106,856)
7	Less: Asset Based Margins (Rev) Cost	$	54	$	(680)	$	(626)
8	Total Cost of Fuel	$	7,235,793	$	7,429,209	$	14,665,002
	KWH SALES						
9	Total Sales of Electricity		323,946,707		320,013,031		643,959,738
10	Less Inter-System Sales		(3,171,788)		(1,589,943)		(4,761,731)
11	Total kWh		320,774,919		318,423,088		639,198,007
12	Cost per KWH				0.022943		
13	Base Cost				0.023163		
14	Annual True-Up Factor				0.0008		
15	Energy Adjustment per kWh				0.00058		

kWh Information For The Billing Month of: June 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	170,329,356	kWh
2	Non-Energy Adjustment Rider Sales	127,169	kWh
3	Total	170,456,525	kWh
	Non-Minnesota Sales		
4	Sales for Resale	124,362	kWh
5	Total Sales of Electricity (ND and SD)	147,842,201	kWh
6	Inter-System Sales	1,589,943	kWh
	Total kWh Sales	320,013,031	kWh

COMPLIANCE REPORT AS ORDERED IN DOCKET NO. E017/M-03-30

As ordered in Docket No. G,E999/AA-01-838, issued December 23, 2002 (In the Matter of the Review of the 2001 Annual Automatic Adjustment of Charges for all Gas and Electric Utilities) Otter Tail filed on January 8, 2003, with the Minnesota Public Utilities Commission, a proposal for a Monthly Fuel Clause Adjustment True-up, Docket No. E017/M-03-30.

On March 4, 2003, the Department of Commerce recommended approval of Otter Tail’s proposed true-up and also recommended that Otter Tail be granted rule variances, which would allow Otter Tail to implement the proposed true-up.

On January 22, 2004, the proposed true-up came before the Commission. After discussions between Otter Tail, Department of Commerce and Commission staff, the following recommendation was made: Within 60 days of the date the Department of Commerce files its initial comments in Docket E,G999/AA-03-1264, Otter Tail shall make a supplemental filing in this docket containing at least the following items: a) An annual true-up mechanism for its automatic fuel clause adjustment; b) An analysis and discussion of the current need for a fuel clause true-up; and c) An analysis and discussion of any implementation issues likely to arise with either the annual or monthly true-up.

On February 18, 2004, the Commission issued its order requiring Otter Tail to make a supplemental filing.

On April 26, 2004, Otter Tail submitted its supplemental filing as ordered by the Commission. Otter Tail's supplemental filing requested approval of an annual true-up procedure to take effect August 1, 2004. This matter came before the Commission on December 16, 2004.

On December 27, 2004, the Commission issued its order in Docket No. E017/M-03-30 granting Otter Tail's proposed annual true-up effective August 1, 2005, and a change from mid-month application to calendar month application of monthly fuel clause adjustment rates.

On July 27, 2005, Otter Tail filed a letter with Dr. Burl Haar where Otter Tail proposed to delay its implementation of the true-up until at least year end 2005 and use 18 months as the basis for the true-up calculation. The proposed delay was the result of circumstances that were not anticipated when Otter Tail made its request for a true-up or when the Commission's Order was issued. These circumstances relate to MISO Day 2 market activity and MPUC Docket No. E017/M-05-284. Along with the MISO Day 2 market, Otter Tail had a several week scheduled outage of one of its major baseload generating plants, which contributed to a under collection amount of $3.5 million for the 12 months ending June 30, 2005. For reasons stated in the letter dated July 27, 2005, and a supplemental letter dated August 12, 2005, Otter Tail requested to delay its annual true-up for 2005. Since this year's true-up indicates an under collection by Otter Tail, no customer is harmed by this delay.

Compliance Report as Ordered in Docket No. E017/M-03-30 (continued)

On December 21, 2005, Otter Tail filed another letter with Dr. Burl Haar where Otter Tail proposed a second delay to its implementation of the true-up until August 1, 2006. Otter Tail proposed to determine the under recovery using 24 months which would be recovered over 12 months. The delay would allow MISO issues to be determined with more certainty. On March 30, 2006, the Commission granted Otter Tail's request.

On July 21, 2006, Otter Tail filed a notice of implementation effective August 1, 2006. On July 31, the Department of Commerce filed comments requesting Otter Tail to withdraw implementation of its true-up until it identifies and excludes MISO related costs that it asserted should be handled in another docket. On August 2 Otter Tail implemented the true-up for the period of July 2005 to June 2006 to be applied during the time period of September 1, 2006, to August 31, 2007. On August 9, 2006, Otter Tail responded to the Department's request, stating it was under Commission order to implement the true-up.

On September 28, 2006, the Minnesota Public Utilities Commission issued an order permitting Otter Tail to continue the FCA true-up mechanism to be collected over a 12-month period, to account for the under-recovery accumulated over the 24 month period from July 2004 through July 2006.

On October 30, 2006, Otter Tail filed a compliance report detailing the true-up costs that were missing from the true-up implementation petition, proposed true-up procedures, and addressed various MISO related adjustments.

On December 27, 2006, the Minnesota Public Utilities Commission issued an order in approving the proposed change in true-up procedures for Otter Tail's filing of its annual true-up to its Fuel Clause Adjustment.

On January 15, 2007, Otter Tail filed a letter of revision to the proposed true-up amount due to an error in a report that extracts sales information from the CIS. A copy of the letter along with the calculation of the true-up was included in the 2006/2007 AAA filing. On March 22, 2007, the Minnesota Public Utilities Commission approved the proposed reduced true-up.

On August 1, 2007, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2006 to June 2007 to be applied during the time period of September 1, 2007, to August 31, 2008. A copy of the Notice was included in the 2006/2007 AAA filing.

On August 31, 2007, Otter Tail filed a letter of change in rounding the true-up to four decimal places instead of five decimal places as previously filed. This changes the rate from a credit of $0.00039 to a credit of $0.0004.
On October 26, 2007, the Commission approved Otter Tail's compliance report and the new annual true-up rate of a decrease of 0.4 mills per kWh.

Compliance Report as Ordered in Docket No. E017/M-03-30 (continued)

On July 31, 2008, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2007 to June 2008 to be applied during the time period of September 1, 2008, to August 31, 2009.
On September 4, 2009, the Commission approved Otter Tail's compliance report and the new annual true-up rate of a decrease of 0.6 mills per kWh.

On July 31, 2009, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2008 to June 2009 to be applied during the time period of September 1, 2009, to August 31, 2010.
On September 14, 2009, the Commission approved Otter Tail's compliance report and the new annual true-up rate of a decrease of 0.1 mills per kWh.

On July 30, 2010, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2009 to June 2010 to be applied during the time period of September 1, 2010, to August 31, 2011.
On August 19, 2010, Otter Tail filed a Correction to Annual Fuel Clause Adjustment True-up Mechanism to correct two minor errors in the calculation.
On October 15, 2010, the Commission approved Otter Tail's compliance report and the new annual true-up rate of 0.3 mills per kWh.

On August 1, 2011, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2010 to June 2011 to be applied during the time period of September 1, 2011, to August 31, 2012.
On December 16, 2011, the Commission approved Otter Tail's compliance report and the new annual true-up rate of 0.5 mills per kWh.

On July 31, 2012, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2011 to June 2012 to be applied during the time period of September 1, 2012, to August 31, 2013.
On October 9, 2012, the Commission approved Otter Tail's compliance report and the annual true-up debit of 0.5 mills per kWh.

On July 31, 2013, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2012 to June 2013 to be applied during the time period of September 1, 2013, to August 31, 2014.
On October 18, 2013, the Commission approved Otter Tail's compliance report and the annual true-up credit of 0.2 mills per kWh.

On July 31, 2014, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2013 to June 2014 to be applied during the time period of September 1, 2014 to August 31, 2015.
On September 25, 2014, the Commission approved Otter Tail's compliance report and the annual true-up debit of 0.8 mills per kWh.

On July 31, 2015, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2014 to June 2015 to be applied during the time period of September 1, 2015 to August 31, 2016. The amount of this year's true-up is a credit of 0.0006. (Part E Section 8 Attachment E)

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July 31, 2015

Mr. Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: Notice of Implementation of Otter Tail Power Company's Annual Fuel Clause Adjustment True-up Mechanism
Minnesota Docket No. E017/M-03-30

Dear Mr. Wolf:

On December 27, 2006, the Minnesota Public Utilities Commission ("Commission") issued an Order in the above docket. In the Order, the Commission approved the revised true-up procedures for Otter Tail Power Company's ("Otter Tail's") filing of its annual true-up to its Energy Adjustment Clause (aka "fuel clause adjustment" or "FCA").

This notice is to advise the Commission that Otter Tail will implement its annual true-up based on the period July 1, 2014 through June 30, 2015, starting with bills dated September 1, 2015 and continuing for 12 months. The amount of this year's true-up is a credit of $1,277,175, which will be refunded in the monthly rates applied to sales that are subject to the FCA from September 2015 through August 2016.

The annual true-up calculation also reflects a true-up of the previous period's actual collections. At the end of each true-up period, Otter Tail compares the true-up target amount with the amount actually refunded or collected. If Otter Tail over-collects or under-refunds a true-up amount, that amount of over-collection or under-refund is included in the subsequent year's true-up amount. For the true-up period ending August 31, 2014, Otter Tail over-collected the target amount by $39,209. This amount is included in the $1,277,175 credit amount referred to above. Any true-up difference for the period ending August 2015 will be reported in the 2016 annual filing and included, if applicable, in that annual true-up calculation.

Mr. Daniel P. Wolf
July 31, 2015
Page 2

Otter Tail's current Energy Adjustment Rider, Section 13.01, Page 2 of 2, includes these two paragraphs describing the annual true-up: *"In addition there shall be an annual true-up for any amount collected over or under the actual cost of energy for the twelve months ending June 30 of each year as reported in the Annual Automatic Adjustment report filed according to Minnesota Rule 7825.2810. The annual true-up shall be based on a historic twelve-month period and shall be applied to the subsequent twelve months. The annual true-up will be effective on billings beginning September 1 of the current year through August 31 of the following year, when a new true-up rate will be calculated and applied. In years when the over- or under-recovery amount is small (a rate rounded to less than 0.001¢), an annual true-up rate shall not apply.*

The annual true-up rate shall be calculated as follows. The over- or under-recovery amount as shown in the current year Annual Automatic Adjustment report will be divided by the Minnesota kilowatt-hours subject to the fuel adjustment clause from the same report. This calculation will produce a true-up rate per kilowatt-hour (rounded to the nearest 0.001¢) that will be applied to Customers' bills in the same manner as the monthly cost of energy adjustment."

Please contact me at (218) 739-8279 or stommerdahl@otpco.com if you have any questions regarding this filing.

Yours truly,

/s/ STUART TOMMERDAHL
Stuart Tommerdahl
Manager, Regulatory Administration

jrb
Enlosures
By electronic filing
c: Service List

Otter Tail Power Company True-up for kWh subject to FCA
Docket E017/M-03-30
Calculation of Annual True-up - July 2014 through June 2015

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line No.	**Month**	**FCA Revenue**		**Subtract Last Year's True-up**	**Net FCA Revenue**	**MN kWh Sales Subject to COE**	**Total System Energy Cost**	**Total System Sales**
	Source:	*FCA Calculation*	*True-up Rate*	*(C)*(F)*	(B)-(D)	*FCA Calculation*	*FCA Calculation*	*FCA Calculation*
1	Jul-14	($76,682)	($0.0002)	($35,553)	($41,130)	177,763,469	$7,796,086	335,166,718
2	Aug-14	$823,173	($0.0002)	($35,957)	$859,130	179,784,084	$8,850,867	339,857,126
3	Sep-14	$496,767	$0.0008	$139,621	$357,146	174,526,179	$6,929,539	338,014,061
4	Oct-14	$400,759	$0.0008	$139,675	$261,084	174,593,713	$7,986,032	336,316,513
5	Nov-14	$171,219	$0.0008	$150,017	$21,203	187,520,821	$8,758,410	372,231,288
6	Dec-14	($50,152)	$0.0008	$167,469	($217,621)	209,336,030	$13,773,720	440,129,087
7	Jan-15	$296,304	$0.0008	$187,286	$109,018	234,107,076	$12,940,272	488,130,203
8	Feb-15	$1,249,869	$0.0008	$186,419	$1,063,449	233,024,161	$11,789,838	472,853,269
9	Mar-15	$1,370,840	$0.0008	$171,449	$1,199,392	214,310,960	$11,303,821	441,505,169
10	Apr-15	$654,400	$0.0008	$155,906	$498,495	194,882,267	$7,882,234	384,728,785
11	May-15	$481,435	$0.0008	$133,950	$347,484	167,437,726	$7,235,793	320,774,919
12	Jun-15	$149,915	$0.0008	$136,263	$13,652	170,329,356	$7,429,209	318,423,088
13	**Totals**	$5,967,847		$1,496,545	$4,471,302	2,317,615,842	$112,675,821	4,588,130,226

Line No.				
14	KWH subject to COE		2,317,615,842	
15	Recovery from FCA		$4,471,302	
16	Recovery from base cost	(1)	$53,682,936	
17	Total adjusted recovery	(2)	$58,154,238	% over/(under)
18	Actual energy cost	(3)	$56,916,272	Recovery (5)
19	**Over/(under) recovery**	(4)	**$1,237,966**	2.18%
20	**Plus over collection from prior year**	(6)	**$39,209**	
21	**Refund to Customers**		**$1,277,175**	
22	**Annual True-up Factor**		**$0.0006**	
23	**Base cost =**		**$0.023163**	

(1) Recovery from base cost: $0.023163 x MN kWh sales subject to FCA
(2) Total adjusted recovery: Sum of recovery from FCA and recovery from base cost
(3) Actual energy cost: MN kwh sales subject to COE / total sys sales x total sys energy cost
(4) Over/under recovery: total adjusted recovery - actual energy cost
(5) % over/under recovery: over/under recovery / actual energy cost
(6) Over(Under) Collection / MN kwh sales subject to COE:
If Otter Tail over collects (over recovers) or under refunds the prior period's true-up, the amount due the customer is included in the calculation of the next year's true-up. Otter Tail under collected the previous period's true-up so there is no adjustment to the calculation.

Previous True-up Amount to be collected (Sep 2013 - Aug 2014) was:	**$497,024**
Amount collected (Sep 2013 - Aug 2014) was:	**($457,815)**
OTP over/(under)collected:	**$39,209**

(a) Current approved True-up Amt - over/(under) collection	**($1,831,116)**
(b) Amount collected (refunded) to-date (Sept 2014 - June 2015):	$1,568,054
(c) Net Balance remaining (a) + (b)	($263,062)
(d) Estimated collections/(refunds) to be received (Jul and Aug 2015)	$286,038
(e) Projected balance yet to be refunded	$22,976

% of MN sales (subject to FCA) to system	50.5133%
Energy costs allocated to MN for sales subject to FCA	$56,916,272

Documentation Requirement 6.a. (1)

BILL IMPACT BY CUSTOMER CLASS

	Sep-15	Oct	Nov	Dec	Jan-16	Feb	Mar	Apr	May	Jun	Jul	Aug	Total
Residential	$ (22,423)	$ (20,781)	$ (26,356)	$ (34,201)	$ (42,091)	$ (41,110)	$ (35,128)	$ (29,511)	$ (22,765)	$ (21,462)	$ (23,166)	$ (24,246)	$ (343,239)
Farm	$ (2,208)	$ (1,976)	$ (2,386)	$ (2,470)	$ (2,577)	$ (2,551)	$ (2,280)	$ (2,008)	$ (1,784)	$ (1,729)	$ (2,177)	$ (2,587)	$ (26,732)
General Service	$ (12,279)	$ (11,144)	$ (12,923)	$ (14,996)	$ (17,674)	$ (17,709)	$ (15,753)	$ (14,008)	$ (11,413)	$ (11,439)	$ (12,544)	$ (12,919)	$ (369,972)
Large General Service	$ (36,629)	$ (35,315)	$ (37,507)	$ (37,692)	$ (39,882)	$ (40,335)	$ (36,979)	$ (36,439)	$ (33,997)	$ (34,726)	$ (35,620)	$ (36,412)	$ (441,532)
OPA	$ (1,029)	$ (951)	$ (981)	$ (1,009)	$ (1,102)	$ (1,122)	$ (1,060)	$ (1,092)	$ (1,034)	$ (1,050)	$ (1,060)	$ (1,025)	$ (12,515)
Street & Area Lighting	$ (509)	$ (517)	$ (528)	$ (550)	$ (569)	$ (641)	$ (524)	$ (514)	$ (503)	$ (499)	$ (498)	$ (502)	$ (454,047)
Pipelines	$ (45,119)	$ (43,543)	$ (45,693)	$ (46,279)	$ (50,809)	$ (47,696)	$ (50,519)	$ (49,093)	$ (48,227)	$ (47,395)	$ (51,085)	$ (50,974)	$ (576,433)
Total Debit	$ (120,194)	$ (114,228)	$ (126,374)	$ (137,197)	$ (154,704)	$ (151,164)	$ (142,244)	$ (132,666)	$ (119,723)	$ (118,300)	$ (126,151)	$ (128,664)	$ (1,571,608)

Documentation Requirement 6.b. (1)

Documentation supporting all calculations

Attached to the filing is EXHIBIT 1 and EXHIBIT 3 (the monthly fuel clause calculation as filed for months July 2014 through June 2015)

Documentation Requirement 6.c. (1)

MWH Sales Forecast Covering Time Period that the True-Up will be Refunded

	Sep-15	Oct	Nov	Dec	Jan-16	Feb	Mar	Apr	May	Jun	Jul	Aug	Total
Residential	37,372	34,636	43,926	57,002	70,152	68,516	58,546	49,185	37,941	35,770	38,610	40,410	572,066
Farm	3,679	3,293	3,977	4,116	4,295	4,252	3,800	3,347	2,973	2,882	3,628	4,311	44,554
General Service	20,464	18,574	21,538	24,993	29,457	29,515	26,256	23,347	19,022	19,065	20,907	21,532	274,667
Large General Service	61,048	58,859	62,512	62,820	66,470	67,225	61,632	60,732	56,661	57,876	59,366	60,686	735,887
OPA	1,714	1,584	1,635	1,681	1,836	1,869	1,767	1,821	1,723	1,749	1,767	1,709	20,858
Street & Area Lighting	849	862	881	917	949	1,069	873	856	839	832	830	837	10,593
Pipelines	75,198	72,572	76,155	77,132	84,682	79,493	84,199	81,821	80,379	78,992	85,142	84,956	960,722
Subject to FCA true-up	200,323	190,380	210,623	228,661	257,841	251,939	237,073	221,110	199,539	197,166	210,251	214,441	2,619,347
Total forecast	200,323	190,380	210,623	228,661	257,841	251,939	237,073	221,110	199,539	197,166	210,251	214,441	2,619,347

(1) Provided per December 27, 2006 Order in this Docket.

Documentation Requirement 6.d. (1)
Plant Outages, Unusual Costs
(From each respective monthly fuel clause filing)

Plant Conditions for June 2014

Big Stone:	The unit generated 248,578 net MWh for the month. Unit availability was 100% and equivalent availability was 95.5%. Fuel prices were on budget.
Coyote:	The Unit generated 164,746 net MWh for the month. Unit availability was 65.3% and equivalent availability was 56.0%. Coyote had 6.37 days of outage for a scheduled boiler wash and 4.06 days of forced outage for a tube leak. Fuel prices were 4.40% under budget.
Hoot Lake:	Unit 2 off the entire month for scheduled major outage.
	Unit 3 off the entire month for scheduled major outage.

Plant Conditions for July 2014

Big Stone:	The unit generated 222,524 net MWh for the month. Unit availability was 100% and equivalent availability was 95.7%. Fuel prices were on budget.
Coyote:	The Unit generated 229,345 net MWh for the month. Unit availability was 87.4% and equivalent availability was 81.3%. Coyote had 2.43 days of forced outage for unit trip due to 345 kV line lightning strike and 1.47 days for a screen tube leak. Fuel prices were 6.95% under budget.
Hoot Lake:	Unit 2 was off the entire month for turbine vibration.
	Unit 3 generated net 32,350 MWh for the month. Unit availability was 82.5% and equivalent availability was 82.5%. Unit #3 had 3.61 days of planned outage extension and 2.26 days of forced outage for low vacuum trip. Fuel prices were 4.55% over budget.

Plant Conditions for August 2014

Big Stone:	The unit generated 207,084 net MWh for the month. Unit availability was 94.7% and equivalent availability was 88.0%. The unit was forced off line for 1.64 days on the 6th due to a boiler tube leak in the reheat section. Fuel prices were on budget.
Coyote:	The Unit generated 253,390 net MWh for the month. Unit availability was 91.6% and equivalent availability was 82.3%. Coyote had 2.59 days of forced outage for GR fan vibration problems. Fuel prices were 7.87% under budget.
Hoot Lake:	Unit 2 generated 3,677 net MWh for the month. Unit availability was 14.1% and equivalent availability was 12.1%. Unit 2 was off line for 24.65 days due to high vibration on turbine. Fuel prices were 2.86% over budget.
	Unit 3 generated 40,794 net MWh for the month. Unit availability was 96.04% and equivalent availability was 95.6%. Unit 3 was off line for 1.23 days to repair bleed trip packing and a feed water heater. Fuel prices were 4.26% over budget.

Plant Conditions for September 2014

Big Stone:	The unit generated 197,072 net MWh for the month. Unit availability was 98.5% and equivalent availability was 95.7%. Fuel prices were 1.45% under budget.
Coyote:	The Unit generated 210,857 net MWh for the month. Unit availability was 84.6% and equivalent availability was 78.5%. Coyote had 2.79 days of planned outage for boiler wash and 1.82 days of planned outage extension for boiler wash. Fuel prices were 8.09% under budget.
Hoot Lake:	Unit 2 generated 27,849 net MWh for the month. Unit availability was 100% and equivalent availability was 98.9%. Fuel prices were 1.79% over budget.
	Unit 3 generated 32,792 net MWh for the month. Unit availability was 85.5% and equivalent availability was 84.8%. Unit 3 was off line for 4.19 days to allow Toshiba to repair a hydrogen leak related to the overhaul. Fuel prices were on budget.

Plant Conditions for October 2014

Big Stone:	The unit generated 204,257 net MWh for the month. Unit availability was 95.2% and equivalent availability was 92.3%. Big Stone had 1.49 days of unplanned outage for a reheat outlet tube leak. Fuel prices were 1.54% under budget.
Coyote:	The Unit generated 259,511 net MWh for the month. Unit availability was 96.2% and equivalent availability was 93.9%. Coyote had 1.17 days of unplanned outage for a tube leak repair. Fuel prices were 4.41% under budget.
Hoot Lake:	Unit 2 generated 26,738 net MWh for the month. Unit availability was 91.62% and equivalent availability was 83.04%. Unit 2 had 2.60 days of unplanned outage for a tube leak, turbine balance and steam valve work. Fuel prices were 6.06% under budget.
	Unit 3 generated 39,384 net MWh for the month. Unit availability was 100.0% and equivalent availability was 89.7%. Fuel prices were 4.09% under budget.

Plant Conditions for November 2014

Big Stone:	The unit generated 199,044 net MWh for the month. Unit availability was 92.6% and equivalent availability was 91.1%. Big Stone had 2.21 days of unplanned outage for “D” Boiler Circ Pump and a tube leak. Fuel prices were 0.81% under budget.
Coyote:	The Unit generated 268,816 net MWh for the month. Unit availability was 100.0% and equivalent availability was 97.4%. Fuel prices were 2.36% under budget.
Hoot Lake:	Unit 2 generated 28,362 net MWh for the month. Unit availability was 95.46% and equivalent availability was 95.46%. Unit 2 had 1.36 days of unplanned outage for an economizer tube leak. Fuel prices were 1.79% under budget.
	Unit 3 generated 40,734 net MWh for the month. Unit availability was 100.0% and equivalent availability was 100.0%. Fuel prices were 2.63% under budget.

(1) Provided per December 27, 2006 Order in this Docket.

Documentation Requirement 6.d. (1)
Plant Outages, Unusual Costs
(From each respective monthly fuel clause filing)

Plant Conditions for December 2014

Big Stone: The unit generated 238,182 net MWh for the month. Unit availability was 99.80% and equivalent availability was 99.28%. Fuel prices were 0.84% under budget.

Coyote: The Unit generated 75,255 net MWh for the month. Unit availability was 39.7% and equivalent availability was 24.5%. Coyote had 15.61 days of unplanned outage for an “A” Boiler Feed Pump fire. Fuel prices were 1.50% under budget.

Hoot Lake: Unit 2 generated 29,558 net MWh for the month. Unit availability was 100.0% and equivalent availability was 100.0%. Fuel prices were 3.37% over budget.
Unit 3 generated 41,488 net MWh for the month. Unit availability was 100.0% and equivalent availability was 100.0%. Fuel prices were 4.81% over budget.

Plant Conditions for January 2015

		Unit	Equivalent	Outage			Fuel Prices	
	Net	Availability	Availability					Actual vs
Plant	MWh	%	%	Days	Type	Reason	%	Budget
Big Stone	262,363	95.9	83.8	1.27	Scheduled	"D" Boiler Circ Pump Failure	3.72	Under
Coyote	174,634	99.4	55.7	0.00			5.43	Over
Hoot Lake Unit 2	26,112	100.0	100.0	0.00			1.36	Under
Hoot Lake Unit 3	27,781	100.0	100.0	0.00			1.37	Under

Plant conditions for February 2015

		Unit	Equivalent	Outage			Fuel Prices	
	Net	Availability	Availability					Actual vs
Plant	MWh	%	%	Days	Type	Reason	%	Budget
Big Stone	261,058	95.8	88.2	1.19	Scheduled	Planned AQCS Outage	2.35	Under
Coyote	148,808	93.5	51.8	1.81	Forced	Gas Recirc Fan Balance	5.12	Over
Hoot Lake Unit 2	15,049	100.0	100.0	0.00			0.03	Under
Hoot Lake Unit 3	25,918	100.0	100.0	0.00			0.06	Under

(1) Provided per December 27, 2006 Order in this Docket.

Documentation Requirement 6.d. (1)
Plant Outages, Unusual Costs
(From each respective monthly fuel clause filing)

Plant Conditions for March 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	0	0.0	0.0	31.00	Scheduled	Planned AQCS Outage	0	
Coyote	173,306	99.8	56.1	0.00			5.18	Over
Hoot Lake Unit 2	27,554	95.8	95.8	1.31	Forced	Primary Superheat Tube Rupture	1.52	Under
Hoot Lake Unit 3	40,007	100.0	99.5	0.00			1.52	Under

Plant Conditions for April 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	0	0.0	0.0	30.00	Scheduled	Planned AQCS Outage	0	
Coyote	167,998	100.0	56.2	0.00			5.93	Over
Hoot Lake Unit 2	10,899	100.0	98.3	0.00			1.9	Over
Hoot Lake Unit 3	13,464	100.0	97.2	0.00			1.89	Over

Plant Conditions for May 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	0	0.0	0.0	31.00	Scheduled	Planned AQCS Outage	0	
Coyote	159,471	93.5	57.6	1.93	Forced	Wind Box Repair	6.26	Over
Hoot Lake Unit 2	0	100.0	100.0	0.00			0	
Hoot Lake Unit 3	226	100.0	100.0	0.00			7.11	Over

(1) Provided per December 27, 2006 Order in this Docket.

Documentation Requirement 6.d. (1)
Plant Outages, Unusual Costs
(From each respective monthly fuel clause filing)

Plant Conditions for June 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	0	0.0	0.0	30.00	Scheduled	Planned AQCS Outage - Extended due to main turbine blading issues	0	
Coyote	147,117	87.5	49.1	3.75	Forced	Boiler Tube Leak	6.38	Over
Hoot Lake Unit 2	0	100.0	100.0	0.00			0	
Hoot Lake Unit 3	0	98.7	98.7	0.00			0	

(1) Provided per December 27, 2006 Order in this Docket.

Documentation of 6.e. (1)

There were no additional requirements in the true-up due to the final Order in E-017/M-05-284.

(1) Provided per December 27, 2006 Order in this Docket.

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CYCLE 01 RATE LEVEL 31

MINNESOTA
OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JULY 31, 2014
FOR BILLINGS TO BE EFFECTIVE SEPTEMBER 2, 2014

Line No.	ENERGY COSTS	(A) 2014 June	(B) 2014 July	(C) Total This Period
1	Plant Generation	$ 4,128,719	$ 5,203,813	$ 9,332,532
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 3,890,249	$ 2,251,882	$ 6,142,131
3	Purchased Power	$ 1,308,075	$ 1,049,534	$ 2,357,609
4	Wind Curtailment	$ (105,007)	$ (10,047)	$ (115,054)
5	Less: MISO ASM (Rev) Cost	$ 3,389	$ 1,052	$ 4,440
6	Less: Intersystem Sales (Rev) Cost	$ (287,134)	$ (484,011)	$ (771,145)
7	Less: Asset Based Margins (Rev) Cost	$ (74,489)	$ (216,137)	$ (290,626)
8	Total Cost of Fuel	$ 8,863,803	7,796,086	$ 16,659,888
	KWH SALES			
9	Total Sales of Electricity	371,893,264	375,625,759	747,519,023
10	Less Inter-System Sales	(46,349,857)	(40,459,041)	(86,808,898)
11	Total kWh	325,543,407	335,166,718	660,710,125
12	Cost per KWH		0.025215	
13	Base Cost		0.023163	
14	Annual True-Up Factor		0.0008	
15	Energy Adjustment per kWh		0.00285	

kWh Information For The Billing Month of: July 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	177,763,469	kWh
2	Non-Energy Adjustment Rider Sales	140,185	kWh
3	Total	177,903,654	kWh
	Non-Minnesota Sales		
4	Sales for Resale	158,046	kWh
5	Total Sales of Electricity (ND and SD)	157,105,018	kWh
6	Inter-System Sales	40,459,041	kWh
	Total kWh Sales	375,625,759	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING AUGUST 31, 2014
FOR BILLINGS TO BE EFFECTIVE OCTOBER 2, 2014

Line No.	ENERGY COSTS		(A) 2014 July		(B) 2014 August		(C) Total This Period
1	Plant Generation	$	5,203,813	$	5,391,495	$	10,595,308
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	2,251,882	$	2,420,886	$	4,672,768
3	Purchased Power	$	1,049,534	$	1,244,926	$	2,294,460
4	Wind Curtailment	$	(10,047)	$	6,327	$	(3,721)
5	Less: MISO ASM (Rev) Cost	$	1,052	$	(5,093)	$	(4,041)
6	Less: Intersystem Sales (Rev) Cost	$	(484,011)	$	(153,985)	$	(637,996)
7	Less: Asset Based Margins (Rev) Cost	$	(216,137)	$	(53,689)	$	(269,826)
8	Total Cost of Fuel	$	7,796,086		8,850,867	$	16,646,953
	KWH SALES						
9	Total Sales of Electricity		375,625,759		352,064,370		727,690,129
10	Less Inter-System Sales		(40,459,041)		(12,207,244)		(52,666,285)
11	Total kWh		335,166,718		339,857,126		675,023,844

12	Cost per KWH	0.024661
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00230

kWh Information For The Billing Month of: August 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	179,784,084	kWh
2	Non-Energy Adjustment Rider Sales	132,609	kWh
3	Total	179,916,693	kWh
	Non-Minnesota Sales		
4	Sales for Resale	252,790	kWh
5	Total Sales of Electricity (ND and SD)	159,687,643	kWh
6	Inter-System Sales	12,207,244	kWh
	Total kWh Sales	352,064,370	kWh

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EFFECTIVE 11/3/2014
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING SEPTEMBER 30, 2014
FOR BILLINGS TO BE EFFECTIVE NOVEMBER 3, 2014

Line No.	ENERGY COSTS	(A) 2014 August	(B) 2014 September	(C) Total This Period
1	Plant Generation	$ 5,391,495	$ 5,137,797	$ 10,529,292
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 2,420,886	$ 2,142,557	$ 4,563,443
3	Purchased Power	$ 1,244,926	$ 518,721	$ 1,763,647
4	Wind Curtailment	$ 6,327	$ (31,316)	$ (24,990)
5	Less: MISO ASM (Rev) Cost	$ (5,093)	$ (22,485)	$ (27,578)
6	Less: Intersystem Sales (Rev) Cost	$ (153,985)	$ (577,242)	$ (731,228)
7	Less: Asset Based Margins (Rev) Cost	$ (53,689)	$ (238,493)	$ (292,182)
8	Total Cost of Fuel	$ 8,850,867	6,929,539	$ 15,780,406
	KWH SALES			
9	Total Sales of Electricity	352,064,370	366,079,838	718,144,208
10	Less Inter-System Sales	(12,207,244)	(28,065,777)	(40,273,021)
11	Total kWh	339,857,126	338,014,061	677,871,187

12	Cost per KWH	0.023279
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00092

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kWh Information For The Billing Month of: September 2014

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	174,526,179	kWh
2	Non-Energy Adjustment Rider Sales	134,730	kWh
3	Total	174,660,909	kWh
	Non-Minnesota Sales		
4	Sales for Resale	249,294	kWh
5	Total Sales of Electricity (ND and SD)	163,103,858	kWh
6	Inter-System Sales	28,065,777	kWh
	Total kWh Sales	366,079,838	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING OCTOBER 31, 2014
FOR BILLINGS TO BE EFFECTIVE DECEMBER 1, 2014

Line No.	ENERGY COSTS	(A) 2014 September	(B) 2014 October	(C) Total This Period
1	Plant Generation	$ 5,137,797	$ 5,873,229	$ 11,011,026
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 2,142,557	$ 1,486,840	$ 3,629,397
3	Purchased Power	$ 518,721	$ 1,699,463	$ 2,218,184
4	Wind Curtailment	$ (31,316)	$ 15,392	$ (15,924)
5	Less: MISO ASM (Rev) Cost	$ (22,485)	$ (24,146)	$ (46,631)
6	Less: Intersystem Sales (Rev) Cost	$ (577,242)	$ (678,959)	$ (1,256,201)
7	Less: Asset Based Margins (Rev) Cost	$ (238,493)	$ (385,787)	$ (624,279)
8	Total Cost of Fuel	$ 6,929,539	7,986,032	$ 14,915,571
	KWH SALES			
9	Total Sales of Electricity	366,079,838	369,893,650	735,973,488
10	Less Inter-System Sales	(28,065,777)	(33,577,137)	(61,642,914)
11	Total kWh	338,014,061	336,316,513	674,330,574

Line		
12	Cost per KWH	0.022119
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	(0.00024)

kWh Information For The Billing Month of: October 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	174,593,713	kWh
2	Non-Energy Adjustment Rider Sales	138,835	kWh
3	Total	174,732,548	kWh
	Non-Minnesota Sales		
4	Sales for Resale	288,845	kWh
5	Total Sales of Electricity (ND and SD)	161,295,120	kWh
6	Inter-System Sales	33,577,137	kWh
	Total kWh Sales	369,893,650	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING NOVEMBER 30, 2014
FOR BILLINGS TO BE EFFECTIVE JANUARY 2, 2015

Line No.	ENERGY COSTS	(A) 2014 October	(B) 2014 November	(C) Total This Period
1	Plant Generation	$ 5,873,229	$ 5,934,820	$ 11,808,049
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 1,486,840	$ 1,818,556	$ 3,305,396
3	Purchased Power	$ 1,699,463	$ 2,118,439	$ 3,817,902
4	Wind Curtailment	$ 15,392	$ 12,958	$ 28,350
5	Less: MISO ASM (Rev) Cost	$ (24,146)	$ (32,960)	$ (57,107)
6	Less: Intersystem Sales (Rev) Cost	$ (678,959)	$ (811,558)	$ (1,490,517)
7	Less: Asset Based Margins (Rev) Cost	$ (385,787)	$ (281,846)	$ (667,632)
8	Total Cost of Fuel	$ 7,986,032	8,758,410	$ 16,744,441
	KWH SALES			
9	Total Sales of Electricity	369,893,650	408,084,122	777,977,772
10	Less Inter-System Sales	(33,577,137)	(35,852,834)	(69,429,971)
11	Total kWh	336,316,513	372,231,288	708,547,801

12	Cost per KWH	0.023632
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00127

kWh Information For The Billing Month of: November 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	187,520,821	kWh
2	Non-Energy Adjustment Rider Sales	187,698	kWh
3	Total	187,708,519	kWh
	Non-Minnesota Sales		
4	Sales for Resale	367,205	kWh
5	Total Sales of Electricity (ND and SD)	184,155,564	kWh
6	Inter-System Sales	35,852,834	kWh
	Total kWh Sales	408,084,122	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING DECEMBER 31, 2014
FOR BILLINGS TO BE EFFECTIVE FEBRUARY 2, 2015

Line No.	ENERGY COSTS		(A) 2014 November		(B) 2014 December		(C) Total This Period
1	Plant Generation	$	5,934,820	$	5,500,877	$	11,435,697
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	1,818,556	$	5,804,312	$	7,622,867
3	Purchased Power	$	2,118,439	$	2,894,939	$	5,013,378
4	Wind Curtailment	$	12,958	$	40,294	$	53,253
5	Less: MISO ASM (Rev) Cost	$	(32,960)	$	(8,227)	$	(41,187)
6	Less: Intersystem Sales (Rev) Cost	$	(811,558)	$	(336,143)	$	(1,147,700)
7	Less: Asset Based Margins (Rev) Cost	$	(281,846)	$	(122,332)	$	(404,178)
8	Total Cost of Fuel	$	8,758,410		13,773,720	$	22,532,130
	KWH SALES						
9	Total Sales of Electricity		408,084,122		453,613,745		861,697,867
10	Less Inter-System Sales		(35,852,834)		(13,484,658)		(49,337,492)
11	Total kWh		372,231,288		440,129,087		812,360,375

12	Cost per KWH	0.027737
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00537

kWh Information For The Billing Month of: December 2014

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	209,336,030	kWh
2	Non-Energy Adjustment Rider Sales	143,031	kWh
3	Total	209,479,061	kWh
	Non-Minnesota Sales		
4	Sales for Resale	560,555	kWh
5	Total Sales of Electricity (ND and SD)	230,089,471	kWh
6	Inter-System Sales	13,484,658	kWh
	Total kWh Sales	453,613,745	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JANUARY 31, 2015
FOR BILLINGS TO BE EFFECTIVE MARCH 3, 2015

Line No.	ENERGY COSTS		(A) 2014 December		(B) 2015 January		(C) Total This Period
1	Plant Generation	$	5,500,877	$	5,941,448	$	11,442,325
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	5,804,312	$	3,817,366	$	9,621,678
3	Purchased Power	$	2,894,939	$	3,362,622	$	6,257,561
4	Wind Curtailment	$	40,294	$	35,163	$	75,457
5	Less: MISO ASM (Rev) Cost	$	(8,227)	$	(1,963)	$	(10,191)
6	Less: Intersystem Sales (Rev) Cost	$	(336,143)	$	(174,174)	$	(510,317)
7	Less: Asset Based Margins (Rev) Cost	$	(122,332)	$	(40,189)	$	(162,520)
8	Total Cost of Fuel	$	13,773,720		12,940,272	$	26,713,993

	KWH SALES			
9	Total Sales of Electricity	453,613,745	496,692,693	950,306,438
10	Less Inter-System Sales	(13,484,658)	(8,562,490)	(22,047,148)
11	Total kWh	440,129,087	488,130,203	928,259,290

12	Cost per KWH	0.028779
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00642

kWh Information For The Billing Month of: January 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	234,107,076	kWh
2	Non-Energy Adjustment Rider Sales	212,906	kWh
3	Total	234,319,982	kWh
	Non-Minnesota Sales		
4	Sales for Resale	455,729	kWh
5	Total Sales of Electricity (ND and SD)	253,354,492	kWh
6	Inter-System Sales	8,562,490	kWh
	Total kWh Sales	496,692,693	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING FEBRUARY 28, 2015
FOR BILLINGS TO BE EFFECTIVE APRIL 2, 2015

Line No.	ENERGY COSTS	(A) 2015 January	(B) 2015 February	(C) Total This Period
1	Plant Generation	$ 5,941,448	$ 5,562,027	$ 11,503,475
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 3,817,366	$ 3,652,476	$ 7,469,842
3	Purchased Power	$ 3,362,622	$ 3,011,453	$ 6,374,075
4	Wind Curtailment	$ 35,163	$ 8,708	$ 43,871
5	Less: MISO ASM (Rev) Cost	$ (1,963)	$ 9,166	$ 7,202
6	Less: Intersystem Sales (Rev) Cost	$ (174,174)	$ (354,419)	$ (528,594)
7	Less: Asset Based Margins (Rev) Cost	$ (40,189)	$ (99,573)	$ (139,762)
8	Total Cost of Fuel	$ 12,940,272	11,789,838	$ 24,730,110
	KWH SALES			
9	Total Sales of Electricity	496,692,693	491,182,428	987,875,121
10	Less Inter-System Sales	(8,562,490)	(18,329,159)	(26,891,649)
11	Total kWh	488,130,203	472,853,269	960,983,472

12	Cost per KWH	0.025734
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00337

kWh Information For The Billing Month of: February 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	233,024,161	kWh
2	Non-Energy Adjustment Rider Sales	205,803	kWh
3	Total	233,229,964	kWh
	Non-Minnesota Sales		
4	Sales for Resale	520,855	kWh
5	Total Sales of Electricity (ND and SD)	239,102,450	kWh
6	Inter-System Sales	18,329,159	kWh
	Total kWh Sales	491,182,428	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA
OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MARCH 31, 2015
FOR BILLINGS TO BE EFFECTIVE MAY 1, 2015

Line No.	ENERGY COSTS		(A) 2015 February		(B) 2015 March		(C) Total This Period
1	Plant Generation	$	5,562,027	$	2,942,415	$	8,504,442
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,652,476	$	5,263,326	$	8,915,802
3	Purchased Power	$	3,011,453	$	3,411,677	$	6,423,130
4	Wind Curtailment	$	8,708	$	(4,669)	$	4,039
5	Less: MISO ASM (Rev) Cost	$	9,166	$	(3,110)	$	6,056
6	Less: Intersystem Sales (Rev) Cost	$	(354,419)	$	(202,135)	$	(556,555)
7	Less: Asset Based Margins (Rev) Cost	$	(99,573)	$	(103,684)	$	(203,257)
8	Total Cost of Fuel	$	11,789,838		11,303,821	$	23,093,658
	KWH SALES						
9	Total Sales of Electricity		491,182,428		449,319,717		940,502,145
10	Less Inter-System Sales		(18,329,159)		(7,814,548)		(26,143,707)
11	Total kWh		472,853,269		441,505,169		914,358,438

12	Cost per KWH	0.025257
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00289

kWh Information For The Billing Month of: March 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	214,310,960	kWh
2	Non-Energy Adjustment Rider Sales	238,938	kWh
3	Total	214,549,898	kWh
	Non-Minnesota Sales		
4	Sales for Resale	414,841	kWh
5	Total Sales of Electricity (ND and SD)	226,540,430	kWh
6	Inter-System Sales	7,814,548	kWh
	Total kWh Sales	449,319,717	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA
OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING APRIL 30, 2015
FOR BILLINGS TO BE EFFECTIVE JUNE 2, 2015

Line No.	ENERGY COSTS	(A) 2015 March	(B) 2015 April	(C) Total This Period
1	Plant Generation	$ 2,942,415	$ 1,816,504	$ 4,758,919
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 5,263,326	$ 3,273,673	$ 8,536,999
3	Purchased Power	$ 3,411,677	$ 2,829,312	$ 6,240,989
4	Wind Curtailment	$ (4,669)	$ 20,929	$ 16,260
5	Less: MISO ASM (Rev) Cost	$ (3,110)	$ 10,188	$ 7,078
6	Less: Intersystem Sales (Rev) Cost	$ (202,135)	$ (65,024)	$ (267,159)
7	Less: Asset Based Margins (Rev) Cost	$ (103,684)	$ (3,347)	$ (107,031)
8	Total Cost of Fuel	$ 11,303,821	$ 7,882,234	$ 19,186,055
	KWH SALES			
9	Total Sales of Electricity	449,319,717	387,742,266	837,061,983
10	Less Inter-System Sales	(7,814,548)	(3,013,481)	(10,828,029)
11	Total kWh	441,505,169	384,728,785	826,233,954

12	Cost per KWH	0.023221
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00086

kWh Information For The Billing Month of: April 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	194,882,267	kWh
2	Non-Energy Adjustment Rider Sales	208,519	kWh
3	Total	195,090,786	kWh
	Non-Minnesota Sales		
4	Sales for Resale	277,387	kWh
5	Total Sales of Electricity (ND and SD)	189,360,612	kWh
6	Inter-System Sales	3,013,481	kWh
	Total kWh Sales	387,742,266	kWh

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EXHIBIT 3
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EFFECTIVE 7/2/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MAY 31, 2015
FOR BILLINGS TO BE EFFECTIVE JULY 2, 2015

Line No.	ENERGY COSTS		(A) 2015 April		(B) 2015 May		(C) Total This Period
1	Plant Generation	$	1,816,504	$	1,186,652	$	3,003,156
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,273,673	$	3,671,352	$	6,945,026
3	Purchased Power	$	2,829,312	$	2,440,165	$	5,269,477
4	Wind Curtailment	$	20,929	$	4,592	$	25,521
5	Less: MISO ASM (Rev) Cost	$	10,188	$	13,085	$	23,273
6	Less: Intersystem Sales (Rev) Cost	$	(65,024)	$	(80,107)	$	(145,131)
7	Less: Asset Based Margins (Rev) Cost	$	(3,347)	$	54	$	(3,294)
8	Total Cost of Fuel	$	7,882,234	$	7,235,793	$	15,118,028
	KWH SALES						
9	Total Sales of Electricity		387,742,266		323,946,707		711,688,973
10	Less Inter-System Sales		(3,013,481)		(3,171,788)		(6,185,269)
11	Total kWh		384,728,785		320,774,919		705,503,704

12	Cost per KWH	0.021429
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	(0.00093)

kWh Information For The Billing Month of: May 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	167,437,726	kWh
2	Non-Energy Adjustment Rider Sales	147,894	kWh
3	Total	167,585,620	kWh
	Non-Minnesota Sales		
4	Sales for Resale	202,247	kWh
5	Total Sales of Electricity (ND and SD)	152,987,052	kWh
6	Inter-System Sales	3,171,788	kWh
	Total kWh Sales	323,946,707	kWh

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EFFECTIVE 8/3/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JUNE 30, 2015
FOR BILLINGS TO BE EFFECTIVE AUGUST 3, 2015

Line No.	ENERGY COSTS		(A) 2015 May		(B) 2015 June		(C) Total This Period
1	Plant Generation	$	1,186,652	$	1,027,126	$	2,213,778
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,671,352	$	4,480,717	$	8,152,070
3	Purchased Power	$	2,440,165	$	1,933,630	$	4,373,795
4	Wind Curtailment	$	4,592	$	115	$	4,707
5	Less: MISO ASM (Rev) Cost	$	13,085	$	15,050	$	28,135
6	Less: Intersystem Sales (Rev) Cost	$	(80,107)	$	(26,749)	$	(106,856)
7	Less: Asset Based Margins (Rev) Cost	$	54	$	(680)	$	(626)
8	Total Cost of Fuel	$	7,235,793	$	7,429,209	$	14,665,002
	KWH SALES						
9	Total Sales of Electricity		323,946,707		320,013,031		643,959,738
10	Less Inter-System Sales		(3,171,788)		(1,589,943)		(4,761,731)
11	Total kWh		320,774,919		318,423,088		639,198,007

12	Cost per KWH	0.022943
13	Base Cost	0.023163
14	Annual True-Up Factor	0.0008
15	Energy Adjustment per kWh	0.00058

kWh Information For The Billing Month of: June 2015

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	170,329,356	kWh
2	Non-Energy Adjustment Rider Sales	127,169	kWh
3	Total	170,456,525	kWh
	Non-Minnesota Sales		
4	Sales for Resale	124,362	kWh
5	Total Sales of Electricity (ND and SD)	147,842,201	kWh
6	Inter-System Sales	1,589,943	kWh
	Total kWh Sales	320,013,031	kWh

Average Bill Impact of True-up

Line No.	Class	Number of Customers	Average Monthly kWh per Customer	Average Monthly Bill	Requested True-Up	Impact/ Month	% Impact
1	Residential *	48,613	980	94.31	(0.0006)	(0.59)	-0.62%
2	Farm *	1,444	2,571	244.76	(0.0006)	(1.54)	-0.63%
3	General Service *	9,608	2,380	220.36	(0.0006)	(1.43)	-0.65%
4	Large General Service *	767	79,893	5,803.52	(0.0006)	(47.94)	-0.83%
5	OPA	222	7,824	587.43	(0.0006)	(4.69)	-0.80%
6	Street & Area Lighting	144	6,130	952.69	(0.0006)	(3.68)	-0.39%
7	Pipelines	11	7,278,195	262,810.12	(0.0006)	(4,366.92)	-1.66%

* Average Includes Controlled Service Water Heating, Controlled Service Interruptible, and Controlled Service Deferred usage related to each class

CERTIFICATE OF SERVICE

Re: Notice of Implementation of Otter Tail Power Company's Annual Fuel Clause Adjustment True-up Mechanism
Minnesota Docket No. E017/M-03-30

I, Wendi Olson, hereby certify that I have this day served a copy of the following, or a summary thereof, on Mr. Daniel P. Wolf and Sharon Ferguson by e-filing, and to all other persons on the attached service list by electronic service or by First Class mail.

Otter Tail Power Company Notice of Implementation

Dated this **31st** day of **July 2015**.

<u>/s/ WENDI OLSON</u>
Wendi Olson, Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8699

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	OFF_SL_3-30_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_3-30_1
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_3-30_1
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_3-30_1
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_3-30_1
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_3-30_1
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	OFF_SL_3-30_1

COMPLIANCE REPORT AS REQUIRED BY ORDER IN DOCKET NO. E017/M-03-970

On February 2, 2006, Otter Tail filed in Docket No. E017/M-03-970 to remove the sunset provision for recovery of the purchase of wind through the fuel clause under the order issued January 13, 2005. On July 12, 2006, the Commission granted an extension of the recovery mechanism in place under the January 13, 2005 Order until a final Order is issued in this proceeding, and directs the Company to revise its tariff as appropriate. On August 10, 2006, Otter Tail filed the Purchase Power Agreement ("PPA") for approval in this proceeding pursuant the July 12, 2006 Order. The Commission deferred the issue of Renewable Energy Obligation ("REO") eligibility to the resource plan proceeding concerning Otter Tail, Docket No. E017/RP 05-968. The Commission also deferred other determinations until this docket returns to the Commission for PPA approval. On November 14, 2006, in Docket No. E017/M-03-970, the Commission approved Otter Tail's request with the following reporting requirements:

1. **Additional language to the Cost of Energy Adjustment Clause**

   Part E Section 1 Attachment B – paragraph 3 (see Part E Section 1 Rule 7825.2810 Subpart 1.A.)

2. **Credit ratepayers through the Fuel Adjustment Clause any compensation it receives from the MISO or any other transmission authority for calling an interruption of the energy generated by the Project during the period that Otter Tail Power Company is recovering curtailment provision costs from ratepayers.**

   There were no credits issued for reporting period of July 2014 to June 2015.

3. **Track all curtailments and curtailment payments and report them in its monthly fuel clause adjustment and AAA filings.**

   Part E Section 9 Attachment F (marked as Trade Secret) contains the curtailment for the time period of July 2014 through June 2015.

Otter Tail Power Company
Wind Curtailment Summary Report - System
Wind Energy Purchase Agreement with FPL Energy North Dakota II, LLC
Docket No. E017/M-03-970
Dated April 1, 2003

Month	(A) Date Paid Delivered MWh	(B) Date Paid Lost MWh	* (C) Wind Production Delivered to OTP MWh	* (D) Wind Production Amount OTP Paid	* (E) Lost Production Lost MWh	* (F) Lost Production Amount OTP Paid	* (G) Total OTP Paid	(H) Reason Codes
			[TRADE SECRET DATA BEGINS . . .					
Jul-14								
Aug-14								
Sep-14								
Oct-14								
Nov-14								
Dec-14								
Jan-15								
Feb-15	2/7, 8	3/12/15						4
Mar-15								
Apr-15								
May-15								
Jun-15								
Total								

. . . TRADE SECRET DATA ENDS]

Reason Code Explanation:
Curtailment was called for by OTP dispatch for voltage control due to high bus voltage readings.

Reason Codes:
1 = lack of firm transmission as described in Attachment C of the MISO OATT (or equivalent successor provision)
2 = low load
3 = transmission loading relief or MISO directive for reasons other than (1) above
4 = other - please explain in detail if compensation requested

* Columns C - G are invoiced amounts

Otter Tail Power Company
Wind Curtailment Summary Report - System
Wind Energy Purchase Agreement with Langdon Wind, LLC
Docket No. E017/M-08-131
Dated August 15, 2008

	(A)	(B)	* (C)	* (D)	* (E)	* (F)	* (G)	(H)
	Date Paid		Wind Production		Lost Production			
Month	Delivered MWh	Lost MWh	Delivered to OTP MWh	Amount OTP Paid	Lost MWh	Amount OTP Paid	Total OTP Paid	Reason Codes
			[TRADE SECRET DATA BEGINS . . .					
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								

. . . TRADE SECRET DATA ENDS]

Reason Code Explanation:

Reason Codes:
1 = lack of firm transmission as described in Attachment C of the MISO OATT (or equivalent successor provision)
2 = low load
3 = transmission loading relief or MISO directive for reasons other than (1) above
4 = other - please explain in detail if compensation requested

* Columns C - G are invoiced amounts

Otter Tail Power Company
Wind Curtailment Summary Report - System
Wind Energy Purchase Agreement with Ashtabula Wind III, LLC
Docket No. E017/M-13-386
Dated August 23, 2013

	(A)	(B)	* (C)	* (D)	* (E)	* (F)	* (G)	(H)
	Date Paid		Wind Production		Lost Production			
Month	Delivered MWh	Lost MWh	Delivered to OTP MWh	Amount OTP Paid	Lost MWh	Amount OTP Paid	Total OTP Paid	Reason Codes
			[TRADE SECRET DATA BEGINS . . .					
Jul-14	6/8,12,14,15,17,21 7/14,18,24,25,27	7/16/14 and 8/15/14						4
Aug-14	8/11	9/16/14						4
Sep-14	9/5,15,16,18,19,20,21, 22,23,24,25,26,27,28, 29,30	10/15/14						4
Oct-14	10/1,3,5,6,7,11,14,16, 17,19,21,22,24,25,27, 28	11/15/14						4
Nov-14	11/3,6,8,12,21,30	12/17/14						4
Dec-14	12/5,12,21,23,24,25, 26,27,28,29,30,31	1/13/15						4
Jan-15	1/1, 18, 29	2/11/15						4
Feb-15	2/20, 23	3/17/15						4
Mar-15	3/3, 12, 13, 14, 15, 16, 28, 29	4/15/15						4
Apr-15	4/1, 14, 15, 19, 20, 21	5/15/15						4
May-15	5/1, 2, 12, 28, 30	6/17/15						4
Jun-15	6/2, 7, 28	7/10/15						4
Total								

. . . TRADE SECRET DATA ENDS]

Reason Code Explanation: July - November 2014 January - June 2015
Curtailment was called for by Otter Tail Power due to negative LMP pricing. As specified in the Ashtabula 3 power purchase agreement, "Company shall pay to seller for such Curtailment Energy net of any Non-Compensable Curtailments, **[TRADE SECRET DATA BEGINS . . .**

. . . TRADE SECRET DATA ENDS]

Reason Code Explanation: December 2014
[TRADE SECRET DATA BEGINS . . .

. . . TRADE SECRET DATA ENDS]

As specified in the Ashtabula 3 power purchase agreement, "Company shall pay to seller for such Curtailment Energy net of any Non-Compensable Curtailments, **[TRADE SECRET DATA BEGINS . . .**

. . . TRADE SECRET DATA ENDS]

Reason Codes:
1 = lack of firm transmission as described in Attachment C of the MISO OATT (or equivalent successor provision)
2 = low load
3 = transmission loading relief or MISO directive for reasons other than (1) above
4 = other - please explain in detail if compensation requested

* Columns C - G are invoiced amounts

PASSING MISO DAY 2 COSTS THROUGH FUEL CLAUSE ORDER IN DOCKET NO. E017/M-05-284

On February 16, 2005, Otter Tail filed a request with the Commission to recover the costs resulting from participation in the "Day 2" operations of the Midwest Independent Transmission System Operator, Inc. ("MISO") through the use of the fuel clause adjustment. On April 7, 2005, the Commission issued its order in Docket No. E017/M-05-284 ordering Otter Tail to account for costs on a net basis in Account 555 and granting recovery of these costs through the fuel clause adjustment subject to refund with interest.

On December 21, 2005, the Commission issued a second interim order in Docket No. E017/M-05-284. On February 24, 2006, the Commission issued an order on reconsideration. A report of the stakeholders was filed with the Commission on June 22, 2006. On November 6, 2006, supplemental comments were filed with the Commission and the Order Establishing Accounting Treatment for MISO Day 2 Costs was issued on December 20, 2006.

In the December 20, 2006, Order utilities were granted deferred accounting treatment with respect to Schedule 16 and 17 costs, and were authorized recovery of charges imposed by the MISO for MISO Day 2 costs through the calculation of our fuel clause adjustment from the period of April 1, 2005, through a period of at least three years after the date of the Order. Utilities were allowed to use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 2005 without interest until the earlier of our next rate case or March 1, 2009, at which time utilities could seek to recover Schedule 16 and 17 costs at an appropriate level of base rate recovery. Over the subsequent twelve months utilities refunded through the fuel clause adjustment, all Schedule 16 and 17 costs previously recovered through the fuel clause adjustment.

In accordance with the December 2006 Order we are submitting the following additional reporting requirements:

7. A. 1. Each utility shall include in its AAA report an overview of the anticipated events and planned actions to address fuel clause costs, and the actions planned by the utility to minimize or lower such costs whenever possible.

Each utility shall provide a discussion of tools for managing fuel clause costs, including:

a) plans for use of financial instruments or other mechanisms to hedge the costs of natural gas or other fuels,

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[TRADE SECRET DATA BEGINS . . .

. . . TRADE SECRET DATA ENDS]

b) plans to hedge purchased energy costs (either through forward bilateral purchases or financial instruments), including how the utility will plan for and cover fuel and energy risk during planned unit outages; and

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. . . TRADE SECRET DATA ENDS]

c) where deemed appropriate, plans for additional optimization of congestion cost hedging through the purchase and/or sale of FTRs in the MISO Day 2 Market.

At this time, the Company has no specific plans to purchase or sell additional Financial Transmission Rights ("FTRs") beyond those held through the normal allocation process. However, in some situations, the Company may sell an excess FTR when a unit is offline for extended maintenance and the FTR is not required to hedge energy flows. In addition, the Company will purchase additional FTRs for bilateral purchases if a monthly or seasonal FTR is anticipated to provide a reasonable hedge against congestion costs.

7. A. 2.These plans are subject to annual review and audit in the AAA process. Congestion costs and revenues shall be reviewed in an annual filing.

Otter Tail has addressed this later in this filing under the section Part H Section 5 ADDITIONAL REPORTING REQUIREMENTS MN PUC ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS DOCKET NOS. E999/AA-09-961 and E999/AA-10-884 Number 25.

7. A. 3. Each utility shall provide and update a list of the network resources that it designates used to serve native load.

See Part E Section 10 Attachment G (marked as Trade Secret) - MISO Module E Data for Otter Tail.

7. B. To help customers manage their energy costs, each utility shall submit an annual FCA forecast of the cost per MWh of fuel and purchased power costs for the next 12 months.

Otter Tail previously supplied a forecast for calendar year 2015. Included with this filing is the forecast for calendar year 2016 (Part E Section 10 Attachment H marked as Trade Secret). The forecast of costs for 2016 reflects generation and purchase costs (purchases through MISO and bilaterally, not by specific charge types). Other costs are forecast as a net group and not forecasted by charge type.

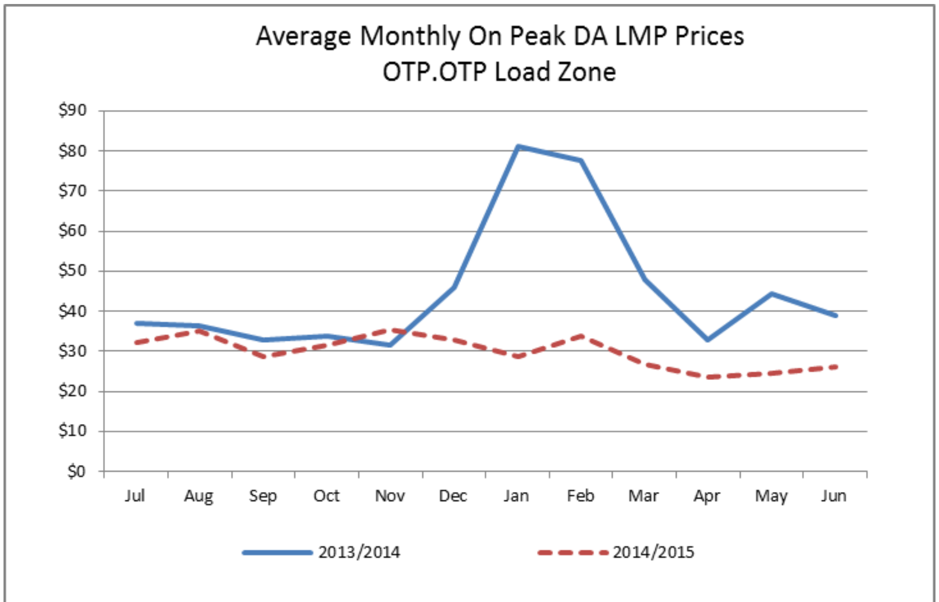
7. C. Each utility shall prepare a summary of its AAA filing stating key factors affecting costs (including Revenue Sufficiency Guarantee costs and Revenue Neutrality Uplift costs) along with the FCA Forecast.

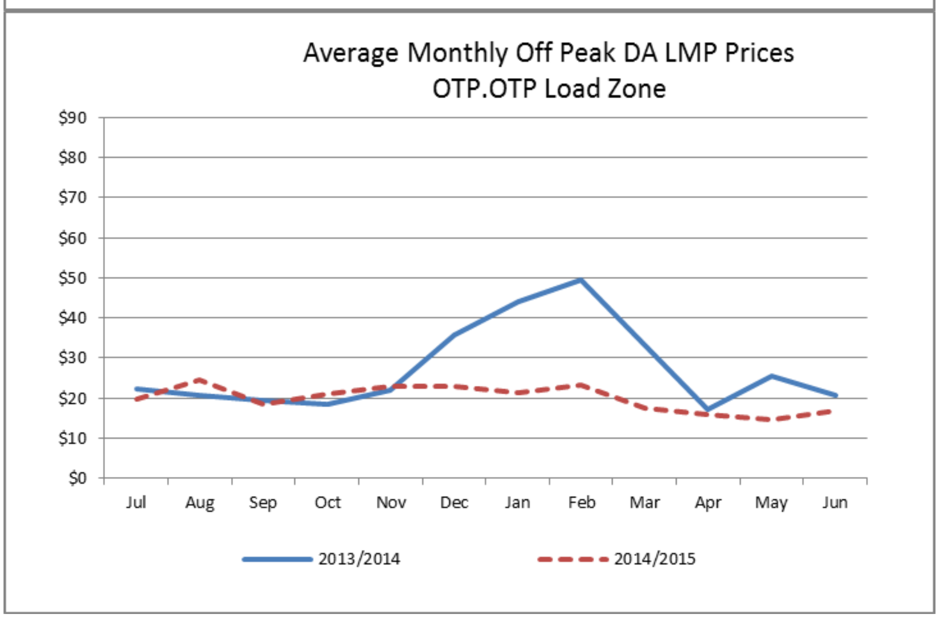
Part E Section 10 Attachments I and I-1 (I-1 marked as Trade Secret) are the summaries by month of MISO costs for the reporting period.

The following is a general discussion of the items of note or general drivers of MISO costs in the reporting period.

MISO Market Prices Down during 2014/2015 AAA Reporting Period
On a system basis, Otter Tail's total MISO charges declined from approximately $42.2 million during the 2013/2014 reporting period to approximately $40.1 million for the current period.

The magnitude of MISO costs which Otter Tail incurs over the course of the year is generally attributable to two key factors; the amount of energy purchased and sold in the MISO market and secondly, the cost associated with that energy. During the 2014/2015 AAA reporting period, Otter Tail procured a higher volume of energy from the market (forward purchases as well as DA and RT purchases) to cover planned outage at Big Stone Plant for the Air Quality Control System ("AQCS") cutover and other plant maintenance; reduced output at the Coyote Plant following the fire in one of that plant's boiler feed pumps; and in recent months, limited dispatch of Otter Tail's Hoot Lake Plant due to low market prices. However, lower LMP prices within the MISO market have helped keep these market purchase costs low. The following charts are provided to help illustrate the reduction in average DA LMP prices for the OTP.OTP load zone for the current reporting period as compared to the 2013/2014 reporting year.





By definition, the LMP price is made up of three different cost components; Energy, Congestion, and Losses. Low natural gas prices and increased wind production have helped keep energy prices lower over the last twelve months. Increased transmission capability in the region has helped reduce congestion costs and their impacts on overall energy costs customers pay.

Loss and Congestion Component Classification Corrections

During preparation of this year's AAA report, a review of the congestion and loss component calculations for the months of January through March, May and June of 2015 revealed that erroneous data was being included in the estimated cost of congestion and loss amounts reported on the MISO statements included with the monthly fuel clause filings. As in the past, these calculations are used to determine loss and congestion amounts for the month, and then those loss and congestion amounts are reclassified from the Total Energy amounts on lines 1 and 4 to their respective lines 7, 8, 20, and 22 of the Detailed MISO Day 2 Charges report (Attachments H and I in this report). The purpose of the adjustment is to breakout the respective costs based of each LMP component that makes up the total costs determined and reported by MISO at full LMP prices. **These calculations do not impact or change the total MISO costs reported, but only impact the classification of these costs.**

Otter Tail has corrected the issue with the erroneous data and included the corrected loss and congestion amounts on the respective lines of the MISO Day 2 Charge for the months listed above in both Attachments H and I included with this filing.

Otter Tail will re-submit the corrected monthly reports for the 2015 months listed above as part of its next monthly energy adjustment clause filing near the end of September.

MISO Module E Data For Otter Tail Power Company
As of July 15, 2015

AGGREGATE RESOURCES AS DEFINED BY MISO - Values reflect the Unforced Capacity rating (UCAP)

No.	Aggregate Resources	Designation	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15
1	Big Stone Plant	OTP.BIGSTON1	240.5	240.5	240.5	240.5	240.5	240.5	240.5	240.5	240.5	240.5	240.5	240.5
2	Coyote Station	OTP.COYOT1	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0	130.0
3	FPL Energy ND Wind II	OTP.EDGLYEDGL	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
4	Hoot Lake 2	OTP.HOOTL2	60.2	60.2	60.2	60.2	60.2	60.2	60.2	60.2	60.2	60.2	60.2	60.2
5	Hoot Lake 3	OTP.HOOTL3	86.4	86.4	86.4	86.4	86.4	86.4	86.4	86.4	86.4	86.4	86.4	86.4
6	Jamestown 1	OTP.JAMSPK1	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
7	Jamestown 2	OTP.JAMSPK2	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
8	Lake Preston	OTP.HETLA1	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
9	Solway	OTP.SOLWAYO1	40.7	40.7	40.7	40.7	40.7	40.7	40.7	40.7	40.7	40.7	40.7	40.7

LOCAL RESOURCES AS DEFINED BY MISO - Values reflect the Unforced Capacity rating (UCAP)

No.	Local Resource	Designation	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15
1	Ashtabula	OTP.ASHTABULA	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9	8.9
2	FPL Energy ND Wind II	OTP.EDGLYEDGL	-	-	-	-	-	-	-	-	-	-	-	-
3	Langdon	OTP.LANGDN1	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
4	Langdon	OTP.LANGDN2	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
5	Luverne	OTP.MPWR	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6

BEHIND-THE-METER RESOURCES AS DEFINED BY MISO - Values reflect the Unforced Capacity rating (UCAP)

No.	BTM Resource	Designation	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15
1	Big Stone Diesel	OTP.OTP	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
2	Dayton Hollow Hydro #1	OTP.OTP	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
3	Dayton Hollow Hydro #2	OTP.OTP	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
4	Fergus Control Diesel	OTP.OTP	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
5	Hoot Lake 2A Diesel	OTP.OTP	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
6	Hoot Lake 3A Diesel	OTP.OTP	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
7	Hoot Lake Hydro	OTP.OTP	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
			[TRADE SECRET DATA BEGINS . . .											
8	Dakota Magic Diesel	OTP.OTP												
9	Fleet Farm Diesel	OTP.OTP												
10	Kindred School Diesel	OTP.OTP												
11	Perham Resource Recovery Facility	OTP.OTP												
12	State Auto Ins. Diesel	OTP.OTP												
13	Stevens Community	OTP.OTP												
14	Valley Queen Cheese	OTP.OTP												
											. . . TRADE SECRET DATA ENDS]			
15	Pisgah Hydro	OTP.OTP	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
16	Wright Hydro	OTP.OTP	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
17	Taplin Gorge Hydro	OTP.OTP	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
18	Bemidji 1 Hydro	OTP.OTP	-	-	-	-	-	-	-	-	-	-	-	-

EXTERNAL RESOURCES AS DEFINED BY MISO - Values reflect the Unforced Capacity rating (UCAP)

No.	External Resources	Designation	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15
1		Garrison Hydro Plant	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
2		Garrison Hydro Plant 2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3

PRC TRANSACTIONS AS DEFINED BY MISO - Values reflect the Planning Resource Credit rating (PRC)

No.	PRC Transaction	Designation	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15
1	GRE Purchase	GREM-OTPW	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
2	EDF Sale	OTPW-EAGL	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)	(100.0)
Total			658.9	658.9	658.9	658.9	658.9	658.9	658.9	658.9	658.9	658.9	658.9	658.9

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

January 2016

Jan-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

February 2016

Feb-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

March 2016

Mar-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

April 2016

Apr-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

May 2016

May-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

June 2016

Jun-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

July 2016

Jul-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

August 2016

Aug-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

September 2016

Sep-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

October 2016

Oct-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

November 2016

Nov-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

December 2016

Dec-16	MWH	Retail MWH	Cost	Ave/Retail MWH
Company Generation	**[TRADE SECRET DATA BEGINS . . .**			
Steam				
Hydro				
I.C.				
Wind				
Total Generation				
Purchases				
MISO Charges				
Administration (4)				
Other Charges (1)				
LMP Differential (2)	*OTP doesn't forecast*			
Total FAC				

. . . TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS . . .

Generator Outages (3)	# days
Coyote	
Big Stone	
Hoot Lake 2	
Hoot Lake 3	

. . . TRADE SECRET DATA ENDS]

(1) Other MISO Charges Include:
Day-Ahead and Real-Time FBT Amounts
Day-Ahead and Real-Time Bilateral Congestion Amounts
Day-Ahead and Real-Time Bilateral Loss Amounts
Day-Ahead and Real-Time RSG Amounts
Real-time Distribution of Losses Amount
Real-Time Net Inadvertant Distribution Amount
Real_Time Revenue Neutrality Uplift amount
Real-Time Miscellaneous Amount
Real-Time Uninstructed Deviation Amount
FTR Allocation Amounts
FTR_ARR
Real-Time ASM

(2) LMP Differential is not forecast or tracked by OTP

(3) Generator Outatges include Scheduled Outages

OTTER TAIL POWER COMPANY
ESTIMATE OF MINNESOTA'S SHARE OF
MISO CHARGE TYPES

No.	Charge Type Description	System - Retail July 14 - June 15	Minnesota - Retail July 14 - June 15
No.	**Day Ahead & Real Time Asset & Non Asset Energy & Loss**		
1	DA Asset Energy Amount	$ 29,124,864.66	$ 14,711,929.36
2	DA FBT Loss Amount	$ -	$ -
3	DA Non-asset Energy Amount	$ 4,626,918.94	$ 2,337,209.30
4	RT Asset Energy Amount	$ (854,341.98)	$ (431,556.30)
5	RT Distribution of Losses Amount	$ (2,200,362.80)	$ (1,111,475.79)
6	RT FBT Loss Amount	$ -	$ -
7	DA Loss Amount	$ 4,910,154.15	$ 2,480,280.74
8	RT Loss Amount	$ 155,924.57	$ 78,762.64
9	RT Non-Asset Energy Amount	$ 125,509.81	$ 63,399.14
10	DA Losses Rebate on Option B GFA	$ -	$ -
	Virtual Energy		
11	DA Virtual Energy Amount	$ -	$ -
12	RT Virtual Energy Amount	$ -	$ -
	Schedules 16 & 17		
13	DA Mkt Admin Amount	$ 577,427.82	$ 291,677.83
14	RT Mkt Admin Amount	$ 49,053.65	$ 24,778.62
15	FTR Mkt Admin Amount	$ 28,735.84	$ 14,515.42
	Congest & FTRs		
16	DA FBT Congestion Amount	$ -	$ -
17	DA Congestion	$ 2,090,695.09	$ 1,056,079.02
18	RT FBT Congestion Amount	$ -	$ -
19	RT Congestion	$ (148,816.54)	$ (75,172.14)
20	FTR Hourly Allocation Amount	$ (1,954,459.39)	$ (987,261.87)
21	FTR Monthly Allocation Amount	$ (81,126.86)	$ (40,979.85)
22	FTR Yearly Allocation Amount	$ (86,057.76)	$ (43,470.61)
23	FTR Monthly Transaction Amount	$ (118,744.43)	$ (59,981.73)
24	FTR Full Funding Guarantee Amount	$ (55,609.34)	$ (28,090.11)
25	FTR Guarantee Uplift Amount	$ 85,400.69	$ 43,138.70
26	FTR Auction Revenue Rights Transaction Amount	$ (9,071,566.30)	$ (4,582,347.22)
27	FTR Annual Transaction Amount	$ 8,997,510.45	$ 4,544,939.17
28	FTR Auction Revenue Rights Infeasible Uplift Amount	$ 204,053.95	$ 103,074.38
29	FTR Auction Revenue Rights Stage 2 Distribution Amount	$ (364,769.95)	$ (184,257.33)
30	DA Congestion Rebate on Option B GFA	$ -	$ -
	RSG & Make Whole Payments		
31	DA Revenue Sufficiency Guarantee Distribution Amount	$ 208,223.70	$ 105,180.66
32	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	$ (14,049.71)	$ (7,096.97)
33	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 225,091.67	$ 113,701.22
34	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	$ -	$ -
35	RT Price Volatility Make Whole Payment	$ (556,385.13)	$ (281,048.47)
	Revenue Neutrality Uplift		
36	RT Revenue Neutrality Uplift Amount	$ 802,469.92	$ 405,354.01
	Other Charges		
37	RT Misc Amount	$ (108,284.28)	$ (54,697.96)
38	RT Net Inadvertent Amount	$ (36,646.43)	$ (18,511.32)
39	RT Uninstructed Deviation Amount	$ -	$ -
40	RT Demand Response Allocation Uplift Amount	$ 3.23	$ 1.63
	ASM Charges		
41	RT ASM Non-Excessive Energy Amount	$ 4,311,135.45	$ 2,177,696.65
42	RT ASM Excessive Energy Amount	$ 20,329.78	$ 10,269.24
	Grandfathered Charge Types		
43	DA Congestion Rebate on COGA	$ -	$ -
44	DA Losses Rebate on COGA	$ -	$ -
45	RT Congestion Rebate on COGA	$ -	$ -
46	RT Loss Rebate on COGA	$ -	$ -
47	**TOTAL CHARGES**	$ 40,892,282.47	$ 20,656,040.05
48	Less Schedule 16 & 17 (Lines 13, 14, 15)	$ (655,217.31)	
49	Congestion and Losses Adjustment	$ (148,224.97)	
50	No DA generation sch., but still had output	$ (4,896.88)	
51	MISO RSG Bad Debt	$ -	

Percent of Minnesota Sales to System (2,317,615,842 / 4,588,130,226) = 0.505132969

Fuel Costs Allocated to Minnesota ($112,675,821) x 0.505132969 = $56,916,272

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
July 2014 includes any adjustments

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						[TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	$ 8,338,324.68	$ (7,612,174.91)	$ -	$ 726,149.77			330,107	(298,482)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 217,365.70	$ -	$ -	$ 217,365.70			8,392	-
4	RT Asset Energy Amount	555.19	$ 367,332.94	$ (113,482.87)	$ 18,847.92	$ 272,697.99			14,785	(5,179)
5	RT Distribution of Losses Amount	555.24	$ 1,990.06	$ (192,775.74)	$ (3,811.74)	$ (194,597.42)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 515,971.27	$ -	$ -	$ 515,971.27			-	-
8	RT Loss Amount		$ 22,738.20	$ -	$ -	$ 22,738.20			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ -	$ -	$ -			-	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 9,463,722.85**	**$ (7,918,433.52)**	**$ 15,036.18**	**$ 1,560,325.51**			**353,283**	**(303,661)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 40,344.42	$ -	$ -	$ 40,344.42			-	-
16	RT Mkt Admin Amount	555.18	$ 4,084.52	$ -	$ (108.13)	$ 3,976.39			-	-
17	FTR Mkt Admin Amount	555.13	$ 3,340.96	$ -	$ -	$ 3,340.96			-	-
18	**TOTAL**		**$ 47,769.90**	**$ -**	**$ (108.13)**	**$ 47,661.77**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion			$ 173,720.93		$ 173,720.93				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 22,991.39			$ 22,991.39				
23	FTR Hourly Allocation Amount	555.14	$ 25,509.53	$ (169,424.52)	$ (47.40)	$ (143,962.39)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (5,890.36)	$ 63.37	$ (5,826.99)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 5,840.98	$ (7,739.84)	$ (15.97)	$ (1,914.83)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 7,739.84	$ (5,857.72)	$ 153.95	$ 2,036.07			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 60,666.14	$ (634,130.02)	$ -	$ (573,463.88)			-	-
30	FTR Annual Transaction Amount	555.38	$ 645,764.87	$ (72,301.08)	$ -	$ 573,463.79			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 16,713.67	$ -	$ (0.25)	$ 16,713.42			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (49,545.45)	$ (73.51)	$ (49,618.96)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 785,226.42**	**$ (771,168.06)**	**$ 80.19**	**$ 14,138.55**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 10,063.02	$ -	$ (1,182.57)	$ 8,880.45			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (201.01)	$ -	$ (201.01)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 8,989.62	$ -	$ (675.76)	$ 8,313.86			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (82,662.64)	$ (567.81)	$ (83,230.45)			-	-
40	**TOTAL**		**$ 19,052.64**	**$ (82,863.65)**	**$ (2,426.14)**	**$ (66,237.15)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 23,526.60	$ (15,868.19)	$ 8,005.19	$ 15,663.60			-	-
42	**TOTAL**		**$ 23,526.60**	**$ (15,868.19)**	**$ 8,005.19**	**$ 15,663.60**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (2,256.37)	$ (2,256.37)			-	-
44	RT Net Inadvertent Amount	555.27	$ 28,060.93	$ (15,351.07)	$ (1,063.40)	$ 11,646.46			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 28,060.93**	**$ (15,351.07)**	**$ (3,319.77)**	**$ 9,390.09**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
July 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)**	
	Charge Type Description	**Acct**	**Retail Debits**	**Retail Credits**	**Retail Adjustments**	**Net Retail**	**Net Intersystem**	**Total**	**Charge types with MWH for Retail**	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 972,601.28	$ (250,607.50)	$ (400.15)	$ 721,593.63			32,827	(12,201)
48	RT ASM Excessive Energy Amount	555.56	$ 9,376.36	$ (14.72)	$ 0.68	$ 9,362.32			0	(724)
49	**TOTAL**		**$ 981,977.64**	**$ (250,622.22)**	**$ (399.47)**	**$ 730,955.95**			**32,827**	**(12,925)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 11,349,336.98	$ (9,054,306.71)	$ 16,868.05	$ 2,311,898.32	$ (565,509.93)	$ 1,746,388.39	386,110	(316,586)
56	**Less Schedule 16 & 17 (Lines 13, 14, 15)**		$ (47,769.90)	$ -	$ 108.13	$ (47,661.77)				
57	**Congestion and Losses Adjustment**				$ (12,323.83)	$ (12,323.83)				
58	**No DA generation sch., but still had output for current month**				$ (30.60)	$ (30.60)				
59	**MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 11,301,567.08**	**$ (9,054,306.71)**	**$ 4,621.75**	**$ 2,251,882.12**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,251,882.12**						
62	Net KWH for retail = ((G) + (H)) * 1,000			69,523,953						**69,523,953**
63	July 2014 covers time period of 6/23/2014 -- 7/23/2014 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 2,247,260.37	69,523,953						
66	**Congestion and Losses Adjustment**		$ (12,323.83)							
67	**MISO RSG Bad Debt**		$ -							
68	**July Adjustments**		$ 16,945.58	616,592						
69	**Total MISO**		$ 2,251,882.12	70,140,545						
									. . . TRADE SECRET DATA ENDS]	

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
August 2014 includes any adjustments

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
No.	**Day Ahead & Real Time Asset & Non Asset Energy & Loss**						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 9,464,182.34	$ (7,899,543.98)	$ -	$ 1,564,638.36			338,330	(282,818)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 587,324.56	$ -	$ -	$ 587,324.56			20,929	-
4	RT Asset Energy Amount	555.19	$ 126,822.49	$ (396,009.70)	$ 132,942.40	$ (136,244.81)			3,172	(14,767)
5	RT Distribution of Losses Amount	555.24	$ 1,069.71	$ (204,989.52)	$ (52,483.86)	$ (256,403.67)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 345,550.69	$ -	$ -	$ 345,550.69			-	-
8	RT Loss Amount		$ (2,021.98)	$ -	$ -	$ (2,021.98)			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ (1,114.58)	$ -	$ (1,114.58)			-	(44)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 10,522,927.81**	**$ (8,501,657.78)**	**$ 80,458.54**	**$ 2,101,728.57**			**362,431**	**(297,629)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 35,711.71	$ -	$ -	$ 35,711.71			-	-
16	RT Mkt Admin Amount	555.18	$ 2,693.06	$ -	$ 92.35	$ 2,785.41			-	-
17	FTR Mkt Admin Amount	555.13	$ 2,674.32	$ -	$ -	$ 2,674.32			-	-
18	**TOTAL**		**$ 41,079.09**	**$ -**	**$ 92.35**	**$ 41,171.44**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion			$ 145,963.26		$ 145,963.26				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (36,771.89)			$ (36,771.89)				
23	FTR Hourly Allocation Amount	555.14	$ 39,321.45	$ (221,265.66)	$ (0.08)	$ (181,944.29)			-	-
24	FTR Monthly Allocation Amount	555.15	$ 0.85	$ (4,966.86)	$ 36.76	$ (4,929.25)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 4,698.84	$ (15,354.49)	$ (36.68)	$ (10,692.33)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 15,354.58	$ (4,082.10)	$ 31.99	$ 11,304.47			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 60,666.14	$ (634,130.02)	$ -	$ (573,463.88)			-	-
30	FTR Annual Transaction Amount	555.38	$ 645,764.87	$ (72,301.08)	$ -	$ 573,463.79			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 16,713.70	$ -	$ 0.03	$ 16,713.73			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (49,549.22)	$ (34.73)	$ (49,583.95)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 745,748.54**	**$ (855,686.17)**	**$ (2.71)**	**$ (109,940.34)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 14,770.37	$ -	$ (171.67)	$ 14,598.70			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (991.99)	$ -	$ (991.99)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 26,008.55	$ -	$ (233.76)	$ 25,774.79			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (78,283.17)	$ -	$ (78,283.17)			-	-
40	**TOTAL**		**$ 40,778.92**	**$ (79,275.16)**	**$ (405.43)**	**$ (38,901.67)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 61,084.91	$ (1,923.44)	$ 39,071.09	$ 98,232.56			-	-
42	**TOTAL**		**$ 61,084.91**	**$ (1,923.44)**	**$ 39,071.09**	**$ 98,232.56**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ 3,663.49	$ 3,663.49			-	-
44	RT Net Inadvertent Amount	555.27	$ 2,615.51	$ (5,075.95)	$ (31,637.13)	$ (34,097.57)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 2,615.51**	**$ (5,075.95)**	**$ (27,973.64)**	**$ (30,434.08)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
August 2014 includes any adjustments

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 588,100.25	$ (180,160.85)	$ 4.02	$ 407,943.42			24,851	(5,494)
48	RT ASM Excessive Energy Amount	555.56	$ 848.80	$ -	$ -	$ 848.80			-	(60)
49	**TOTAL**		**$ 588,949.05**	**$ (180,160.85)**	**$ 4.02**	**$ 408,792.22**			**24,851**	**(5,554)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 12,003,183.83	$ (9,623,779.35)	$ 91,244.22	$ 2,470,648.70	$ (141,562.66)	$ 2,329,086.04	387,282	(303,182)
56	**Less Schedule 16 & 17 (Lines 15, 16, 17)**		$ (41,079.09)	$ -	$ (92.35)	$ (41,171.44)				
57	**Congestion and Losses Adjustment**				$ (8,591.05)	$ (8,591.05)				
58	**No DA generation sch., but still had output for current month**				$ (0.17)	$ (0.17)				
59	**MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 11,962,104.74**	**$ (9,623,779.35)**	**$ 82,560.65**	**$ 2,420,886.04**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,420,886.04**						
62	Net KWH for retail = ((G) + (H)) * 1,000			84,099,247						**84,099,247**
63	August 2014 covers time period of 7/24/2014 -- 8/21/2014 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 2,338,325.39	84,099,247						
66	**Congestion and Losses Adjustment**		$ (8,591.05)							
67	**MISO RSG Bad Debt**		$ -							
68	**August Adjustments**		$ 91,151.70	5,222,726						
69	**Total MISO**		$ 2,420,886.04	89,321,973						
								. . . TRADE SECRET DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
September 2014 includes any adjustments

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 8,477,576.59	$ (7,226,619.18)	$ -	$ 1,250,957.41			349,605	(303,896)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 446,973.08	$ -	$ -	$ 446,973.08			17,607	-
4	RT Asset Energy Amount	555.19	$ 128,750.72	$ (490,548.43)	$ 174,923.31	$ (186,874.40)			6,926	(19,389)
5	RT Distribution of Losses Amount	555.24	$ 2,354.21	$ (155,061.76)	$ (5,183.69)	$ (157,891.24)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 326,646.26	$ -	$ -	$ 326,646.26			-	-
8	RT Loss Amount		$ 27,322.50	$ -	$ -	$ 27,322.50			-	-
9	RT Non-Asset Energy Amount	555.26	$ 644.41	$ -	$ -	$ 644.41			24	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 9,410,267.77**	**$ (7,872,229.37)**	**$ 169,739.62**	**$ 1,707,778.02**			**374,162**	**(323,285)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 39,547.66	$ -	$ -	$ 39,547.66			-	-
16	RT Mkt Admin Amount	555.18	$ 4,156.69	$ -	$ 20.54	$ 4,177.23			-	-
17	FTR Mkt Admin Amount	555.13	$ 2,624.64	$ -	$ -	$ 2,624.64			-	-
18	**TOTAL**		**$ 46,328.99**	**$ -**	**$ 20.54**	**$ 46,349.53**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion			$ 202,878.96		$ 202,878.96				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 13,394.82			$ 13,394.82				
23	FTR Hourly Allocation Amount	555.14	$ 153,607.87	$ (329,581.06)	$ 13.47	$ (175,959.72)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (9,540.72)	$ 2.17	$ (9,538.55)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 9,574.17	$ (30,966.52)	$ (15.64)	$ (21,407.99)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 30,966.52	$ (10,812.04)	$ 16.55	$ 20,171.03			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 18,664.88	$ (733,582.76)	$ -	$ (714,917.88)			-	-
30	FTR Annual Transaction Amount	555.38	$ 749,313.78	$ (34,304.72)	$ -	$ 715,009.06			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 12,265.08	$ -	$ 0.25	$ 12,265.33			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (27,690.96)	$ (447.81)	$ (28,138.77)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 987,787.12**	**$ (973,599.82)**	**$ (431.01)**	**$ 13,756.29**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 19,039.86	$ -	$ (1,052.87)	$ 17,986.99			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (122.50)	$ -	$ (122.50)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 16,626.53	$ -	$ (444.14)	$ 16,182.39			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (65,932.10)	$ 0.08	$ (65,932.02)			-	-
40	**TOTAL**		**$ 35,666.39**	**$ (66,054.60)**	**$ (1,496.93)**	**$ (31,885.14)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 40,593.87	$ (2,466.17)	$ (700.39)	$ 37,427.31			-	-
42	**TOTAL**		**$ 40,593.87**	**$ (2,466.17)**	**$ (700.39)**	**$ 37,427.31**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (522.46)	$ (522.46)			-	-
44	RT Net Inadvertent Amount	555.27	$ 3,345.16	$ (5,273.14)	$ (781.17)	$ (2,709.15)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 3,345.16**	**$ (5,273.14)**	**$ (1,303.63)**	**$ (3,231.61)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
September 2014 includes any adjustments

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 701,280.39	$ (264,516.10)	$ 123.35	$ 436,887.64			32,241	(12,959)
48	RT ASM Excessive Energy Amount	555.56	$ 4,051.00	$ -	$ 0.72	$ 4,051.72			-	(460)
49	**TOTAL**		**$ 705,331.39**	**$ (264,516.10)**	**$ 124.07**	**$ 440,939.36**			**32,241**	**(13,419)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 11,229,320.69	$ (9,184,139.20)	$ 165,952.27	$ 2,211,133.76	$ (947,042.05)	$ 1,264,091.71	406,403	(336,703)
56	**Less Schedule 16 & 17 (Lines 15, 16, 17)**		$ (46,328.99)	$ -	$ (20.54)	$ (46,349.53)				
57	**Congestion and Losses Adjustment**				$ (22,227.08)	$ (22,227.08)				
58	**No DA generation sch., but still had output for current month**				$ -	$ -				
59	**MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 11,182,991.70**	**$ (9,184,139.20)**	**$ 143,704.65**	**$ 2,142,557.15**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,142,557.15**						
62	Net KWH for retail = ((G) + (H)) * 1,000			69,700,119						**69,700,119**
63	September 2014 covers time period of 8/22/2014 -- 9/22/2014 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 1,998,852.50	69,700,119						
66	**Congestion and Losses Adjustment**		$ (22,227.08)							
67	**MISO RSG Bad Debt**		$ -							
68	**September Adjustments**		$ 165,931.73	6,640,067						
69	**Total MISO**		$ 2,142,557.15	76,340,186						
									. . . TRADE SECRET DATA ENDS]	

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
October 2014 includes any adjustments

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 8,131,163.85	$ (8,022,331.36)	$ -	$ 108,832.49			341,174	(337,473)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 312,731.27	$ (32,572.83)	$ -	$ 280,158.44			13,057	(1,436)
4	RT Asset Energy Amount	555.19	$ 190,089.39	$ (151,594.07)	$ 74,468.66	$ 112,963.98			6,863	(7,621)
5	RT Distribution of Losses Amount	555.24	$ 2,107.97	$ (168,234.77)	$ (1,128.88)	$ (167,255.68)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 504,005.34	$ -	$ -	$ 504,005.34			-	-
8	RT Loss Amount		$ 27,089.99	$ -	$ -	$ 27,089.99			-	-
9	RT Non-Asset Energy Amount	555.26	$ 131,048.62	$ -	$ -	$ 131,048.62			6,351	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 9,298,236.43**	**$ (8,374,733.03)**	**$ 73,339.78**	**$ 996,843.18**			**367,444**	**(346,529)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 45,127.41	$ -	$ -	$ 45,127.41			-	-
16	RT Mkt Admin Amount	555.18	$ 4,088.09	$ -	$ (150.31)	$ 3,937.78			-	-
17	FTR Mkt Admin Amount	555.13	$ 2,160.56	$ -	$ -	$ 2,160.56			-	-
18	**TOTAL**		**$ 51,376.06**	**$ -**	**$ (150.31)**	**$ 51,225.75**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion			$ 571,653.84		$ 571,653.84				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (21,553.96)			$ (21,553.96)				
23	FTR Hourly Allocation Amount	555.14	$ 239,743.66	$ (756,358.76)	$ (144.89)	$ (516,759.99)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (12,111.16)	$ 94.35	$ (12,016.81)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 11,485.79	$ (76,237.18)	$ 50.54	$ (64,700.85)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 76,237.18	$ (11,604.94)	$ (35.00)	$ 64,597.24			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 18,664.88	$ (733,582.76)	$ -	$ (714,917.88)			-	-
30	FTR Annual Transaction Amount	555.38	$ 749,313.78	$ (34,304.72)	$ -	$ 715,009.06			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 12,265.08	$ -	$ -	$ 12,265.08			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (27,643.65)	$ 285.83	$ (27,357.82)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 1,086,156.41**	**$ (1,080,189.33)**	**$ 250.83**	**$ 6,217.91**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 15,559.46	$ -	$ (806.86)	$ 14,752.60			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 24,029.66	$ -	$ 438.96	$ 24,468.62			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (74,765.67)	$ (568.92)	$ (75,334.59)			-	-
40	**TOTAL**		**$ 39,589.12**	**$ (74,765.67)**	**$ (936.82)**	**$ (36,113.37)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 84,400.63	$ (841.09)	$ 409.07	$ 83,968.61			-	-
42	**TOTAL**		**$ 84,400.63**	**$ (841.09)**	**$ 409.07**	**$ 83,968.61**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (935.14)	$ (935.14)			-	-
44	RT Net Inadvertent Amount	555.27	$ 8,209.75	$ (1,543.10)	$ 258.78	$ 6,925.43			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 8,209.75**	**$ (1,543.10)**	**$ (676.36)**	**$ 5,990.29**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
October 2014 includes any adjustments

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 721,098.49	$ (250,295.68)	$ (684.13)	$ 470,118.68			29,438	(12,410)
48	RT ASM Excessive Energy Amount	555.56	$ 310.40	$ (260.32)	$ 1.30	$ 51.38			-	(118)
49	**TOTAL**		**$ 721,408.89**	**$ (250,556.00)**	**$ (682.83)**	**$ 470,170.06**			**29,438**	**(12,528)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 11,289,377.29	$ (9,782,628.22)	$ 71,553.36	$ 1,578,302.43	$ (1,198,095.77)	$ 380,206.66	396,882	(359,057)
56	**Less Schedule 16 & 17 (Lines 15, 16, 17)**		$ (51,376.06)	$ -	$ 150.31	$ (51,225.75)				
57	**Congestion and Losses Adjustment**				$ (39,673.12)	$ (39,673.12)				
58	**No DA generation sch., but still had output for current month**				$ (563.60)	$ (563.60)				
59	**MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 11,238,001.23**	**$ (9,782,628.22)**	**$ 31,466.95**	**$ 1,486,839.96**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 1,486,839.96**						
62	Net KWH for retail = ((G) + (H)) * 1,000			37,824,685						**37,824,685**
63	October 2014 covers time period of 9/23/2014 -- 10/23/2014 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 1,455,373.01	37,824,685						
66	**Congestion and Losses Adjustment**		$ (39,673.12)							
67	**MISO RSG Bad Debt**		$ -							
68	**October Adjustments**		$ 71,140.07	3,393,405						
69	**Total MISO**		$ 1,486,839.96	41,218,091						
									. . . TRADE SECRET DATA ENDS]	

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
November 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)**	
	Charge Type Description	**Acct**	**Retail Debits**	**Retail Credits**	**Retail Adjustments**	**Net Retail**	**Net Intersystem**	**Total**	**Charge types with MWH for Retail**	
No.	**Day Ahead & Real Time Asset & Non Asset Energy & Loss**						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 9,728,448.83	$ (8,884,663.49)	$ -	$ 843,785.34			363,596	(330,771)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 426,051.18	$ (8,709.58)	$ -	$ 417,341.60			17,355	(319)
4	RT Asset Energy Amount	555.19	$ 259,678.95	$ (203,601.89)	$ (96,048.79)	$ (39,971.73)			9,866	(7,498)
5	RT Distribution of Losses Amount	555.24	$ 3,167.95	$ (245,102.49)	$ 1,189.26	$ (240,745.28)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 583,615.47	$ -	$ -	$ 583,615.47			-	-
8	RT Loss Amount		$ 22,632.29	$ -	$ -	$ 22,632.29			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ -	$ -	$ -			-	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 11,023,594.67**	**$ (9,342,077.45)**	**$ (94,859.53)**	**$ 1,586,657.69**			**390,817**	**(338,588)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 57,097.53	$ -	$ -	$ 57,097.53			-	-
16	RT Mkt Admin Amount	555.18	$ 4,480.00	$ -	$ 143.39	$ 4,623.39			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,997.76	$ -	$ -	$ 1,997.76			-	-
18	**TOTAL**		**$ 63,575.29**	**$ -**	**$ 143.39**	**$ 63,718.68**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion			$ 398,893.74		$ 398,893.74				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (22,929.61)			$ (22,929.61)				
23	FTR Hourly Allocation Amount	555.14	$ 136,151.14	$ (485,984.35)	$ (96.26)	$ (349,929.47)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (13,082.46)	$ 66.89	$ (13,015.57)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 11,834.37	$ (52,649.35)	$ 29.37	$ (40,785.61)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 52,649.35	$ (1,997.82)	$ (52.78)	$ 50,598.75			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 18,664.88	$ (733,582.76)	$ -	$ (714,917.88)			-	-
30	FTR Annual Transaction Amount	555.38	$ 749,313.78	$ (34,304.72)	$ -	$ 715,009.06			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 12,265.08	$ -	$ -	$ 12,265.08			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (27,568.44)	$ (5,360.88)	$ (32,929.32)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 957,948.99**	**$ (950,276.16)**	**$ (5,413.66)**	**$ 2,259.17**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 15,883.64	$ -	$ (1,229.39)	$ 14,654.25			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (112.57)	$ -	$ (112.57)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 16,851.40	$ -	$ 76.49	$ 16,927.89			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (107,758.53)	$ (4,134.12)	$ (111,892.65)			-	-
40	**TOTAL**		**$ 32,735.04**	**$ (107,871.10)**	**$ (5,287.02)**	**$ (80,423.08)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 118,271.50	$ -	$ (539.72)	$ 117,731.78			-	-
42	**TOTAL**		**$ 118,271.50**	**$ -**	**$ (539.72)**	**$ 117,731.78**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ 5,699.77	$ 5,699.77			-	-
44	RT Net Inadvertent Amount	555.27	$ 2,112.19	$ (4,263.83)	$ (680.81)	$ (2,832.45)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 2,112.19**	**$ (4,263.83)**	**$ 5,018.96**	**$ 2,867.32**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
November 2014 includes any adjustments

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 574,579.83	$ (247,912.78)	$ (102,338.90)	$ 224,328.15			28,641	(11,832)
48	RT ASM Excessive Energy Amount	555.56	$ 212.26	$ (16.75)	$ 0.64	$ 196.15			-	(79)
49	**TOTAL**		**$ 574,792.09**	**$ (247,929.53)**	**$ (102,338.26)**	**$ 224,524.30**			**28,641**	**(11,911)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 12,773,029.77	$ (10,652,418.07)	$ (203,275.84)	$ 1,917,335.86	$ (1,243,896.07)	$ 673,439.79	419,458	(350,499)
56	**Less Schedule 16 & 17 (Lines 15, 16, 17)**		$ (63,575.29)	$ -	$ (143.39)	$ (63,718.68)				
57	**Congestion and Losses Adjustment**				$ (34,062.93)	$ (34,062.93)				
58	**No DA generation sch., but still had output for current month**				$ (998.65)	$ (998.65)				
59	**MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 12,709,454.48**	**$ (10,652,418.07)**	**$ (238,480.81)**	**$ 1,818,555.60**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 1,818,555.60**						
62	Net KWH for retail = ((G) + (H)) * 1,000			68,959,658						**68,959,658**

63 November 2014 covers time period of 10/24/2014 -- 11/20/2014 ** increased for losses of 2.8%

		Net Retail	Net MISO KWH	per kWh	Net Intersystem	Total
63				**[TRADE SECRET DATA BEGINS . . .**		
64		**Net Retail**	**Net MISO KWH**	**per kWh**	**Net Intersystem**	**Total**
65	**MISO Book Totals**	$ 2,057,036.41	68,959,658			
66	**Congestion and Losses Adjustment**	$ (34,062.93)				
67	**MISO RSG Bad Debt**	$ -				
68	**November Adjustments**	$ (204,417.88)	(7,895,187)			
69	**Total MISO**	$ 1,818,555.60	61,064,471			
						. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
December 2014 includes any adjustments

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						[TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	$ 13,800,611.87	$ (9,781,111.78)	$ -	$ 4,019,500.09			523,135	(371,795)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 731,647.49	$ (5,164.76)	$ -	$ 726,482.73			30,000	(164)
4	RT Asset Energy Amount	555.19	$ 274,888.35	$ (422,269.41)	$ (155,980.09)	$ (303,361.15)			9,894	(14,275)
5	RT Distribution of Losses Amount	555.24	$ 10,087.43	$ (276,075.78)	$ 3,920.24	$ (262,068.11)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 661,158.60	$ -	$ -	$ 661,158.60			-	-
8	RT Loss Amount		$ 12,759.30	$ -	$ -	$ 12,759.30			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ (1,386.82)	$ -	$ (1,386.82)			-	(38)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 15,491,153.04**	**$ (10,486,008.55)**	**$ (152,059.85)**	**$ 4,853,084.64**			**563,029**	**(386,273)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 67,207.51	$ -	$ -	$ 67,207.51			-	-
16	RT Mkt Admin Amount	555.18	$ 5,386.18	$ -	$ (34.47)	$ 5,351.71			-	-
17	FTR Mkt Admin Amount	555.13	$ 3,088.80	$ -	$ -	$ 3,088.80			-	-
18	**TOTAL**		**$ 75,682.49**	**$ -**	**$ (34.47)**	**$ 75,648.02**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion			$ 260,600.33		$ 260,600.33				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 3,555.51			$ 3,555.51				
23	FTR Hourly Allocation Amount	555.14	$ 70,865.78	$ (314,158.62)	$ -	$ (243,292.84)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (9,828.88)	$ -	$ (9,828.88)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 9,201.66	$ (11,348.92)	$ -	$ (2,147.26)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 22,988.32	$ (2.67)	$ -	$ 22,985.65			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 14,787.17	$ (1,188,109.34)	$ -	$ (1,173,322.17)			-	-
30	FTR Annual Transaction Amount	555.38	$ 1,192,820.63	$ (19,933.73)	$ -	$ 1,172,886.90			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 18,154.56	$ -	$ -	$ 18,154.56			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (21,728.46)	$ (17.64)	$ (21,746.10)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 1,332,373.63**	**$ (1,304,510.29)**	**$ (17.64)**	**$ 27,845.70**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 30,728.25	$ -	$ (1,314.18)	$ 29,414.07			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (12,236.25)	$ -	$ (12,236.25)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 22,240.46	$ -	$ 77.66	$ 22,318.12			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (68,956.40)	$ (170.83)	$ (69,127.23)			-	-
40	**TOTAL**		**$ 52,968.71**	**$ (81,192.65)**	**$ (1,407.35)**	**$ (29,631.29)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 126,461.41	$ (6,754.59)	$ (4,316.00)	$ 115,390.82			-	-
42	**TOTAL**		**$ 126,461.41**	**$ (6,754.59)**	**$ (4,316.00)**	**$ 115,390.82**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (12,920.93)	$ (12,920.93)			-	-
44	RT Net Inadvertent Amount	555.27	$ 18,395.27	$ (18,536.63)	$ 104.92	$ (36.44)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 18,395.27**	**$ (18,536.63)**	**$ (12,816.01)**	**$ (12,957.37)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
December 2014 includes any adjustments

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 1,217,686.87	$ (340,284.43)	$ (11,661.57)	$ 865,740.87			43,761	(12,532)
48	RT ASM Excessive Energy Amount	555.56	$ 1,037.27	$ (50.19)	$ -	$ 987.08			-	(122)
49	**TOTAL**		**$ 1,218,724.14**	**$ (340,334.62)**	**$ (11,661.57)**	**$ 866,727.95**			**43,761**	**(12,654)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 18,315,758.69	$ (12,237,337.33)	$ (182,312.89)	$ 5,896,108.47	$ (922,186.68)	$ 4,973,921.79	606,790	(398,926)
56	**Less Schedule 16 & 17 (Lines 15, 16, 17)**		$ (75,682.49)	$ -	$ 34.47	$ (75,648.02)				
57	**Congestion and Losses Adjustment**				$ (15,927.26)	$ (15,927.26)				
58	**No DA generation sch., but still had output for current month**				$ (221.54)	$ (221.54)				
59	**MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 18,240,076.20**	**$ (12,237,337.33)**	**$ (198,427.22)**	**$ 5,804,311.65**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 5,804,311.65**						
62	Net KWH for retail = ((G) + (H)) * 1,000			207,863,167						**207,863,167**
63	December 2014 covers time period of 11/21/2014 -- 12/25/2014 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 6,002,738.87	207,863,167						
66	**Congestion and Losses Adjustment**		$ (15,927.26)							
67	**MISO RSG Bad Debt**		$ -							
68	**December Adjustments**		$ (182,499.96)	(6,564,254)						
69	**Total MISO**		$ 5,804,311.65	201,298,913						
								. . . TRADE SECRET DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
January 2015 includes any adjustments REVISED 08_2015

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 10,809,078.62	$ (7,900,208.10)	$ -	$ 2,908,870.52			438,328	(323,843)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 676,868.16	$ -	$ -	$ 676,868.16			27,608	-
4	RT Asset Energy Amount	555.19	$ 422,015.73	$ (203,545.63)	$ (592,008.52)	$ (373,538.42)			15,604	(8,742)
5	RT Distribution of Losses Amount	555.24	$ 4,470.95	$ (220,965.37)	$ 6,938.78	$ (209,555.64)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 425,309.14	$ -	$ -	$ 425,309.14			-	-
8	RT Loss Amount		$ 407.37	$ -	$ -	$ 407.37			-	-
9	RT Non-Asset Energy Amount	555.26	$ 723.41	$ (241.41)	$ -	$ 482.00			53	(12)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 12,338,873.38**	**$ (8,324,960.51)**	**$ (585,069.74)**	**$ 3,428,843.13**			**481,593**	**(332,597)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 49,710.66	$ -	$ -	$ 49,710.66			-	-
16	RT Mkt Admin Amount	555.18	$ 3,609.12	$ -	$ 1,019.75	$ 4,628.87			-	-
17	FTR Mkt Admin Amount	555.13	$ 2,621.92	$ -	$ -	$ 2,621.92			-	-
18	**TOTAL**		**$ 55,941.70**	**$ -**	**$ 1,019.75**	**$ 56,961.45**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion			$ (18,179.63)		$ (18,179.63)				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (850.62)			$ (850.62)				
23	FTR Hourly Allocation Amount	555.14	$ 87,120.86	$ (79,061.60)	$ (3.18)	$ 8,056.08			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (4,925.70)	$ 0.16	$ (4,925.54)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 4,668.92	$ (3,423.07)	$ 3.02	$ 1,248.87			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 3,423.07	$ (4,598.85)	$ (2.76)	$ (1,178.54)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 14,787.17	$ (1,188,109.34)	$ -	$ (1,173,322.17)			-	-
30	FTR Annual Transaction Amount	555.38	$ 1,192,820.63	$ (19,933.73)	$ -	$ 1,172,886.90			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 18,154.93	$ -	$ -	$ 18,154.93			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (21,764.33)	$ 5,702.80	$ (16,061.53)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 1,320,124.96**	**$ (1,339,996.25)**	**$ 5,700.04**	**$ (14,171.25)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 16,748.36	$ -	$ (350.98)	$ 16,397.38			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 12,329.95	$ -	$ 1,048.15	$ 13,378.10			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (22,231.50)	$ (139.17)	$ (22,370.67)			-	-
40	**TOTAL**		**$ 29,078.31**	**$ (22,231.50)**	**$ 558.00**	**$ 7,404.81**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 52,060.29	$ (9,934.34)	$ (4,311.15)	$ 37,814.80			-	-
42	**TOTAL**		**$ 52,060.29**	**$ (9,934.34)**	**$ (4,311.15)**	**$ 37,814.80**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (23,445.65)	$ (23,445.65)			-	-
44	RT Net Inadvertent Amount	555.27	$ 418.95	$ (5,931.71)	$ (1,911.57)	$ (7,424.33)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 418.95**	**$ (5,931.71)**	**$ (25,357.22)**	**$ (30,869.98)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
January 2015 includes any adjustments REVISED 08_2015

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 654,293.99	$ (263,489.21)	$ (39.07)	$ 390,765.71			27,583	(11,271)
48	RT ASM Excessive Energy Amount	555.56	$ 17,376.21	$ (15,078.24)	$ -	$ 2,297.97			1,186	(1,475)
49	**TOTAL**		**$ 671,670.20**	**$ (278,567.45)**	**$ (39.07)**	**$ 393,063.68**			**28,769**	**(12,746)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 14,468,167.79	$ (9,981,621.76)	$ (607,499.39)	$ 3,879,046.64	$ (307,421.59)	$ 3,571,625.05	510,362	(345,344)
56	**Less Schedule 16 & 17 (Lines 15, 16, 17)**		$ (55,941.70)	$ -	$ (1,019.75)	$ (56,961.45)				
57	**Congestion and Losses Adjustment**				$ (4,719.26)	$ (4,719.26)				
58	**No DA generation sch., but still had output for current month**				$ -	$ -				
59	**MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 14,412,226.09**	**$ (9,981,621.76)**	**$ (613,238.40)**	**$ 3,817,365.93**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 3,817,365.93**						
62	Net KWH for retail = ((G) + (H)) * 1,000			165,018,413						**165,018,413**
63	January 2015 covers time period of 12/26/2014 -- 1/22/2015 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 4,430,604.33	165,018,413						
66	**Congestion and Losses Adjustment**		$ (4,719.26)							
67	**MISO RSG Bad Debt**		$ -							
68	**January Adjustments**		$ (608,519.14)	(19,036,150)						
69	**Total MISO**		$ 3,817,365.93	145,982,263						
									. . . TRADE SECRET DATA ENDS]	

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
February 2015 includes any adjustments REVISED 08_2015

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 9,902,845.33	$ (7,051,135.84)	$ -	$ 2,851,709.49			425,234	(309,167)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 421,727.08	$ -	$ -	$ 421,727.08			18,683	-
4	RT Asset Energy Amount	555.19	$ 255,847.12	$ (349,033.36)	$ (42,171.73)	$ (135,357.97)			7,169	(12,732)
5	RT Distribution of Losses Amount	555.24	$ 734.17	$ (247,723.89)	$ (4,092.43)	$ (251,082.15)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 511,945.71	$ -	$ -	$ 511,945.71			-	-
8	RT Loss Amount		$ (2,848.15)	$ -	$ -	$ (2,848.15)			-	-
9	RT Non-Asset Energy Amount	555.26	$ 1,661.63	$ (279.81)	$ -	$ 1,381.82			73	(12)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 11,091,912.89**	**$ (7,648,172.90)**	**$ (46,264.16)**	**$ 3,397,475.83**			**451,159**	**(321,911)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 59,031.43	$ -	$ -	$ 59,031.43			-	-
16	RT Mkt Admin Amount	555.18	$ 3,987.19	$ -	$ (319.14)	$ 3,668.05			-	-
17	FTR Mkt Admin Amount	555.13	$ 2,665.84	$ -	$ -	$ 2,665.84			-	-
18	**TOTAL**		**$ 65,684.46**	**$ -**	**$ (319.14)**	**$ 65,365.32**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion			$ 93,446.83		$ 93,446.83				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (41,814.53)			$ (41,814.53)				
23	FTR Hourly Allocation Amount	555.14	$ 39,284.31	$ (145,693.55)	$ -	$ (106,409.24)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (5,961.60)	$ 0.06	$ (5,961.54)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 5,730.96	$ (12,495.92)	$ (0.06)	$ (6,765.02)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 12,495.92	$ (5,879.33)	$ 0.33	$ 6,616.92			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 14,787.17	$ (1,188,109.34)	$ -	$ (1,173,322.17)			-	-
30	FTR Annual Transaction Amount	555.38	$ 1,192,820.63	$ (19,933.73)	$ -	$ 1,172,886.90			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 18,154.93	$ -	$ -	$ 18,154.93			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (21,960.53)	$ -	$ (21,960.53)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 1,241,459.39**	**$ (1,306,587.17)**	**$ 0.33**	**$ (65,127.45)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 20,167.71	$ -	$ (0.46)	$ 20,167.25			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 17,927.32	$ -	$ (699.74)	$ 17,227.58			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (16,450.85)	$ 19.74	$ (16,431.11)			-	-
40	**TOTAL**		**$ 38,095.03**	**$ (16,450.85)**	**$ (680.46)**	**$ 20,963.72**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 73,941.59	$ (9,811.87)	$ 1,682.06	$ 65,811.78			-	-
42	**TOTAL**		**$ 73,941.59**	**$ (9,811.87)**	**$ 1,682.06**	**$ 65,811.78**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (29,723.26)	$ (29,723.26)			-	-
44	RT Net Inadvertent Amount	555.27	$ 368.85	$ (5,079.92)	$ (1,378.77)	$ (6,089.84)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 368.85**	**$ (5,079.92)**	**$ (31,102.03)**	**$ (35,813.10)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
February 2015 includes any adjustments REVISED 08_2015

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 528,329.19	$ (189,696.21)	$ (59,377.58)	$ 279,255.40			24,465	(7,099)
48	RT ASM Excessive Energy Amount	555.56	$ 106.43	$ -	$ (1,036.73)	$ (930.30)			-	(22)
49	**TOTAL**		**$ 528,435.62**	**$ (189,696.21)**	**$ (60,414.31)**	**$ 278,325.10**			**24,465**	**(7,120)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 13,039,897.83	$ (9,175,798.92)	$ (137,097.71)	$ 3,727,001.20	$ (465,614.24)	$ 3,261,386.96	475,624	(329,032)
56	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (65,684.46)	$ -	$ 319.14	$ (65,365.32)				
57	**Less: Congestion and Losses Adjustment**				$ (8,825.67)	$ (8,825.67)				
58	**Less: No DA generation sch., but still had output for current month**				$ (333.89)	$ (333.89)				
59	**Less: MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 12,974,213.37**	**$ (9,175,798.92)**	**$ (145,938.13)**	**$ 3,652,476.32**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 3,652,476.32**						
62	Net KWH for retail = ((G) + (H)) * 1,000			146,592,610						**146,592,610**
63	February 2014 covers time period of 1/23/2015 -- 2/19/2015 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 3,798,414.45	146,592,610						
66	**Congestion and Losses Adjustment**		$ (8,825.67)							
67	**MISO RSG Bad Debt**		$ -							
68	**February Adjustments**		$ (137,112.46)	(3,432,606)						
69	**Total MISO**		$ 3,652,476.32	143,160,004						
								. . . TRADE SECRET DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
March 2015 includes any adjustments REVISED 08_2015

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 10,825,683.85	$ (6,526,766.81)	$ -	$ 4,298,917.04			444,836	(272,646)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 522,786.71	$ (207.65)	$ -	$ 522,579.06			22,309	-
4	RT Asset Energy Amount	555.19	$ 256,042.56	$ (383,006.30)	$ 139,350.96	$ 12,387.22			10,240	(17,407)
5	RT Distribution of Losses Amount	555.24	$ 6,394.01	$ (229,192.52)	$ (2,447.28)	$ (225,245.79)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 430,040.24	$ -	$ -	$ 430,040.24			-	-
8	RT Loss Amount		$ 22,904.03	$ -	$ -	$ 22,904.03			-	-
9	RT Non-Asset Energy Amount	555.26	$ 246.00	$ -	$ -	$ 246.00			-	(21)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 12,064,097.40**	**$ (7,139,173.28)**	**$ 136,903.68**	**$ 5,061,827.80**			**477,385**	**(290,074)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 67,704.43	$ -	$ -	$ 67,704.43			-	-
16	RT Mkt Admin Amount	555.18	$ 5,914.96	$ -	$ (670.12)	$ 5,244.84			-	-
17	FTR Mkt Admin Amount	555.13	$ 2,708.64	$ -	$ -	$ 2,708.64			-	-
18	**TOTAL**		**$ 76,328.03**	**$ -**	**$ (670.12)**	**$ 75,657.91**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 12,558.95	$ -	$ 12,558.95				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (24,144.66)	$ -	$ -	$ (24,144.66)				
23	FTR Hourly Allocation Amount	555.14	$ 42,389.73	$ (150,099.27)	$ 0.81	$ (107,708.73)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (7,685.81)	$ 3.54	$ (7,682.27)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 7,628.07	$ (4,354.92)	$ (4.35)	$ 3,268.80			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 4,354.92	$ (8,262.13)	$ 4.99	$ (3,902.22)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 11,401.39	$ (695,262.63)	$ -	$ (683,861.24)			-	-
30	FTR Annual Transaction Amount	555.38	$ 687,726.51	$ (20,150.17)	$ -	$ 667,576.34			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 24,662.40	$ -	$ -	$ 24,662.40			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (30,457.59)	$ 196.20	$ (30,261.39)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 754,018.36**	**$ (903,713.57)**	**$ 201.19**	**$ (149,494.02)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 55,695.29	$ -	$ (1,041.10)	$ 54,654.19			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (385.39)	$ -	$ (385.39)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 45,739.12	$ -	$ 780.06	$ 46,519.18			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (14,057.70)	$ (42.86)	$ (14,100.56)			-	-
40	**TOTAL**		**$ 101,434.41**	**$ (14,443.09)**	**$ (303.90)**	**$ 86,687.42**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 78,752.80	$ (13,737.87)	$ 3,227.32	$ 68,242.25			-	-
42	**TOTAL**		**$ 78,752.80**	**$ (13,737.87)**	**$ 3,227.32**	**$ 68,242.25**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ 465.57	$ -	$ (35,664.96)	$ (35,199.39)			-	-
44	RT Net Inadvertent Amount	555.27	$ 6,034.23	$ (4,590.77)	$ 612.15	$ 2,055.61			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 6,499.80**	**$ (4,590.77)**	**$ (35,052.81)**	**$ (33,143.78)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
March 2015 includes any adjustments REVISED 08_2015

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 512,655.35	$ (277,024.63)	$ (5,659.16)	$ 229,971.56			22,799	(12,186)
48	RT ASM Excessive Energy Amount	555.56	$ 1,542.55	$ -	$ (108.36)	$ 1,434.19			-	(100)
49	**TOTAL**		**$ 514,197.90**	**$ (277,024.63)**	**$ (5,767.52)**	**$ 231,405.75**			**22,799**	**(12,286)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 13,595,328.70	$ (8,352,683.21)	$ 98,537.84	$ 5,341,183.33	$ (333,286.08)	$ 5,007,897.25	500,185	(302,360)
56	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (76,328.03)	$ -	$ 670.12	$ (75,657.91)				
57	**Less: Congestion and Losses Adjustment**				$ (2,199.85)	$ (2,199.85)				
58	**Less: No DA generation sch., but still had output for current month**				$ -	$ -				
59	**Less: MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 13,519,000.67**	**$ (8,352,683.21)**	**$ 97,008.11**	**$ 5,263,325.57**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 5,263,325.57**						
62	Net KWH for retail = ((G) + (H)) * 1,000			197,824,771						**197,824,771**
63	March 2015 covers time period of 2/20/2015 -- 3/23/2015 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			

		Net Retail	Net MISO KWH	per kWh	Net Intersystem	Total
65	**MISO Book Totals**	$ 5,166,317.46	197,824,771			
66	**Congestion and Losses Adjustment**	$ (2,199.85)				
67	**MISO RSG Bad Debt**	$ -				
68	**March Adjustments**	$ 99,207.96	3,609,757			
69	**Total MISO**	$ 5,263,325.57	201,434,529			

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
April 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)**	
	Charge Type Description	**Acct**	**Retail Debits**	**Retail Credits**	**Retail Adjustments**	**Net Retail**	**Net Intersystem**	**Total**	**Charge types with MWH for Retail**	
No.	**Day Ahead & Real Time Asset & Non Asset Energy & Loss**						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 6,448,152.53	$ (3,382,673.39)	$ -	$ 3,065,479.14			347,146	(194,436)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 139,847.79	$ (399.34)	$ -	$ 139,448.45			8,278	(49)
4	RT Asset Energy Amount	555.19	$ 175,408.44	$ (144,303.61)	$ (119,931.39)	$ (88,826.56)			8,741	(8,439)
5	RT Distribution of Losses Amount	555.24	$ 2,570.07	$ (100,258.56)	$ 2,075.60	$ (95,612.89)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 251,329.24	$ -	$ -	$ 251,329.24			-	-
8	RT Loss Amount		$ 8,459.60	$ -	$ -	$ 8,459.60			-	-
9	RT Non-Asset Energy Amount	555.26	$ 450.51	$ -	$ -	$ 450.51			27	(21)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 7,026,218.18**	**$ (3,627,634.90)**	**$ (117,855.79)**	**$ 3,280,727.49**			**364,192**	**(202,945)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 47,636.46	$ -	$ -	$ 47,636.46			-	-
16	RT Mkt Admin Amount	555.18	$ 3,665.57	$ -	$ 242.14	$ 3,907.71			-	-
17	FTR Mkt Admin Amount	555.13	$ 2,520.48	$ -	$ -	$ 2,520.48			-	-
18	**TOTAL**		**$ 53,822.51**	**$ -**	**$ 242.14**	**$ 54,064.65**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 102,053.11	$ -	$ 102,053.11				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (14,108.51)	$ -	$ -	$ (14,108.51)				
23	FTR Hourly Allocation Amount	555.14	$ 37,519.60	$ (129,385.63)	$ -	$ (91,866.03)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (2,844.15)	$ (0.01)	$ (2,844.16)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ (86,057.76)	$ (86,057.76)			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 2,830.30	$ (3,035.37)	$ 86,057.77	$ 85,852.70			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 3,035.37	$ (2,830.30)	$ (85,599.57)	$ (85,394.50)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 11,401.39	$ (695,262.63)	$ -	$ (683,861.24)			-	-
30	FTR Annual Transaction Amount	555.38	$ 687,726.51	$ (20,150.17)	$ -	$ 667,576.34			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 24,662.40	$ -	$ -	$ 24,662.40			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ 14.30	$ (30,173.53)	$ 255.66	$ (29,903.57)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 753,081.36**	**$ (781,628.67)**	**$ (85,343.91)**	**$ (113,891.22)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 14,296.71	$ -	$ (5,713.72)	$ 8,582.99			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 7,432.36	$ -	$ (3,284.76)	$ 4,147.60			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (6,911.29)	$ (31.58)	$ (6,942.87)			-	-
40	**TOTAL**		**$ 21,729.07**	**$ (6,911.29)**	**$ (9,030.06)**	**$ 5,787.72**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 59,458.76	$ (7,518.15)	$ (6,946.92)	$ 44,993.69			-	-
42	**TOTAL**		**$ 59,458.76**	**$ (7,518.15)**	**$ (6,946.92)**	**$ 44,993.69**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (13,860.86)	$ (13,860.86)			-	-
44	RT Net Inadvertent Amount	555.27	$ 1,595.71	$ (3,644.07)	$ (25.49)	$ (2,073.85)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 1,595.71**	**$ (3,644.07)**	**$ (13,886.35)**	**$ (15,934.71)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
April 2015 includes any adjustments

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 267,309.25	$ (193,331.19)	$ 18.08	$ 73,996.14			15,284	(11,509)
48	RT ASM Excessive Energy Amount	555.56	$ 467.88	$ (22.80)	$ -	$ 445.08			0	(156)
49	**TOTAL**		**$ 267,777.13**	**$ (193,353.99)**	**$ 18.08**	**$ 74,441.22**			**15,284**	**(11,665)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 8,183,682.72	$ (4,620,691.07)	$ (232,802.81)	$ 3,330,188.84	$ (89,020.08)	$ 3,241,168.76	379,476	(214,610)
56	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (53,822.51)	$ -	$ (242.14)	$ (54,064.65)				
57	**Less: Congestion and Losses Adjustment**				$ 297.54	$ 297.54				
58	**Less: No DA generation sch., but still had output for current month**				$ (2,748.43)	$ (2,748.43)				
59	**Less: MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 8,129,860.21**	**$ (4,620,691.07)**	**$ (235,495.84)**	**$ 3,273,673.30**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 3,273,673.30**						
62	Net KWH for retail = ((G) + (H)) * 1,000			164,865,960						**164,865,960**
63	April 2014 covers time period of 3/24/2015 -- 4/22/2015 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 3,509,169.14	164,865,960						
66	**Congestion and Losses Adjustment**		$ 297.54							
67	**MISO RSG Bad Debt**		$ -							
68	**April Adjustments**		$ (235,793.38)	(5,064,895)						
69	**Total MISO**		$ 3,273,673.30	159,801,064						
									. . . TRADE SECRET DATA ENDS]	

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
May 2015 includes any adjustments REVISED 08_2015

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 5,693,880.40	$ (2,493,596.02)	$ -	$ 3,200,284.38			292,985	(138,036)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 108,905.44	$ (5,411.97)	$ -	$ 103,493.47			6,416	(290)
4	RT Asset Energy Amount	555.19	$ 214,552.04	$ (145,593.08)	$ 23,741.87	$ 92,700.83			9,435	(6,854)
5	RT Distribution of Losses Amount	555.24	$ 1,884.35	$ (70,743.71)	$ (1,904.57)	$ (70,763.93)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 222,876.89	$ -	$ -	$ 222,876.89			-	-
8	RT Loss Amount		$ 407.35	$ -	$ -	$ 407.35			-	-
9	RT Non-Asset Energy Amount	555.26	$ 190.26	$ (8,369.09)	$ -	$ (8,178.83)			147	(431)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 6,242,696.73**	**$ (2,723,713.87)**	**$ 21,837.30**	**$ 3,540,820.16**			**308,983**	**(145,611)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 34,197.66	$ -	$ -	$ 34,197.66			-	-
16	RT Mkt Admin Amount	555.18	$ 3,498.49	$ -	$ (221.34)	$ 3,277.15			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,385.04	$ -	$ -	$ 1,385.04			-	-
18	**TOTAL**		**$ 39,081.19**	**$ -**	**$ (221.34)**	**$ 38,859.85**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 127,887.74	$ -	$ 127,887.74				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (37,693.11)	$ -	$ -	$ (37,693.11)				
23	FTR Hourly Allocation Amount	555.14	$ 35,058.67	$ (70,658.54)	$ -	$ (35,599.87)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (3,628.18)	$ -	$ (3,628.18)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (58,898.80)	$ -	$ (58,898.80)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 3,614.45	$ (1,180.29)	$ -	$ 2,434.16			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 1,180.29	$ (3,614.45)	$ -	$ (2,434.16)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 11,401.39	$ (695,262.63)	$ -	$ (683,861.24)			-	-
30	FTR Annual Transaction Amount	555.38	$ 687,726.51	$ (20,150.17)	$ -	$ 667,576.34			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 24,662.40	$ -	$ -	$ 24,662.40			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (30,218.31)	$ (24.06)	$ (30,242.37)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 725,950.60**	**$ (755,723.63)**	**$ (24.06)**	**$ (29,797.09)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 16,466.29	$ -	$ (15,546.82)	$ 919.47			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 13,967.68	$ -	$ (1,128.57)	$ 12,839.11			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (7,173.27)	$ -	$ (7,173.27)			-	-
40	**TOTAL**		**$ 30,433.97**	**$ (7,173.27)**	**$ (16,675.39)**	**$ 6,585.31**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 64,749.73	$ (4,371.53)	$ (5,076.34)	$ 55,301.86			-	-
42	**TOTAL**		**$ 64,749.73**	**$ (4,371.53)**	**$ (5,076.34)**	**$ 55,301.86**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ 1,231.90	$ 1,231.90			-	-
44	RT Net Inadvertent Amount	555.27	$ 1,843.62	$ (3,800.70)	$ (886.87)	$ (2,843.95)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	**TOTAL**		**$ 1,843.62**	**$ (3,800.70)**	**$ 345.03**	**$ (1,612.05)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
May 2015 includes any adjustments REVISED 08_2015

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
47	RT ASM Non-Excessive Energy Amount	555.55	$ 284,497.51	$ (184,942.00)	$ 21.67	$ 99,577.18			17,347	(11,080)
48	RT ASM Excessive Energy Amount	555.56	$ 570.12	$ -	$ -	$ 570.12			-	(140)
49	**TOTAL**		**$ 285,067.63**	**$ (184,942.00)**	**$ 21.67**	**$ 100,147.30**			**17,347**	**(11,220)**
	Grandfathered Charge Types									
50	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
51	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
52	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
53	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
54	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
55	**TOTAL MISO DAY 2 CHARGES**		$ 7,389,823.47	$ (3,679,725.00)	$ 206.87	$ 3,710,305.34	$ (107,048.84)	$ 3,603,256.50	326,329	(156,831)
56	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (39,081.19)	$ -	$ 221.34	$ (38,859.85)				
57	**Less: Congestion and Losses Adjustment**				$ (93.03)	$ (93.03)				
58	**Less: No DA generation sch., but still had output for current month**				$ -	$ -				
59	**Less: MISO RSG Bad Debt**				$ -	$ -				
60	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 7,350,742.28**	**$ (3,679,725.00)**	**$ 335.18**	**$ 3,671,352.46**				
61	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 3,671,352.46**						
62	Net KWH for retail = ((G) + (H)) * 1,000			169,497,704						**169,497,704**
63	May 2015 covers time period of 4/23/2015 -- 5/21/2015 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
64			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
65	**MISO Book Totals**		$ 3,671,017.28	169,497,704						
66	**Congestion and Losses Adjustment**		$ (93.03)							
67	**MISO RSG Bad Debt**		$ -							
68	**May Adjustments**		$ 428.21	1,980,504						
69	**Total MISO**		$ 3,671,352.46	171,478,208						
									. . . TRADE SECRET DATA ENDS]	

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
June 2015 includes any adjustments REVISED 08_2015

No.	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	Day Ahead & Real Time Asset & Non Asset Energy & Loss						**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 6,345,119.64	$ (2,059,379.01)	$ -	$ 4,285,740.63			320,813	(114,796)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 105,110.36	$ (17,953.75)	$ -	$ 87,156.61			5,044	(1,146)
4	RT Asset Energy Amount	555.19	$ 109,319.22	$ (228,459.97)	$ 38,223.79	$ (80,916.96)			7,486	(11,188)
5	RT Distribution of Losses Amount	555.24	$ 1,783.84	$ (71,019.05)	$ 94.21	$ (69,141.00)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 131,705.30	$ -	$ -	$ 131,705.30			-	-
8	RT Loss Amount		$ 16,074.07	$ -	$ -	$ 16,074.07			-	-
9	RT Non-Asset Energy Amount	555.26	$ 1,936.68	$ -	$ -	$ 1,936.68			153	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 6,711,049.11**	**$ (2,376,811.78)**	**$ 38,318.00**	**$ 4,372,555.33**			**333,497**	**(127,130)**
	Virtual Energy									
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -			-	-
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -			-	-
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
	Schedules 16 & 17									
15	DA Mkt Admin Amount	555.01	$ 34,110.94	$ -	$ -	$ 34,110.94			-	-
16	RT Mkt Admin Amount	555.18	$ 3,647.15	$ -	$ (172.03)	$ 3,475.12			-	-
17	FTR Mkt Admin Amount	555.13	$ 946.88	$ -	$ -	$ 946.88			-	-
18	**TOTAL**		**$ 38,704.97**	**$ -**	**$ (172.03)**	**$ 38,532.94**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 19,217.03	$ -	$ 19,217.03				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 11,108.63	$ -	$ -	$ 11,108.63				
23	FTR Hourly Allocation Amount	555.14	$ 22,827.04	$ (31,909.94)	$ -	$ (9,082.90)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (929.12)	$ -	$ (929.12)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (59,845.63)	$ -	$ (59,845.63)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 884.03	$ (884.01)	$ -	$ 0.02			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 884.01	$ (884.03)	$ -	$ (0.02)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 23,531.72	$ (231,866.39)	$ -	$ (208,334.67)			-	-
30	FTR Annual Transaction Amount	555.38	$ 207,963.16	$ (23,797.19)	$ -	$ 184,165.97			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 5,379.69	$ -	$ -	$ 5,379.69			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (26,965.64)	$ -	$ (26,965.64)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 272,578.28**	**$ (357,864.92)**	**$ -**	**$ (85,286.64)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 10,018.69	$ -	$ (2,803.33)	$ 7,215.36			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 18,408.05	$ -	$ (1,413.62)	$ 16,994.43			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (5,596.99)	$ 30.45	$ (5,566.54)			-	-
40	**TOTAL**		**$ 28,426.74**	**$ (5,596.99)**	**$ (4,186.50)**	**$ 18,643.25**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 74,701.30	$ (14,624.40)	$ 1,813.96	$ 61,890.86			-	-
42	**TOTAL**		**$ 74,701.30**	**$ (14,624.40)**	**$ 1,813.96**	**$ 61,890.86**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ 518.97	$ -	$ (534.35)	$ (15.38)			-	-
44	RT Net Inadvertent Amount	555.27	$ 3,357.97	$ (2,887.20)	$ 362.88	$ 833.65			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ 3.23	$ -	$ -	$ 3.23			-	-
47	**TOTAL**		**$ 3,880.17**	**$ (2,887.20)**	**$ (171.47)**	**$ 821.50**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
June 2015 includes any adjustments REVISED 08_2015

	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
	ASM Charges									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 327,180.74	$ (216,011.30)	$ (212.37)	$ 110,957.07			17,710	(12,489)
49	RT ASM Excessive Energy Amount	555.56	$ 1,015.31	$ -	$ (0.04)	$ 1,015.27			-	(54)
50	**TOTAL**		**$ 328,196.05**	**$ (216,011.30)**	**$ (212.41)**	**$ 111,972.34**			**17,710**	**(12,543)**
	Grandfathered Charge Types									
51	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
52	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
53	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
54	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
55	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . TRADE SECRET DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 7,457,536.62	$ (2,973,796.59)	$ 35,389.55	$ 4,519,129.58	$ (29,088.77)	$ 4,490,040.81	351,207	(139,673)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (38,704.97)	$ -	$ 172.03	$ (38,532.94)				
58	**Less: Congestion and Losses Adjustment**				$ 120.57	$ 120.57				
59	**Less: No DA generation sch., but still had output for current month**				$ -	$ -				
60	**Less: MISO RSG Bad Debt**				$ -	$ -				
61	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 7,418,831.65**	**$ (2,973,796.59)**	**$ 35,682.15**	**$ 4,480,717.21**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 4,480,717.21**						
63	Net KWH for retail = ((G) + (H)) * 1,000			211,534,250						**211,534,250**
64	June 2015 covers time period of 5/22/2015 -- 6/22/2015 ** increased for losses of 2.8%						**[TRADE SECRET DATA BEGINS . . .**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 4,445,035.06	211,534,250						
67	**Congestion and Losses Adjustment**		$ 120.57							
68	**MISO RSG Bad Debt**		$ -							
69	**June Adjustments**		$ 35,561.58	(5,708,609)						
70	**Total MISO**		$ 4,480,717.21	205,825,641						
								. . . TRADE SECRET DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group - Net Retail - System
July 2014 through June 2015 includes any adjustments

No.	Charge Type Description	(A) Acct	(B) JULY 2014	(C) AUGUST	(D) SEPTEMBER	(E) OCTOBER	(F) NOVEMBER	(G) DECEMBER	(H) JANUARY 2015	(I) FEBRUARY	(J) MARCH	(K) APRIL	(L) MAY	(M) JUNE	YEAR TO DATE 2014 - 2015
	Day Ahead & Real Time Asset & Non Asset Energy & Loss														
1	DA Asset Energy Amount	555.02	$ 726,149.77	$1,564,638.36	$1,250,957.41	$ 108,832.49	$ 843,785.34	$ 4,019,500.09	$ 2,908,870.52	$ 2,851,709.49	$4,298,917.04	$3,065,479.14	$3,200,284.38	$4,285,740.63	$29,124,864.66
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	DA Non-asset Energy Amount	555.09	$ 217,365.70	$ 587,324.56	$ 446,973.08	$ 280,158.44	$ 417,341.60	$ 726,482.73	$ 676,868.16	$ 421,727.08	$ 522,579.06	$ 139,448.45	$ 103,493.47	$ 87,156.61	$ 4,626,918.94
4	RT Asset Energy Amount	555.19	$ 272,697.99	$ (136,244.81)	$ (186,874.40)	$ 112,963.98	$ (39,971.73)	$ (303,361.15)	$ (373,538.42)	$ (135,357.97)	$ 12,387.22	$ (88,826.56)	$ 92,700.83	$ (80,916.96)	$ (854,341.98)
5	RT Distribution of Losses Amount	555.24	$ (194,597.42)	$ (256,403.67)	$ (157,891.24)	$ (167,255.68)	$ (240,745.28)	$ (262,068.11)	$ (209,555.64)	$ (251,082.15)	$ (225,245.79)	$ (95,612.89)	$ (70,763.93)	$ (69,141.00)	$ (2,200,362.80)
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	DA Loss Amount		$ 515,971.27	$ 345,550.69	$ 326,646.26	$ 504,005.34	$ 583,615.47	$ 661,158.60	$ 425,309.14	$ 511,945.71	$ 430,040.24	$ 251,329.24	$ 222,876.89	$ 131,705.30	$ 4,910,154.15
8	RT Loss Amount		$ 22,738.20	$ (2,021.98)	$ 27,322.50	$ 27,089.99	$ 22,632.29	$ 12,759.30	$ 407.37	$ (2,848.15)	$ 22,904.03	$ 8,459.60	$ 407.35	$ 16,074.07	$ 155,924.57
9	RT Non-Asset Energy Amount	555.26	$ -	$ (1,114.58)	$ 644.41	$ 131,048.62	$ -	$ (1,386.82)	$ 482.00	$ 1,381.82	$ 246.00	$ 450.51	$ (8,178.83)	$ 1,936.68	$ 125,509.81
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	**TOTAL**		**$1,560,325.51**	**$2,101,728.57**	**$1,707,778.02**	**$ 996,843.18**	**$1,586,657.69**	**$ 4,853,084.64**	**$ 3,428,843.13**	**$ 3,397,475.83**	**$5,061,827.80**	**$3,280,727.49**	**$3,540,820.16**	**$4,372,555.33**	**$35,888,667.35**
	Virtual Energy														
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Schedules 16 & 17														
15	DA Mkt Admin Amount	555.01	$ 40,344.42	$ 35,711.71	$ 39,547.66	$ 45,127.41	$ 57,097.53	$ 67,207.51	$ 49,710.66	$ 59,031.43	$ 67,704.43	$ 47,636.46	$ 34,197.66	$ 34,110.94	$ 577,427.82
16	RT Mkt Admin Amount	555.18	$ 3,976.39	$ 2,785.41	$ 4,177.23	$ 3,937.78	$ 4,623.39	$ 5,351.71	$ 4,628.87	$ 3,668.05	$ 5,244.84	$ 3,907.71	$ 3,277.15	$ 3,475.12	$ 49,053.65
17	FTR Mkt Admin Amount	555.13	$ 3,340.96	$ 2,674.32	$ 2,624.64	$ 2,160.56	$ 1,997.76	$ 3,088.80	$ 2,621.92	$ 2,665.84	$ 2,708.64	$ 2,520.48	$ 1,385.04	$ 946.88	$ 28,735.84
18	**TOTAL**		**$ 47,661.77**	**$ 41,171.44**	**$ 46,349.53**	**$ 51,225.75**	**$ 63,718.68**	**$ 75,648.02**	**$ 56,961.45**	**$ 65,365.32**	**$ 75,657.91**	**$ 54,064.65**	**$ 38,859.85**	**$ 38,532.94**	**$ 655,217.31**
	Congest & FTRs														
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DA Congestion		$ 173,720.93	$ 145,963.26	$ 202,878.96	$ 571,653.84	$ 398,893.74	$ 260,600.33	$ (18,179.63)	$ 93,446.83	$ 12,558.95	$ 102,053.11	$ 127,887.74	$ 19,217.03	$ 2,090,695.09
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	RT Congestion		$ 22,991.39	$ (36,771.89)	$ 13,394.82	$ (21,553.96)	$ (22,929.61)	$ 3,555.51	$ (850.62)	$ (41,814.53)	$ (24,144.66)	$ (14,108.51)	$ (37,693.11)	$ 11,108.63	$ (148,816.54)
23	FTR Hourly Allocation Amount	555.14	$ (143,962.39)	$ (181,944.29)	$ (175,959.72)	$ (516,759.99)	$ (349,929.47)	$ (243,292.84)	$ 8,056.08	$ (106,409.24)	$ (107,708.73)	$ (91,866.03)	$ (35,599.87)	$ (9,082.90)	$ (1,954,459.39)
24	FTR Monthly Allocation Amount	555.15	$ (5,826.99)	$ (4,929.25)	$ (9,538.55)	$ (12,016.81)	$ (13,015.57)	$ (9,828.88)	$ (4,925.54)	$ (5,961.54)	$ (7,682.27)	$ (2,844.16)	$ (3,628.18)	$ (929.12)	$ (81,126.86)
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (86,057.76)	$ -	$ -	$ (86,057.76)
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (58,898.80)	$ (59,845.63)	$ (118,744.43)
27	FTR Full Funding Guarantee Amount	555.36	$ (1,914.83)	$ (10,692.33)	$ (21,407.99)	$ (64,700.85)	$ (40,785.61)	$ (2,147.26)	$ 1,248.87	$ (6,765.02)	$ 3,268.80	$ 85,852.70	$ 2,434.16	$ 0.02	$ (55,609.34)
28	FTR Guarantee Uplift Amount	555.37	$ 2,036.07	$ 11,304.47	$ 20,171.03	$ 64,597.24	$ 50,598.75	$ 22,985.65	$ (1,178.54)	$ 6,616.92	$ (3,902.22)	$ (85,394.50)	$ (2,434.16)	$ (0.02)	$ 85,400.69
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ (573,463.88)	$ (573,463.88)	$ (714,917.88)	$ (714,917.88)	$ (714,917.88)	$(1,173,322.17)	$(1,173,322.17)	$(1,173,322.17)	$ (683,861.24)	$ (683,861.24)	$ (683,861.24)	$ (208,334.67)	$ (9,071,566.30)
30	FTR Annual Transaction Amount	555.38	$ 573,463.79	$ 573,463.79	$ 715,009.06	$ 715,009.06	$ 715,009.06	$ 1,172,886.90	$ 1,172,886.90	$ 1,172,886.90	$ 667,576.34	$ 667,576.34	$ 667,576.34	$ 184,165.97	$ 8,997,510.45
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 16,713.42	$ 16,713.73	$ 12,265.33	$ 12,265.08	$ 12,265.08	$ 18,154.56	$ 18,154.93	$ 18,154.93	$ 24,662.40	$ 24,662.40	$ 24,662.40	$ 5,379.69	$ 204,053.95
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ (49,618.96)	$ (49,583.95)	$ (28,138.77)	$ (27,357.82)	$ (32,929.32)	$ (21,746.10)	$ (16,061.53)	$ (21,960.53)	$ (30,261.39)	$ (29,903.57)	$ (30,242.37)	$ (26,965.64)	$ (364,769.95)
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	**TOTAL**		**$ 14,138.55**	**$ (109,940.34)**	**$ 13,756.29**	**$ 6,217.91**	**$ 2,259.17**	**$ 27,845.70**	**$ (14,171.25)**	**$ (65,127.45)**	**$ (149,494.02)**	**$ (113,891.22)**	**$ (29,797.09)**	**$ (85,286.64)**	**$ (503,490.39)**
	RSG & Make Whole Payments														
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 8,880.45	$ 14,598.70	$ 17,986.99	$ 14,752.60	$ 14,654.25	$ 29,414.07	$ 16,397.38	$ 20,167.25	$ 54,654.19	$ 8,582.99	$ 919.47	$ 7,215.36	$ 208,223.70
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ (201.01)	$ (991.99)	$ (122.50)	$ -	$ (112.57)	$ (12,236.25)	$ -	$ -	$ (385.39)	$ -	$ -	$ -	$ (14,049.71)
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	$ 8,313.86	$ 25,774.79	$ 16,182.39	$ 24,468.62	$ 16,927.89	$ 22,318.12	$ 13,378.10	$ 17,227.58	$ 46,519.18	$ 4,147.60	$ 12,839.11	$ 16,994.43	$ 225,091.67
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	RT Price Volatility Make Whole Payment	555.42	$ (83,230.45)	$ (78,283.17)	$ (65,932.02)	$ (75,334.59)	$ (111,892.65)	$ (69,127.23)	$ (22,370.67)	$ (16,431.11)	$ (14,100.56)	$ (6,942.87)	$ (7,173.27)	$ (5,566.54)	$ (556,385.13)
40	**TOTAL**		**$ (66,237.15)**	**$ (38,901.67)**	**$ (31,885.14)**	**$ (36,113.37)**	**$ (80,423.08)**	**$ (29,631.29)**	**$ 7,404.81**	**$ 20,963.72**	**$ 86,687.42**	**$ 5,787.72**	**$ 6,585.31**	**$ 18,643.25**	**$ (137,119.47)**
	Revenue Neutrality Uplift														
41	RT Revenue Neutrality Uplift Amount	555.28	$ 15,663.60	$ 98,232.56	$ 37,427.31	$ 83,968.61	$ 117,731.78	$ 115,390.82	$ 37,814.80	$ 65,811.78	$ 68,242.25	$ 44,993.69	$ 55,301.86	$ 61,890.86	$ 802,469.92
42	**TOTAL**		**$ 15,663.60**	**$ 98,232.56**	**$ 37,427.31**	**$ 83,968.61**	**$ 117,731.78**	**$ 115,390.82**	**$ 37,814.80**	**$ 65,811.78**	**$ 68,242.25**	**$ 44,993.69**	**$ 55,301.86**	**$ 61,890.86**	**$ 802,469.92**
	Other Charges														
43	RT Misc Amount	555.25	$ (2,256.37)	$ 3,663.49	$ (522.46)	$ (935.14)	$ 5,699.77	$ (12,920.93)	$ (23,445.65)	$ (29,723.26)	$ (35,199.39)	$ (13,860.86)	$ 1,231.90	$ (15.38)	$ (108,284.28)
44	RT Net Inadvertent Amount	555.27	$ 11,646.46	$ (34,097.57)	$ (2,709.15)	$ 6,925.43	$ (2,832.45)	$ (36.44)	$ (7,424.33)	$ (6,089.84)	$ 2,055.61	$ (2,073.85)	$ (2,843.95)	$ 833.65	$ (36,646.43)
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.23	$ 3.23
47	**TOTAL**		**$ 9,390.09**	**$ (30,434.08)**	**$ (3,231.61)**	**$ 5,990.29**	**$ 2,867.32**	**$ (12,957.37)**	**$ (30,869.98)**	**$ (35,813.10)**	**$ (33,143.78)**	**$ (15,934.71)**	**$ (1,612.05)**	**$ 821.50**	**$ (144,927.48)**

	Charge Type Description	(A) Acct	(B) JULY 2014	(C) AUGUST	(D) SEPTEMBER	(E) OCTOBER	(F) NOVEMBER	(G) DECEMBER	(H) JANUARY 2015	(I) FEBRUARY	(J) MARCH	(K) APRIL	(L) MAY	(M) JUNE	YEAR TO DATE 2014 - 2015
	ASM Charges														
48	RT ASM Non-Excessive Energy Amount	555.55	$ 721,593.63	$ 407,943.42	$ 436,887.64	$ 470,118.68	$ 224,328.15	$ 865,740.87	$ 390,765.71	$ 279,255.40	$ 229,971.56	$ 73,996.14	$ 99,577.18	$ 110,957.07	$ 4,311,135.45
49	RT ASM Excessive Energy Amount	555.56	$ 9,362.32	$ 848.80	$ 4,051.72	$ 51.38	$ 196.15	$ 987.08	$ 2,297.97	$ (930.30)	$ 1,434.19	$ 445.08	$ 570.12	$ 1,015.27	$ 20,329.78
50	**TOTAL**		**$ 730,955.95**	**$ 408,792.22**	**$ 440,939.36**	**$ 470,170.06**	**$ 224,524.30**	**$ 866,727.95**	**$ 393,063.68**	**$ 278,325.10**	**$ 231,405.75**	**$ 74,441.22**	**$ 100,147.30**	**$ 111,972.34**	**$ 4,331,465.23**
	Grandfathered Charge Types														
51	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
56	**TOTAL MISO DAY 2 CHARGES**		$2,311,898.32	$2,470,648.70	$2,211,133.76	$1,578,302.43	$1,917,335.86	$ 5,896,108.47	$ 3,879,046.64	$ 3,727,001.20	$5,341,183.33	$3,330,188.84	$3,710,305.34	$4,519,129.58	$40,892,282.47
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (47,661.77)	$ (41,171.44)	$ (46,349.53)	$ (51,225.75)	$ (63,718.68)	$ (75,648.02)	$ (56,961.45)	$ (65,365.32)	$ (75,657.91)	$ (54,064.65)	$ (38,859.85)	$ (38,532.94)	$ (655,217.31)
58	**Less: Congestion and Losses Adjustment**		$ (12,323.83)	$ (8,591.05)	$ (22,227.08)	$ (39,673.12)	$ (34,062.93)	$ (15,927.26)	$ (4,719.26)	$ (8,825.67)	$ (2,199.85)	$ 297.54	$ (93.03)	$ 120.57	$ (148,224.97)
59	**Less: No DA generation sch., but still had output for current month**		$ (30.60)	$ (0.17)	$ -	$ (563.60)	$ (998.65)	$ (221.54)	$ -	$ (333.89)	$ -	$ (2,748.43)	$ -	$ -	$ (4,896.88)
60	**Less: MISO RSG Bad Debt**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$2,251,882.12**	**$2,420,886.04**	**$2,142,557.15**	**$1,486,839.96**	**$1,818,555.60**	**$ 5,804,311.65**	**$ 3,817,365.93**	**$ 3,652,476.32**	**$5,263,325.57**	**$3,273,673.30**	**$3,671,352.46**	**$4,480,717.21**	**$40,083,943.31**

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-___

OTTER TAIL
POWER COMPANY

PART F - RULE 7825.2820 ANNUAL INDEPENDENT AUDITORS’ REPORT

Otter Tail Power Company

Schedule of Costs of Energy Adjustment Factors
For Minnesota Customers
Period from July 1, 2014 through June 30, 2015

Deloitte.

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www.deloitte.com

INDEPENDENT ACCOUNTANTS' REPORT

Otter Tail Power Company:

We have examined the accompanying Schedule of Costs of Energy Adjustment Factors ("the Schedule") of Otter Tail Power Company (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 clause adjustment factors of the Company for the period from July 1, 2014 to June 30, 2015, as accounted for in accordance with the criteria established by the Minnesota Public Utilities Commission (the "Commission") Rules 7825.2500 to 7825.2840 governing automatic adjustment of energy charges, and with the Energy Adjustment Rider and Dockets as defined in Minnesota Section 13.01 of the electric rates filed by the Company with the Commission, including the following revisions:

- MN Docket No. E017/PA-01-1391 dated May 9, 2002
- MN Docket No. E017/M-03-30 dated September 28, 2006
- MN Docket No. E017/M-03-970 dated November 14, 2006
- MN Docket No. E017/M-05-284 dated December 20, 2006
- MN Docket No. E017/M-06-1332 dated January 16, 2007
- MN Docket No. E999/AA-06-1208 dated February 6, 2008
- MN Docket No. E017/M-08-528 dated August 23, 2010
- MN Docket No. E999/AA-07-1130 dated October 20, 2010
- MN Docket No. E017/M-10-1013 dated January 26, 2011
- MN Docket No. E017/GR-10-239 approved April 25, 2011 with an effective date of October 1, 2011
- MN Docket Nos. E999/AA-09-961 and E999/AA-10-884, dated April 6, 2012
- MN Docket No. E999/AA-11-792, dated August 16, 2013

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

Deloitte & Touche LLP

August 24, 2015

OTTER TAIL POWER COMPANY

SCHEDULE OF COSTS OF ENERGY ADJUSTMENT FACTORS
FOR MINNESOTA CUSTOMERS
PERIOD FROM JULY 1, 2014 THROUGH JUNE 30, 2015

Based on Costs in the Two-Month Period Ended	Effective for the Monthly Bill Dated on or After	Adjustment per KWH
July 31, 2014	September 2, 2014	$ 0.00285
August 31, 2014	October 2, 2014	0.00230
September 30, 2014	November 3, 2014	0.00092
October 31, 2014	December 1, 2014	(0.00024)
November 30, 2014	January 2, 2015	0.00127
December 31, 2014	February 2, 2015	0.00537
January 31, 2015	March 3, 2015	0.00642
February 28, 2015	April 2, 2015	0.00337
March 31, 2015	May 1, 2015	0.00289
April 30, 2015	June 2, 2015	0.00086
May 31, 2015	July 2, 2015	(0.00093)
June 30, 2015	August 3, 2015	0.00058

See accompanying note to the Schedule of Costs of Energy Adjustment Factors.

OTTER TAIL POWER COMPANY

NOTE TO THE SCHEDULE OF COSTS OF ENERGY ADJUSTMENT FACTORS FOR THE YEAR ENDED JUNE 30, 2015

1. INTERPRETATIONS OF THE COST OF ENERGY ADJUSTMENT CLAUSE

The Company has developed the following interpretations with respect to the cost of energy adjustment clause:

1. The monthly fuel costs for electric generation and the monthly kilowatt-hour (kWh) sales of the combined Minnesota system and the non-Minnesota system are used in the calculation of the Minnesota cost of energy adjustment clause factors.

2. The fuel-related costs calculated by the Company to be associated with intersystem sales and the production of steam supplied to wholesale customers are not included in the calculation of the Minnesota cost of energy adjustment clause factors.

3. The Minnesota Energy Adjustment Rider states that the fuel costs and energy associated with retail kilowatt-hour sales (exclusive of intersystem sales) for the most recent two-month period are to be used in calculating the cost of energy adjustment factor; this has been interpreted to mean the most recent two-month period for which the actual costs and sales are available. The energy associated with retail sales has been interpreted to mean actual kilowatt-hour sales of electricity.

* * * * * *

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-___

PART G - RULE 7825.2830 ANNUAL FIVE-YEAR PROJECTION REPORT

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

OTTER TAIL POWER COMPANY
RULE 7825.2830 - ANNUAL FIVE-YEAR PROJECTION

SUPPORTING DOCUMENTATION

Fuel cost by source and system use purchased power cost is projected by month for July 2015 through December 2017 and projected annually for 2018 through 2020.
These projections are consistent with historical dispatch generation levels, but do not take into account any regulatory changes that may cause Otter Tail Power Company to limit generation.

Fuel costs are based on current contracts and forecasts when contracts are not available.

OTTER TAIL POWER COMPANY
RULE 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

July 2015 - December 2020

	Jul	Aug	Sep	Oct	Nov	Dec	Total
2015	**[TRADE SECRET DATA BEGINS . . .**						
MWH-Steam							
Hydro							
Wind							
Other							
Subtotal							
Purchases							
Total							
Cost-Steam							
Other							
Subtotal							
Purchases							
Total							
$/MWH-Steam							
Other							
Purchases							
Total							

MWH Allocation
Steam

Purchased Power

. . . TRADE SECRET DATA ENDS]

OTTER TAIL POWER COMPANY
RULE 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

July 2015 - December 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2016	**[TRADE SECRET DATA BEGINS . . .**												
MWH-Steam													
Hydro													
Wind													
Other													
Subtotal													
Purchases													
Total													
Cost-Steam													
Other													
Subtotal													
Purchases													
Total													
$/MWH-Steam													
Other													
Purchases													
Total													

MWH Allocation
Steam

Purchased Power

. . . TRADE SECRET DATA ENDS]

OTTER TAIL POWER COMPANY
RULE 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA

July 2015 - December 2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2017	**[TRADE SECRET DATA BEGINS . . .**												
MWH-Steam													
Hydro													
Wind													
Other													
Subtotal													
Purchases													
Total													
Cost-Steam													
Other													
Subtotal													
Purchases													
Total													
$/MWH-Steam													
Other													
Purchases													
Total													

MWH Allocation
Steam

Purchased Power

. . . TRADE SECRET DATA ENDS]

OTTER TAIL POWER COMPANY
RULE 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA
July 2015 - December 2020

	Total
2018	**[TRADE SECRET DATA BEGINS . .**
MWH-Steam	
Hydro	
Wind	
Other	
Subtotal	
Purchases	
Total	
Cost-Steam	
Other	
Subtotal	
Purchases	
Total	
$/MWH-Steam	
Other	
Purchases	
Total	
	. . . TRADE SECRET DATA ENDS]

OTTER TAIL POWER COMPANY
RULE 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA
July 2015 - December 2020

	Total
2019	**[TRADE SECRET DATA BEGINS . .**
MWH-Steam	
Hydro	
Wind	
Other	
Subtotal	
Purchases	
Total	
Cost-Steam	
Other	
Subtotal	
Purchases	
Total	
$/MWH-Steam	
Other	
Purchases	
Total	
	. . . TRADE SECRET DATA ENDS]

OTTER TAIL POWER COMPANY
RULE 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
NONPUBLIC DOCUMENT - CONTAINS TRADE SECRET DATA
July 2015 - December 2020

	Total
2020	**[TRADE SECRET DATA BEGINS . .**
MWH-Steam	
Hydro	
Wind	
Other	
Subtotal	
Purchases	
Total	
Cost-Steam	
Other	
Subtotal	
Purchases	
Total	
$/MWH-Steam	
Other	
Purchases	
Total	
	. . . TRADE SECRET DATA ENDS]

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-___

OTTER TAIL POWER COMPANY

PART H - ADDITIONAL REPORTING REQUIREMENTS

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

OTTER TAIL POWER COMPANY COMPLIANCE REPORT AS REQUIRED BY ORDER IN DOCKET E017/M-06-1332

As ordered in Docket No. E017/M-06-1332, issued January 16, 2007, (In The Matter of Otter Tail Power Company's Petition for Approval of an Electric Service Agreement with Enbridge Energy, Limited Partnership) Otter Tail submits the following compliance report with its Annual Automatic Adjustment of Charges report ("AAA") filed under Minn. Rules part 7825.2800.

For convenience, the conditions are listed with the same numbering system as the order in Docket No. E017/M-06-1332 used.

b. As part of its annual automatic adjustment filing, Otter Tail shall report the following information:

- **the amount of incremental energy purchased by the customer under the LGS Rider,**

  [TRADE SECRET DATA BEGINS . . .

  . . . TRADE SECRET DATA ENDS]

- **the retail rate paid by the customer on Fixed Rate Energy Pricing,**

  [TRADE SECRET DATA BEGINS . . .

  . . . TRADE SECRET DATA ENDS]

- **and the retail rate of the energy had System Marginal Energy Pricing been used to determine the retail rate paid by the customer**

  [TRADE SECRET DATA BEGINS . . .

  . . . TRADE SECRET DATA ENDS]

Otter Tail requests that consideration be given to drop this compliance reporting requirement from future Annual Automatic Adjustment filings.

MN DOC'S REVIEW OF 2005/2006 AAA REPORT DOCKET NO. E,G999/AA-06-1208

In the Minnesota Department of Commerce's Review of the 2005-2006 Annual Automatic Adjustment Report dated April 16, 2007, the DOC recommended:

On page 63, that the utilities comment on why utilities are using virtual transactions for retail and/or non-retail and the significance of virtual energy in the next AAA docket.

For retail load serving purposes, the Company will occasionally use virtual transactions to convert bilateral purchases between the day-ahead and real-time markets. For instance, bilateral purchases are frequently designed to settle in the real-time market while the Company clears its load in the day-ahead market. Therefore, a virtual will be used to convert the real-time purchase to the day-ahead market so that the purchase more accurately hedges the Company's load. The Company does not use virtual transactions in the Asset-Based sales category. The Company uses virtual transactions in the Non-Asset-Based sales category for both hedging and speculative purposes.

For the most recent AAA period (July 2014 through June 2015), the Company did not use any virtual transactions on behalf of retail customers. The Company completed 258,102 MWh of virtual sales and 266,765 MWh of virtual purchases in the MISO Non-Asset-Based sales category. As of January 1, 2015, the Company discontinued all Non-Asset Based trading activities.

In accordance with the February 6, 2008, Order issued by the Commission, on page 9:

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

    Otter Tail has addressed this earlier in this filing under PART D - RULE 7825.2800 POLICIES AND ACTIONS - SECTION 5 COMPLIANCE REPORT AS REQUIRED BY ORDER IN DOCKET NO. E017/PA-01-1391 8. d)

18. **All electric utilities 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.**

    Part H Section 2 Attachment J contains maintenance expenses for test year 2009 and actual for 2010, 2011, 2012 , 2013 and 2014.

21. All electric utilities 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 filing.

See Part E Section 10 Attachment I-1 (marked as Trade Secret)

OTTER TAIL POWER COMPANY
GENERATION MAINTENANCE EXPENSE

		Test Year 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014
STEAM POWER MAINTENANCE:							
SUPERVISION AND ENGINEERING	402 - 510	$ 721,308	883,656	$ 778,527	$ 816,833	$ 758,277	$ 773,643
STRUCTURES	402 - 511	560,715	642,272	597,892	717,803	770,212	708,960
BOILER	402 - 512	6,231,149	5,511,489	7,404,372	6,655,306	6,172,350	7,236,561
ELECTRIC	402 - 513	3,061,762	792,083	1,155,193	1,390,201	1,139,056	4,755,818
MISCELLANEOUS	402 - 514	1,180,678	947,125	1,005,810	1,113,359	1,037,412	1,555,138
Total Steam Power Maintenance		11,755,612	8,776,625	10,941,794	10,693,502	9,877,307	15,030,120
HYDRO POWER MAINTENANCE:							
SUPERVISION & ENGINEERING	402 - 541	4,861	5,498	3,653	2,907	3,188	4,133
STRUCTURES	402 - 542	7,809	2,307	23,082	3,651	9,994	1,155
RESERVOIRS - DAMS	402 - 543	381,374	224,410	332,332	281,218	220,302	221,334
ELECTRIC	402 - 544	94,084	37,586	8,707	8,739	27,164	18,516
MISCELLANEOUS EXPENSE	402 - 545	6,349	7,445	18,714	319		2,089
Total Hydro Maintenance		494,478	277,245	386,488	296,834	260,648	247,227
IC POWER MAINTENANCE WITHOUT WIND:							
SUPERVISION AND ENGINEERING	402 - 551	22,680	32,388	37,446	24,123	40,378	22,937
STRUCTURES	402 - 552	18,168	79,869	5,010	65,536	39,732	37,245
GENERATING AND ELECTRIC	402 - 553	562,318	1,095,287	343,525	524,580	602,805	583,072
MISCELLANEOUS EXPENSE	402 - 554	9,334	(6,203)	1,937	15,771	47,467	23,537
Total IC Maintenance without wind		612,501	1,201,341	387,918	630,010	730,382	666,791
IC POWER MAINTENANCE WIND ONLY:							
SUPERVISION AND ENGINEERING	402 - 551	-	-	1,095	13,294	400	96
GENERATING AND ELECTRIC	402 - 553	-	-	7,104	13,092	89,224	207,125
MISCELLANEOUS EXPENSE	402 - 554	-	-	1,173	6,704	10,429	118,912
		-	-	9,372	33,090	100,053	326,133
Additional Contracted Wind Maintenance*		280,129	249,942	288,570	258,442	446,807	316,763
Total Maintenance		$ 13,142,720	$ 10,505,153	$ 12,014,142	$ 11,911,878	$ 11,415,197	$ 16,587,034
		Corrected**	Corrected**	Corrected**	Corrected**		

Note: Budgeted amounts were not used in the most recent rate case.
The above numbers are on a calendar year basis.
Please see V. Additional Reporting Requirements - MN PUC Order Acting on Electric Utilities' Annual Reports and Requiring Additional Filings Docket Nos. E999/AA-09-961 and E999/AA-10-884 Number 22. for outage information.

*These amounts reflect the appropriate maintenance portion of combined O & M contracts for OTP wind facilities.
** Amounts corrected and reported in Docket E999/AA-14-579.

MN OES'S REVIEW OF 2006/2007 AAA REPORT DOCKET NO. E,G999/AA-07-1130

In the Minnesota Office of Energy Security's ("OES") Review of the 2006-2007 Annual Automatic Adjustment Report dated June 30, 2008, the OES recommended that Otter Tail provide a more summarized approach in the next AAA, such as MISO Daily Settlement Summaries that tie out to Asset and Non-Asset Based Transactions.

Part H Section 3 Attachment K (marked as Trade Secret) contains a monthly and year to date breakdown.

The OES also recommended Otter Tail address how the Auction Revenue Rights ("ARR") process will be treated for retail and wholesale purposes and provide information regarding what ARRs if any a utility purchased, how much they paid, and what FTR revenues and costs were received to date for ARRs purchases.

Otter Tail has no activity to report for this item.

The OES also recommended the Commission require electric utilities to report on the number and size of transformers on their systems and to assess whether they have a reasonable number of spares in the event of an outage. Require this information to be included in the AAA reports starting with fiscal year 2011).

Otter Tail addresses later in this filing under PART H - ADDITIONAL REPORTING REQUIREMENTS – SECTION 7 ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING REFUND OF CERTAIN CURTAILMENT COSTS, AND REQUIRING ADDITIONAL FILINGS IN 2010/2011 (FYE11) ANNUAL AUTOMATIC ADJUSTMENT REPORTS DOCKET NO. E999/AA-11-792

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
No.	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy										**TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(330,107)	$ (8,338,324.68)	290,352	$ 7,612,174.91	0	$ -	17,645	$ 468,839.12				
2	DA Non-asset Energy Amount	555.09	(8,392)	$ (217,365.70)	0	$ -	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(19,179)	$ (518,784.14)	8,800	$ 246,086.15	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(357,677)**	**$ (9,074,474.52)**	**299,153**	**$ 7,858,261.06**	**0**	**$ -**	**17,645**	**$ 468,839.12**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (4,855.64)	0	$ 199,453.06	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (515,971.27)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (22,738.20)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (543,565.11)**	**0**	**$ 199,453.06**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (40,344.42)	0	$ -	0	$ (1,121.17)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (4,160.70)	0	$ 184.31	0	$ (1,164.46)	0	$ -				
18	FTR Mkt Admin Amount	555.13	0	$ (3,340.96)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (47,846.08)**	**0**	**$ 184.31**	**0**	**$ (2,285.63)**	**0**	**$ -**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (173,720.93)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (22,991.39)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (25,527.82)	0	$ 169,490.21	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (63.37)	0	$ 5,890.36	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (5,891.38)	0	$ 7,806.21	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (7,944.19)	0	$ 5,908.12	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (60,666.14)	0	$ 634,130.02	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (645,764.87)	0	$ 72,301.08	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (16,713.67)	0	$ 0.25	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 49,618.96	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (785,562.83)**	**0**	**$ 771,424.28**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (10,065.82)	0	$ 1,185.37	0	$ (731.32)	0	$ 85.98				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 201.01	0	$ -	0	$ 542.44				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (9,297.29)	0	$ 983.43	0	$ (675.38)	0	$ 71.26				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 3,130.81				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (58.96)	0	$ 83,289.41	0	$ (4.28)	0	$ 6,053.07				
41	**SUBTOTAL**		**0**	**$ (19,422.07)**	**0**	**$ 85,659.22**	**0**	**$ (1,410.98)**	**0**	**$ 9,883.56**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ -	0	$ 2,256.37	0	$ -	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (28,411.44)	0	$ 16,764.98	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (33,151.12)	0	$ 17,487.52	0	$ (2,408.90)	0	$ 1,270.69				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (61,562.56)**	**0**	**$ 36,508.87**	**0**	**$ (2,408.90)**	**0**	**$ 1,270.69**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(32,833)	$ (972,759.22)	11,890	$ 251,165.59	(5,732)	$ (85,034.51)	11,727	$ 310,419.22				
48	RT ASM Excessive Energy Amount	555.56	(0)	$ (9,377.06)	704	$ 14.74	(1)	$ -	20	$ 419.31				
49	**SUBTOTAL**		**(32,833)**	**$ (982,136.28)**	**12,594**	**$ 251,180.33**	**(5,733)**	**$ (85,034.51)**	**11,747**	**$ 310,838.53**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	**Acct**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(390,510)**	**$ (11,514,569.45)**	**311,747**	**$ 9,202,671.13**	**(5,733)**	**$ (91,140.02)**	**29,392**	**$ 790,831.90**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (47,846.08)**		**$ 184.31**								
57	**Congestion and Losses Adjustment**			**$ (12,323.83)**										
58	**No DA generation sch., but still had output for current month**			**$ (30.60)**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (11,454,368.94)**		**$ 9,202,486.82**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (2,251,882.12)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 699,691.88**				
64	**Less: Fuel Cost**								**23,659**	**$ 483,257.80**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 297.03**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 216,137.05**				

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
August 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	**Day Ahead & Real Time Energy**										TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(338,330)	$ (9,464,182.34)	275,115	$ 7,899,543.98	0	$ -	1,624	$ 46,983.15				
2	DA Non-asset Energy Amount	555.09	(20,929)	$ (587,324.56)	0	$ -	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(10,104)	$ (304,397.47)	16,074	$ 440,642.28	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	43	$ 1,114.58	0	$ -	0	$ -				
5	**SUBTOTAL**		**(369,363)**	**$ (10,355,904.37)**	**291,232**	**$ 8,341,300.84**	**0**	**$ -**	**1,624**	**$ 46,983.15**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (3,216.56)	0	$ 259,620.23	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (345,550.69)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ 2,021.98	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (346,745.27)**	**0**	**$ 259,620.23**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (35,711.71)	0	$ -	0	$ (98.96)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (2,933.34)	0	$ 147.93	0	$ (383.89)	0	$ 0.92				
18	FTR Mkt Admin Amount	555.13	0	$ (2,674.32)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (41,319.37)**	**0**	**$ 147.93**	**0**	**$ (482.85)**	**0**	**$ 0.92**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (145,963.26)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 36,771.89	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (39,321.49)	0	$ 221,265.78	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (37.61)	0	$ 4,966.86	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (4,698.92)	0	$ 15,391.25	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (15,386.65)	0	$ 4,082.18	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (60,666.14)	0	$ 634,130.02	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (645,764.87)	0	$ 72,301.08	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (16,713.73)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 49,583.95	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (745,817.52)**	**0**	**$ 855,757.86**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (14,770.39)	0	$ 171.69	0	$ (291.03)	0	$ 3.34				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 991.99	0	$ -	0	$ 256.07				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (26,072.18)	0	$ 297.39	0	$ (513.68)	0	$ 5.69				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 2,097.67				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 78,283.17	0	$ -	0	$ 1,543.23				
41	**SUBTOTAL**		**0**	**$ (40,842.57)**	**0**	**$ 79,744.24**	**0**	**$ (804.71)**	**0**	**$ 3,906.00**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (3,754.90)	0	$ 91.41	0	$ -	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (3,661.96)	0	$ 37,759.53	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (102,569.74)	0	$ 4,337.18	0	$ (2,021.70)	0	$ 85.33				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (109,986.60)**	**0**	**$ 42,188.12**	**0**	**$ (2,021.70)**	**0**	**$ 85.33**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(24,851)	$ (588,104.27)	5,344	$ 180,160.85	(791)	$ (12,783.28)	5,754	$ 160,539.13				
48	RT ASM Excessive Energy Amount	555.56	0	$ (848.80)	58	$ -	0	$ -	20	$ 281.50				
49	**SUBTOTAL**		**(24,851)**	**$ (588,953.07)**	**5,402**	**$ 180,160.85**	**(791)**	**$ (12,783.28)**	**5,774**	**$ 160,820.63**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
August 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(394,214)**	**$ (12,229,568.77)**	**296,634**	**$ 9,758,920.07**	**(791)**	**$ (16,092.54)**	**7,398**	**$ 211,796.03**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (41,319.37)**		**$ 147.93**								
57	**Congestion and Losses Adjustment**			**$ (8,591.05)**										
58	**No DA generation sch., but still had output for current month**			**$ (0.17)**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (12,179,658.18)**		**$ 9,758,772.14**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (2,420,886.04)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 195,703.49**				
64	**Less: Fuel Cost**								**6,607**	**$ 141,945.31**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 69.51**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 53,688.67**				

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
September 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	**Day Ahead & Real Time Energy**										TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(349,605)	$ (8,477,576.59)	295,618	$ 7,226,619.18	0	$ -	11,046	$ 346,659.69				
2	DA Non-asset Energy Amount	555.09	(17,607)	$ (446,973.08)	0	$ -	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(14,616)	$ (339,897.09)	19,905	$ 526,771.49	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(24)	$ (644.41)	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(381,851)**	**$ (9,265,091.17)**	**315,523**	**$ 7,753,390.67**	**0**	**$ -**	**11,046**	**$ 346,659.69**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (3,727.53)	0	$ 161,618.77	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (326,646.26)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (27,322.50)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (357,696.29)**	**0**	**$ 161,618.77**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (39,547.66)	0	$ -	0	$ (671.05)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (4,320.68)	0	$ 143.45	0	$ (1,304.68)	0	$ 0.67				
18	FTR Mkt Admin Amount	555.13	0	$ (2,624.64)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (46,492.98)**	**0**	**$ 143.45**	**0**	**$ (1,975.73)**	**0**	**$ 0.67**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (202,878.96)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (13,394.82)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (153,649.60)	0	$ 329,609.32	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (2.17)	0	$ 9,540.72	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (9,581.12)	0	$ 30,989.11	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (30,990.02)	0	$ 10,818.99	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (18,664.88)	0	$ 733,582.76	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (749,313.78)	0	$ 34,304.72	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (12,265.33)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 28,138.77	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (987,861.72)**	**0**	**$ 974,105.43**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (19,104.10)	0	$ 1,117.11	0	$ (1,577.44)	0	$ 92.22				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 122.50	0	$ -	0	$ 248.69				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (16,781.71)	0	$ 599.32	0	$ (1,385.55)	0	$ 49.26				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 9,967.26				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (0.08)	0	$ 65,932.10	0	$ -	0	$ 5,444.75				
41	**SUBTOTAL**		**0**	**$ (35,885.89)**	**0**	**$ 67,771.03**	**0**	**$ (2,962.99)**	**0**	**$ 15,802.18**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ -	0	$ 522.46	0	$ -	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (3,647.28)	0	$ 6,356.43	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (42,970.03)	0	$ 5,542.72	0	$ (3,548.16)	0	$ 457.56				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (46,617.31)**	**0**	**$ 12,421.61**	**0**	**$ (3,548.16)**	**0**	**$ 457.56**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(32,242)	$ (701,417.12)	12,610	$ 264,529.48	(2,116)	$ (51,111.93)	19,113	$ 512,745.12				
48	RT ASM Excessive Energy Amount	555.56	(0)	$ (4,051.74)	448	$ 0.02	0	$ (123.49)	23	$ 108.63				
49	**SUBTOTAL**		**(32,242)**	**$ (705,468.86)**	**13,058**	**$ 264,529.50**	**(2,116)**	**$ (51,235.42)**	**19,136**	**$ 512,853.75**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
September 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(414,093)**	**$ (11,445,114.22)**	**328,582**	**$ 9,233,980.46**	**(2,116)**	**$ (59,722.30)**	**30,182**	**$ 875,773.85**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (46,492.98)**		**$ 143.45**								
57	**Congestion and Losses Adjustment**			**$ (22,227.08)**										
58	**No DA generation sch., but still had output for current month**			**$ -**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (11,376,394.16)**		**$ 9,233,837.01**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (2,142,557.15)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 816,051.55**				
64	**Less: Fuel Cost**								**28,066**	**$ 577,242.37**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 316.33**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 238,492.85**				

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
October 2014 includes any adjustments

No.	Charge Type Description	(A) Acct	(B) RETAIL MWh	(C) RETAIL Cost	(D) RETAIL MWh	(E) RETAIL Revenue	(F) ASSET BASED WHOLESALE MWh	(G) ASSET BASED WHOLESALE Cost	(H) ASSET BASED WHOLESALE MWh	(I) ASSET BASED WHOLESALE Revenue	(J) NON ASSET BASED WHOLESALE MWh	(K) NON ASSET BASED WHOLESALE Cost	(L) NON ASSET BASED WHOLESALE MWh	(M) NON ASSET BASED WHOLESALE Revenue
	Day Ahead & Real Time Energy										TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(341,174)	$ (8,131,163.85)	328,281	$ 8,022,331.36	0	$ -	29,189	$ 877,149.62				
2	DA Non-asset Energy Amount	555.09	(13,057)	$ (312,731.27)	1,397	$ 32,572.83	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(12,120)	$ (322,255.38)	9,247	$ 209,291.40	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(6,351)	$ (131,048.62)	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(372,701)**	**$ (8,897,199.12)**	**338,925**	**$ 8,264,195.59**	**0**	**$ -**	**29,189**	**$ 877,149.62**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (4,209.00)	0	$ 171,464.68	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (504,005.34)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (27,089.99)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (535,304.33)**	**0**	**$ 171,464.68**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (45,127.41)	0	$ -	0	$ (1,960.56)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (4,141.14)	0	$ 203.36	0	$ (1,733.22)	0	$ 2.13				
18	FTR Mkt Admin Amount	555.13	0	$ (2,160.56)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (51,429.11)**	**0**	**$ 203.36**	**0**	**$ (3,693.78)**	**0**	**$ 2.13**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (571,653.84)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 21,553.96	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (239,791.79)	0	$ 756,551.78	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (94.35)	0	$ 12,111.16	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (11,651.86)	0	$ 76,352.71	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (76,368.25)	0	$ 11,771.01	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (18,664.88)	0	$ 733,582.76	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (749,313.78)	0	$ 34,304.72	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (12,265.08)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (285.83)	0	$ 27,643.65	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (1,086,881.86)**	**0**	**$ 1,080,663.95**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (15,559.48)	0	$ 806.88	0	$ (1,545.47)	0	$ 80.12				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ -	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (25,019.66)	0	$ 551.04	0	$ (2,485.00)	0	$ 54.54				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 5,002.97				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (0.01)	0	$ 75,334.60	0	$ -	0	$ 7,483.50				
41	**SUBTOTAL**		**0**	**$ (40,579.15)**	**0**	**$ 76,692.52**	**0**	**$ (4,030.47)**	**0**	**$ 12,621.13**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ -	0	$ 935.14	0	$ -	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (9,199.86)	0	$ 2,274.43	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (86,136.40)	0	$ 2,167.79	0	$ (8,556.11)	0	$ 215.16				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (95,336.26)**	**0**	**$ 5,377.36**	**0**	**$ (8,556.11)**	**0**	**$ 215.16**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(29,451)	$ (721,316.28)	12,115	$ 251,197.60	(10,475)	$ (165,049.29)	14,838	$ 356,346.80				
48	RT ASM Excessive Energy Amount	555.56	(0)	$ (311.97)	115	$ 260.59	0	$ (19.36)	25	$ 283.04				
49	**SUBTOTAL**		**(29,451)**	**$ (721,628.25)**	**12,230**	**$ 251,458.19**	**(10,475)**	**$ (165,068.65)**	**14,863**	**$ 356,629.84**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
October 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(402,152)**	**$ (11,428,358.08)**	**351,154**	**$ 9,850,055.65**	**(10,475)**	**$ (181,349.01)**	**44,052**	**$ 1,246,617.88**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (51,429.11)**		**$ 203.36**								
57	**Congestion and Losses Adjustment**			**$ (39,673.12)**										
58	**No DA generation sch., but still had output for current month**			**$ (563.60)**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (11,336,692.25)**		**$ 9,849,852.29**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (1,486,839.96)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 1,065,268.87**				
64	**Less: Fuel Cost**								**33,577**	**$ 678,959.08**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 523.22**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 385,786.57**				
												. . . TRADE SECRET DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
November 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	**Day Ahead & Real Time Energy**										TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(363,596)	$ (9,728,448.83)	330,771	$ 8,884,663.49	0	$ -	29,516	$ 913,658.72				
2	DA Non-asset Energy Amount	555.09	(17,355)	$ (426,051.18)	319	$ 8,709.58	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(14,443)	$ (406,927.04)	17,280	$ 446,898.77	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(395,394)**	**$ (10,561,427.05)**	**348,371**	**$ 9,340,271.84**	**0**	**$ -**	**29,516**	**$ 913,658.72**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (9,657.65)	0	$ 250,402.93	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (583,615.47)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (22,632.29)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (615,905.41)**	**0**	**$ 250,402.93**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (57,097.53)	0	$ -	0	$ (2,352.99)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (4,814.82)	0	$ 191.43	0	$ (1,735.32)	0	$ 490.95				
18	FTR Mkt Admin Amount	555.13	0	$ (1,997.76)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (63,910.11)**	**0**	**$ 191.43**	**0**	**$ (4,088.31)**	**0**	**$ 490.95**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (398,893.74)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 22,929.61	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (136,159.46)	0	$ 486,088.93	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (66.96)	0	$ 13,082.53	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (11,932.44)	0	$ 52,718.05	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (52,694.64)	0	$ 2,095.89	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (18,664.88)	0	$ 733,582.76	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (749,313.78)	0	$ 34,304.72	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (12,265.08)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (281.99)	0	$ 33,211.31	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (958,449.62)**	**0**	**$ 956,190.45**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (15,891.40)	0	$ 1,237.15	0	$ (1,693.91)	0	$ 131.85				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 112.57	0	$ -	0	$ 626.40				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (17,353.25)	0	$ 425.36	0	$ (1,849.63)	0	$ 45.16				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 6,205.94				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (23.40)	0	$ 111,916.05	0	$ (2.47)	0	$ 11,930.76				
41	**SUBTOTAL**		**0**	**$ (33,268.05)**	**0**	**$ 113,691.13**	**0**	**$ (3,546.01)**	**0**	**$ 18,940.11**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (5,716.27)	0	$ 16.50	0	$ -	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (3,181.54)	0	$ 6,013.99	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (120,610.84)	0	$ 2,879.06	0	$ (12,857.32)	0	$ 306.73				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (129,508.65)**	**0**	**$ 8,909.55**	**0**	**$ (12,857.32)**	**0**	**$ 306.73**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(30,439)	$ (606,633.68)	16,320	$ 382,305.53	(7,187)	$ (181,364.86)	13,508	$ 362,254.28				
48	RT ASM Excessive Energy Amount	555.56	0	$ (212.90)	79	$ 16.75	(10)	$ (177.21)	26	$ 185.12				
49	**SUBTOTAL**		**(30,439)**	**$ (606,846.58)**	**16,398**	**$ 382,322.28**	**(7,197)**	**$ (181,542.07)**	**13,534**	**$ 362,439.40**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
November 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(425,833)**	**$ (12,969,315.47)**	**364,769**	**$ 11,051,979.61**	**(7,197)**	**$ (202,033.71)**	**43,049**	**$ 1,295,835.91**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (63,910.11)**		**$ 191.43**								
57	**Congestion and Losses Adjustment**			**$ (34,062.93)**										
58	**No DA generation sch., but still had output for current month**			**$ (998.65)**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (12,870,343.78)**		**$ 11,051,788.18**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (1,818,555.60)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 1,093,802.20**				
64	**Less: Fuel Cost**								**35,853**	**$ 811,557.59**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 398.89**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 281,845.72**				

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
December 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	**Acct**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
No.	**Day Ahead & Real Time Energy**										**TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(523,135)	$ (13,800,611.87)	371,795	$ 9,781,111.78	0	$ -	4,365	$ 151,576.06				
2	DA Non-asset Energy Amount	555.09	(30,000)	$ (731,647.49)	164	$ 5,164.76	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(15,021)	$ (399,757.62)	24,977	$ 703,118.77	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	38	$ 1,386.82	0	$ -	0	$ -				
5	**SUBTOTAL**		**(568,156)**	**$ (14,932,016.98)**	**396,975**	**$ 10,490,782.13**	**0**	**$ -**	**4,365**	**$ 151,576.06**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (17,459.89)	0	$ 279,528.00	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (661,158.60)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (12,759.30)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (691,377.79)**	**0**	**$ 279,528.00**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (67,207.51)	0	$ -	0	$ (332.59)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (5,672.62)	0	$ 320.91	0	$ (846.57)	0	$ 2.64				
18	FTR Mkt Admin Amount	555.13	0	$ (3,088.80)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (75,968.93)**	**0**	**$ 320.91**	**0**	**$ (1,179.16)**	**0**	**$ 2.64**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (260,600.33)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (3,555.51)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (70,865.78)	0	$ 314,158.62	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 9,828.88	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (9,201.66)	0	$ 11,348.92	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (22,988.32)	0	$ 2.67	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (14,787.17)	0	$ 1,188,109.34	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (1,192,820.63)	0	$ 19,933.73	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (18,154.56)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (74.81)	0	$ 21,820.91	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (1,332,448.44)**	**0**	**$ 1,304,602.74**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (30,741.31)	0	$ 1,327.24	0	$ (1,113.45)	0	$ 48.07				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 12,236.25	0	$ -	0	$ 5,956.60				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (24,216.16)	0	$ 1,898.04	0	$ (876.86)	0	$ 68.63				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 23,614.77				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (208.20)	0	$ 69,335.43	0	$ (7.40)	0	$ 2,511.77				
41	**SUBTOTAL**		**0**	**$ (55,165.67)**	**0**	**$ 84,796.96**	**0**	**$ (1,997.71)**	**0**	**$ 32,199.84**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (2,355.18)	0	$ 15,276.11	0	$ (28.03)	0	$ 77.38				
43	RT Net Inadvertent Amount	555.27	0	$ (18,812.07)	0	$ 18,848.51	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (127,604.09)	0	$ 12,213.27	0	$ (4,622.38)	0	$ 442.20				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (148,771.34)**	**0**	**$ 46,337.89**	**0**	**$ (4,650.41)**	**0**	**$ 519.58**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(45,134)	$ (1,244,812.42)	14,895	$ 379,071.55	(1,156)	$ (30,386.53)	10,257	$ 312,062.68				
48	RT ASM Excessive Energy Amount	555.56	0	$ (1,037.27)	122	$ 50.19	0	$ -	19	$ 460.97				
49	**SUBTOTAL**		**(45,134)**	**$ (1,245,849.69)**	**15,016**	**$ 379,121.74**	**(1,156)**	**$ (30,386.53)**	**10,276**	**$ 312,523.65**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
December 2014 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	**Acct**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(613,290)**	**$ (18,481,598.84)**	**411,991**	**$ 12,585,490.37**	**(1,156)**	**$ (38,213.81)**	**14,640**	**$ 496,821.77**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (75,968.93)**		**$ 320.91**								
57	**Congestion and Losses Adjustment**			**$ (15,927.26)**										
58	**No DA generation sch., but still had output for current month**			**$ (221.54)**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (18,389,481.11)**		**$ 12,585,169.46**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (5,804,311.65)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 458,607.96**				
64	**Less: Fuel Cost**								**13,485**	**$ 336,142.63**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 133.54**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 122,331.79**				

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
January 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				**ASSET BASED WHOLESALE**				**NON ASSET BASED WHOLESALE**			
	Charge Type Description	**Acct**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
No.	**Day Ahead & Real Time Energy**										**TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(438,328)	$ (10,809,078.62)	323,843	$ 7,900,208.10	0	$ -	3,060	$ 76,873.92				
2	DA Non-asset Energy Amount	555.09	(27,608)	$ (676,868.16)	0	$ -	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(21,543)	$ (559,379.31)	33,717	$ 932,917.73	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(53)	$ (723.41)	12	$ 241.41	0	$ -	0	$ -				
5	**SUBTOTAL**		**(487,532)**	**$ (12,046,049.50)**	**357,572**	**$ 8,833,367.24**	**0**	**$ -**	**3,060**	**$ 76,873.92**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (17,828.59)	0	$ 227,384.23	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (425,309.14)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (407.37)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (443,545.10)**	**0**	**$ 227,384.23**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (49,710.66)	0	$ -	0	$ (192.75)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (4,893.98)	0	$ 265.11	0	$ (418.94)	0	$ 4.00				
18	FTR Mkt Admin Amount	555.13	0	$ (2,621.92)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (57,226.56)**	**0**	**$ 265.11**	**0**	**$ (611.69)**	**0**	**$ 4.00**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ 18,179.63	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 850.62	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (87,121.94)	0	$ 79,065.86	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (0.16)	0	$ 4,925.70	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (4,672.10)	0	$ 3,423.23	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (3,423.49)	0	$ 4,602.03	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (14,787.17)	0	$ 1,188,109.34	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (1,192,820.63)	0	$ 19,933.73	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (18,154.93)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (5,718.17)	0	$ 21,779.70	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (1,325,847.97)**	**0**	**$ 1,340,019.22**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (16,748.42)	0	$ 351.04	0	$ (325.69)	0	$ 6.79				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ -	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (14,218.74)	0	$ 840.64	0	$ (276.35)	0	$ 16.20				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 9,113.48				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (93.33)	0	$ 22,464.00	0	$ (1.73)	0	$ 436.94				
41	**SUBTOTAL**		**0**	**$ (31,060.49)**	**0**	**$ 23,655.68**	**0**	**$ (603.77)**	**0**	**$ 9,573.41**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (2,591.54)	0	$ 26,037.19	0	$ (136.27)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (740.97)	0	$ 8,165.30	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (55,309.42)	0	$ 17,494.62	0	$ (1,075.76)	0	$ 340.16				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (58,641.93)**	**0**	**$ 51,697.11**	**0**	**$ (1,212.03)**	**0**	**$ 340.16**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(27,595)	$ (654,578.35)	11,284	$ 263,812.64	(845)	$ (21,607.53)	6,344	$ 151,679.89				
48	RT ASM Excessive Energy Amount	555.56	(1,186)	$ (17,376.21)	1,475	$ 15,078.24	0	$ -	3	$ 3.16				
49	**SUBTOTAL**		**(28,781)**	**$ (671,954.56)**	**12,759**	**$ 278,890.88**	**(845)**	**$ (21,607.53)**	**6,348**	**$ 151,683.05**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
January 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(516,313)**	**$ (14,634,326.11)**	**370,331**	**$ 10,755,279.47**	**(845)**	**$ (24,035.02)**	**9,408**	**$ 238,474.54**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (57,226.56)**		**$ 265.11**								
57	**Congestion and Losses Adjustment**			**$ (4,719.26)**										
58	**No DA generation sch., but still had output for current month**			**$ -**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (14,572,380.29)**		**$ 10,755,014.36**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (3,817,365.93)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 214,439.52**				
64	**Less: Fuel Cost**								**8,562**	**$ 174,174.43**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 76.53**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 40,188.56**				
												. . . TRADE SECRET DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
February 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	**Day Ahead & Real Time Energy**										TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(425,234)	$ (9,902,845.33)	309,167	$ 7,051,135.84	0	$ -	4,295	$ 150,343.82				
2	DA Non-asset Energy Amount	555.09	(18,683)	$ (421,727.08)	0	$ -	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(17,511)	$ (530,996.90)	25,369	$ 666,354.87	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(73)	$ (1,661.63)	12	$ 279.81	0	$ -	0	$ -				
5	**SUBTOTAL**		**(461,502)**	**$ (10,857,230.94)**	**334,549**	**$ 7,717,770.52**	**0**	**$ -**	**4,295**	**$ 150,343.82**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (6,934.36)	0	$ 258,016.51	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (511,945.71)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ 2,848.15	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (516,031.92)**	**0**	**$ 258,016.51**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (59,031.43)	0	$ -	0	$ (309.71)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (4,360.26)	0	$ 692.21	0	$ (1,173.20)	0	$ 196.20				
18	FTR Mkt Admin Amount	555.13	0	$ (2,665.84)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (66,057.53)**	**0**	**$ 692.21**	**0**	**$ (1,482.91)**	**0**	**$ 196.20**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (93,446.83)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 41,814.53	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (39,284.31)	0	$ 145,693.55	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (0.06)	0	$ 5,961.60	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (5,730.96)	0	$ 12,495.98	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (12,496.25)	0	$ 5,879.33	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (14,787.17)	0	$ 1,188,109.34	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (1,192,820.63)	0	$ 19,933.73	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (18,154.93)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 21,960.53	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (1,241,459.78)**	**0**	**$ 1,306,587.23**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (20,167.71)	0	$ 0.46	0	$ (757.16)	0	$ 0.01				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ -	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (18,267.83)	0	$ 1,040.25	0	$ (685.69)	0	$ 38.90				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 4,233.10				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (237.12)	0	$ 16,668.23	0	$ (8.87)	0	$ 625.71				
41	**SUBTOTAL**		**0**	**$ (38,672.66)**	**0**	**$ 17,708.94**	**0**	**$ (1,451.72)**	**0**	**$ 4,897.72**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (0.42)	0	$ 29,723.68	0	$ -	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (801.63)	0	$ 6,891.47	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (79,187.65)	0	$ 13,375.87	0	$ (2,973.20)	0	$ 502.07				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (79,989.70)**	**0**	**$ 49,991.02**	**0**	**$ (2,973.20)**	**0**	**$ 502.07**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(24,736)	$ (534,101.69)	8,610	$ 254,846.29	(967)	$ (22,137.57)	15,001	$ 326,248.75				
48	RT ASM Excessive Energy Amount	555.56	(103)	$ (106.43)	22	$ 1,036.73	0	$ -	0	$ -				
49	**SUBTOTAL**		**(24,839)**	**$ (534,208.12)**	**8,632**	**$ 255,883.02**	**(967)**	**$ (22,137.57)**	**15,001**	**$ 326,248.75**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
February 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	**Acct**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(486,341)**	**$ (13,333,650.65)**	**343,181**	**$ 9,606,649.45**	**(967)**	**$ (28,045.40)**	**19,296**	**$ 482,188.56**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (66,057.53)**		**$ 692.21**								
57	**Congestion and Losses Adjustment**			**$ (8,825.67)**										
58	**No DA generation sch., but still had output for current month**			**$ (333.89)**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (13,258,433.56)**		**$ 9,605,957.24**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (3,652,476.32)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 454,143.16**				
64	**Less: Fuel Cost**								**18,329**	**$ 354,419.30**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 150.83**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 99,573.03**				
												. . . TRADE SECRET DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
March 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	**Day Ahead & Real Time Energy**										TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(444,836)	$ (10,825,683.85)	272,646	$ 6,526,766.81	0	$ -	6,407	$ 236,601.23				
2	DA Non-asset Energy Amount	555.09	(22,309)	$ (522,786.71)	0	$ 207.65	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(23,778)	$ (663,483.73)	27,048	$ 651,096.51	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ (246.00)	21	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(490,923)**	**$ (12,012,200.29)**	**299,715**	**$ 7,178,070.97**	**0**	**$ -**	**6,407**	**$ 236,601.23**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (13,040.32)	0	$ 238,286.11	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (430,040.24)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (22,904.03)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (465,984.59)**	**0**	**$ 238,286.11**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (67,704.43)	0	$ -	0	$ (565.00)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (6,097.44)	0	$ 852.60	0	$ (541.24)	0	$ 4.25				
18	FTR Mkt Admin Amount	555.13	0	$ (2,708.64)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (76,510.51)**	**0**	**$ 852.60**	**0**	**$ (1,106.24)**	**0**	**$ 4.25**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (12,558.95)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 24,144.66	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (42,392.20)	0	$ 150,100.93	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (3.54)	0	$ 7,685.81	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (7,628.09)	0	$ 4,359.29	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (4,359.93)	0	$ 8,262.15	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (11,401.39)	0	$ 695,262.63	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (687,726.51)	0	$ 20,150.17	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (24,662.40)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (196.20)	0	$ 30,457.59	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (754,225.60)**	**0**	**$ 903,719.62**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (55,877.55)	0	$ 1,223.36	0	$ (923.30)	0	$ 20.11				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 385.39	0	$ -	0	$ 95.34				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (46,827.31)	0	$ 308.13	0	$ (773.51)	0	$ 4.96				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 16,206.16				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (0.82)	0	$ 14,101.38	0	$ (0.01)	0	$ 233.02				
41	**SUBTOTAL**		**0**	**$ (102,705.68)**	**0**	**$ 16,018.26**	**0**	**$ (1,696.82)**	**0**	**$ 16,559.59**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (1,992.13)	0	$ 37,191.52	0	$ (72.46)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (7,076.22)	0	$ 5,020.61	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (83,904.40)	0	$ 15,662.15	0	$ (1,386.25)	0	$ 258.68				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (92,972.75)**	**0**	**$ 57,874.28**	**0**	**$ (1,458.71)**	**0**	**$ 258.68**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(22,833)	$ (513,586.58)	12,510	$ 283,615.02	(2,313)	$ (35,510.48)	3,714	$ 92,284.25				
48	RT ASM Excessive Energy Amount	555.56	(4)	$ (1,542.56)	100	$ 108.37	0	$ -	6	$ -				
49	**SUBTOTAL**		**(22,837)**	**$ (515,129.14)**	**12,611**	**$ 283,723.39**	**(2,313)**	**$ (35,510.48)**	**3,720**	**$ 92,284.25**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
March 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(513,760)**	**$ (14,019,728.56)**	**312,326**	**$ 8,678,545.23**	**(2,313)**	**$ (39,772.25)**	**10,128**	**$ 345,708.00**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (76,510.51)**		**$ 852.60**								
57	**Congestion and Losses Adjustment**			**$ (2,199.85)**										
58	**No DA generation sch., but still had output for current month**			**$ -**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (13,941,018.20)**		**$ 8,677,692.63**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (5,263,325.57)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 305,935.75**				
64	**Less: Fuel Cost**								**7,815**	**$ 202,135.20**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 117.03**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 103,683.52**				

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
April 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	**Day Ahead & Real Time Energy**										TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(347,146)	$ (6,448,152.53)	194,436	$ 3,382,673.39	0	$ -	1,455	$ 31,634.12				
2	DA Non-asset Energy Amount	555.09	(8,278)	$ (139,847.79)	49	$ 399.34	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(9,614)	$ (202,206.02)	14,378	$ 291,032.58	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(27)	$ (450.51)	21	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(365,065)**	**$ (6,790,656.85)**	**208,884**	**$ 3,674,105.31**	**0**	**$ -**	**1,455**	**$ 31,634.12**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (5,788.22)	0	$ 101,401.11	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (251,329.24)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (8,459.60)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (265,577.06)**	**0**	**$ 101,401.11**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (47,636.46)	0	$ -	0	$ (129.43)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (3,973.25)	0	$ 65.54	0	$ (187.25)	0	$ -				
18	FTR Mkt Admin Amount	555.13	0	$ (2,520.48)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (54,130.19)**	**0**	**$ 65.54**	**0**	**$ (316.68)**	**0**	**$ -**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (102,053.11)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 14,108.51	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (37,519.60)	0	$ 129,385.63	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 2,844.16	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ 86,057.76	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ -	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (88,888.07)	0	$ 3,035.37	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (3,035.37)	0	$ 88,429.87	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (11,401.39)	0	$ 695,262.63	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (687,726.51)	0	$ 20,150.17	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (24,662.40)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (312.66)	0	$ 30,216.23	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (839,437.49)**	**0**	**$ 953,328.71**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (14,384.47)	0	$ 5,801.48	0	$ (98.02)	0	$ 39.53				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ -	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (8,137.80)	0	$ 3,990.20	0	$ (55.25)	0	$ 26.88				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ (2.31)	0	$ 6,357.10				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (13.44)	0	$ 6,956.31	0	$ (0.09)	0	$ 47.36				
41	**SUBTOTAL**		**0**	**$ (22,535.71)**	**0**	**$ 16,747.99**	**0**	**$ (155.67)**	**0**	**$ 6,470.87**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (469.31)	0	$ 14,330.17	0	$ (11.00)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (1,783.62)	0	$ 3,857.47	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (60,725.46)	0	$ 15,731.77	0	$ (414.12)	0	$ 107.04				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (62,978.39)**	**0**	**$ 33,919.41**	**0**	**$ (425.12)**	**0**	**$ 107.04**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(15,293)	$ (267,557.32)	11,517	$ 193,561.18	(330)	$ (5,894.08)	1,884	$ 36,873.01				
48	RT ASM Excessive Energy Amount	555.56	(8)	$ (511.53)	164	$ 66.45	(15)	$ (398.35)	21	$ 512.17				
49	**SUBTOTAL**		**(15,301)**	**$ (268,068.85)**	**11,681**	**$ 193,627.63**	**(346)**	**$ (6,292.43)**	**1,904**	**$ 37,385.18**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
April 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(380,366)**	**$ (8,303,384.54)**	**220,565**	**$ 4,973,195.70**	**(346)**	**$ (7,189.90)**	**3,359**	**$ 75,597.21**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (54,130.19)**		**$ 65.54**								
57	**Congestion and Losses Adjustment**			**$ 297.54**										
58	**No DA generation sch., but still had output for current month**			**$ (2,748.43)**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (8,246,803.46)**		**$ 4,973,130.16**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (3,273,673.30)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 68,407.31**				
64	**Less: Fuel Cost**								**3,013**	**$ 65,024.16**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 35.75**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 3,347.40**				

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
May 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	**Acct**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**	**MWh**	**Cost**	**MWh**	**Revenue**
No.	**Day Ahead & Real Time Energy**										**TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(292,985)	$ (5,693,880.40)	138,036	$ 2,493,596.02	0	$ -	837	$ 19,027.60				
2	DA Non-asset Energy Amount	555.09	(6,416)	$ (108,905.44)	290	$ 5,411.97	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(13,386)	$ (284,116.26)	8,829	$ 191,415.43	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(147)	$ (190.26)	431	$ 8,369.09	0	$ -	0	$ -				
5	**SUBTOTAL**		**(312,934)**	**$ (6,087,092.36)**	**147,585**	**$ 2,698,792.51**	**0**	**$ -**	**837**	**$ 19,027.60**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (7,681.46)	0	$ 78,445.39	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (222,876.89)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (407.35)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (230,965.70)**	**0**	**$ 78,445.39**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (34,197.66)	0	$ -	0	$ (66.50)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (3,571.43)	0	$ 294.28	0	$ (243.25)	0	$ -				
18	FTR Mkt Admin Amount	555.13	0	$ (1,385.04)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (39,154.13)**	**0**	**$ 294.28**	**0**	**$ (309.75)**	**0**	**$ -**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (127,887.74)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 37,693.11	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (35,058.67)	0	$ 70,658.54	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 3,628.18	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 58,898.80	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (3,614.45)	0	$ 1,180.29	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (1,180.29)	0	$ 3,614.45	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (11,401.39)	0	$ 695,262.63	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (687,726.51)	0	$ 20,150.17	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (24,662.40)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 30,242.37	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (725,950.60)**	**0**	**$ 755,747.69**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (16,466.55)	0	$ 15,547.08	0	$ (135.59)	0	$ 128.09				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ -	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (14,231.69)	0	$ 1,392.58	0	$ (117.06)	0	$ 11.33				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 13,917.20				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 7,173.27	0	$ -	0	$ 59.14				
41	**SUBTOTAL**		**0**	**$ (30,698.24)**	**0**	**$ 24,112.93**	**0**	**$ (252.65)**	**0**	**$ 14,115.76**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (1,339.95)	0	$ 108.05	0	$ (49.83)	0	$ 0.47				
43	RT Net Inadvertent Amount	555.27	0	$ (2,002.90)	0	$ 4,846.85	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (70,113.47)	0	$ 14,811.61	0	$ (577.69)	0	$ 121.98				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	**SUBTOTAL**		**0**	**$ (73,456.32)**	**0**	**$ 19,766.51**	**0**	**$ (627.52)**	**0**	**$ 122.45**				
	ASM Charges													
47	RT ASM Non-Excessive Energy Amount	555.55	(17,351)	$ (284,539.04)	11,080	$ 184,961.86	(394)	$ (6,178.13)	2,724	$ 54,064.47				
48	RT ASM Excessive Energy Amount	555.56	0	$ (572.09)	141	$ 1.97	0	$ -	5	$ 128.75				
49	**SUBTOTAL**		**(17,351)**	**$ (285,111.13)**	**11,221**	**$ 184,963.83**	**(394)**	**$ (6,178.13)**	**2,729**	**$ 54,193.22**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
May 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
50	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
51	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
52	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
54	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
55	**TOTAL MISO DAY 2 CHARGES**		**(330,285)**	**$ (7,472,428.48)**	**158,807**	**$ 3,762,123.14**	**(394)**	**$ (7,368.05)**	**3,566**	**$ 87,459.03**				
56	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (39,154.13)**		**$ 294.28**								
57	**Congestion and Losses Adjustment**			**$ (93.03)**										
58	**No DA generation sch., but still had output for current month**			**$ -**										
59	**MISO RSG Bad Debt**			**$ -**		**$ -**								
60	**Total for MN Energy Adjustment Rider**			**$ (7,433,181.32)**		**$ 3,761,828.86**								
61	**Net Retail for MN Energy Adjustment Rider**				**$ (3,671,352.46)**									
62	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
63	**NET MISO (Rev-Cost and MWh)**									**$ 80,090.98**				
64	**Less: Fuel Cost**								**3,172**	**$ 80,106.94**				
65	**Less: Misc Cost Adjustment**									**$ -**				
66	**Plus: Capacity Revenue**													
67	**Plus: Bilateral Sales**													
68	**Less: Bilateral Purchases**													
69	**Less: Schedule 24 for Asset Based Sales**									**$ 37.76**				
70														
71	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ (53.72)**				
											. . . TRADE SECRET DATA ENDS]			

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
June 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	**Day Ahead & Real Time Energy**										TRADE SECRET DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(320,813)	$ (6,345,119.64)	114,796	$ 2,059,379.01	0	$ -	228	$ 4,814.92				
2	DA Non-asset Energy Amount	555.09	(5,044)	$ (105,110.36)	1,146	$ 17,953.75	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(12,188)	$ (345,111.52)	21,588	$ 426,028.48	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(153)	$ (1,936.68)	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(338,199)**	**$ (6,797,278.20)**	**137,530**	**$ 2,503,361.24**	**0**	**$ -**	**228**	**$ 4,814.92**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (3,184.69)	0	$ 72,325.69	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (131,705.30)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (16,074.07)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (150,964.06)**	**0**	**$ 72,325.69**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (34,110.94)	0	$ -	0	$ (17.38)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (3,710.18)	0	$ 235.06	0	$ (123.85)	0	$ 21.32				
18	FTR Mkt Admin Amount	555.13	0	$ (946.88)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (38,768.00)**	**0**	**$ 235.06**	**0**	**$ (141.23)**	**0**	**$ 21.32**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (19,217.03)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (11,108.63)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (22,827.04)	0	$ 31,909.94	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 929.12	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 59,845.63	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (884.03)	0	$ 884.01	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (884.01)	0	$ 884.03	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (23,531.72)	0	$ 231,866.39	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (207,963.16)	0	$ 23,797.19	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (5,379.69)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 26,965.64	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (272,578.28)**	**0**	**$ 357,864.92**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (10,018.69)	0	$ 2,803.33	0	$ (49.49)	0	$ 13.86				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ -	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (19,288.64)	0	$ 2,294.21	0	$ (95.27)	0	$ 11.25				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ -				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (30.45)	0	$ 5,596.99	0	$ (0.13)	0	$ 27.73				
41	**SUBTOTAL**		**0**	**$ (29,337.78)**	**0**	**$ 10,694.53**	**0**	**$ (144.89)**	**0**	**$ 52.84**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (568.69)	0	$ 584.07	0	$ (33.48)	0	$ 5.05				
43	RT Net Inadvertent Amount	555.27	0	$ (3,847.76)	0	$ 3,014.11	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (77,593.96)	0	$ 15,703.10	0	$ (384.25)	0	$ 77.67				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (3.23)	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (82,013.64)**	**0**	**$ 19,301.28**	**0**	**$ (417.73)**	**0**	**$ 82.72**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(17,718)	$ (327,361.82)	12,507	$ 216,404.75	(29)	$ (396.82)	1,391	$ 23,573.92				
49	RT ASM Excessive Energy Amount	555.56	(0)	$ (1,015.31)	54	$ 0.04	0	$ -	0	$ -				
50	**SUBTOTAL**		**(17,718)**	**$ (328,377.13)**	**12,561**	**$ 216,404.79**	**(29)**	**$ (396.82)**	**1,391**	**$ 23,573.92**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
June 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
51	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
52	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
54	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
55	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
56	**TOTAL MISO DAY 2 CHARGES**		**(355,917)**	**$ (7,699,317.09)**	**150,091**	**$ 3,180,187.51**	**(29)**	**$ (1,100.67)**	**1,619**	**$ 28,545.72**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (38,768.00)**		**$ 235.06**								
58	**Congestion and Losses Adjustment**			**$ 120.57**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**		**$ -**								
61	**Total for MN Energy Adjustment Rider**			**$ (7,660,669.66)**		**$ 3,179,952.45**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (4,480,717.21)**									
63	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
64	**NET MISO (Rev-Cost and MWh)**									**$ 27,445.05**				
65	**Less: Fuel Cost**								**1,590**	**$ 26,749.32**				
66	**Less: Misc Cost Adjustment**									**$ -**				
67	**Plus: Capacity Revenue**													
68	**Plus: Bilateral Sales**													
69	**Less: Bilateral Purchases**													
70	**Less: Schedule 24 for Asset Based Sales**									**$ 16.14**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 679.59**				

. . . TRADE SECRET DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2014 - June 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
No.	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Day Ahead & Real Time Energy										**[TRADE SECRET DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(4,515,291)	$ (107,965,068.53)	3,244,857	$ 78,840,203.87	0	$ -	109,667	$ 3,324,161.97				
2	DA Non-asset Energy Amount	555.09	(195,677)	$ (4,697,338.82)	3,366	$ 70,419.88	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(183,503)	$ (4,877,312.48)	227,212	$ 5,731,654.46	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(6,828)	$ (136,901.52)	578	$ 11,391.71	0	$ -	0	$ -				
5	**SUBTOTAL**		**(4,901,299)**	**$ (117,676,621.35)**	**3,476,013**	**$ 84,653,669.92**	**0**	**$ -**	**109,667**	**$ 3,324,161.97**				
	Day Ahead & Real Time Energy Loss													
6	DA FBT Loss Amount	555.04	0	$ -	0	$ -	0	$ -	0	$ -				
7	RT Distribution of Losses Amount	555.24	0	$ (97,583.91)	0	$ 2,297,946.71	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (4,910,154.15)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (155,924.57)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (5,163,662.63)**	**0**	**$ 2,297,946.71**	**0**	**$ -**	**0**	**$ -**				
	Virtual Energy													
13	DA Virtual Energy Amount	555.12	0	$ -	0	$ -	0	$ -	0	$ -				
14	RT Virtual Energy Amount	555.32	0	$ -	0	$ -	0	$ -	0	$ -				
15	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
	Schedules 16 & 17													
16	DA Mkt Admin Amount	555.01	0	$ (577,427.82)	0	$ -	0	$ (7,818.09)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (52,649.84)	0	$ 3,596.19	0	$ (9,855.87)	0	$ 723.08				
18	FTR Mkt Admin Amount	555.13	0	$ (28,735.84)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (658,813.50)**	**0**	**$ 3,596.19**	**0**	**$ (17,673.96)**	**0**	**$ 723.08**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (2,090,695.09)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 148,816.54	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (929,519.70)	0	$ 2,883,979.09	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (268.22)	0	$ 81,395.08	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ 86,057.76	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 118,744.43	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (164,375.08)	0	$ 219,984.42	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (231,751.41)	0	$ 146,350.72	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (279,424.32)	0	$ 9,350,990.62	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (9,389,075.66)	0	$ 391,565.21	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (204,054.20)	0	$ 0.25	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (6,869.66)	0	$ 371,639.61	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (11,056,521.71)**	**0**	**$ 11,560,012.10**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (239,795.89)	0	$ 31,572.19	0	$ (9,241.87)	0	$ 649.97				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 14,049.71	0	$ -	0	$ 7,725.54				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (239,712.26)	0	$ 14,620.59	0	$ (9,789.23)	0	$ 404.06				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ (2.31)	0	$ 99,846.46				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (665.81)	0	$ 557,050.94	0	$ (24.98)	0	$ 36,396.98				
41	**SUBTOTAL**		**0**	**$ (480,173.96)**	**0**	**$ 617,293.43**	**0**	**$ (19,058.39)**	**0**	**$ 145,023.01**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (18,788.39)	0	$ 127,072.67	0	$ (331.07)	0	$ 82.90				
43	RT Net Inadvertent Amount	555.27	0	$ (83,167.25)	0	$ 119,813.68	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (939,876.58)	0	$ 137,406.66	0	$ (40,825.84)	0	$ 4,185.27				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (3.23)	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (1,041,835.45)**	**0**	**$ 384,293.01**	**0**	**$ (41,156.91)**	**0**	**$ 4,268.17**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(320,475)	$ (7,416,767.79)	140,682	$ 3,105,632.34	(32,335)	$ (617,455.01)	106,255	$ 2,699,091.52				
49	RT ASM Excessive Energy Amount	555.56	(1,301)	$ (36,963.87)	3,482	$ 16,634.09	(26)	$ (718.41)	167	$ 2,382.65				
50	**SUBTOTAL**		**(321,776)**	**$ (7,453,731.66)**	**144,164**	**$ 3,122,266.43**	**(32,361)**	**$ (618,173.42)**	**106,422**	**$ 2,701,474.17**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2014 - June 2015 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
	Charge Type Description	Acct	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
51	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
52	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
53	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
54	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
55	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
56	**TOTAL MISO DAY 2 CHARGES**		**(5,223,075)**	**$ (143,531,360.26)**	**3,620,177**	**$ 102,639,077.79**	**(32,361)**	**$ (696,062.68)**	**216,089**	**$ 6,175,650.40**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (658,813.50)**		**$ 3,596.19**								
58	**Congestion and Losses Adjustment**			**$ (148,224.97)**		**$ -**								
59	**No DA generation sch., but had usage for current month**			**$ (4,896.88)**		**$ -**								
60	**MISO RSG Bad Debt**			**$ -**		**$ -**								
61	**Total for MN Energy Adjustment Rider**			**$ (142,719,424.91)**		**$ 102,635,481.60**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (40,083,943.31)**									
63	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
64	**NET MISO (Rev-Cost and MWh)** [1]									**$ 5,479,587.72**				
65	**Less: Fuel Cost**								**183,727**	**$ 3,931,714.13**				
66	**Less: Misc Cost Adjustment**									**$ -**				
67	**Plus: Capacity Revenue**													
68	**Plus: Bilateral Sales**													
69	**Less: Bilateral Purchases**													
70	**Less: Schedule 24 for Asset Based Sales**									**$ 2,172.56**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 1,545,701.03**				

[1] Schedule 24 Costs and Revenues are not included in this calculation prior to October 2011

. . . TRADE SECRET DATA ENDS]

MN OES'S ORDER AUTHORIZING ONGOING USE OF FUEL CLAUSE ADJUSTMENT AND SETTING REPORTING REQUIREMENTS DOCKET NO. E001,015,002,017/M-08-528

In the Minnesota Public Utilities Commission's August 23, 2010, Order the MNPUC ordered:

5. **The three utilities shall include costs and revenues from their participation in the MISO ancillary services market in future automatic adjustment reports filed under Minn. Rules, parts 7825.2390 *et seq*., including the annual filing required thereunder. They shall include costs/revenues through June 30, 2010 in the 2011 annual filings, which are due in September 2010; they shall include costs/revenues beginning July 1, 2010 in the 2012 annual filings, which are due in September 2011.**

    Schedule 1 of Part H Section 4 Attachment L summarizes the 12 ancillary services market ("ASM") charge types by month for the AAA period.

8. **In their annual summaries on the 12 MISO ancillary services charges the utilities shall use a format similar to that used by Minnesota Power in its Attachment 1 to its February 5, 2010 filing (4th quarter report) and shall work with the OES to develop a format that is acceptable.**

    See Part H Section 4 Attachment L - Schedule 1, Schedule 2, and Schedule 3

9. **In reporting daily ancillary services market activity and overall net savings created by participation in the ancillary services market, utilities shall use a format similar to that used by Xcel in Attachment A to its February 5, 2010 filing and shall work with the OES to develop a format that is acceptable.**

    Otter Tail does not have the software to perform a daily activity and savings report. Otter Tail is providing a monthly breakdown of charges (see Part H Section 4 Attachment L - Schedule 1 and Schedule 2).

10. **The utilities' written narratives on the benefits of the ancillary services market and the market's impact on their systems shall be formatted consistent with Xcel's and Minnesota Power's 4th quarter report in this docket.**

    See Part H Section 4 Attachment L

11. **The utilities shall file detailed and specific explanations for all Contingency Reserve Deployment Failure and Excess/Deficient Energy Charges incurred, including an explanation as to why they should be recovered and what actions the utility took to minimize these charges.**

    See Part H Section 4 Attachment L

In the Matter of Xcel Energy, Minnesota Power, Otter Tail Power Company, and Interstate Power and Light Company's Petition for Approval of Revisions to Riders for Fuel Adjustment to Recover Costs and Pass-Through Related to MISO Ancillary Services Market - Docket No. E001,E015,E002,E017/M-08-528

I. Introduction

In an Order dated March 17, 2009, in the above-referenced Docket, the Minnesota Public Utilities Commission ("MPUC" or "Commission") authorized the four investor owned utilities in the State of Minnesota conditional approval to recover 12 charge types to each utility's fuel clause. These 12 charges (credits and costs) were new charges passed on to the utilities for participating in the Midwest Independent Transmission System Operator ("MISO") ancillary services market ("ASM") that began on January 6, 2009.

The Commission's Order at Paragraph 1.a. required that no later than February 6, 2010, the utilities shall file a request to validate recovery to date and continue to recover ASM charges (credits and costs) by an analysis of the costs and benefits of each utility's participation in the ASM Market. The utilities were also to address the potential for double recovery of these costs, and the impacts of ASM on Schedule 17 costs.

II. The Benefits to Otter Tail Power Company Customers of ASM Participation

Otter Tail Power's ASM Cost and Benefit Analysis

Overview

Otter Tail has been participating in Midwest ISO's ("MISO") Ancillary Service Market ("ASM") since it started on January 6, 2009. Since market start, Otter Tail has not seen any major changes to operation or clearing our units for energy in the market. We have had some additional opportunities in the ASM to optimize generation portfolio revenues by providing regulation and spinning reserve without creating a negative impact on available energy necessary to meet customer needs.

Spinning Reserves

Currently, Otter Tail has 8 generating units that are qualified to supply energy, regulation, or spinning reserves service for MISO. Under normal operating conditions Otter Tail now has the potential of carrying up to 13 MW of spinning reserves above the cruise operating level on our Hoot Lake units without reducing energy available for customers. The additional ancillary service revenues reduce overall costs.

The ASM has also added value for customers when generating units have backed down to minimum generation levels due to low energy prices. The generators can be backed down and still provide spinning reserves at the lower operating levels. MISO's Spinning Reserves process has provided a net benefit of $34,051 for the AAA period (Schedule 1 of Part H Section 4 Attachment L, column R, line 8).

Supplemental Reserves

MISO Supplemental Reserves process has provided a net benefit of $12,839 for the AAA period (Schedule 1 of Part H Section 4 Attachment L, column R, line 12).

Regulation

Prior to ASM, Otter Tail scheduled regulation on our system on an hourly basis to meet Balancing Authority control performance criteria requirements. Under ASM, Otter Tail units are only selected by MISO for regulation when it is cost effective. Most of the time our units are cleared for energy instead of being held back to provide the MW we used to reserve for regulation. Under ASM, due to regulation clearing and our ability to purchase affordable regulation service, we have more economic energy available from our low cost generation facilities to serve our customers. Including ASM charge type impact only, MISO's Regulation Reserves process has resulted in a net cost of ($19,088) for the AAA period (Schedule 1 of Part H Section 4 Attachment L, column R, line 4).

Real-Time Excessive/Deficient Energy Deployment Charge Amount and Real-Time Contingency Deployment Failure Charge Amount

The Real-Time Excessive/Deficient Energy Deployment Charge Amount represents the charge to an Asset Owner owning Generation where the Asset Owner's unit fails to follow Setpoint instructions for 4 consecutive intervals within 1 hour without an Exemption. This charge consists of taking back any cleared Day Ahead Regulation Operating Reserve payment and any cleared Net Real Time Regulation payment and also assesses a prorated share of the Day Ahead and Real Time Regulation Market cost. During the reporting period there was a total of ($1,290) of penalties assessed to Otter Tail units (Schedule 1 of Part H Section 4 Attachment L, column R, line 14). These are normally mechanical failure situations where the unit fails to follow dispatch for a short time period while small repairs are made.

The Real-Time Contingency Deployment Failure Charge Amount represents the charge incurred by Resources that fail to deploy Contingency Reserves at or above the Contingency Reserve Deployment Instruction. Again, these would normally be short intervals where some mechanical failure occurred. For the reporting period, there was a total of ($81) in charges (Schedule 1 of Part H Section 4 Attachment L, column R, line 13).

ASM Charge Summary

The transition to the ASM market has been smooth from an operational standpoint. There has also been a positive economic benefit for Otter Tail. We are now able to maximize the capabilities of our units to a greater extent, which ultimately has led to greater operational efficiencies for Otter Tail. Our overall strategy is to continue to develop strategies that will continue to allow the ASM to have a positive impact for our customers.

Otter Tail reviews all MISO charges and credits including ASM charge types on a daily basis.

Schedule 1 of Part H Section 4 Attachment L provides the summary of ASM hourly charges for the AAA period, which has provided $24,977 (column R, line 17) of net ASM charge benefit.

Schedule 2 of Part H Section 4 Attachment L provides a summary of hourly MWh related to ASM products for the period of July 2014 through June 2015.

III. Schedule 17 Costs

Schedule 17 Costs
MISO took on additional system and analysis responsibilities with the start of the ASM and as a result, additional costs were incurred at MISO. These costs were recovered from Market Participants including Otter Tail through increased Schedule 17 charges. Schedule 3 of Part H Section 4 Attachment L provides a summary of the Schedule 17 rates before and after the start of ASM.

IV. No Double Recovery of Costs

The Commission requested the utilities other than Otter Tail address the potential double recovery of costs associated with Operating Reserves costs and revenues from MISO being collected through the FCA and the costs of the generation being recovered in base rates. As a result of Otter Tail's general rate case, Docket E017/GR-10-239, Otter Tail will pass ASM through its FCA. First and foremost, the potential for any double recovery of such costs is eliminated by operation of the fuel clause pass through of ASM charges. In addition, there is no double recovery of costs because there are two kinds of reserve requirements the Company must meet.

The fixed costs of generation included in base rates reflect the Capacity reserve requirement established under Module E of the MISO Tariff (resource adequacy) costs. In addition, the start of the ASM and MISO's role as regional balancing authority means Otter Tail (as a balancing authority) can now purchase rather than self-provide the regulating reserve and spinning reserve requirements imposed by NERC reliability standards. The costs of regulating reserve and spinning reserve are distinct from capacity reserve costs, and reflect either direct energy costs or the incremental costs of holding generation in reserve (*i.e*., the cost of energy generated in place of the energy that could have been produced by the unit(s) providing the regulation and/or spinning reserves), which have always been recovered through the fuel clause rather than base rates.

V. As Requested in Docket No. E017/GR-10-239, the Commission Should Allow Continued ASM Charge Recovery

Otter Tail's 2010 report, and this report, have validated the net savings of ASM participation to Otter Tail. The ancillary services markets are achieving significant benefits in terms of generation resource optimization, with the savings flowing through the fuel clause to Otter Tail's customers. Otter Tail has been required since its last general rate case, Docket No. E017/GR-10-239, to utilize FCA treatment of ASM charges (credits and costs) in its fuel clause on an ongoing basis.

Summary

MISO ASM has allowed Otter Tail the ability to more fully utilize our generation assets for the benefit of our customers. Otter Tail fully expects these benefits to continue due to our ability to offer generation into both markets which better utilizes the full benefits of our generation facilities.

SUMMARY OF 12 ASM CHARGE TYPES (Dollars)

Line No.		(A) Jul-14	(B) Aug-14	(C) Sep-14	(D) 3rd Qtr 2014 Total	(E) Oct-14	(F) Nov-14	(G) Dec-14	(H) 4th Qtr 2014 Total	(I) Jan-15	(J) Feb-15	(K) Mar-15	(L) 1st Qtr 2015 Total	(M) Apr-15	(N) May-15	(O) Jun-15	(P) 2nd Qtr 2015 Total	(Q) 12-Month Total	(R) MN Amount @ 0.505132969
1	Day Ahead Regulation Amount	1,161	1,838	4,686	7,684	5,103	11,667	2,568	19,338	-	-	412	412	-	158	-	158	27,592	13,937
2	Real Time Regulation Amount	3,030	1,711	5,936	10,677	8,931	10,650	11,451	31,032	2,810	1,273	6,862	10,945	90	1,572	481	2,143	54,797	27,680
3	Regulation Cost Distribution Amount	(8,524)	(7,259)	(8,788)	(24,570)	(11,373)	(13,967)	(14,097)	(39,436)	(8,807)	(8,203)	(13,699)	(30,709)	(8,528)	(9,081)	(7,853)	(25,461)	(120,177)	(60,706)
4	**Regulation Subtotal**	**(4,333)**	**(3,710)**	**1,834**	**(6,209)**	**2,661**	**8,350**	**(78)**	**10,934**	**(5,997)**	**(6,930)**	**(6,425)**	**(19,352)**	**(8,438)**	**(7,351)**	**(7,371)**	**(23,160)**	**(37,788)**	**(19,088)**
5	Day Ahead Spinning Reserve Amount	6,040	13,401	30,421	49,862	29,547	35,084	21,846	86,477	13,685	7,768	21,058	42,510	7,534	1,451	813	9,798	188,647	95,292
6	Real Time Spinning Reserve Amount	648	82	(5,817)	(5,087)	(4,163)	563	854	(2,746)	3,578	(885)	(1,659)	1,034	(638)	(26)	(332)	(996)	(7,796)	(3,938)
7	Spinning Reserve Cost Distribution Amount	(7,499)	(6,785)	(8,774)	(23,059)	(12,260)	(13,740)	(11,388)	(37,388)	(7,770)	(7,776)	(12,995)	(28,542)	(8,372)	(7,337)	(8,745)	(24,453)	(113,442)	(57,303)
8	**Spinning Reserve Subtotal**	**(811)**	**6,698**	**15,830**	**21,716**	**13,124**	**21,907**	**11,312**	**46,343**	**9,492**	**(894)**	**6,403**	**15,002**	**(1,476)**	**(5,912)**	**(8,264)**	**(15,652)**	**67,409**	**34,051**
9	Day Ahead Supplemental Reserve Amount	11,287	7,425	12,264	30,976	18,674	9,378	3,007	31,059	1,544	2,453	8,753	12,749	3,666	3,984	5,083	12,734	87,517	44,208
10	Real Time Supplemental Reserve Amount	(2,520)	(2,673)	(2,511)	(7,704)	(2,237)	(840)	(1,084)	(4,160)	(148)	(483)	(662)	(1,293)	(792)	(1,105)	(1,000)	(2,896)	(16,053)	(8,109)
11	Supplemental Reserve Cost Distribution Amount	(3,814)	(2,979)	(4,382)	(11,176)	(7,524)	(4,775)	(3,766)	(16,065)	(2,350)	(3,250)	(5,031)	(10,631)	(2,948)	(2,571)	(2,656)	(8,175)	(46,046)	(23,260)
12	**Supplemental Reserve Subtotal**	**4,953**	**1,773**	**5,371**	**12,096**	**8,913**	**3,763**	**(1,843)**	**10,833**	**(953)**	**(1,280)**	**3,059**	**826**	**(73)**	**308**	**1,428**	**1,663**	**25,418**	**12,839**
13	Contingency Reserve Deployment Failure Charge Amount	-	-	-	-	-	-	-	-	(432)	-	432	-	(161)	-	-	(161)	(161)	(81)
14	Real Time Excessive Deficient Energy Deployment Charge Amount	(203)	(80)	(657)	(940)	(534)	(297)	(351)	(1,183)	(85)	(29)	(140)	(254)	(47)	(89)	(41)	(177)	(2,554)	(1,290)
15	Net Regulation Adjustment Amount	(657)	412	108	(137)	(17)	(763)	(813)	(1,593)	(62)	(32)	(220)	(314)	7	(41)	(22)	(56)	(2,100)	(1,061)
16	Real Time Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(778)	(778)	(778)	(393)
16	**Other Charge Subtotal**	**(860)**	**333**	**(549)**	**(1,077)**	**(552)**	**(1,060)**	**(1,164)**	**(2,776)**	**(579)**	**(61)**	**72**	**(568)**	**(201)**	**(130)**	**(842)**	**(1,173)**	**(5,593)**	**(2,825)**
17	**TOTAL**	**(1,052)**	**5,093**	**22,485**	**26,526**	**24,146**	**32,960**	**8,227**	**65,334**	**1,963**	**(9,166)**	**3,110**	**(4,092)**	**(10,188)**	**(13,085)**	**(15,050)**	**(38,322)**	**49,445**	**24,977**

Summary of 12 ASM Charge Types (MWH)

Line No.		(A) Jul-14	(B) Aug-14	(C) Sep-14	(D) 3rd Qtr 2014 Total	(E) Oct-14	(F) Nov-14	(G) Dec-14	(H) 4th Qtr 2014 Total	(I) Jan-15	(J) Feb-15	(K) Mar-15	(L) 1st Qtr 2015 Total	(M) Apr-15	(N) May-15	(O) Jun-15	(P) 2nd Qtr 2015 Total	(Q) 12-Month Total	(R) MN Amount @ 0.505132969
1	Day Ahead Regulation Amount	55.50	130.10	287.40	473.00	318.60	603.90	148.90	1,071.40	0.00	0.00	16.00	16.00	0.00	10.60	0.00	10.60	1,571.00	793.56
2	Real Time Regulation Amount	97.77	(43.38)	99.78	154.17	253.61	401.79	398.13	1,053.52	55.34	74.42	182.90	312.66	3.03	56.48	8.79	68.31	1,588.66	802.48
3	Regulation Cost Distribution Amount	(331,074.58)	(322,918.25)	(334,438.10)	(988,430.93)	(334,473.76)	(325,840.86)	(500,205.53)	(1,160,520.16)	(383,465.13)	(404,800.00)	(404,712.58)	(1,192,977.72)	(84,798.00)	0.00	0.00	(84,798.00)	(3,426,726.81)	(1,730,952.69)
4	**Regulation Subtotal**	**(330,921.31)**	**(322,831.53)**	**(334,050.92)**	**(987,803.76)**	**(333,901.56)**	**(324,835.18)**	**(499,658.51)**	**(1,158,395.24)**	**(383,409.80)**	**(404,725.58)**	**(404,513.68)**	**(1,192,649.06)**	**(84,794.97)**	**67.08**	**8.79**	**(84,719.09)**	**(3,423,567.15)**	**(1,729,356.64)**
5	Day Ahead Spinning Reserve Amount	2,763.10	5,740.20	10,654.70	19,158.00	9,291.30	10,317.80	11,682.10	31,291.20	8,349.10	5,024.50	9,321.80	22,695.40	4,700.00	716.50	199.50	5,616.00	78,760.60	39,784.58
6	Real Time Spinning Reserve Amount	(126.93)	(841.90)	(2,261.68)	(3,230.51)	(1,472.07)	(1,584.47)	(508.75)	(3,565.30)	(389.79)	(210.60)	(730.33)	(1,330.72)	(377.25)	(190.67)	(189.29)	(757.21)	(8,883.73)	(4,487.47)
7	Spinning Reserve Cost Distribution Amount	(342,323.87)	(345,520.29)	(354,326.96)	(1,042,171.12)	(354,426.64)	(370,149.84)	(531,687.22)	(1,256,263.70)	(411,213.91)	(428,809.55)	(430,203.09)	(1,270,226.55)	(89,379.12)	0.00	0.00	(89,379.12)	(3,658,040.49)	(1,847,796.85)
8	**Spinning Reserve Subtotal**	**(339,687.69)**	**(340,621.99)**	**(345,933.95)**	**(1,026,243.63)**	**(346,607.42)**	**(361,416.50)**	**(520,513.87)**	**(1,228,537.79)**	**(403,254.60)**	**(423,995.65)**	**(421,611.62)**	**(1,248,861.87)**	**(85,056.37)**	**525.83**	**10.21**	**(84,520.33)**	**(3,588,163.62)**	**(1,812,499.74)**
9	Day Ahead Supplemental Reserve Amount	11,709.30	10,263.90	12,287.80	34,261.00	12,390.00	8,650.60	5,623.50	26,664.10	2,431.50	2,294.30	7,198.10	11,923.90	5,958.10	6,216.10	6,328.20	18,502.40	91,351.40	46,144.60
10	Real Time Supplemental Reserve Amount	(8,704.21)	(9,035.18)	(9,465.28)	(27,204.67)	(7,423.33)	(5,712.12)	(5,015.74)	(18,151.19)	(2,056.87)	(1,989.17)	(5,626.07)	(9,672.11)	(3,506.92)	(3,774.70)	(3,589.44)	(10,871.07)	(65,899.04)	(33,287.78)
11	Supplemental Reserve Cost Distribution Amount	(343,119.96)	(347,134.91)	(355,708.89)	(1,045,963.76)	(355,782.76)	(371,458.18)	(533,695.32)	(1,260,936.26)	(412,834.67)	(430,148.27)	(431,347.71)	(1,274,330.65)	(89,649.06)	0.00	0.00	(89,649.06)	(3,670,879.72)	(1,854,282.37)
12	**Supplemental Reserve Subtotal**	**(340,114.86)**	**(345,906.19)**	**(352,886.38)**	**(1,038,907.43)**	**(350,816.09)**	**(368,519.70)**	**(533,087.56)**	**(1,252,423.35)**	**(412,460.04)**	**(429,843.14)**	**(429,775.68)**	**(1,272,078.86)**	**(87,197.88)**	**2,441.40**	**2,738.76**	**(82,017.72)**	**(3,645,427.36)**	**(1,841,425.54)**
13	Contingency Reserve Deployment Failure Charge Amount	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	Real Time Excessive Deficient Energy Deployment Charge Amount	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15	Net Regulation Adjustment Amount	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	Real Time Miscellaneous	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	**Other Charge Subtotal**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
17	**TOTAL**	**(1,010,723.87)**	**(1,009,359.71)**	**(1,032,871.24)**	**(3,052,954.81)**	**(1,031,325.07)**	**(1,054,771.38)**	**(1,553,259.93)**	**(3,639,356.38)**	**(1,199,124.44)**	**(1,258,564.37)**	**(1,255,900.99)**	**(3,713,589.79)**	**(257,049.21)**	**3,034.31**	**2,757.76**	**(251,257.15)**	**(10,657,158.13)**	**(5,383,281.93)**

Comparison of MISO Schedule 17 Rates and Amounts before and after the start of the ASM Market

Montly Average Schedule 17 Amount

April '05 through December '08	$ 48,983.00
January '09 through December '09	$ 68,439.00
January '10 through December '10	$ 67,171.00
January '11 through June '11	$ 67,418.00
July '11 through July '12	$ 60,573.57
July '12 through June '13	$ 62,582.95
July '13 through June '14	$ 59,249.43
July '14 through June '15	$ 52,206.79
Average monthly decrease from prior period	$ (7,042.64)

Montly Average Schedule 17 Rate per MWh

April '05 through December '08	$ 0.07220
January '09 through December '09	$ 0.09750
January '10 through December '10	$ 0.09380
January '11 through June '11	$ 0.09300
July '11 through July '12	$ 0.09040
July '12 through June '13	$ 0.08820
July '13 through June '14	$ 0.07656
July '14 through June '15	$ 0.07337
Average monthly decrease from prior period	$ (0.00320)

MN PUC ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS DOCKET NOS. E999/AA-09-961 and E999/AA-10-884

In the Minnesota Public Utilities Commission's April 6, 2012 Order, the following was ordered for Otter Tail Power Company:

8. 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.

Otter Tail is not aware of any offsetting revenues for contracts that are not passed back through the energy adjustment.

22. 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.

Information Sharing/Lessons Learned:
Otter Tail continues to utilize multiple forums and resources deemed most beneficial in gathering and sharing information relevant to the unique aspects of Otter Tail's generation fleet. In Reply Comments submitted by Otter Tail in Docket No. E999/AA-13-599, Otter Tail provided a list of resources (Conferences, Consultants/Vendors/Contractors, Publications, and Trade Organizations) in Attachment 1 of those Reply Comments, which Otter Tail and the other utilities within Minnesota take advantage of to address each utility's specific needs.

Additionally, Otter Tail noted the following points in those Reply Comments, which continue to hold true today:

As noted earlier, each utility's generation fleet is different. Otter Tail's base load generating fleet is small, consisting of three plants:

Big Stone Plant, of which Otter Tail is a 53.9% co-owner;
Coyote Plant, of which Otter Tail is a 35% co-owner;
Hoot Lake Plant, of which Otter Tail is a 100% owner.

Otter Tail plant personnel participate in various user groups, training events, and conferences related to our steam based generation units. Otter Tail believes that some of the most beneficial information sharing takes place at specific technology user groups often hosted by the original equipment manufacturers, for example, "B&W Cyclone Users Association or B&W Environmental Users Group." It is Otter Tail's experience that focusing on technologies that are specific to our generation units is the most productive use of time with regards to sharing best practices in operation and minimizing forced outages.

As noted above, Otter Tail is part owner of two co-owned generation facilities; the Big Stone Plant and the Coyote Plant (Otter Tail is also the Operating Agent for these plants). The co-owners at Big Stone and Coyote are also operators or part owners of other similar sized facilities. Regularly scheduled owner's meetings, as necessitated by these joint ownership arrangements, provides Otter Tail with the opportunity to gather additional information and gain perspectives from peers on forced outage rates and other plant operations issues that occur in the natural course of being part of jointly-owned generating units.

Otter Tail notes that there are occasions when discussions and information sharing does take place between Minnesota utilities. Recent examples include Otter Tail and Xcel Energy staff meeting at the July 2014 Boiler conference to discuss best cyclone boiler practices. In addition, Xcel Energy met with Otter Tail consultants regarding details of the company's 2015 outage work at Otter Tail's Big Stone plant and Xcel Energy recently visited Big Stone plant to discuss best boiler outage/reliability/combustion practices. When opportunities arise for information sharing, Otter Tail is willing take advantage of them.

Plant personnel also attend general conferences such as the local Energy Manager Associations, The Energy Generation Conference in Bismarck, ND or the much larger Power-Gen conference. These conferences provide useful venues for gathering and sharing information but are generally not as informative as specific equipment users groups.

One additional source of information which Otter Tail finds beneficial is through Otter Tail's insurance provider. When issues occur at other plants which the insurance provider is involved, it is common for the provider to share information with other companies so that similar situations can be avoided or mitigated if possible.

In general, attendance or participation at relevant conferences, training, or users groups is more effective than information sharing between utilities that may be neighbors, but that do not have similar generation technologies and/or equipment.

Forced Outages:
Otter Tail's generators experienced an aggregate of 17 forced outages in excess of 24 hours over the July 2014 – June 2015 period; three at the Big Stone Plant, eight at Coyote Station and six at the Hoot Lake Plant units #2 and #3. A summary of these forced outages for this reporting period can be found in Part H, Section 5, Attachment M (marked as Trade Secret), providing a brief overview of the following aspects of each forced outage:

a. Dates of outage
b. Primary Reason for Outage
c. Duration of Outage
d. Estimated Replacement Power Cost
f. Steps Taken to Alleviate Reoccurrence

Of the 17 forced outages experience during the reporting period, eight of those outages were tube leaks. Because tube leaks are common to all of Otter Tail's generating plants, the following discussion addresses the nature of tube leaks. Other than outages relating to tube leaks, Otter Tail's plants experienced nine forced outages: one at Big Stone, five at Coyote, and three at Hoot Lake units #2 and #3.

Tube Leaks:
Tube leaks in coal-fired boilers are a fact of operation due to the extreme environment (boiler tubes have temperatures of 2000 degrees Fahrenheit on the outside with 600 to 1000 degree water/steam on the inside operating at up to 3000 psi). There are miles of tubing in a boiler and many tubes are inaccessible without great effort. The tubes at the top of the boiler can be 250 feet in the air and require special scaffolding to access. Additionally, the boiler tubes can be configured in tight bundles, with only the outside tubes of the bundle accessible without disassembly of the bundle. Soot blowing, or cleaning of the boiler tubes by using steam, can lead to erosion of the tubes and ultimately to tube failures, but this process is necessary to maintain heat transfer efficiency and to prevent plugging. The level of soot blowing is a function of the ash characteristics of the fuel used at the plant. Lignite fuel (used at Coyote Station), for example, requires more soot blowing than sub bituminous coal (used at Hoot Lake and Big Stone Plants).

With reasonable maintenance and operating procedures, tube leaks can be managed but not eliminated. Establishing these procedures requires a balancing of the costs and benefits. In order to increase maintenance with the hope of reducing tube leaks, the operator must have the boiler off line for more time for more inspections and to spend more time completing repairs. Similarly, increasing tube replacements increases the time off line and is very expensive. Thus, the industry standard is to reasonably manage tube leaks as opposed to endeavoring to eliminate them.

Utilities have migrated from the average standard six weeks of scheduled overhaul per year to up to six weeks of overhaul every three to five years. This will inherently mean more tube leak forced outages, but is usually still a less expensive option in the long run. When tube leaks occur and when possible, Otter Tail strives to run a number of hours or days with the tube leak in order to schedule the outage for an appropriate time, such as over a weekend when replacement power may be less expensive. Otter Tail also takes the opportunity to fix other failed equipment during tube leak outages.

There are many methods Otter Tail employs to reduce tube leak outages. Physical visual inspections can be effective, but are limited to major overhauls when scaffolding is in place. Thorough inspections are completed during major overhauls which may include removing and submitting tube samples to a laboratory for analysis. Otter Tail also employs numerous other industry standard methods for detecting and preventing tube leaks, including use of ultrasonic thickness testers, ultrasonic listening devices, water chemistry, chemical cleaning, soot blower pressure control, gas stream temperature control, boiler cleanliness, tube material, tube overlays, tube shields, tube alignments, and tube replacements. In some cases, conditions of the boiler tubes warrant a replacement of a section. For example, at Big Stone, the reheat section and the upper primary superheat section of the boiler were replaced in 2015.

25. Otter Tail shall correctly report congestion and firm transmission rights costs and revenues (currently reflected in the Day-Ahead and Real-Time Energy sections of its AAA report) in the congestion and firm transmission rights sections of its report starting with a revised or supplemental filing for the fiscal-year 2011 report, in Docket No. E999/AA-11-792.

Otter Tail incurs congestion costs when moving energy from its resources (generators and purchased power agreements) to load. The congestion costs incurred for the AAA period were $1,941,878 (system basis). To offset these congestion costs, the company is allocated Auction Revenue Rights (“ARRs”) which can subsequently be self-scheduled into Financial Transmission Rights (“FTRs”). In addition, the company receives congestion offsets on grandfathered transmission rights. For the AAA period, the total of the congestion offsets was $2,445,369 (system basis) for a net congestion revenue of $503,491 (system basis).

Part H Section 3 Attachment K (marked as Trade Secret) reflect year to date (July 2014 - June 2015) MISO Day 2 Charges.

28. 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.

Please see Part H Section 5 Attachment N (marked as Trade Secret) for Otter Tail’s Generation Deliverability Results for MISO Planning Year 2014/2015. The MISO planning year starts on June 1 and ends on May 31.

Please see Attachment O (marked as Trade Secret) for a side-by-side comparison of Otter Tail's MISO accredited capacity values and Otter Tail's Integrated Resource Plan capacity values. Otter Tail uses the MISO Unforced Capacity ("UCAP") accredited capacity values to establish its Integrated Resource Plan capacity values so there is no difference between the two.

For MISO Planning Year 2014/2015, five resources, excluding behind-the-meter-generation, were designated as local resources in full or in part: OTP.ASHTUBULA (Ashtabula), OTP.LANGDN1 (Langdon Owned), OTP.LANGDN2 (Langdon PPA), OTP.MPWR (Luverne), and OTP.ASHTAIII (Ashtabula III PPA). All five are wind resources.

OTP.EDGLYEDGL (Edgeley PPA) was partly designated as a local resource for planning year 2011/2012 because its UCAP value exceeded its Network Resource Interconnection Service (NRIS) value. For planning year 2014/2015, its UCAP value fell to a level less than its NRIS and therefore its entire UCAP was designated as aggregate deliverable.

Ashtabula, Langdon Owned, Langdon PPA, Luverne, and Ashtabula III PPA are interconnected to a neighboring utility's transmission system (Minnkota Power Cooperative) which is not a MISO transmission owner. Minnkota does not offer aggregate deliverable interconnection service, but Otter Tail does have an agreement with Minnkota allowing for these resources to have transmission rights for delivery to Otter Tail load. Therefore, Otter Tail can only obtain local deliverability of these resources to Otter Tail load.

There is no impact on the integrated resource plan as a result of these resources being available only locally. Otter Tail has obtained local deliverability rights for these resources to adequately serve Otter Tail's load with firm transmission service.

Otter Tail does not plan to address the limited local resource to make them network resources. All local resources have acquired adequate firm transmission rights to serve Otter Tail's load on the Otter Tail transmission system. In addition, Otter Tail has an agreement with Minnkota to allow resources interconnected to Minnkota's transmission system to have firm transmission rights to deliver to Otter Tail load.

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Big Stone Plant Forced Outage Info

Outage Dates Start	Outage Dates End	Primary Reason for Outage	Duration (days)	Description of Equipment Failure	Change in Energy Costs	Steps Taken to Alleviate Reoccurrence
8/6/2014	8/8/2014	Reheat tube leak	1.64	Excessive sootblowing on tubes without shielding was the cause.		We've reduced sootblowing in this area.
10/20/2014	10/21/2014	Reheat outlet tube leak	1.49	Root cause was overheating.		Tubes are at the end of life and will be replaced in 2015.
11/6/2014	11/9/2014	"D" Boiler Circ Pump and a tube leak	2.21	During the previous shutdown, the boiler was in the process of being drained to make needed repairs. During this non-routine process, the boiler circ pump was inadvertently operated in a dry condition. Water is needed for proper operation and as a result, this pump needed to be repaired during this outage.		We've conducted further training and added some logic to the control system to prevent a future event.

Coyote Station Forced Outage Info

Outage Dates Start	Outage Dates End	Primary Reason for Outage	Duration (days)	Description of Equipment Failure	Change in Energy Costs	Steps Taken to Alleviate Reoccurrence
7/6/2014	7/9/2014	Unit trip due to 345 line lightning strike	2.43	No failure at the plant. Transmission line was taken out by lighting and repairs to line needed to bring plant back on line.		Unavoidable
7/18/2014	7/20/2014	Screen tube leak	1.47	Boiler tube leak		These tubes are visually inspected every outage.
8/29/2014	8/31/2014	GR Fan vibration problems	2.59	The unit was shut down to examine the fan to determine the cause of the excessive vibration. Ash buildup on the fan wheel can sometimes cause vibration and the unit must be shut down to clean or inspect.		A fan vibration engineer was contacted after this outage to determine the cause of the vibration. They provided suggestions on what might be causing the vibration issues but could not confidently confirm the issue.
10/20/2014	10/22/2014	Tube leak on #6 cyclone	1.17	Cyclone tubes are in a very high wear area as this is the location where fuel is injected and the start of the combustion process. Significant refractory replacement and repair is necessary at specific maintenance intervals. One of the tubes in this area failed.		Cyclones are completely cleaned and inspected once a year. NDE testing is very difficult in cyclones due to the refractory.
12/4/2014 & 12/8/2014	12/4/2014 & 12/22/2014	"A" Boiler Feed Pump fire	15.61	The boiler feed pump was isolated to work on the boiler feed pump seals. There are two valves in the steam supply line that had internal issues and problems unknown at the time that did not allow positive isolation to the turbine. The boiler feed pump was sitting at 0 rpm and the steam supply was slowly leaking by the isolation valves until a flow path of steam began turning the boiler feed pump. The BFP reached an overspeed condition and failed. The resulting failure started the eventual lube oil fire.		The isolation valves were inspected and repaired. The isolation valve to the other boiler feed pump was also inspected. Additionally, similar valves at the Big Stone station for the boiler feed pumps were inspected as a result of this incident.
2/24/2015	2/26/2015	Gas Recirc Fan Balance	1.81	Related to the August 2014 issue, it was determined that the floor (attached to the foundation of the GR Fan) was causing the vibration. The two solutions that were presented were to either repour the floor or add a VFD to the fan motor to be able to damper the vibration.		A VFD project that was planned for this fan resulted in a reduction in the vibration.
5/4/2015	5/6/2015	Wind Box Repair	1.93	The wind box in a power plant is an air chamber that surrounds the boiler combustion area. Outside preheated air is blown into this chamber and is maintained at a positive pressure. This hot air is used to mix with fuel for combustion. During operation of the boiler, cracks in the wind box wall allowed hot air to escape into the plant area.		Additional attention to the condition of the windbox during off-line inspections.
6/10/2015	6/14/2015	Boiler Tube Leak	3.75	Boiler tube leak		These tubes are visually inspected every outage.

. . . TRADE SECRET DATA ENDS]

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Hoot Lake Plant Forced Outage Info

Outage Dates Start	End	Primary Reason for Outage	Duration (days)	Description of Equipment Failure	Change in Energy Costs	Steps Taken to Alleviate Reoccurrence
	Hoot Lake Plant #2					
7/10/2014	8/26/2014	Turbine vibration due to steam seal rub (Note: There were intermittent periods of on-line testing over this time period)	47	During startup after a long maintenance outage, a feedwater heater tube ruptured and caused excessive feedwater to enter into one of the feedwater heaters of the unit. The isolation valves of the Hoot Lake vintage unit are of the type intended to stop a burst of steam or water to prevent turbine overspeed, and not a positive isolation for slower water induction. As a result, the feedwater within the heater backed up into a steam line causing localized cooling of the turbine case and resulted in a turbine steam seal rub. During this event, a high alarm instrument failed to give the operators an indication that the situation was abnormal. The resultant cooling and rub of the turbine required disassembly, inspection and repair of the turbine, which is the main cause of the longer outage.		The feedwater heater tube and the high level alarm of the feedwater heater were repaired. The isolation valves were disassembled and re-checked to verify operation.
10/27/2014	10/30/2014	Tube leak, turbine repairs, steam valve work	2.60	Repair of tube leak on a waterwall tube due to exterior erosion.		Adjacent tubing was inspected during the repair to prevent a similar occurrence. The turbine was given a trim weight following the major outage to decrease bearing wear. The main steam and intercept valves had additional calibration checks to ensure optimal operation.
11/2/2014	11/3/2014	Economizer tube leak	1.36	Experiencing on-going leaks due to sootblower erosion.		The plant has previously modified sootblowing operations and installed progressive helix sootblowers in the highest problem areas to reduce the sootblowing erosion damage.
3/5/2015	3/7/2015	Primary Superheat Tube Rupture	1.31	Experiencing on-going leaks due to sootblower erosion.		The plant has previously modified sootblowing operations and installed progressive helix sootblowers in the highest problem areas to reduce the sootblowing erosion damage.
	Hoot Lake Plant #3					
7/5/2014	7/7/2014	Low vacuum trip	2.26	On the outlet of the condenser cooling water box, there is a 2" PVC line for auxiliary cooling that failed. The unit needed to be shut down to repair the line.		The line was replaced.
8/22/2014	8/24/2014	Repair bleed trip packing and 3-5 Feedwater Heater	1.23	Outage was taken to eliminate excessive steam leaking out of the valve packing and inside the plant area. Bleed trip valves are used at a power plant as protection from bursts of steam or water flows backward towards the turbine which help to prevent possible turbine overspeed. Like any valve, packing is used as a compression material that prevents fluid leakage out of the system around the valve stem.		Packing was replaced in bleed trip valve.

. . . TRADE SECRET DATA ENDS]

Otter Tail's Generation Deliverability Results for MISO Planning Year 2014/2015

Plan Year: 2014-2015 Asset Owner: All

Resource Name	LRZ	Asset Owner	Type	Effective ICAP	GVTC	Total IS	NRIS	ERIS	XEFORd	Wind %	TL% Inc	UCAP (Total)	UCAP (ERIS)
BEMIDJI HYDRO 1	Zone 1	OTPW	LMR (BTMG)	0	0	0	0	0	0		4.6	0	0
BIG STONE DIESEL	Zone 1	OTPW	LMR (BTMG)	1.1	1.1	1.1	0	1.1	0.09820		4.6	1	1
DAYTON HOLLOW I	Zone 1	OTPW	LMR (BTMG)	0.5	0.5	0.5	0	0.5	0		4.6	0.5	0.5
DAYTON HOLLOW II	Zone 1	OTPW	LMR (BTMG)	0.5	0.5	0.5	0	0.5	0		4.6	0.5	0.5
FERGUS CONTROL CENTE	Zone 1	OTPW	LMR (BTMG)	1.9	1.9	1.9	0	1.9	0.09820		4.6	1.8	1.8
GARRISON HYDRO PLT 2	Zone 1	OTPW	LMR (ER)	4	4	4.4	0	4.4	0.01801			4.3	4.3
HOOT LAKE DIESEL 2A	Zone 1	OTPW	LMR (BTMG)	0.3	0.3	0.3	0	0.3	0.09820		4.6	0.3	0.3
HOOT LAKE DIESEL 3A	Zone 1	OTPW	LMR (BTMG)	0.2	0.2	0.2	0	0.2	0.09820		4.6	0.2	0.2
HOOT LAKE HYDRO	Zone 1	OTPW	LMR (BTMG)	0.3	0.3	0.3	0	0.3	0		4.6	0.3	0.3
OTP.ASHTAIII	Zone 1	OTPW	CP_NODE	62.4	62.4	9999	0	9999	0	0.16939		10.6	10.6
OTP.ASHTUBULA	Zone 1	OTPW	CP_NODE	48	48	9999	0	9999	0	0.18487		8.9	8.9
OTP.BIGSTON1	Zone 1	OTPW	CP_NODE	257.6	257.6	318.7	318.7	0	0.06648			240.5	0
OTP.COYOT1	Zone 1	OTPW	CP_NODE	150.2	150.2	174	174	0	0.13426			130	0
OTP.EDGLYEDGL	Zone 1	OTPW	CP_NODE	21	21	21	4.2	16.8	0	0.13365		2.8	0
OTP.HETLA	Zone 1	OTPW	CP_NODE	19.7	19.7	29	21	8	0.10923			17.6	0
OTP.HOOTL2	Zone 1	OTPW	CP_NODE	61.1	61.1	65	65	0	0.01434			60.2	0
OTP.HOOTL3	Zone 1	OTPW	CP_NODE	87.5	87.5	88	88	0	0.01262			86.4	0
OTP.JAMSPK1	Zone 1	OTPW	CP_NODE	20.5	20.5	29	21	8	0.09678			18.5	0
OTP.JAMSPK2	Zone 1	OTPW	CP_NODE	21	21	29	21	8	0.21286			16.5	0
OTP.LANGDN1	Zone 1	OTPW	CP_NODE	40.5	40.5	9999	0	9999	0	0.18667		7.6	7.6
OTP.LANGDN2	Zone 1	OTPW	CP_NODE	19.5	19.5	9999	0	9999	0	0.1924		3.8	3.8
OTP.MPWR	Zone 1	OTPW	CP_NODE	49.5	49.5	9999	0	9999	0	0.21439		10.6	10.6
OTP.SLWAYO1	Zone 1	OTPW	CP_NODE	43.1	43.1	50	50	0	0.05493			40.7	0
PISGAH HYDRO	Zone 1	OTPW	LMR (BTMG)	0.6	0.6	0.6	0	0.6	0		4.6	0.6	0.6
TAPLIN GORGE HYDRO	Zone 1	OTPW	LMR (BTMG)	0.4	0.4	0.4	0	0.4	0		4.6	0.4	0.4
WRIGHT HYDRO	Zone 1	OTPW	LMR (BTMG)	0.2	0.2	0.2	0	0.2	0		4.6	0.2	0.2
				[TRADE SECRET DATA BEGINS….									
DAKOTA MAGIC CASINO	Zone 1	OTPW	LMR (BTMG)										
KINDRED SCHOOL DISTR	Zone 1	OTPW	LMR (BTMG)										
PERHAM RESOURCE RECO	Zone 1	OTPW	LMR (BTMG)										
STEVENS COMMUNITY ME	Zone 1	OTPW	LMR (BTMG)										
VALLEY QUEEN CHEESE	Zone 1	OTPW	LMR (BTMG)										

…TRADE SECRET DATA ENDS]

Plan Year: 2014-2015

PRC Type	CP Node	LMR Resource Name	MISO UCAP (MW)	Resource Plan Capacity Ratings	Difference	% Difference	Explanation
external	Garrison Hydro Plant_2		4.3	4.3	0	0%	
local	OTP.ASHTUBULA		8.9	8.9	0	0%	
aggregate	OTP.BIGSTON1		240.5	240.5	0	0%	
aggregate	OTP.COYOT1		130	130	0	0%	
aggregate	OTP.EDGLYEDGL		2.8	2.8	0	0%	
aggregate	OTP.HETLA1		17.6	17.6	0	0%	
aggregate	OTP.HOOTL2		60.2	60.2	0	0%	
aggregate	OTP.HOOTL3		86.4	86.4	0	0%	
aggregate	OTP.JAMSPK1		18.5	18.5	0	0%	
aggregate	OTP.JAMSPK2		16.5	16.5	0	0%	
local	OTP.LANGDN1		7.6	7.6	0	0%	
local	OTP.LANGDN2		3.8	3.8	0	0%	
local	OTP.MPWR		10.6	10.6	0	0%	
local	OTP.ASHTAIII		10.6				
btmg(local)	OTP.OTP	Bemidji 1 Hydro	0	0	0	0%	
btmg(local)	OTP.OTP	Big Stone Diesel	1	1	0	0%	
btmg(local)	OTP.OTP	Dayton Hollow Hydro I	0.9	0.9	0	0%	
btmg(local)	OTP.OTP	Dayton Hollow II	0.5	0.5	0	0%	
btmg(local)	OTP.OTP	Fergus Control Center Diesel	1.8	1.8	0	0%	
btmg(local)	OTP.OTP	Hoot Lake Diesel 2A	0.3	0.3	0	0%	
btmg(local)	OTP.OTP	Hoot Lake Diesel 3A	0.2	0.2	0	0%	
btmg(local)	OTP.OTP	Hoot Lake Hydro	0.3	0.3	0	0%	
btmg(local)	OTP.OTP	Pisgah Hydro	0.6	0.6	0	0%	
btmg(local)	OTP.OTP	Taplin Gorge Hydro	0.4	0.4	0	0%	
btmg(local)	OTP.OTP	Wright Hydro	0.2	0.2	0	0%	
aggregate	OTP.SLWAYO1		40.7	40.7	0	0%	
			[TRADE SECRET DATA BEGINS…				
btmg(local)	OTP.OTP	Dakota Magic Casino					
btmg(local)	OTP.OTP	Kindred School District					
btmg(local)	OTP.OTP	Perham Resource Recovery Facility					
btmg(local)	OTP.OTP	State Auto Insurance					
btmg(local)	OTP.OTP	Stevens Community Medical Cntr					
btmg(local)	OTP.OTP	Valley Queen Cheese					
					…TRADE SECRET DATA ENDS]		

MN OES'S ORDER FOR APPROVAL OF A POWER PURCHASE AGREEMENT WITH DISTRICT 45 DAIRY, LLP DOCKET NO. E017/M-10-1013

In the Minnesota Public Utilities Commission's January 26, 2011, Order the following disposition was made:

3. **Require Otter Tail Power to report in its automatic adjustment reports whether Otter Tail Power obtains any revenue from any source as a result of unit specific sales relating to the power purchase agreement and to itemize any such revenues by source and amount.**

Otter Tail has no activity to report for this item.

MN PUC ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS, REQUIRING REFUND OF CERTAIN CURTAILMENT COSTS, AND REQUIRING ADDITIONAL FILINGS IN 2010/2011 (FYE11) ANNUAL AUTOMATIC ADJUSTMENT REPORTS - DOCKET NO. E999/AA-11-792

In the Minnesota Public Utilities Commission's August 16, 2013 Order, the following was ordered for Otter Tail Power Company and other electric utilities:

18. The Commission finds that the Companies' responses have complied generally with all of the AAA MISO Day 1 compliance reporting requirements. 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.

Otter Tail's MISO Schedule 10 costs (does not include FERC Schedule 10 charges) increased from $687,456.80 (System-wide) in the 2013-2014 AAA period to $809,139.43 (System-wide) in the 2014-2015 AAA period. These cost increases equate to a 17.7% increase of MISO Schedule 10 costs over the last year. Otter Tail did not see any change in benefits as a result of these cost increases.

MISO Schedule 10 costs are costs associated with MISO's management of the transmission system and administration of the transmission tariff. They are accounted for as Miscellaneous Transmission Expenses in FERC account 566, with jurisdictional cost allocation based on the Transmission Demand Factor D2. Using Otter Tail's D2 factor of 47.889095% approved in Otter Tail's last general rate case (2009), the Minnesota share of the costs would be $ $387,489.55 for the 2014-2015 reporting period.

20. Beginning with the fiscal year 2012 AAA filing, to assist the Department with its plans to do more detailed review of congested paths, including related costs and revenues in the fiscal year 2012 AAA, the electric utilities shall:

a. 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.

Attachment P to this response contains the hourly information requested in an Access file format (Attachment P to AAA2014-2015NONPUBLIC.accdb) (marked as Trade Secret). *This attachment will be provided separately on a cd as it is not in a format that can be electronically filed.*

Attachment Q contains a description of the fields contained in Attachment P.

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 the 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?

In response to b.i. through c.iii.:

The Company serves load at three locations (within the Otter Tail balancing authority, within the Xcel balancing authority, and in the WAUE balancing authority). Since almost all of Otter Tail's load is contained in the Otter Tail balancing authority, we only examined the paths from generators to this load (OTP.OTP) for simplicity.

A summary of the FTR revenues, congestion expenses, and resulting net congestion on each of the top 10 paths sinking at the Otter Tail balancing authority load zone follows:

[TRADE SECRET DATA BEGINS . . .

. . . **TRADE SECRET DATA ENDS]**

[TRADE SECRET DATA BEGINS . . .

. . . **TRADE SECRET DATA ENDS]**

The Company's plans to continue reducing congestion costs include:

- Annually analyzing and reviewing Option A versus Option B grandfathered rights treatment for our Big Stone and Coyote generation units.
- Reviewing and reporting on congestion costs, offsets, and net costs in the AAA report.
- Reviewing congestion costs and nomination/allocation strategy during the process completed annually.
- Nominating additional MW of ARRs for existing and future generation resources as feasibility allows.

22. 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).

See Attachment R

23. In future AAA filings starting with the filings for fiscal year 2012, Xcel, Minnesota Power, Otter Tail Power, and Interstate Power and Light shall include the following for Annual Transformer Reporting:

a. 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 stand-alone, in-service duplicate, on-order, or storage.

b. provide information regarding policy on backup strategies for transformers like MP did in their Attachment 13.

c. provide their policy for transformer maintenance.

Transmission level transformers on Otter Tail's system operated with a low side voltage of 100 kV or above include the following:

Primary Voltage (kV)	Secondary Voltage (kV)	Maximum MVA	Location (Substation)	State	Status
345	230	336	Maple River	ND	In-Service Stand Alone
345	230	336	Maple River	ND	In-Service Stand Alone
345	115	112	Jamestown	ND	In-Service Stand Alone
345	115	112	Jamestown	ND	In-Service Stand Alone
345	115	112	Buffalo	ND	In-Service Stand Alone
230	115	140	Forman	ND	In-Service Stand Alone
230	115	125	Rugby	ND	Failed Out of Service
230	115	140	Rugby	MN	In-Service Stand Alone
230	115	140	Winger	MN	In-Service Stand Alone
230	115	233	Big Stone	SD	In-Service Stand Alone
230	115	187	Cass Lake	MN	In-Service Stand Alone
230	115	N.A.	Wilton Area	MN	Not needed due to BGR in-service

Backup Strategies

Otter Tail's transmission system is planned and operated with several neighboring utilities. The system is designed to withstand the loss of a transformer and still be able to reliably serve all loads. As a result, Otter Tail does not have any spare transformers with a low side winding of greater than 100 kV. However, the Wilton 230/115 kV transformer can be considered as an "In-Service Duplicate" due to the completion of the Bemidji – Grand Rapids 230 kV project. This 230 kV project included the installation of a new 230/115 kV transformer at Cass Lake. The Cass Lake 230/115 kV transformer, coupled with Minnkota Power Cooperative's Wilton 230/115 kV transformer, offer adequate redundancy to the Bemidji area for all possible N-1 conditions, thereby making the Otter Tail owned transformer at Wilton available for other locations if need be.

In the fall of 2013, Otter Tail's Rugby transformer as listed in the Table above failed and Otter Tail implemented the aforementioned back-up strategy. The Otter Tail Wilton transformer was moved to Rugby and energized in the late winter/early spring of 2014 leaving only one Minnkota Power Cooperative transformer remaining at Wilton.

At our two largest generating stations (Big Stone and Coyote), Otter Tail, along with other co-owners, has invested to have a spare generator step-up transformer on site at each location in the event of a failure to reduce the down-time of these generators.

Transformer Maintenance Policy

Otter Tail's policy for transformer maintenance for the transmission level transformers is similar to the maintenance policy used for all transformers on the Otter Tail system with a capacity of 10 MVA or higher.

For new transformer installations, the following tests are performed to ensure the transformer will operate as expected.

- Meggar testing to identify if there is adequate insulation protection to ground and between windings within the transformer.

- Transformer Turns Ratio ("TTR") test to verify the turns ratio of the transformer is as specified on the nameplate.

- Doble insulation power factor test to verify the electrical insulation level of the transformer and its components (oil, paper, bushings, etc.) are within specifications.

- Winding resistance test to identify if there is consistent and comparable resistance measurements between windings within the transformer.

- Dissolved Gas in Oil Analysis ("DGA") to determine the level of gases and moisture present in the transformer oil.

For existing transformers on the system, Otter Tail performs the following transformer tests on an annual basis, with the frequency of these tests increasing to as often as monthly if transformers are showing signs of internal failures:

- Routine inspections to assess the physical condition of the transformer and its components.

- Thermal imaging of transformer connections and bushings for hot spots to ensure appropriate conductivity between terminal connections.

- Dissolved Gas in Oil Analysis ("DGA"), on transformers 10 MVA and above, to determine the level of gases and moisture present in the transformer oil.

The annual frequency of this testing allows for the comparison of test results to transformer nameplate values, and from year-to-year, in an effort to help identify the early signs of transformer breakdown in order to prevent a catastrophic failure of a transformer.

REFERENCE GUIDE FOR Table DALMP_YR 2013-2014

Note that we included the dates from June 23, 2014 - June 22, 2015 since this matches our accounting months for which data was supplied for the other requests in this year's AAA Audit response. This was done so that we could validate numbers against our monthly reports which are on an accounting period basis.

Column Headings:

NODES
Generation Nodes include:

OTP.ASHTUBULA – wind unit
OTP.ASHIII – wind unit
OTP.BIGSTON1 – baseload unit
OTP.COYOT1 – baseload unit
OTP.EDGLYEDGL – wind unit
OTP.HETLA – peaking unit
OTP.HOOTL2 – baseload unit
OTP.HOOTL3 – baseload unit
OTP.JAMSPK1 – peaking unit
OTP.JAMSPK2 – peaking unit
OTP.LANGDN1 – wind unit
OTP.LANGDN2 – wind unit
OTP.MPWR –wind unit
OTP.SLWAYO1 – peaking unit

Load Nodes include:

MDU.OTP – Our load in MDU control area
NSP.OTP – Our load in NSP control area
OTP.MUAG – Municipal load in OTP control area
OTP.OTP – Otter Tail load in our control area

Hubs include:

MINN.HUB

DATE:
Includes the dates of June 21, 2014 to June 22, 2015 corresponding to our accounting practices.

HE:
Hour ending

DALMP:
Day Ahead LMP for this node, date and hour.

ENERGY:
The energy component of the DA LMP calculated by subtracting the congestion and loss components from the DA LMP.

MLC:
Marginal Loss component of the LMP

MCC:
Marginal Congestion component of the LMP

REFERENCE GUIDE FOR Table Top 10

Note that we included the dates from June 23, 2014 – June 22, 2015 since this matches our accounting months for which data was supplied for the other requests in this year's AAA Audit response. This was done so that we could validate numbers against our monthly reports which are on an accounting period basis.

Column Headings:

GENERATOR NODE
Generation Nodes include:

OTP.ASHTUBULA – wind unit
OTP.ASHIII – wind unit
OTP.BIGSTON1 – baseload unit
OTP.COYOT1 – baseload unit
OTP.EDGLYEDGL – wind unit
OTP.HOOTL2 – baseload unit
OTP.HOOTL3 – baseload unit
OTP.LANGDN1 – wind unit
OTP.LANGDN2 – wind unit
OTP.MPWR –wind unit

FIELD 2

Text field valued "TO"

LOAD NODE:
OTP.OTP – Otter Tail load in our control area. For simplification all congestion was calculated between the generators and the primary OTP load zone. Other load zones are so small as to be irrelevant to the calculation.

TOTAL NET CONGESTION
This equals the MWs generated at the node times the difference between the MCC at the generator node and the MCC at the load node totaled for the AAA Audit year 2013-2014 for each path.

REFERENCE GUIDE FOR ACCESS TABLE NAMED Path Detail

Note that we included the dates from June 23, 2014 - June 22, 2015 since this matches our accounting months for which data was supplied for the other requests in this year's AAA Audit response. This was done so that we could validate numbers against our monthly reports which are on an accounting period basis.

Column Headings:

DATE
Includes the dates of June 23, 2014 - June 22, 2015 corresponding to our accounting practices.

NODE
Generation Nodes include:

OTP.ASHTUBULA – wind unit
OTP.ASHIII – wind unit
OTP.BIGSTON1 – baseload unit
OTP.COYOT1 – baseload unit
OTP.EDGLYEDGL – wind unit
OTP.HETLA – peaking unit
OTP.HOOTL2 – baseload unit
OTP.HOOTL3 – baseload unit
OTP.JAMSPK1 – peaking unit
OTP.JAMSPK2 – peaking unit
OTP.LANGDN1 – wind unit
OTP.LANGDN2 – wind unit
OTP.MPWR –wind unit
OTP.SLWAYO1 – Peaking unit

Product
OTP internal transaction type:

"DA Gen Sched Customer – NETMCCPrice" is the hourly DA MCC congestion difference between OTP.OTP load zone and the named generator. It is defined as the hourly DA MCC at the OTP.OTP load zone minus the hourly DA MCC at the named generator.

"DA Gen Sched Customer – TOTAL_NETMCC" is the hourly congestion between the OTP.OTP load zone and the named generator. It is defined as the "DA Gen Sched Customer – NetMCCPrice" multiplied by the DA cleared MW schedule at the generator.

"MTRADJGEN-NETMCCPrice" is the hourly congestion difference between the DA congestion at OTP.OTP and the RT congestion at the named generator. It is defined as the DA MCC at OTP.OTP minus the RT MCC at the named generator.

"MTRADJGEN – TOTAL_NETMCC" is the additional hourly congestion charges/revenues accrued in the RT market due to the difference between actual RT generation and DA cleared MW schedules and also the difference between the DA congestion at the load and RT congestion at the generator. It is defined as the "MTRADJGEN-NETMCCPrice" multiplied by the meter adjustments to the generation (seen in the RT market as compared to DA cleared generation).

HE = Hour Ending (1-24)

Total
Sum of the hourly net congestions for this node on this date.

Otter Tail Power Company

Transmission Maintenance Expense Approved in Docket No. E017/GR-10-239 Compared to 2014 Actual

Line No.	Account Description	FERC Account	2009 Test Year Amount	2014 Actual Year Expense
1	Maintenance Supervision and Engineering	568.0	$ 448,117	$ 263,031
2	Maintenance of Computer Hardware, Software, etc	569.1; 569.2; 569.3	826,293	896,654
3	Maintenance of Station Equipment	570.0	1,170,884	1,088,198
4	Maintenance of Overhead System	571.0	1,183,741	2,559,518
5	Maintenance of Underground Lines	572.0	220	0
6	Maintenance of Computer Software	576.3	285,036	280,611
7	Total System Historical Transmission Maintenance Expense		$ 3,914,291	$ 5,088,012
8	Test Year Adjustment on MN TY-15 to Increase Vegetation Maintenance Expense		$ 142,314	
9	Total System Adjusted Transmission Maintenance Expense		$ 4,056,605	$ 5,088,012
10	Jurisdictional D2 Allocation Factor (2009 Rate Case)		47.889095%	47.889095%
11	Total MN Jurisdictional Transmission Maintenance Expense		$ 1,942,672	$ 2,436,603

The 2014 above numbers are on a calendar year basis.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-15-___

PART I - RULE 7825.2840 NOTICE OF REPORTS AVAILABILITY, CERTIFICATE OF SERVICE, AND SERVICE LISTS

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com (web site)

August 31, 2015

Notice of Availability of Reports

To: All Intervenors in Otter Tail Power Company
Retail Rate Proceedings
Docket No. E017/GR-07-1178
Docket No. E017/GR-10-239

The Minnesota Public Utilities Commission requires Otter Tail Power Company and other Minnesota public utilities to file various annual reports concerning utility operations with the Commission as specified in Minnesota Rules 7825.2800 to 7825.2830. The subject matter of the reports filed includes the following:

Rule 7825.2800 Policies and Actions
Rule 7825.2810 Automatic Adjustment Charges
Rule 7825.2820 Annual Independent Auditors' Report
Rule 7825.2830 Annual Five-Year Projection Report
Rule 7825.2840 Notice of Reports Availability, Certificate of Service, and Service Lists

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

Minnesota Rule 7825.2840 requires Otter Tail Power Company to provide this notice of availability of such reports to all intervenors in the previous two general rate cases. The above report is available for public inspection at the MPUC offices or on the Minnesota Department of Commerce edockets website (https://www.edockets.state.mn.us/efiling). Copies of the above reports are also available upon written request to Otter Tail Power Company. Please note that certain information contained in these reports is considered trade secret and is unavailable to the public.

Sincerely,

/s/ STUART TOMMERDAHL
Stuart Tommerdahl
Manager, Regulatory Administration

CERTIFICATE OF SERVICE

RE: 2015 Annual Automatic Adjustment of Charges Report - Electric
Minnesota Rules 7825.2800 – 7825.2840
Docket No. E999/AA-15-___

I, Wendi A. Olson, hereby certify that I have this day served a copy of the following, or a summary thereof, on Daniel P. Wolf and Sharon Ferguson by e-filing, and Letters of Availability to all other persons on the attached service list by electronic service or by first class mail.

Otter Tail Power Company
Annual Report

Dated: August 31, 2015

/s/ WENDI A. OLSON

Wendi A. Olson
Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8699

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Jonathan	Drews	N/A		822 S Woodland Dr Fergus Falls, MN 56537-4628	Paper Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Patrick	Mastel	N/A	Missouri River Energy Services	3724 W. Avera Drive PO Box 88920 Sioux Falls, SD 57109-8920	Paper Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
James	Nessa	N/A		6424 Walrath Circle Ashtabula, OH 44004	Paper Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Rick	Oakes	roakes@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Ave S Burnsville, MN 55337-3527	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Gary	Oetken	goetken@agp.com	Ag Processing, Inc.	12700 West Dodge Road P.O. Box 2047 Omaha, NE 681032047	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2015