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September 1, 2016

PUBLIC DOCUMENT – NOT PUBLIC (OR PRIVILEGED) 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
2016 Annual Automatic Adjustment of Charges Report - Electric
Minn. R. 7825.2800 – 7825.2840
Docket No. E999/AA-16-625

Dear Mr. Wolf:

Otter Tail Power Company (Otter Tail) hereby submits to the Minnesota Public Utilities Commission (Commission) its annual report pursuant to Minn. R. 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 (AttachmentPtoAAA_2015-2016_NOT PUBLIC.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. R. 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 **NOT PUBLIC DOCUMENT – NOT FOR PUBLIC DISCLOSURE**, according to Minn. Stat. § 13.37, subd. 1(b). This statute protects certain "government data," as that term is defined at Minn. Stat. § 13.02, Subd. 7, from being disclosed by an administrative agency to the public.

- Minn. R. 7825.2810 Subpt. 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 2017 (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);
- 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);
- Portion of reply to 22. of MN PUC Order Acting on Electric Utilities' Annual Reports and Requiring Additional Filings Docket Nos. E999/AA-09-961 and E999/AA-10-884 (Part H Section 6);
- Otter Tail's Forced Outage Information Change in Energy Costs Column (Part H Section 6 Attachment M);
- Otter Tail's Generation Deliverability Results for MISO Planning Year 2015/2016 (Part H Section 6 Attachment N);
- Comparison of Otter Tail's MISO Generation Deliverability Results and Otter Tail's current Integrated Resource Plan (Part H Section 6 Attachment O);
- Hourly information in an Access file format (Part H Section 8 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 8).

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: September 1, 2016

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-16-625 **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. R. 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges (AAA) for electric utilities for the period of July 1, 2015 to June 30, 2016.

II. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subpt. 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. R. 7825.2840, the date of this filing is September 1, 2016. The information contained in this filing is submitted in compliance with the aforementioned Rules concerning Automatic Adjustment of Charges.

D. Statute Controlling Schedule for Processing the Filing.

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

E. 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:

Minn. R. 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

Minn. R. 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, 2015 to June 30, 2016. It includes the following:

Section 1 Subpt. 1.A. Commission Approved Base Cost of Fuel
Section 2 and 3 Subpt. 1.B. and 1.C. Billing Adjustment Amounts
Section 4 Subpt. 1.D. Total Cost of Fuel Delivered to Customers
Section 5 Subpt. 1.E. Revenue Collected from Customer for Energy Delivered
Section 6 and 7 Subpt. 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

Minn. R. 7825.2810 Annual Report: Automatic Adjustment of Charges (continued)

Section 10 Passing MISO Day 2 Costs Through Fuel Clause Order in Docket No. E017/M-05-284
Section 11 Southwest Power Pool (SPP) Energy Costs

Minn. R. 7825.2820 Annual Auditor's Report

Part F contains the Independent Auditor's Report for the period of July 1, 2015 to June 30, 2016.

Minn. R. 7825.2830 Annual Five-Year Projection

Part G contains a monthly five-year projection of fuel cost by energy source marked as Not Public.

Additional Reporting Requirements

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

Minn. R. 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 pertained to one particular customer and compared 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 recommended the Commission approve the removal of this requirement. The Commission approved this request in its June 2, 2016 Order in AA-14-579. Otter Tail acknowledges this change in Part H Section 1 of this year's Annual Filing.

V. CONTINGENCY PLANS AND CONTRACTOR PERFORMANCE IN DOCKET NO. AA-08-995

While Otter Tail has not understood or construed Ordering Point 12 from Docket No. E999/AA-08-995 to create an annual reporting requirement within annual AAA Dockets, Otter Tail has provided an overview of its procurement and contracting practices in Part H Section 5 of this Annual Filing.

VI. SOUTHWEST POWER POOL (SPP) ENERGY COSTS

Otter Tail began incurring SPP energy market charges on October 1, 2015. Otter Tail has included the monthly day ahead and real time energy charges assessed by SPP in the monthly fuel clause, consistent with paragraph 2 of the Energy Adjustment Rider, Rate Schedule 13.01. Further discussion on these SPP energy market charges is included in Part E Section 11 of this Annual Filing and a summary of charges is included in Part E Section 11 Attachment I-2.

VII. CONCLUSION

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

Dated: September 1, 2016

Respectfully submitted,

OTTER TAIL POWER COMPANY

By: */s/ STUART TOMMERDAHL*

Stuart Tommerdahl
Manager, Regulatory Administration
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ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-625

OTTER TAIL POWER COMPANY

PART D – MINN. R. 7825.2800 POLICIES AND ACTIONS

MINN. R. 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.

Minn. R. 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 expired 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 entered into a contract in January 2016 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 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.

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.

Minn. R. 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, stator high potential tests, and other critical points are performed during these inspections.

   (c) Complete inspections of the turbines are performed at approximately six- to ten-year intervals, including lifting of covers and rotors, checking blade clearances, inspection of steam valves, bearings, lube oil systems, and bleeder line nonreturn valves. The blades will generally be cleaned and tested for cracks by professional testers, and coupling alignment is checked. Major turbine overhauls are performed on six- to ten-year intervals, per manufacturer recommendations.

   (d) Complete inspection of generators are performed at approximately 10-year intervals, including removal of the rotor and complete visual inspection. All electrical and mechanical components are checked and tested and all clearances confirmed. "Megger" resistance tests and high potential 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 three to five years.

Minn. R. 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

Minn. R. 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, 2016.

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, 2016.

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 Minn. R. 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; (2015/2016) $1,138,862.43

      Attachment A provides the monthly breakdown for 2015/2016.

   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 voices its concerns and actively engages in matters 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 a relatively small market participant in MISO, OTP has found that 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 2015 to June 2016

	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 2015	$42,137.45	$0.00	47.889095%	$20,179.24	$24,864.55
AUG 2015	$66,590.44	$0.00	47.889095%	$31,889.56	$23,230.59
SEP 2015	$62,886.86	$0.00	47.889095%	$30,115.95	$23,936.38
OCT 2015	$56,191.52	$0.00	47.889095%	$26,909.61	$20,674.04
NOV 2015	$74,251.90	$0.00	47.889095%	$35,558.56	$23,545.63
DEC 2015	$100,587.68	$0.00	47.889095%	$48,170.53	$27,364.95
JAN 2016	$92,388.71	$0.00	47.889095%	$44,244.12	$29,397.75
FEB 2016	$80,610.90	$0.00	47.889095%	$38,603.83	$24,494.55
MAR 2016	$79,565.06	$0.00	47.889095%	$38,102.99	$24,632.61
APR 2016	$78,985.59	$0.00	47.889095%	$37,825.48	$21,766.66
MAY 2016	$63,597.23	$0.00	47.889095%	$30,456.14	$20,248.66
JUN 2016	$57,155.93	$0.00	47.889095%	$27,371.46	$19,756.79
TOTALS	$854,949.27	$0.00	47.889095%	$409,427.47	$283,913.16

*Non-system use is not allocated to MN.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-625

PART E – MINN. R. 7825.2810 AUTOMATIC ADJUSTMENT CHARGES

PUBLIC DOCUMENT
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

MINN. R. 7825.2810 ANNUAL REPORT - AUTOMATIC ADJUSTMENT CHARGES

PERIOD: July 1, 2015 - June 30, 2016

Minn. R. 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 14, 2016, in Docket No. E017/MR-15-1034.

Minn. R. 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 2015 to June 2016.
   While Otter Tail was preparing this attachment, a correction to the Gas and Fuel Oil classification was identified. A diesel standby generating unit was inadvertently being included in the Gas classification when it should have been included in the Fuel Oil category. Otter Tail has corrected both the Gas and Fuel Oil categories to properly reflect the appropriate classifications. This revision does not affect the total kWh, only the reporting classification.
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 Not Public).

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 2015 through June 2016.

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

Does not apply.

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

Date	Amount (System)
July-15	$10,081,148
August	$10,637,667
September	$7,542,902
October	$8,085,740
November	$8,378,494
December	$10,462,288
January-16	$11,143,743
February	$9,687,483
March	$9,887,249
April	$7,699,140
May	$6,675,600
June	$8,771,716
Total	$109,053,170

Minn. R. 7825.2810 Subpart 1.D. The Total Cost of Fuel Delivered to Customers (continued)

Total kWh Sales – System = 4,646,536,462
Total kWh Sales Subject to COE – Minnesota = 2,481,395,298
Percent of Minnesota Sales to System
(2,481,395,298 / 4,646,536,462) = 0.534031169
Fuel Costs Allocated to Minnesota: ($109,053,170) x 0.534031169 = $58,237,792

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

Revenue does not include the collection of true-up during July 2015 – June 2016 in the amount of ($959,747):

Date	Amount (System)
July-15	$139,081
August	$163,257
September	($121,384)
October	($111,996)
November	($114,298)
December	($124,082)
January-16	($145,381)
February	($148,501)
March	($138,421)
April	($127,872)
May	($117,260)
June	($112,889)
Total	($959,747)

Recovery From FCA	Recovery From Fuel Base	Total Adj. Recovery	Actual Fuel Cost	Total Over/(Under) Recovery
$786,574	[1]$58,169,602	$58,956,176	$58,237,792	[2]$718,384

[1] Recovery from fuel base cost:

Total Minnesota kWh Sales July 2015 – April 15, 2016	2,012,171,804
Minnesota Base Cost	x $0.023163
Amount Recovered From Base Cost	$ 46,607,935
Total Minnesota kWh Sales April 16, 2016 to June 2016	469,223,494
Minnesota Base Cost	x $0.024640
Amount Recovered From Base Cost	$ 11,561,667

[2] Refer to attached July 29, 2016, true-up implementation filing (Part E Section 8 Attachment E)

Minn. R. 7825.2810 Subpart 1.F. The Amount of Supplier Refunds Received

None

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

The result was a refund of ($1,262,084) for the same time period.

The May 2016 system costs of $6,675,600 include a credit of ($37,058). This disallowance of May 2013 Revenue Sufficiency Guarantee Make-Whole Payments was ordered in the June 2, 2016 Order in Docket No E999/AA-13-599.

ENERGY ADJUSTMENT RIDER

DESCRIPTION	RATE CODE
Energy Adjustment Rider	31-540

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

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 2.4640¢ per Kilowatt-Hour. **R**
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:

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.

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.

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.

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.

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.

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.

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	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
1	COAL	99,091,747	184,034,751	156,275,965	163,698,192	162,488,721	158,395,852	240,341,767	196,171,374	180,126,885	100,762,434	82,822,961	172,316,784
2	BIOMASS	0	0	0	0	0	0	0	0	0	0	0	0
3	HYDRO	1,987,456	2,105,562	1,891,108	1,275,912	1,350,016	2,135,882	2,163,431	2,062,937	2,240,586	2,160,850	2,202,523	1,942,770
4	GAS	0	461,599	2,995,706	(183,046)	1,100,287	207,248	1,360,543	2,195,648	530,845	681,090	2,904,222	3,057,639
5	WIND	30,546,081	28,179,215	36,064,993	48,538,195	41,559,327	34,225,254	36,504,781	34,485,658	41,774,043	54,513,611	39,278,964	38,253,541
6	FUEL OIL	(10,756)	85	1,662	1,699	2,523	(6,164)	1,560	20,212	214,803	(41,625)	1,703	1,836
7	UNKNOWN	271,377,223	184,063,777	140,377,920	156,987,707	180,294,145	295,758,060	199,025,168	196,037,542	221,995,469	208,027,880	190,312,700	191,567,317
8	1-MONTH TOTAL	402,991,751	398,844,989	337,607,354	370,318,659	386,795,019	490,716,132	479,397,250	430,973,371	446,882,631	366,104,240	317,523,073	407,139,887

Big Stone Plant came back on-line in August 2015 after being down for air-quality control system (AQCS) installation starting February 27, 2015.

Coyote Plant was down for a scheduled 10 week outage starting in March 2016. The Plant was back up in May 2016.

Hoot Lake Plant has periodically been off-line for economic reasons July 2015 - June 2016.

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

Line No.		Based on Period Ending	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
	FUEL COSTS BY ENERGY TYPE:													
1	GENERATION	COAL	$2,308,752	$4,415,091	$3,438,168	$3,741,149	$4,312,247	$3,956,437	$5,512,267	$4,469,075	$4,566,104	$2,758,032	$2,170,981	$4,163,252
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	$12	$14,031	$90,562	($34,956)	$50,818	($3,509)	$39,739	$48,384	$12,570	$14,951	$51,315	$70,534
5		WIND	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6		FUEL OIL	$56,924	$150,496	$49,685	$35,798	($135,547)	$72,606	$12,607	$176,295	$71,973	$61,297	$3,998	$180
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	$918,870	$1,046,176	$675,301	$680,312	$596,999	$729,573	$968,612	$1,032,582	$1,101,865	$972,003	$1,024,543	$883,563
11		GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12		WIND	$698,111	$642,035	$840,622	$1,134,529	$981,839	$842,830	$777,875	$817,216	$971,433	$1,261,684	$967,929	$858,919
13		SOLAR	$556	$709	$644	$689	$458	$287	$152	$220	$484	$888	$1,242	$1,672
14		FUEL OIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15		UNKNOWN	$6,097,922	$4,369,129	$2,447,920	$2,528,219	$2,571,680	$4,864,063	$3,832,491	$3,143,711	$3,162,820	$2,630,286	$2,455,592	$2,793,596
16		1-MONTH TOTAL	$10,081,148	$10,637,667	$7,542,902	$8,085,740	$8,378,494	$10,462,288	$11,143,743	$9,687,483	$9,887,249	$7,699,140	$6,675,600	$8,771,716
17	RETAIL kWh SALES	1-MONTH TOTAL	334,042,722	370,900,190	364,584,007	342,631,935	359,045,181	402,389,198	479,963,658	472,198,276	434,673,233	397,375,784	349,198,168	339,534,110
18	ACTUAL COST (cents/kWh)		3.01792	2.86807	2.06891	2.35989	2.33355	2.60004	2.32179	2.05157	2.27464	1.93750	1.91169	2.58346
	ONE-MONTH COST DISTRIBUTION BY ENERGY TYPE:													
19	GENERATION	COAL	0.69115	1.19037	0.94304	1.09189	1.20103	0.98324	1.14848	0.94644	1.05047	0.69406	0.62170	1.22617
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	0.00000	0.00378	0.02484	-0.01020	0.01415	-0.00087	0.00828	0.01025	0.00289	0.00376	0.01470	0.02077
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	0.01704	0.04058	0.01363	0.01045	-0.03775	0.01804	0.00263	0.03733	0.01656	0.01543	0.00114	0.00005
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	0.27508	0.28206	0.18523	0.19855	0.16627	0.18131	0.20181	0.21868	0.25349	0.24461	0.29340	0.26023
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	0.20899	0.17310	0.23057	0.33112	0.27346	0.20946	0.16207	0.17307	0.22349	0.31750	0.27719	0.25297
31		SOLAR	0.00017	0.00019	0.00018	0.00020	0.00013	0.00007	0.00003	0.00005	0.00011	0.00022	0.00036	0.00049
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	1.82549	1.17798	0.67143	0.73788	0.71626	1.20880	0.79850	0.66576	0.72763	0.66191	0.70321	0.82277
34	ACTUAL COST (cents/kWh)		3.01792	2.86807	2.06891	2.35989	2.33355	2.60004	2.32179	2.05157	2.27464	1.93750	1.91169	2.58346

Big Stone Plant came back on-line in August 2015 after being down for air-quality control system (AQCS) installation starting February 27, 2015.

Coyote Plant was down for a scheduled 10 week outage starting in March 2016. The Plant was back up in May 2016.

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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)	**[PROTECTED 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												
2006 Big Stone cost per Mbtu												
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2013 Big Stone cost per Mbtu												
2014 Big Stone cost per Mbtu												
2015 Big Stone cost per Mbtu												
2016 Big Stone cost per Mbtu												
2001 Coyote cost per Mbtu												
2002 Coyote cost per Mbtu												
2003 Coyote cost per Mbtu												
2004 Coyote cost per Mbtu												
2005 Coyote cost per Mbtu												
2006 Coyote cost per Mbtu												
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2012 Coyote cost per Mbtu												
2013 Coyote cost per Mbtu												
2014 Coyote cost per Mbtu												
2015 Coyote cost per Mbtu												
2016 Coyote cost per Mbtu												
2001 Hoot Lake cost per Mbtu												
2002 Hoot Lake cost per Mbtu												
2003 Hoot Lake cost per Mbtu												
2004 Hoot Lake cost per Mbtu												
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2012 Hoot Lake cost per Mbtu												
2013 Hoot Lake cost per Mbtu												
2014 Hoot Lake cost per Mbtu												
2015 Hoot Lake cost per Mbtu												
2016 Hoot Lake cost per Mbtu												

. . . PROTECTED DATA ENDS]

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MONTHLY COST COMPONENTS BY FUEL TYPE

	January	February	March	April	May	June	July	August	September	October	November	December
Cost of delivered natural gas	**[PROTECTED 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												
2009 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												
2016 Solway Plant cost per Mbtu												
										. . . PROTECTED 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	21.64	15.93	0.00	16.07	20.65	20.95
2016 IC Plants and FF Control Ctr diesel, $/Mbtu	0.00	20.62	21.32	18.20	22.14	16.36	0.00	0.00	0.00	0.00	0.00	0.00
Cost of wholesale purchases ($/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	28.15	31.51	27.51	27.00	21.91	21.44
2016 Purchased Power	27.88	25.03	23.90	23.15	22.89	24.35	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 7/2/2015
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

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

Line No.		
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

EFFECTIVE 9/1/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

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

Line No.	ENERGY COSTS		(A) 2015 June		(B) 2015 July		(C) Total This Period
1	Plant Generation	$	1,027,126	$	2,417,737	$	3,444,863
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	4,480,717	$	6,094,831	$	10,575,549
3	Purchased Power	$	1,933,630	$	1,617,370	$	3,551,000
4	Wind Curtailment	$	115	$	168	$	283
5	Less: MISO ASM (Rev) Cost	$	15,050	$	17,249	$	32,298
6	Less: Intersystem Sales (Rev) Cost	$	(26,749)	$	(52,049)	$	(78,799)
7	Less: Asset Based Margins (Rev) Cost	$	(680)	$	(14,157)	$	(14,837)
8	Total Cost of Fuel	$	7,429,209	$	10,081,148	$	17,510,357

Line No.	KWH SALES	(A) 2015 June	(B) 2015 July	(C) Total This Period
9	Total Sales of Electricity	320,013,031	335,448,400	655,461,431
10	Less Inter-System Sales	(1,589,943)	(1,405,678)	(2,995,621)
11	Total kWh	318,423,088	334,042,722	652,465,810

Line No.		
12	Cost per KWH	0.026837
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	0.00307

kWh Information For The Billing Month of: July 2015

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	173,850,633	kWh
2	Non-Energy Adjustment Rider Sales	133,505	kWh
3	Total	173,984,138	kWh
	Non-Minnesota Sales		
4	Sales for Resale	173,133	kWh
5	Total Sales of Electricity (ND and SD)	159,885,451	kWh
6	Inter-System Sales	1,405,678	kWh
	Total kWh Sales	335,448,400	kWh

EFFECTIVE 10/2/2015

CYCLE 01 RATE LEVEL 31

MINNESOTA

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

Line No.	ENERGY COSTS		(A) 2015 July		(B) 2015 August		(C) Total This Period
1	Plant Generation	$	2,417,737	$	4,792,487	$	7,210,224
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	6,094,831	$	4,226,203	$	10,321,034
3	Purchased Power	$	1,617,370	$	1,688,681	$	3,306,051
4	Wind Curtailment	$	168	$	239	$	408
5	Less: MISO ASM (Rev) Cost	$	17,249	$	9,608	$	26,857
6	Less: Intersystem Sales (Rev) Cost	$	(52,049)	$	(212,870)	$	(264,919)
7	Less: Asset Based Margins (Rev) Cost	$	(14,157)	$	133,318	$	119,161
8	Total Cost of Fuel	$	10,081,148	$	10,637,667	$	20,718,815
	KWH SALES						
9	Total Sales of Electricity		335,448,400		381,895,816		717,344,216
10	Less Inter-System Sales		(1,405,678)		(10,995,626)		(12,401,304)
11	Total kWh		334,042,722		370,900,190		704,942,912

12	Cost per KWH	0.029391
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	0.00563

kWh Information For The Billing Month of: August 2015

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	204,070,800	kWh
2	Non-Energy Adjustment Rider Sales	125,134	kWh
3	Total	204,195,934	kWh
	Non-Minnesota Sales		
4	Sales for Resale	227,800	kWh
5	Total Sales of Electricity (ND and SD)	166,476,456	kWh
6	Inter-System Sales	10,995,626	kWh
	Total kWh Sales	381,895,816	kWh

EFFECTIVE 11/2/2015
CYCLE 01 RATE LEVEL 31

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

Line No.	ENERGY COSTS	(A) 2015 August	(B) 2015 September	(C) Total This Period
1	Plant Generation	$ 4,792,487	$ 3,760,542	$ 8,553,029
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 4,226,203	$ 2,431,785	$ 6,657,988
3	Purchased Power	$ 1,688,681	$ 1,514,970	$ 3,203,651
4	Wind Curtailment	$ 239	$ 1,597	$ 1,837
5	Less: MISO ASM (Rev) Cost	$ 9,608	$ 15,789	$ 25,398
6	Less: Intersystem Sales (Rev) Cost	$ (212,870)	$ (182,128)	$ (394,998)
7	Less: Asset Based Margins (Rev) Cost	$ 133,318	$ 347	$ 133,665
8	Total Cost of Fuel	$ 10,637,667	$ 7,542,902	$ 18,180,570
	KWH SALES			
9	Total Sales of Electricity	381,895,816	373,680,545	755,576,361
10	Less Inter-System Sales	(10,995,626)	(9,096,538)	(20,092,164)
11	Total kWh	370,900,190	364,584,007	735,484,197

12	Cost per KWH	0.024719
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	0.00096

kWh Information For The Billing Month of: September 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	202,307,495	kWh
2	Non-Energy Adjustment Rider Sales	158,621	kWh
3	Total	202,466,116	kWh
	Non-Minnesota Sales		
4	Sales for Resale	216,613	kWh
5	Total Sales of Electricity (ND and SD)	161,901,278	kWh
6	Inter-System Sales	9,096,538	kWh
	Total kWh Sales	373,680,545	kWh

EFFECTIVE 12/1/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

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

Line No.	ENERGY COSTS		(A) 2015 September		(B) 2015 October		(C) Total This Period
1	Plant Generation	$	3,760,542	$	3,933,633	$	7,694,175
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	2,431,785	$	2,508,547	$	4,940,332
3	Purchased Power	$	1,514,970	$	1,779,771	$	3,294,741
4	Wind Curtailment	$	1,597	$	38,906	$	40,504
5	Less: MISO ASM (Rev) Cost	$	15,789	$	23,074	$	38,863
6	Less: Intersystem Sales (Rev) Cost	$	(182,128)	$	(191,642)	$	(373,770)
7	Less: Asset Based Margins (Rev) Cost	$	347	$	(6,549)	$	(6,202)
8	Total Cost of Fuel	$	7,542,902	$	8,085,740	$	15,628,643
	KWH SALES						
9	Total Sales of Electricity		373,680,545		350,610,783		724,291,328
10	Less Inter-System Sales		(9,096,538)		(7,978,848)		(17,075,386)
11	Total kWh		364,584,007		342,631,935		707,215,942

12	Cost per KWH	0.022099
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	(0.00166)

kWh Information For The Billing Month of: October 2015

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	186,659,298	kWh
2	Non-Energy Adjustment Rider Sales	109,165	kWh
3	Total	186,768,463	kWh
	Non-Minnesota Sales		
4	Sales for Resale	190,441	kWh
5	Total Sales of Electricity (ND and SD)	155,673,031	kWh
6	Inter-System Sales	7,978,848	kWh
	Total kWh Sales	350,610,783	kWh

EFFECTIVE 1/4/2016

CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING NOVEMBER 30, 2015
FOR BILLINGS TO BE EFFECTIVE JANUARY 4, 2016

Line No.	ENERGY COSTS		(A) 2015 October		(B) 2015 November		(C) Total This Period
1	Plant Generation	$	3,933,633	$	4,583,538	$	8,517,171
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	2,508,547	$	2,457,118	$	4,965,665
3	Purchased Power	$	1,779,771	$	1,563,892	$	3,343,664
4	Wind Curtailment	$	38,906	$	20,518	$	59,424
5	Less: MISO ASM (Rev) Cost	$	23,074	$	16,780	$	39,854
6	Less: Intersystem Sales (Rev) Cost	$	(191,642)	$	(356,020)	$	(547,662)
7	Less: Asset Based Margins (Rev) Cost	$	(6,549)	$	92,667	$	86,118
8	Total Cost of Fuel	$	8,085,740	$	8,378,494	$	16,464,234
	KWH SALES						
9	Total Sales of Electricity		350,610,783		376,293,818		726,904,601
10	Less Inter-System Sales		(7,978,848)		(17,248,637)		(25,227,485)
11	Total kWh		342,631,935		359,045,181		701,677,116

12	Cost per KWH	0.023464
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	(0.00030)

kWh Information For The Billing Month of: November 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	190,496,284	kWh
2	Non-Energy Adjustment Rider Sales	140,395	kWh
3	Total	190,636,679	kWh
	Non-Minnesota Sales		
4	Sales for Resale	245,844	kWh
5	Total Sales of Electricity (ND and SD)	168,162,658	kWh
6	Inter-System Sales	17,248,637	kWh
	Total kWh Sales	376,293,818	kWh

EFFECTIVE 2/1/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING DECEMBER 31, 2015
FOR BILLINGS TO BE EFFECTIVE FEBRUARY 1, 2016

Line No.	ENERGY COSTS	(A) 2015 November	(B) 2015 December	(C) Total This Period
1	Plant Generation	$ 4,583,538	$ 4,320,840	$ 8,904,379
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 2,457,118	$ 4,861,814	$ 7,318,932
3	Purchased Power	$ 1,563,892	$ 1,580,811	$ 3,144,703
4	Wind Curtailment	$ 20,518	$ 2,574	$ 23,092
5	Less: MISO ASM (Rev) Cost	$ 16,780	$ 14,914	$ 31,694
6	Less: Intersystem Sales (Rev) Cost	$ (356,020)	$ (295,307)	$ (651,327)
7	Less: Asset Based Margins (Rev) Cost	$ 92,667	$ (23,359)	$ 69,308
8	Total Cost of Fuel	$ 8,378,494	$ 10,462,288	$ 18,840,782
	KWH SALES			
9	Total Sales of Electricity	376,293,818	417,215,155	793,508,973
10	Less Inter-System Sales	(17,248,637)	(14,825,957)	(32,074,594)
11	Total kWh	359,045,181	402,389,198	761,434,379

Line		
12	Cost per KWH	0.024744
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	0.00098

kWh Information For The Billing Month of: December 2015

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	206,803,149	kWh
2	Non-Energy Adjustment Rider Sales	166,442	kWh
3	Total	206,969,591	kWh
	Non-Minnesota Sales		
4	Sales for Resale	428,095	kWh
5	Total Sales of Electricity (ND and SD)	194,991,512	kWh
6	Inter-System Sales	14,825,957	kWh
	Total kWh Sales	417,215,155	kWh

EFFECTIVE 3/2/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JANUARY 31, 2016
FOR BILLINGS TO BE EFFECTIVE MARCH 2, 2016

Line No.	ENERGY COSTS	(A) 2015 December	(B) 2016 January	(C) Total This Period
1	Plant Generation	$ 4,320,840	$ 5,784,232	$ 10,105,072
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 4,861,814	$ 3,867,396	$ 8,729,210
3	Purchased Power	$ 1,580,811	$ 1,724,425	$ 3,305,236
4	Wind Curtailment	$ 2,574	$ 8,552	$ 11,127
5	Less: MISO ASM (Rev) Cost	$ 14,914	$ 11,252	$ 26,166
6	Less: Intersystem Sales (Rev) Cost	$ (295,307)	$ (219,620)	$ (514,927)
7	Less: Asset Based Margins (Rev) Cost	$ (23,359)	$ (32,495)	$ (55,853)
8	Total Cost of Fuel	$ 10,462,288	$ 11,143,743	$ 21,606,031
	KWH SALES			
9	Total Sales of Electricity	417,215,155	491,682,615	908,897,770
10	Less Inter-System Sales	(14,825,957)	(11,718,957)	(26,544,914)
11	Total kWh	402,389,198	479,963,658	882,352,856

12	Cost per KWH	0.024487
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	0.00072

kWh Information For The Billing Month of: January 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	242,300,867	kWh
2	Non-Energy Adjustment Rider Sales	202,097	kWh
3	Total	242,502,964	kWh
	Non-Minnesota Sales		
4	Sales for Resale	501,905	kWh
5	Total Sales of Electricity (ND and SD)	236,958,789	kWh
6	Inter-System Sales	11,718,957	kWh
	Total kWh Sales	491,682,615	kWh

EFFECTIVE 4/1/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING FEBRUARY 29, 2016
FOR BILLINGS TO BE **EFFECTIVE APRIL 1 thru APRIL 15, 2016**

Line No.	ENERGY COSTS	(A) 2016 January	(B) 2016 February	(C) Total This Period
1	Plant Generation	$ 5,784,232	$ 5,018,225	$ 10,802,457
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 3,867,396	$ 3,130,770	$ 6,998,166
3	Purchased Power	$ 1,724,425	$ 1,848,907	$ 3,573,332
4	Wind Curtailment	$ 8,552	$ 10,002	$ 18,554
5	Less: MISO ASM (Rev) Cost	$ 11,252	$ 9,466	$ 20,718
6	Less: Intersystem Sales (Rev) Cost	$ (219,620)	$ (324,472)	$ (544,092)
7	Less: Asset Based Margins (Rev) Cost	$ (32,495)	$ (5,416)	$ (37,910)
8	Total Cost of Fuel	$ 11,143,743	$ 9,687,483	$ 20,831,226
	KWH SALES			
9	Total Sales of Electricity	491,682,615	489,167,233	980,849,848
10	Less Inter-System Sales	(11,718,957)	(16,968,957)	(28,687,914)
11	Total kWh	479,963,658	472,198,276	952,161,934

Line No.		
12	Cost per KWH	0.021878
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	(0.00189)

kWh Information For The Billing Month of: February 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	247,501,763	kWh
2	Non-Energy Adjustment Rider Sales	198,355	kWh
3	Total	247,700,118	kWh
	Non-Minnesota Sales		
4	Sales for Resale	514,095	kWh
5	Total Sales of Electricity (ND and SD)	223,984,063	kWh
6	Inter-System Sales	16,968,957	kWh
	Total kWh Sales	489,167,233	kWh

EFFECTIVE 4/16/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING FEBRUARY 29, 2016
FOR BILLINGS TO BE **EFFECTIVE APRIL 16 thru APRIL 30, 2016**

Line No.	ENERGY COSTS	(A) 2016 January	(B) 2016 February	(C) Total This Period
1	Plant Generation	$ 5,784,232	$ 5,018,225	$ 10,802,457
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 3,867,396	$ 3,130,770	$ 6,998,166
3	Purchased Power	$ 1,724,425	$ 1,848,907	$ 3,573,332
4	Wind Curtailment	$ 8,552	$ 10,002	$ 18,554
5	Less: MISO ASM (Rev) Cost	$ 11,252	$ 9,466	$ 20,718
6	Less: Intersystem Sales (Rev) Cost	$ (219,620)	$ (324,472)	$ (544,092)
7	Less: Asset Based Margins (Rev) Cost	$ (32,495)	$ (5,416)	$ (37,910)
8	Total Cost of Fuel	$ 11,143,743	$ 9,687,483	$ 20,831,226
	KWH SALES			
9	Total Sales of Electricity	491,682,615	489,167,233	980,849,848
10	Less Inter-System Sales	(11,718,957)	(16,968,957)	(28,687,914)
11	Total kWh	479,963,658	472,198,276	952,161,934

12	Cost per KWH	0.021878
13	Base Cost	0.024640
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	(0.00336)

kWh Information For The Billing Month of: February 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	247,501,763	kWh
2	Non-Energy Adjustment Rider Sales	198,355	kWh
3	Total	247,700,118	kWh
	Non-Minnesota Sales		
4	Sales for Resale	514,095	kWh
5	Total Sales of Electricity (ND and SD)	223,984,063	kWh
6	Inter-System Sales	16,968,957	kWh
	Total kWh Sales	489,167,233	kWh

EFFECTIVE 5/2/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MARCH 31, 2016
FOR BILLINGS TO BE EFFECTIVE MAY 2, 2016

Line No.	ENERGY COSTS		(A) 2016 February		(B) 2016 March		(C) Total This Period
1	Plant Generation	$	5,018,225	$	4,898,195	$	9,916,420
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,130,770	$	3,129,472	$	6,260,243
3	Purchased Power	$	1,848,907	$	2,092,587	$	3,941,494
4	Wind Curtailment	$	10,002	$	27,993	$	37,995
5	Less: MISO ASM (Rev) Cost	$	9,466	$	(1,220)	$	8,246
6	Less: Intersystem Sales (Rev) Cost	$	(324,472)	$	(247,549)	$	(572,020)
7	Less: Asset Based Margins (Rev) Cost	$	(5,416)	$	(12,231)	$	(17,646)
8	Total Cost of Fuel	$	9,687,483	$	9,887,249	$	19,574,731
	KWH SALES						
9	Total Sales of Electricity		489,167,233		448,064,932		937,232,165
10	Less Inter-System Sales		(16,968,957)		(13,391,699)		(30,360,656)
11	Total kWh		472,198,276		434,673,233		906,871,509
12	Cost per KWH				0.021585		
13	Base Cost				0.024640		
14	Annual True-Up Factor				-0.0006		
15	Energy Adjustment per kWh				(0.00366)		

kWh Information For The Billing Month of: March 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	230,702,205	kWh
2	Non-Energy Adjustment Rider Sales	188,669	kWh
3	Total	230,890,874	kWh
	Non-Minnesota Sales		
4	Sales for Resale	313,566	kWh
5	Total Sales of Electricity (ND and SD)	203,468,793	kWh
6	Inter-System Sales	13,391,699	kWh
	Total kWh Sales	448,064,932	kWh

EFFECTIVE 6/2/2016

CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING APRIL 30, 2016
FOR BILLINGS TO BE EFFECTIVE JUNE 2, 2016

Line No.	ENERGY COSTS		(A) 2016 March		(B) 2016 April		(C) Total This Period
1	Plant Generation	$	4,898,195	$	3,049,074	$	7,947,269
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	3,129,472	$	2,611,096	$	5,740,569
3	Purchased Power	$	2,092,587	$	2,267,231	$	4,359,818
4	Wind Curtailment	$	27,993	$	20,204	$	48,197
5	Less: MISO ASM (Rev) Cost	$	(1,220)	$	(4,074)	$	(5,293)
6	Less: Intersystem Sales (Rev) Cost	$	(247,549)	$	(214,795)	$	(462,343)
7	Less: Asset Based Margins (Rev) Cost	$	(12,231)	$	(29,597)	$	(41,828)
8	Total Cost of Fuel	$	9,887,249	$	7,699,140	$	17,586,389
	KWH SALES						
9	Total Sales of Electricity		448,064,932		408,004,058		856,068,990
10	Less Inter-System Sales		(13,391,699)		(10,628,274)		(24,019,973)
11	Total kWh		434,673,233		397,375,784		832,049,017

12	Cost per KWH	0.021136
13	Base Cost	0.024640
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	(0.00410)

kWh Information For The Billing Month of: April 2016

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	213,119,802	kWh
2	Non-Energy Adjustment Rider Sales	152,571	kWh
3	Total	213,272,373	kWh
	Non-Minnesota Sales		
4	Sales for Resale	275,945	kWh
5	Total Sales of Electricity (ND and SD)	183,827,466	kWh
6	Inter-System Sales	10,628,274	kWh
	Total kWh Sales	408,004,058	kWh

EFFECTIVE 7/1/2016

CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MAY 31, 2016
FOR BILLINGS TO BE EFFECTIVE JULY 1, 2016

Line No.	ENERGY COSTS		(A) 2016 April		(B) 2016 May		(C) Total This Period
1	Plant Generation	$	3,049,074	$	2,371,042	$	5,420,116
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	2,611,096	$	2,486,121	$	5,097,218
3	* May 2013 MISO Day 2 Charge RSG_MWP	$	-	$	(37,058)	$	(37,058)
4	Purchased Power	$	2,267,231	$	1,932,836	$	4,200,067
5	Wind Curtailment	$	20,204	$	59,843	$	80,048
6	Less: MISO ASM (Rev) Cost	$	(4,074)	$	2,344	$	(1,730)
7	Less: Intersystem Sales (Rev) Cost	$	(214,795)	$	(144,748)	$	(359,542)
8	Less: Asset Based Margins (Rev) Cost	$	(29,597)	$	5,219	$	(24,378)
9	Total Cost of Fuel	$	7,699,140	$	6,675,600	$	14,374,740
	KWH SALES						
10	Total Sales of Electricity		408,004,058		356,197,746		764,201,804
11	Less Inter-System Sales		(10,628,274)		(6,999,578)		(17,627,852)
12	Total kWh		397,375,784		349,198,168		746,573,952

Line		
13	Cost per KWH	0.019254
14	Base Cost	0.024640
15	Annual True-Up Factor	-0.0006
16	Energy Adjustment per kWh	(0.00599)

* In Docket No. E999/AA-13-599 the June 2, 2016, Order the Commission accepted Otter Tail's identification of and explanation for the higher Revenue Sufficiency Guarantee Make-Whole Payments in May 2013. The Commission is disallowing recovery of $37,058.

kWh Information For The Billing Month of: May 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	195,433,968	kWh
2	Non-Energy Adjustment Rider Sales	135,378	kWh
3	Total	195,569,346	kWh
	Non-Minnesota Sales		
4	Sales for Resale	241,189	kWh
5	Total Sales of Electricity (ND and SD)	153,387,633	kWh
6	Inter-System Sales	6,999,578	kWh
	Total kWh Sales	356,197,746	kWh

EFFECTIVE 8/2/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JUNE 30, 2016
FOR BILLINGS TO BE EFFECTIVE AUGUST 2, 2016

Line No.	ENERGY COSTS		(A) 2016 May		(B) 2016 June		(C) Total This Period
1	Plant Generation	$	2,371,042	$	4,569,520	$	6,940,562
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	2,486,121	$	2,905,867	$	5,391,988
3	* May 2013 MISO Day 2 Charge RSG_MWP	$	(37,058)	$	-	$	(37,058)
4	Purchased Power	$	1,932,836	$	1,736,705	$	3,669,541
5	Wind Curtailment	$	59,843	$	11,134	$	70,977
6	Less: MISO ASM (Rev) Cost	$	2,344	$	(20,020)	$	(17,676)
7	Less: Intersystem Sales (Rev) Cost	$	(144,748)	$	(335,553)	$	(480,301)
8	Less: Asset Based Margins (Rev) Cost	$	5,219	$	(95,936)	$	(90,717)
9	Total Cost of Fuel	$	6,675,600	$	8,771,716	$	15,447,316
	KWH SALES						
10	Total Sales of Electricity		356,197,746		358,566,884		714,764,630
11	Less Inter-System Sales		(6,999,578)		(19,032,774)		(26,032,352)
12	Total kWh		349,198,168		339,534,110		688,732,278
13	Cost per KWH				0.022429		
14	Base Cost				0.024640		
15	Annual True-Up Factor				-0.0006		
16	Energy Adjustment per kWh				(0.00281)		

* In Docket No. E999/AA-13-599 the June 2, 2016, Order the Commission accepted Otter Tail's identification of and explanation for the higher Revenue Sufficiency Guarantee Make-Whole Payments in Jun 2013. The Commission is disallowing recovery of $37,058.

kWh Information For The Billing Month of: June 2016

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	188,149,034	kWh
2	Non-Energy Adjustment Rider Sales	131,438	kWh
3	Total	188,280,472	kWh
	Non-Minnesota Sales		
4	Sales for Resale	(13,561)	kWh
5	Total Sales of Electricity (ND and SD)	151,267,199	kWh
6	Inter-System Sales	19,032,774	kWh
	Total kWh Sales	358,566,884	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.

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

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.
On October 6, 2015, the Commission approved Otter Tail's compliance report and the annual true-up credit of 0. 6 mills per kWh.

On July 29, 2016, Otter Tail filed a Notice of Implementation along with the calculation of the true-up for the period of July 2015 to June 2016 to be applied during the time period of September 1, 2016 to August 31, 2017. The amount of this year's true-up is a credit of 0. 3 mills per kWh. (Part E Section 8 Attachment E)

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OTTER TAIL POWER COMPANY

July 29, 2016

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, 2015 through June 30, 2016, starting with bills dated September 1, 2016 and continuing for 12 months. The amount of this year's true-up is a credit of $757,659, which will be refunded in the monthly rates applied to sales that are subject to the FCA from September 2016 through August 2017.

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, 2015, Otter Tail over-collected the target amount by $39,275. This amount is included in the $757,659 credit amount referred to above. Any true-up difference for the period ending August 2016 will be reported in the 2017 annual filing and included, if applicable, in that annual true-up calculation.

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 2015 through June 2016

	(A)		(B)	(C)	(D)	(E)	(F)	(G)		(H)
Line No.	**Month**	*Source:*	**FCA Revenue** *Monthly Billings*	*True-up Rate*	**Subtract Last Year's True-up** *(C)*(F)*	**Net FCA Revenue** *(B)-(D)*	**MN kWh Sales Subject to COE** *FCA Calculation*	**Total System Energy Cost** *FCA Calculation*		**Total System Sales** *FCA Calculation*
1	Jul-15		($160,586)	$0.0008	$139,081	($299,666)	173,850,633	$10,081,148		334,042,722
2	Aug-15		$117,959	$0.0008	$163,257	($45,298)	204,070,800	$10,637,667		370,900,190
3	Sep-15		$618,348	($0.0006)	($121,384)	$739,732	202,307,495	$7,542,902		364,584,007
4	Oct-15		$1,046,273	($0.0006)	($111,996)	$1,158,269	186,659,298	$8,085,740		342,631,935
5	Nov-15		$192,273	($0.0006)	($114,298)	$306,571	190,496,284	$8,378,494		359,045,181
6	Dec-15		($347,568)	($0.0006)	($124,082)	($223,486)	206,803,149	$10,462,288		402,389,198
7	Jan-16		($72,355)	($0.0006)	($145,381)	$73,026	242,300,867	$11,143,743		479,963,658
8	Feb-16		$237,199	($0.0006)	($148,501)	$385,700	247,501,763	$9,687,483		472,198,276
9	Mar-16		$165,854	($0.0006)	($138,421)	$304,275	230,702,205	$9,887,249		434,673,233
10	Apr-16	4/1-15	$427,349	($0.0006)	($127,872)	($360,838)	127,479,310	$7,699,140		397,375,784
		4/16-30	($916,059)				85,640,492			
11	May-16		($713,318)	($0.0006)	($117,260)	($596,058)	195,433,968	$6,675,600	(7)	349,198,168
12	Jun-16		($768,542)	($0.0006)	($112,889)	($655,653)	188,149,034	$8,771,716		339,534,110
13	**Totals**		($173,173)		($959,747)	$786,574	2,481,395,298	$109,053,170		4,646,536,462

Line No.					
14	kWh subject to COE July 2015 - April 15, 201		2,012,171,804		
	kWh subject to COE April 16, 2016 - June 201		469,223,494		
15	Recovery from FCA		$786,574		
16	Recovery from base cost	(1)	$58,169,602		
17	Total adjusted recovery	(2)	$58,956,176	% over/(under)	
18	Actual energy cost	(3)	$58,237,792	Recovery (5)	
19	**Over/(under) recovery**	(4)	**$718,384**	1.23%	
20	**Plus over collection from prior year**	(6)	**$39,275**		
21	**Refund to Customers**		**$757,659**		
22	**Annual True-up Factor**		**$0.0003**		
23	**Base cost =**	**$0.023163**	July 2015 - April 15, 2016		
	Base cost =	**$0.024640**	April 16, 2016 - June 2016		

(1) Recovery from base cost: $0.023163 x MN kWh sales subject to FCA (Jul 2015 - Apr 15, 2016) $0.024640 x MN kWh sales subject to FCA (Apr 16, 2016 - June 2016)
(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 over collected the previous period's true-up, so there is an adjustment to the calculation.
(7) Includes $37,058 disallowance recovery of May 2013 Revenue Sufficiency Guarantee Make-Whole Payments in Docket No. E999/AA-13-599 June 2, 2016 Order.

Previous True-up Amount to be collected (Sep 2014 - Aug 2015) was:	**($1,831,116)**
Amount collected (Sep 2014 - Aug 2015) was:	**$1,870,391**
OTP over/(under)collected:	**$39,275**

(a) Current approved True-up Amt - over/(under) collection	**$1,277,175**
(b) Amount collected (refunded) to-date (Sept 2015 - June 2016):	($1,262,084)
(c) Net Balance remaining (a) + (b)	$15,091
(d) Estimated collections/(refunds) to be received (Jul and Aug 2016)	($226,753)
(e) Projected balance yet to be refunded	($211,662)

% of MN sales (subject to FCA) to system	53.4031%
Energy costs allocated to MN for sales subject to FCA	$58,237,792

Documentation Requirement 6.a. (1)

BILL IMPACT BY CUSTOMER CLASS

	Sep-16	Oct	Nov	Dec	Jan-17	Feb	Mar	Apr	May	Jun	Jul	Aug	Total
Residential	$ (11,849)	$ (10,807)	$ (13,055)	$ (16,376)	$ (21,162)	$ (20,701)	$ (18,149)	$ (14,414)	$ (11,594)	$ (11,216)	$ (12,212)	$ (12,806)	$ (174,340)
Farm	$ (1,049)	$ (925)	$ (1,117)	$ (1,086)	$ (1,170)	$ (1,155)	$ (1,035)	$ (914)	$ (807)	$ (791)	$ (1,023)	$ (1,239)	$ (12,310)
General Service	$ (6,100)	$ (5,572)	$ (6,460)	$ (7,477)	$ (8,783)	$ (8,793)	$ (7,822)	$ (6,966)	$ (5,676)	$ (5,655)	$ (6,193)	$ (6,382)	$ (186,650)
Large General Service	$ (18,320)	$ (17,617)	$ (18,762)	$ (18,855)	$ (19,835)	$ (20,086)	$ (18,383)	$ (18,124)	$ (16,877)	$ (17,191)	$ (17,635)	$ (18,096)	$ (219,779)
OPA	$ (505)	$ (467)	$ (482)	$ (496)	$ (548)	$ (558)	$ (527)	$ (542)	$ (512)	$ (521)	$ (526)	$ (508)	$ (6,191)
Street & Area Lighting	$ (255)	$ (259)	$ (264)	$ (274)	$ (284)	$ (320)	$ (262)	$ (257)	$ (252)	$ (250)	$ (249)	$ (250)	$ (225,970)
Pipelines	$ (29,273)	$ (25,848)	$ (28,769)	$ (29,119)	$ (21,743)	$ (22,184)	$ (19,542)	$ (21,310)	$ (19,893)	$ (19,090)	$ (19,158)	$ (26,300)	$ (282,229)
Total Debit	$ (67,352)	$ (61,493)	$ (68,908)	$ (73,682)	$ (73,524)	$ (73,796)	$ (65,719)	$ (62,528)	$ (55,611)	$ (54,714)	$ (56,997)	$ (65,581)	$ (779,905)

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 2015 through June 2016)

Documentation Requirement 6.c. (1)

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

	Sep-16	Oct	Nov	Dec	Jan-17	Feb	Mar	Apr	May	Jun	Jul	Aug	Total
Residential	39,495	36,022	43,516	54,587	70,540	69,003	60,495	48,047	38,647	37,388	40,707	42,688	581,132
Farm	3,498	3,084	3,722	3,619	3,899	3,849	3,449	3,048	2,691	2,637	3,411	4,128	41,033
General Service	20,333	18,572	21,534	24,925	29,277	29,309	26,073	23,221	18,920	18,851	20,645	21,273	272,932
Large General Service	61,066	58,722	62,540	62,849	66,117	66,955	61,277	60,413	56,256	57,302	58,783	60,320	732,598
OPA	1,685	1,555	1,606	1,652	1,825	1,859	1,756	1,808	1,707	1,737	1,753	1,695	20,637
Street & Area Lighting	851	864	881	912	947	1,065	874	858	841	833	829	834	10,589
Pipelines	97,577	86,159	95,896	97,062	72,478	73,947	65,140	71,033	66,310	63,633	63,861	87,666	940,762
Subject to FCA true-up	224,505	204,978	229,693	245,606	245,081	245,985	219,063	208,427	185,371	182,381	189,989	218,603	2,599,683
Total forecast	224,505	204,978	229,693	245,606	245,081	245,985	219,063	208,427	185,371	182,381	189,989	218,603	2,599,683

(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)

Otter Tail Power Company
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	

Otter Tail Power Company
Plant Conditions for July 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 - Extended due to main turbine blading issues	0	
Coyote	175,620	100.0	56.2	0.00			9.00	Over
Hoot Lake Unit 2	17,473	100.0	100.0	0.00			7.86	Over
Hoot Lake Unit 3	22,691	100.0	100.0	0.00			7.86	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)

Otter Tail Power Company
Plant Conditions for August 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	208,019	80.9	67.7	1.32 3.61	Forced Scheduled	Gas Recirc Fan Vibration Planned AQCS Outage - Extended (Main Turbine)	3.88	Over
Coyote	174,154	100.0	56.2	0.00			10.04	Over
Hoot Lake Unit 2	9,044	100.0	99.9	0.00			8.42	Over
Hoot Lake Unit 3	12,154	100.0	99.9	0.00			8.43	Over

Otter Tail Power Company
Plant Conditions for September 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	195,044	75.9	71.8	3.00 4.24	Forced Scheduled	Secondary Superheat Tube Leak Install SCR Testing Grid & Fix Turbine Valve Leaks	1.41	Under
Coyote	168,119	100.0	56.2	0.00			10.62	Over
Hoot Lake Unit 2	3,465	100.0	100.0	0.00			13.89	Over
Hoot Lake Unit 3	0	95.5	95.5	1.35	Forced	Tube Leak		

(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)

Otter Tail Power Company
Plant Conditions for October 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	198,079	87.5	86.5	3.73	Scheduled	Outage to modify scrubber inlet ductwork	2.25	Under
Coyote	170,982	100.0	56.2	0.00			7.19	Over
Hoot Lake Unit 2	0	100.0	100.0	0.00				
Hoot Lake Unit 3	0	100.0	100.0	0.00				

Otter Tail Power Company
Plant Conditions for November 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	182,238	99.7	89.3	2.37	Scheduled	Outage to modify scrubber inlet ductwork	7.84	Over
Coyote	154,156	94.6	53.0	1.61	Forced	A Circulating Water Pump Breaker Failure	6.01	Over
Hoot Lake Unit 2	19,714	93.5	92.2	1.96	Forced	Steam Leak on Turbine Flange	52.65	Over
Hoot Lake Unit 3	1,838	91.2	99.9	0.00			52.64	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)

Otter Tail Power Company
Plant Conditions for December 2015

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	191,887	100.0	99.8				2.99	Over
Coyote	106,773	62.7	35.8	5.09 4.92 1.55	Scheduled Scheduled Scheduled	Wash Outage and "A" BFP Install Extended Outage Remove Strainers from "A" BFP	5.43	Over
Hoot Lake Unit 2	22,812	96.4	96.4	1.10	Scheduled	Tube Leak	26.8	Over
Hoot Lake Unit 3	0	100.0	100.0	0.00				

Otter Tail Power Company
Plant Conditions for January 2016

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	235,910	99.7	98.6				0.82	Under
Coyote	278,176	100.0	97.3				3.12	Over
Hoot Lake Unit 2	24,205	100.0	100.0				15.54	Over
Hoot Lake Unit 3	0	100.0	100.0					

(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)

Otter Tail Power Company
Plant Conditions for February 2016

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	180,346	100.0	97.7				1.99	Under
Coyote	247,945	100.0	99.8				3.84	Over
Hoot Lake Unit 2	17,671	97.0	96.9				5.31	Over
Hoot Lake Unit 3	10,433	100.0	99.9				5.46	Over

Otter Tail Power Company
Plant Conditions for March 2016

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	130,516	80.2	80.1	3.27 2.84	Scheduled Forced	Maintenance Outage to Inspect SCR BFP B Isolation Valve Packing Leak	0.48	Over
Coyote	157,955	62.9	62.8	11.49	Scheduled	10 Week Outage	4.27	Over
Hoot Lake Unit 2	26,701	100.0	99.9				1.10	Under
Hoot Lake Unit 3	38,474	100.0	99.9				1.17	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)

Otter Tail Power Company
Plant Conditions for April 2016

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	151,615	100.0	99.9				0.21	Under
Coyote	0	0.0	0.0	20.00	Scheduled	10 Week Outage	0.00	
Hoot Lake Unit 2	6,610	99.3	97.9				1.29	Under
Hoot Lake Unit 3	15,922	96.9	95.9				1.39	Under

Otter Tail Power Company
Plant Conditions for May 2016

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	155,599	99.9	93.6				0.3	Under
Coyote	0	0.0	0.0	1.25 29.75	Scheduled Scheduled	Extended Outage 10 Week Outage	0.00	
Hoot Lake Unit 2	0	98.1	98.1				0.00	
Hoot Lake Unit 3	0	100.0	100.0				0.00	

(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)

Otter Tail Power Company
Plant Conditions for June 2016

Plant	Net MWh	Unit Availability %	Equivalent Availability %	Outage Days	Outage Type	Outage Reason	Fuel Prices %	Fuel Prices Actual vs Budget
Big Stone	204,152	100.0	98.2				0.56	Under
Coyote	187,156	69.5	59.1	1.62 1.22 6.31	Forced Forced Scheduled	Windbox Leak MFT Air Flow Fixing Boiler Door Extended Outage	5.48	Over
Hoot Lake Unit 2	346	94.7	94.7	2.17	Scheduled	Ductwork repair and tube leak repair	6.58	Over
Hoot Lake Unit 3	394	92.8	92.8	2.12	Scheduled	Tube lead and insulation repairs	6.74	Over

(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, 2015
FOR BILLINGS TO BE EFFECTIVE SEPTEMBER 1, 2015

Line No.	ENERGY COSTS		(A) 2015 June		(B) 2015 July		(C) Total This Period
1	Plant Generation	$	1,027,126	$	2,417,737	$	3,444,863
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	4,480,717	$	6,094,831	$	10,575,549
3	Purchased Power	$	1,933,630	$	1,617,370	$	3,551,000
4	Wind Curtailment	$	115	$	168	$	283
5	Less: MISO ASM (Rev) Cost	$	15,050	$	17,249	$	32,298
6	Less: Intersystem Sales (Rev) Cost	$	(26,749)	$	(52,049)	$	(78,799)
7	Less: Asset Based Margins (Rev) Cost	$	(680)	$	(14,157)	$	(14,837)
8	Total Cost of Fuel	$	7,429,209	$	10,081,148	$	17,510,357
	KWH SALES						
9	Total Sales of Electricity		320,013,031		335,448,400		655,461,431
10	Less Inter-System Sales		(1,589,943)		(1,405,678)		(2,995,621)
11	Total kWh		318,423,088		334,042,722		652,465,810

12	Cost per KWH	0.026837
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	0.00307

kWh Information For The Billing Month of: July 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	173,850,633	kWh
2	Non-Energy Adjustment Rider Sales	133,505	kWh
3	Total	173,984,138	kWh
	Non-Minnesota Sales		
4	Sales for Resale	173,133	kWh
5	Total Sales of Electricity (ND and SD)	159,885,451	kWh
6	Inter-System Sales	1,405,678	kWh
	Total kWh Sales	335,448,400	kWh

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EFFECTIVE 10/2/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

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

Line No.	ENERGY COSTS	(A) 2015 July	(B) 2015 August	(C) Total This Period
1	Plant Generation	$ 2,417,737	$ 4,792,487	$ 7,210,224
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 6,094,831	$ 4,226,203	$ 10,321,034
3	Purchased Power	$ 1,617,370	$ 1,688,681	$ 3,306,051
4	Wind Curtailment	$ 168	$ 239	$ 408
5	Less: MISO ASM (Rev) Cost	$ 17,249	$ 9,608	$ 26,857
6	Less: Intersystem Sales (Rev) Cost	$ (52,049)	$ (212,870)	$ (264,919)
7	Less: Asset Based Margins (Rev) Cost	$ (14,157)	$ 133,318	$ 119,161
8	Total Cost of Fuel	$ 10,081,148	$ 10,637,667	$ 20,718,815
	KWH SALES			
9	Total Sales of Electricity	335,448,400	381,895,816	717,344,216
10	Less Inter-System Sales	(1,405,678)	(10,995,626)	(12,401,304)
11	Total kWh	334,042,722	370,900,190	704,942,912
12	Cost per KWH		0.029391	
13	Base Cost		0.023163	
14	Annual True-Up Factor		-0.0006	
15	Energy Adjustment per kWh		0.00563	

kWh Information For The Billing Month of: August 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	204,070,800	kWh
2	Non-Energy Adjustment Rider Sales	125,134	kWh
3	Total	204,195,934	kWh
	Non-Minnesota Sales		
4	Sales for Resale	227,800	kWh
5	Total Sales of Electricity (ND and SD)	166,476,456	kWh
6	Inter-System Sales	10,995,626	kWh
	Total kWh Sales	381,895,816	kWh

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EFFECTIVE 11/2/2015
CYCLE 01 RATE LEVEL 31

MINNESOTA

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

Line No.	ENERGY COSTS	(A) 2015 August	(B) 2015 September	(C) Total This Period
1	Plant Generation	$ 4,792,487	$ 3,760,542	$ 8,553,029
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 4,226,203	$ 2,431,785	$ 6,657,988
3	Purchased Power	$ 1,688,681	$ 1,514,970	$ 3,203,651
4	Wind Curtailment	$ 239	$ 1,597	$ 1,837
5	Less: MISO ASM (Rev) Cost	$ 9,608	$ 15,789	$ 25,398
6	Less: Intersystem Sales (Rev) Cost	$ (212,870)	$ (182,128)	$ (394,998)
7	Less: Asset Based Margins (Rev) Cost	$ 133,318	$ 347	$ 133,665
8	Total Cost of Fuel	$ 10,637,667	$ 7,542,902	$ 18,180,570
	KWH SALES			
9	Total Sales of Electricity	381,895,816	373,680,545	755,576,361
10	Less Inter-System Sales	(10,995,626)	(9,096,538)	(20,092,164)
11	Total kWh	370,900,190	364,584,007	735,484,197
12	Cost per KWH		0.024719	
13	Base Cost		0.023163	
14	Annual True-Up Factor		-0.0006	
15	Energy Adjustment per kWh		0.00096	

kWh Information For The Billing Month of: September 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	202,307,495	kWh
2	Non-Energy Adjustment Rider Sales	158,621	kWh
3	Total	202,466,116	kWh
	Non-Minnesota Sales		
4	Sales for Resale	216,613	kWh
5	Total Sales of Electricity (ND and SD)	161,901,278	kWh
6	Inter-System Sales	9,096,538	kWh
	Total kWh Sales	373,680,545	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA

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

Line No.	ENERGY COSTS		(A) 2015 September		(B) 2015 October		(C) Total This Period
1	Plant Generation	$	3,760,542	$	3,933,633	$	7,694,175
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	2,431,785	$	2,508,547	$	4,940,332
3	Purchased Power	$	1,514,970	$	1,779,771	$	3,294,741
4	Wind Curtailment	$	1,597	$	38,906	$	40,504
5	Less: MISO ASM (Rev) Cost	$	15,789	$	23,074	$	38,863
6	Less: Intersystem Sales (Rev) Cost	$	(182,128)	$	(191,642)	$	(373,770)
7	Less: Asset Based Margins (Rev) Cost	$	347	$	(6,549)	$	(6,202)
8	Total Cost of Fuel	$	7,542,902	$	8,085,740	$	15,628,643
	KWH SALES						
9	Total Sales of Electricity		373,680,545		350,610,783		724,291,328
10	Less Inter-System Sales		(9,096,538)		(7,978,848)		(17,075,386)
11	Total kWh		364,584,007		342,631,935		707,215,942
12	Cost per KWH				0.022099		
13	Base Cost				0.023163		
14	Annual True-Up Factor				-0.0006		
15	Energy Adjustment per kWh				(0.00166)		

kWh Information For The Billing Month of: October 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	186,659,298	kWh
2	Non-Energy Adjustment Rider Sales	109,165	kWh
3	Total	186,768,463	kWh
	Non-Minnesota Sales		
4	Sales for Resale	190,441	kWh
5	Total Sales of Electricity (ND and SD)	155,673,031	kWh
6	Inter-System Sales	7,978,848	kWh
	Total kWh Sales	350,610,783	kWh

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EFFECTIVE 1/4/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING NOVEMBER 30, 2015
FOR BILLINGS TO BE EFFECTIVE JANUARY 4, 2016

Line No.	ENERGY COSTS	(A) 2015 October	(B) 2015 November	(C) Total This Period
1	Plant Generation	$ 3,933,633	$ 4,583,538	$ 8,517,171
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 2,508,547	$ 2,457,118	$ 4,965,665
3	Purchased Power	$ 1,779,771	$ 1,563,892	$ 3,343,664
4	Wind Curtailment	$ 38,906	$ 20,518	$ 59,424
5	Less: MISO ASM (Rev) Cost	$ 23,074	$ 16,780	$ 39,854
6	Less: Intersystem Sales (Rev) Cost	$ (191,642)	$ (356,020)	$ (547,662)
7	Less: Asset Based Margins (Rev) Cost	$ (6,549)	$ 92,667	$ 86,118
8	Total Cost of Fuel	$ 8,085,740	$ 8,378,494	$ 16,464,234
	KWH SALES			
9	Total Sales of Electricity	350,610,783	376,293,818	726,904,601
10	Less Inter-System Sales	(7,978,848)	(17,248,637)	(25,227,485)
11	Total kWh	342,631,935	359,045,181	701,677,116

12	Cost per KWH	0.023464
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	(0.00030)

kWh Information For The Billing Month of: November 2015

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	190,496,284	kWh
2	Non-Energy Adjustment Rider Sales	140,395	kWh
3	Total	190,636,679	kWh
	Non-Minnesota Sales		
4	Sales for Resale	245,844	kWh
5	Total Sales of Electricity (ND and SD)	168,162,658	kWh
6	Inter-System Sales	17,248,637	kWh
	Total kWh Sales	376,293,818	kWh

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CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING DECEMBER 31, 2015
FOR BILLINGS TO BE EFFECTIVE FEBRUARY 1, 2016

Line No.	ENERGY COSTS	(A) 2015 November	(B) 2015 December	(C) Total This Period
1	Plant Generation	$ 4,583,538	$ 4,320,840	$ 8,904,379
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 2,457,118	$ 4,861,814	$ 7,318,932
3	Purchased Power	$ 1,563,892	$ 1,580,811	$ 3,144,703
4	Wind Curtailment	$ 20,518	$ 2,574	$ 23,092
5	Less: MISO ASM (Rev) Cost	$ 16,780	$ 14,914	$ 31,694
6	Less: Intersystem Sales (Rev) Cost	$ (356,020)	$ (295,307)	$ (651,327)
7	Less: Asset Based Margins (Rev) Cost	$ 92,667	$ (23,359)	$ 69,308
8	Total Cost of Fuel	$ 8,378,494	$ 10,462,288	$ 18,840,782
	KWH SALES			
9	Total Sales of Electricity	376,293,818	417,215,155	793,508,973
10	Less Inter-System Sales	(17,248,637)	(14,825,957)	(32,074,594)
11	Total kWh	359,045,181	402,389,198	761,434,379

Line No.		
12	Cost per KWH	0.024744
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	0.00098

kWh Information For The Billing Month of: December 2015

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	206,803,149	kWh
2	Non-Energy Adjustment Rider Sales	166,442	kWh
3	Total	206,969,591	kWh
	Non-Minnesota Sales		
4	Sales for Resale	428,095	kWh
5	Total Sales of Electricity (ND and SD)	194,991,512	kWh
6	Inter-System Sales	14,825,957	kWh
	Total kWh Sales	417,215,155	kWh

EFFECTIVE 3/2/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JANUARY 31, 2016
FOR BILLINGS TO BE EFFECTIVE MARCH 2, 2016

Line No.	ENERGY COSTS		(A) 2015 December		(B) 2016 January		(C) Total This Period
1	Plant Generation	$	4,320,840	$	5,784,232	$	10,105,072
2	MISO Day 2 Charges (not Schedule 16 & 17)	$	4,861,814	$	3,867,396	$	8,729,210
3	Purchased Power	$	1,580,811	$	1,724,425	$	3,305,236
4	Wind Curtailment	$	2,574	$	8,552	$	11,127
5	Less: MISO ASM (Rev) Cost	$	14,914	$	11,252	$	26,166
6	Less: Intersystem Sales (Rev) Cost	$	(295,307)	$	(219,620)	$	(514,927)
7	Less: Asset Based Margins (Rev) Cost	$	(23,359)	$	(32,495)	$	(55,853)
8	Total Cost of Fuel	$	10,462,288	$	11,143,743	$	21,606,031
	KWH SALES						
9	Total Sales of Electricity		417,215,155		491,682,615		908,897,770
10	Less Inter-System Sales		(14,825,957)		(11,718,957)		(26,544,914)
11	Total kWh		402,389,198		479,963,658		882,352,856

Line No.		
12	Cost per KWH	0.024487
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	0.00072

kWh Information For The Billing Month of: January 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	242,300,867	kWh
2	Non-Energy Adjustment Rider Sales	202,097	kWh
3	Total	242,502,964	kWh
	Non-Minnesota Sales		
4	Sales for Resale	501,905	kWh
5	Total Sales of Electricity (ND and SD)	236,958,789	kWh
6	Inter-System Sales	11,718,957	kWh
	Total kWh Sales	491,682,615	kWh

EFFECTIVE 4/1/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING FEBRUARY 29, 2016
FOR BILLINGS TO BE **EFFECTIVE APRIL 1 thru APRIL 15, 2016**

Line No.	ENERGY COSTS	(A) 2016 January	(B) 2016 February	(C) Total This Period
1	Plant Generation	$ 5,784,232	$ 5,018,225	$ 10,802,457
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 3,867,396	$ 3,130,770	$ 6,998,166
3	Purchased Power	$ 1,724,425	$ 1,848,907	$ 3,573,332
4	Wind Curtailment	$ 8,552	$ 10,002	$ 18,554
5	Less: MISO ASM (Rev) Cost	$ 11,252	$ 9,466	$ 20,718
6	Less: Intersystem Sales (Rev) Cost	$ (219,620)	$ (324,472)	$ (544,092)
7	Less: Asset Based Margins (Rev) Cost	$ (32,495)	$ (5,416)	$ (37,910)
8	Total Cost of Fuel	$ 11,143,743	$ 9,687,483	$ 20,831,226
	KWH SALES			
9	Total Sales of Electricity	491,682,615	489,167,233	980,849,848
10	Less Inter-System Sales	(11,718,957)	(16,968,957)	(28,687,914)
11	Total kWh	479,963,658	472,198,276	952,161,934

12	Cost per KWH	0.021878
13	Base Cost	0.023163
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	(0.00189)

kWh Information For The Billing Month of: February 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	247,501,763	kWh
2	Non-Energy Adjustment Rider Sales	198,355	kWh
3	Total	247,700,118	kWh
	Non-Minnesota Sales		
4	Sales for Resale	514,095	kWh
5	Total Sales of Electricity (ND and SD)	223,984,063	kWh
6	Inter-System Sales	16,968,957	kWh
	Total kWh Sales	489,167,233	kWh

EFFECTIVE 4/16/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING FEBRUARY 29, 2016
FOR BILLINGS TO BE **EFFECTIVE APRIL 16 thru APRIL 30, 2016**

Line No.	ENERGY COSTS	(A) 2016 January	(B) 2016 February	(C) Total This Period
1	Plant Generation	$ 5,784,232	$ 5,018,225	$ 10,802,457
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 3,867,396	$ 3,130,770	$ 6,998,166
3	Purchased Power	$ 1,724,425	$ 1,848,907	$ 3,573,332
4	Wind Curtailment	$ 8,552	$ 10,002	$ 18,554
5	Less: MISO ASM (Rev) Cost	$ 11,252	$ 9,466	$ 20,718
6	Less: Intersystem Sales (Rev) Cost	$ (219,620)	$ (324,472)	$ (544,092)
7	Less: Asset Based Margins (Rev) Cost	$ (32,495)	$ (5,416)	$ (37,910)
8	Total Cost of Fuel	$ 11,143,743	$ 9,687,483	$ 20,831,226
	KWH SALES			
9	Total Sales of Electricity	491,682,615	489,167,233	980,849,848
10	Less Inter-System Sales	(11,718,957)	(16,968,957)	(28,687,914)
11	Total kWh	479,963,658	472,198,276	952,161,934

Line		
12	Cost per KWH	0.021878
13	Base Cost	0.024640
14	Annual True-Up Factor	-0.0006
15	Energy Adjustment per kWh	(0.00336)

kWh Information For The Billing Month of: February 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	247,501,763	kWh
2	Non-Energy Adjustment Rider Sales	198,355	kWh
3	Total	247,700,118	kWh
	Non-Minnesota Sales		
4	Sales for Resale	514,095	kWh
5	Total Sales of Electricity (ND and SD)	223,984,063	kWh
6	Inter-System Sales	16,968,957	kWh
	Total kWh Sales	489,167,233	kWh

EFFECTIVE 5/2/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MARCH 31, 2016
FOR BILLINGS TO BE EFFECTIVE MAY 2, 2016

Line No.	ENERGY COSTS	(A) 2016 February	(B) 2016 March	(C) Total This Period
1	Plant Generation	$ 5,018,225	$ 4,898,195	$ 9,916,420
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 3,130,770	$ 3,129,472	$ 6,260,243
3	Purchased Power	$ 1,848,907	$ 2,092,587	$ 3,941,494
4	Wind Curtailment	$ 10,002	$ 27,993	$ 37,995
5	Less: MISO ASM (Rev) Cost	$ 9,466	$ (1,220)	$ 8,246
6	Less: Intersystem Sales (Rev) Cost	$ (324,472)	$ (247,549)	$ (572,020)
7	Less: Asset Based Margins (Rev) Cost	$ (5,416)	$ (12,231)	$ (17,646)
8	Total Cost of Fuel	$ 9,687,483	$ 9,887,249	$ 19,574,731
	KWH SALES			
9	Total Sales of Electricity	489,167,233	448,064,932	937,232,165
10	Less Inter-System Sales	(16,968,957)	(13,391,699)	(30,360,656)
11	Total kWh	472,198,276	434,673,233	906,871,509
12	Cost per KWH		0.021585	
13	Base Cost		0.024640	
14	Annual True-Up Factor		-0.0006	
15	Energy Adjustment per kWh		(0.00366)	

kWh Information For The Billing Month of: March 2016

Line No.		kWh Sales	
	Minnesota - Retail Sales		
1	Subject to Energy Adjustment Rider	230,702,205	kWh
2	Non-Energy Adjustment Rider Sales	188,669	kWh
3	Total	230,890,874	kWh
	Non-Minnesota Sales		
4	Sales for Resale	313,566	kWh
5	Total Sales of Electricity (ND and SD)	203,468,793	kWh
6	Inter-System Sales	13,391,699	kWh
	Total kWh Sales	448,064,932	kWh

EFFECTIVE 6/2/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA
OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING APRIL 30, 2016
FOR BILLINGS TO BE EFFECTIVE JUNE 2, 2016

Line No.	ENERGY COSTS	(A) 2016 March	(B) 2016 April	(C) Total This Period
1	Plant Generation	$ 4,898,195	$ 3,049,074	$ 7,947,269
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 3,129,472	$ 2,611,096	$ 5,740,569
3	Purchased Power	$ 2,092,587	$ 2,267,231	$ 4,359,818
4	Wind Curtailment	$ 27,993	$ 20,204	$ 48,197
5	Less: MISO ASM (Rev) Cost	$ (1,220)	$ (4,074)	$ (5,293)
6	Less: Intersystem Sales (Rev) Cost	$ (247,549)	$ (214,795)	$ (462,343)
7	Less: Asset Based Margins (Rev) Cost	$ (12,231)	$ (29,597)	$ (41,828)
8	Total Cost of Fuel	$ 9,887,249	$ 7,699,140	$ 17,586,389
	KWH SALES			
9	Total Sales of Electricity	448,064,932	408,004,058	856,068,990
10	Less Inter-System Sales	(13,391,699)	(10,628,274)	(24,019,973)
11	Total kWh	434,673,233	397,375,784	832,049,017
12	Cost per KWH		0.021136	
13	Base Cost		0.024640	
14	Annual True-Up Factor		-0.0006	
15	Energy Adjustment per kWh		(0.00410)	

kWh Information For The Billing Month of: April 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	213,119,802	kWh
2	Non-Energy Adjustment Rider Sales	152,571	kWh
3	Total	213,272,373	kWh
	Non-Minnesota Sales		
4	Sales for Resale	275,945	kWh
5	Total Sales of Electricity (ND and SD)	183,827,466	kWh
6	Inter-System Sales	10,628,274	kWh
	Total kWh Sales	408,004,058	kWh

EFFECTIVE 7/1/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING MAY 31, 2016
FOR BILLINGS TO BE EFFECTIVE JULY 1, 2016

Line No.	ENERGY COSTS	(A) 2016 April	(B) 2016 May	(C) Total This Period
1	Plant Generation	$ 3,049,074	$ 2,371,042	$ 5,420,116
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 2,611,096	$ 2,486,121	$ 5,097,218
3	* May 2013 MISO Day 2 Charge RSG_MWP	$ -	$ (37,058)	$ (37,058)
4	Purchased Power	$ 2,267,231	$ 1,932,836	$ 4,200,067
5	Wind Curtailment	$ 20,204	$ 59,843	$ 80,048
6	Less: MISO ASM (Rev) Cost	$ (4,074)	$ 2,344	$ (1,730)
7	Less: Intersystem Sales (Rev) Cost	$ (214,795)	$ (144,748)	$ (359,542)
8	Less: Asset Based Margins (Rev) Cost	$ (29,597)	$ 5,219	$ (24,378)
9	Total Cost of Fuel	$ 7,699,140	$ 6,675,600	$ 14,374,740
	KWH SALES			
10	Total Sales of Electricity	408,004,058	356,197,746	764,201,804
11	Less Inter-System Sales	(10,628,274)	(6,999,578)	(17,627,852)
12	Total kWh	397,375,784	349,198,168	746,573,952

13	Cost per KWH	0.019254
14	Base Cost	0.024640
15	Annual True-Up Factor	-0.0006
16	Energy Adjustment per kWh	(0.00599)

* In Docket No. E999/AA-13-599 the June 2, 2016, Order the Commission accepted Otter Tail's identification of and explanation for the higher Revenue Sufficiency Guarantee Make-Whole Payments in May 2013. The Commission is disallowing recovery of $37,058.

kWh Information For The Billing Month of: May 2016

Line No.			
	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	195,433,968	kWh
2	Non-Energy Adjustment Rider Sales	135,378	kWh
3	Total	195,569,346	kWh
	Non-Minnesota Sales		
4	Sales for Resale	241,189	kWh
5	Total Sales of Electricity (ND and SD)	153,387,633	kWh
6	Inter-System Sales	6,999,578	kWh
	Total kWh Sales	356,197,746	kWh

EFFECTIVE 8/2/2016
CYCLE 01 RATE LEVEL 31

MINNESOTA

OTTER TAIL POWER COMPANY
ENERGY ADJUSTMENT RIDER
BASED ON PERIOD ENDING JUNE 30, 2016
FOR BILLINGS TO BE EFFECTIVE AUGUST 2, 2016

Line No.	ENERGY COSTS	(A) 2016 May	(B) 2016 Jun	(C) Total This Period
1	Plant Generation	$ 2,371,042	$ 4,569,520	$ 6,940,562
2	MISO Day 2 Charges (not Schedule 16 & 17)	$ 2,486,121	$ 2,905,867	$ 5,391,988
3	* Jun 2013 MISO Day 2 Charge RSG_MWP	$ (37,058)	$ -	$ (37,058)
4	Purchased Power	$ 1,932,836	$ 1,736,705	$ 3,669,541
5	Wind Curtailment	$ 59,843	$ 11,134	$ 70,977
6	Less: MISO ASM (Rev) Cost	$ 2,344	$ (20,020)	$ (17,676)
7	Less: Intersystem Sales (Rev) Cost	$ (144,748)	$ (335,553)	$ (480,301)
8	Less: Asset Based Margins (Rev) Cost	$ 5,219	$ (95,936)	$ (90,717)
9	Total Cost of Fuel	$ 6,675,600	$ 8,771,716	$ 15,447,316
	KWH SALES			
10	Total Sales of Electricity	356,197,746	358,566,884	714,764,630
11	Less Inter-System Sales	(6,999,578)	(19,032,774)	(26,032,352)
12	Total kWh	349,198,168	339,534,110	688,732,278

Line No.		
13	Cost per KWH	0.022429
14	Base Cost	0.024640
15	Annual True-Up Factor	-0.0006
16	Energy Adjustment per kWh	(0.00281)

* In Docket No. E999/AA-13-599 the June 2, 2016, Order the Commission accepted Otter Tail's identification of and explanation for the higher Revenue Sufficiency Guarantee Make-Whole Payments in Jun 2013. The Commission is disallowing recovery of $37,058.

kWh Information For The Billing Month of: June 2016

Line No.	Minnesota - Retail Sales	kWh Sales	
1	Subject to Energy Adjustment Rider	188,149,034	kWh
2	Non-Energy Adjustment Rider Sales	131,438	kWh
3	Total	188,280,472	kWh
	Non-Minnesota Sales		
4	Sales for Resale	(13,561)	kWh
5	Total Sales of Electricity (ND and SD)	151,267,199	kWh
6	Inter-System Sales	19,032,774	kWh
	Total kWh Sales	358,566,884	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 *	48,834	992	94.00	(0.0003)	(0.30)	-0.32%
2	Farm *	1,444	2,368	243.44	(0.0003)	(0.71)	-0.29%
3	General Service *	9,642	2,359	225.56	(0.0003)	(0.71)	-0.31%
4	Large General Service *	767	79,596	6,278.94	(0.0003)	(23.88)	-0.38%
5	OPA	228	7,543	595.30	(0.0003)	(2.26)	-0.38%
6	Street & Area Lighting	154	5,730	920.83	(0.0003)	(1.72)	-0.19%
7	Pipelines	11	7,126,983	350,244.91	(0.0003)	(2,138.09)	-0.61%

* 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, Nancy 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 **29th** day of **July 2016**.

/s/ NANCY OLSON
Nancy Olson, Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8376

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
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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 to 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 Minn. R. 7825.2810 Subpt 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 2015 to June 2016.

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 Not Public) contains the curtailment for the time period of July 2015 through June 2016.

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

	(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
			[PROTECTED DATA BEGINS . . .					
Jul-15							$0.00	
Aug-15							$0.00	
Sep-15							$0.00	
Oct-15							$0.00	
Nov-15							$0.00	
Dec-15							$0.00	
Jan-16							$0.00	
Feb-16							$0.00	
Mar-16							$0.00	
Apr-16							$0.00	
May-16							$0.00	
Jun-16							$0.00	
Total			0	$0.00	0	$0.00	$0.00	
					. . . PROTECTED 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 Langdon Wind, LLC
Docket No. E017/M-08-131
Dated August 15, 2008

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
			[PROTECTED DATA BEGINS . . .					
Jul-15							$0.00	
Aug-15							$0.00	
Sep-15							$0.00	
Oct-15							$0.00	
Nov-15							$0.00	
Dec-15							$0.00	
Jan-16							$0.00	
Feb-16							$0.00	
Mar-16							$0.00	
Apr-16							$0.00	
May-16							$0.00	
Jun-16							$0.00	
Total			0	$0.00	0	$0.00	$0.00	

. . . PROTECTED 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
			[PROTECTED DATA BEGINS . . .					
Jul-15	7/5	8/14/15						4
Aug-15	8/19, 23	9/11/15						4
Sep-15	9/8, 9, 13, 14, 17, 18, 21, 30	10/15/15						4
Oct-15	10/1, 2, 3, 8, 9, 10, 11, 12, 15, 23, 24, 28, 29, 30, 31	11/17/15						4
Nov-15	11/1, 3, 4, 5, 6, 7, 8, 12, 16, 17, 19	12/15/15						4
Dec-15	12/5, 7, 10, 24, 31	1/14/16						4
Jan-16	1/1, 27, 28	2/17/16						4
Feb-16	2/6, 7, 27, 28, 29	3/16/16						4
Mar-16	3/5, 6, 7, 8, 11, 12, 13, 18, 23, 28, 29	4/15/16						4
Apr-16	4/1, 2, 3, 9, 10, 11, 12, 13, 14, 15, 16, 21, 22, 23, 24, 25, 27, 30	5/17/16						4
May-16	5/3, 4, 6, 11, 12, 13, 14, 16, 18, 19, 20, 21, 22, 23, 25, 26, 31	6/15/16						4
Jun-16	6/1, 2, 3, 4, 6, 9, 12, 19, 21, 25	7/15/16						4
Total								
					. . . PROTECTED DATA ENDS]			

Reason Code Explanation:
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, **[PROTECTED DATA BEGINS . . .**

. . . PROTECTED 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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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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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 6 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 Not Public) - 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 2016 in Docket No. E999/AA-15-611. Included with this filing is the forecast for calendar year 2017 (Part E Section 10 Attachment H marked as Not Public). The forecast of costs for 2017 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 Not Public) 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 charges during the 2015/2016 AAA Reporting Period Similar to Prior Year.

On a system basis, Otter Tail's total MISO charges for this reporting period were very similar to last year, increasing slightly from approximately \$40.1 million during the 2014/2015 reporting period to approximately \$40.7 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. The following overview helps set some context with regard to factors (primarily market price) that have influenced the amount of net energy and associated costs Otter Tail has procured from the MISO market in the last few years.

The following table summarizes the last four years of net MISO energy acquired and the associated costs. These amounts are found on Line 5 of Part H Section 3 Docket No. AA-07-1130 Attachment K Detail of MISO Day 2 Charges – System, for each year's respective reporting periods (Note - This table excludes losses, congestion and other market-related charges). Column A and B reflect the energy acquired in the MISO market and associated costs. Columns C and D reflect the MWhs of generation sold into the MISO market. While retail MWhs acquired to serve load, as reflected in Column A, has grown over the four reporting periods, offsetting revenue for Otter Tail generation, based on economic dispatch and plant availability, has fluctuated. When demand and associated prices were high during 2013/2014 (Polar Vortex year), Otter Tail plants were dispatched at higher levels than the other three years.

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
			Retail								
Line	AAA Reporting Period	Charge Type	MWh (1)	Cost (1)	MWh (1)	Revenue (1)	**Net MWhs (A) + (C)**	Cost/ MWh (B)/(A)	Rev/ MWh (D)/(C)	Net Cost (B) + (D)	Avg Energy Cost/ MWh (H)/(E)
1	2012/2013	Total Day Ahead & Real Time Energy	(4,635,473)	$ (120,334,416)	3,588,873	$ 98,052,843	**(1,046,600)**	$ 25.96	$27.32	**$ (22,281,573)**	$ 21.29
2	2013/2014	Total Day Ahead & Real Time Energy	(4,959,325)	$ (175,738,995)	4,075,568	$ 146,011,923	**(883,757)**	$ 35.44	$35.83	**$ (29,727,072)**	$ 33.64
3	2014/2015	Total Day Ahead & Real Time Energy	(4,901,299)	$ (117,676,621)	3,476,013	$ 84,653,670	**(1,425,286)**	$ 24.01	$24.35	**$ (33,022,951)**	$ 23.17
4	2015/2016	Total Day Ahead & Real Time Energy	(5,004,481)	$ (96,670,751)	3,239,880	$ 60,594,490	**(1,764,601)**	$ 19.32	$18.70	**$ (36,076,261)**	$ 20.44

(1) Source**: Line 5** of Annual Report:Detail of MISO Day 2 Charges - System (Part H, Section 3) for respective reporting periods. These amounts reflect energy costs only and do not included congestion or losses.

Market prices have softened over the last two years due to low natural gas prices and increased wind production within the MISO footprint. Also, during the 2014/2015 and 2015/2016 AAA reporting periods, Otter Tail generation was reduced due to the planned outage at Big Stone Plant for the Air Quality Control System (AQCS) cutover and other plant maintenance (March – early August 2015) and reduced output at the Coyote Plant following the fire in one of that plant's boiler feed pumps (much of calendar 2015). Also, due to low market price conditions over the last two reporting periods, limited dispatch of Otter Tail's Hoot Lake Plant occurred (market was cheaper for customers). As a result, the net MWhs acquired from MISO, as reflected in Column E above increased. While the net overall cost of energy acquired in MISO has increased, as reflected in Column H, the average cost per MWh, as reflected in Column I in the table above is the lowest in the last four years.

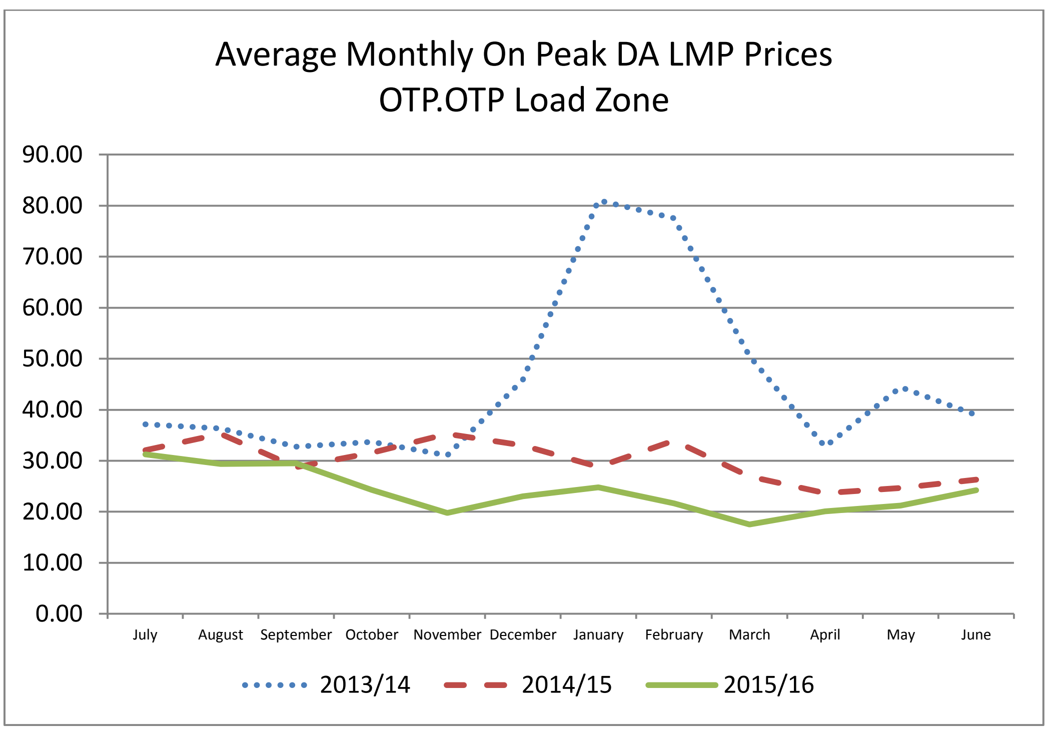
To put the amount of net energy from MISO into context with total energy recovered through the fuel clause, the table below compares the net MISO MWhs (Column A) to total MWhs of energy sold to customers (Column B) as reported in the annual true-up filings in Docket No. E017/M-03-30. Total system energy costs declined from a high of $114 million (System) in 2013/2014, to $109 million (System) in the current reporting period. The average cost per MWh, as shown in Column D below, is the lowest of the last 4 years, at $23.47/MWh. This includes all costs recovered through the fuel clause, including all MISO costs approved for FCA recovery. Column E shows that while approximately 19% of the energy was acquired from the market in 2013/2014, 38% came from the market in the current reporting period.

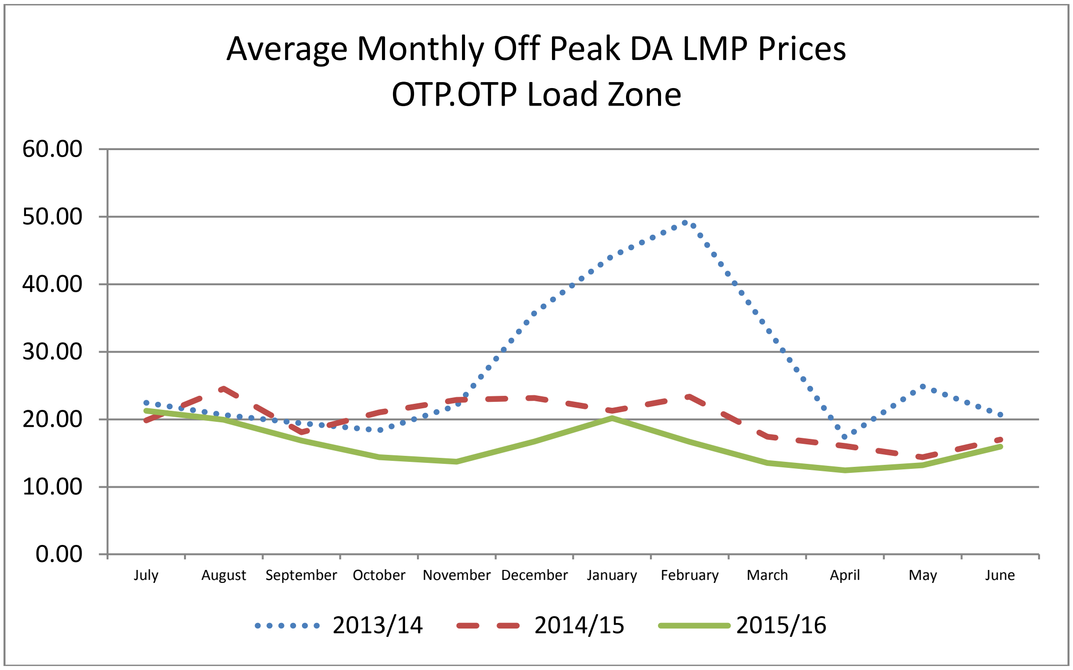
			(A)	(B)	(C)	(D)	(E)
				From Annual True-Up Filings Docket E017/M-03-30			
Line	AAA Reporting Period	Charge Type	Net MWhs (A) + (C) (1)	Total System Sales MWhs (2)	Total System Cost (2)	Average Cost per MWh (C)/(B)	% of system energy served from market (A/B)
1	2012/2013	Total Day Ahead & Real Time Energy	(1,046,600)	4,405,289	$103,883,299	$ 23.58	24%
2	2013/2014	Total Day Ahead & Real Time Energy	(883,757)	4,636,516	$114,090,227	$ 24.61	19%
3	2014/2015	Total Day Ahead & Real Time Energy	(1,425,286)	4,588,130	$112,675,821	$ 24.56	31%
4	2015/2016	Total Day Ahead & Real Time Energy	(1,764,601)	4,646,536	$109,053,170	$ 23.47	38%

(1) Source: Line 5 of Annual Report:Detail of MISO Day 2 Charges - System (Part H, Section 3) for respective reporting periods. These amounts reflect energy costs only and do not included congestion or losses.

(2) Exhibit 1 of Annual True-Up Filings in Docket E017/M-03-30 for respective reporting periods. Reflects all System sales and Energy costs eligible for fuel clause recovery.

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 and 2014/15 reporting years.





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

MISO Module E Data For Otter Tail Power Company
As of July 14, 2016

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

No.	Aggregate Resources	Designation	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16
1	Big Stone Plant	OTP.BIGSTON1	234.4	234.4	234.4	234.4	234.4	234.4	234.4	234.4	234.4	234.4	234.4	234.4
2	Coyote Station	OTP.COYOT1	129.3	129.3	129.3	129.3	129.3	129.3	129.3	129.3	129.3	129.3	129.3	129.3
3	FPL Energy ND Wind II	OTP.EDGLYEDGL	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
4	Hoot Lake 2	OTP.HOOTL2	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1	56.1
5	Hoot Lake 3	OTP.HOOTL3	80.3	80.3	80.3	80.3	80.3	80.3	80.3	80.3	80.3	80.3	80.3	80.3
6	Jamestown 1	OTP.JAMSPK1	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
7	Jamestown 2	OTP.JAMSPK2	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
8	Lake Preston	OTP.HETLA1	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3	18.3
9	Solway	OTP.SOLWAYO1	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7	42.7

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

No.	Local Resource	Designation	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16
1	Ashtabula	OTP.ASHTABULA	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
2	FPL Energy ND Wind II	OTP.EDGLYEDGL	-	-	-	-	-	-	-	-	-	-	-	-
3	Langdon	OTP.LANGDN1	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
4	Langdon	OTP.LANGDN2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
5	Luverne	OTP.MPWR	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6	12.6

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

No.	BTM Resource	Designation	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16
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	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
6	Hoot Lake 3A Diesel	OTP.OTP	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
7	Hoot Lake 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
			[PROTECTED DATA BEGINS . . .											
8	Dakota Magic Diesel	OTP.OTP												
9	Kindred School Diesel	OTP.OTP												
10	Perham Resource Recovery Facility	OTP.OTP												
11	Stevens Community	OTP.OTP												
														. . . PROTECTED DATA ENDS]
12	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
13	Wright Hydro	OTP.OTP	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
14	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
15	Bemidji 1 Hydro	OTP.OTP	-	-	-	-	-	-	-	-	-	-	-	-

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

No.	External Resources	Designation	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16
1		Garrison Hydro Plant	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
2		Garrison Hydro Plant 2	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.4

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

No.	PRC Transaction	Designation	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16
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	MMPA Sale	OTPW-EAGL	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)	(15.0)
3	MRES Sale	OTPW-EAGL	(25.0)	(25.0)	(25.0)	(25.0)	(25.0)	(25.0)	(25.0)	(25.0)	(25.0)	(25.0)	(25.0)	(25.0)
4	FPLP Sale	OTPW-EAGL	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)	(8.0)
Total			704.3	704.3	704.3	704.3	704.3	704.3	704.3	704.3	704.3	704.3	704.3	704.3

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

January 2017

Jan-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

February 2017

Feb-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

March 2017

Mar-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

April 2017

Apr-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

May 2017

May-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

June 2017

Jun-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

July 2017

Jul-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

August 2017

Aug-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

September 2017

Sep-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

October 2017

Oct-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

November 2017

Nov-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

Otter Tail Power Company
Monthly Detail FAC Forecast

FORECAST

December 2017

Dec-17	MWh	Retail MWh	Cost	Ave/Retail MWh
Company Generation	**[PROTECTED 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				

. . . PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS . . .

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

. . . PROTECTED 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 Ramp Product 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
Real-Time ASM Amounts
Real-Time Price Volatility Make Whole Amount
Real-Time Demand Response Allocation Uplift Amount
FTR Allocation Amounts
FTR_ARR

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

(3) Generator Outages include Scheduled Outages

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

No.	Charge Type Description	System - Retail July 15 - June 16	Minnesota - Retail July 15 - June 16
No.	**Day Ahead & Real Time Asset & Non Asset Energy & Loss**		
1	DA Asset Energy Amount	$ 37,615,369.78	$ 20,087,779.90
2	DA FBT Loss Amount	$ -	$ -
3	DA Non-asset Energy Amount	$ 67,244.09	$ 35,910.44
4	RT Asset Energy Amount	$ (1,655,330.25)	$ (883,997.95)
5	RT Distribution of Losses Amount	$ (1,498,467.15)	$ (800,228.16)
6	RT FBT Loss Amount	$ -	$ -
7	DA Loss Amount	$ 3,058,781.18	$ 1,633,484.49
8	RT Loss Amount	$ 158,899.77	$ 84,857.43
9	RT Non-Asset Energy Amount	$ 48,977.31	$ 26,155.41
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	$ 568,608.10	$ 303,654.45
14	RT Mkt Admin Amount	$ 58,784.47	$ 31,392.74
15	FTR Mkt Admin Amount	$ 19,578.80	$ 10,455.69
	Congest & FTRs		
16	DA FBT Congestion Amount	$ -	$ -
17	DA Congestion	$ 896,517.95	$ 478,768.53
18	RT FBT Congestion Amount	$ -	$ -
19	RT Congestion	$ (124,207.15)	$ (66,330.49)
20	FTR Hourly Allocation Amount	$ (1,140,422.94)	$ (609,021.40)
21	FTR Monthly Allocation Amount	$ (91,596.50)	$ (48,915.39)
22	FTR Yearly Allocation Amount	$ (36,489.21)	$ (19,486.38)
23	FTR Monthly Transaction Amount	$ (201,068.95)	$ (107,377.09)
24	FTR Full Funding Guarantee Amount	$ (16,229.58)	$ (8,667.10)
25	FTR Guarantee Uplift Amount	$ 15,151.32	$ 8,091.28
26	FTR Auction Revenue Rights Transaction Amount	$ (2,486,475.11)	$ (1,327,855.21)
27	FTR Annual Transaction Amount	$ 2,435,542.90	$ 1,300,655.82
28	FTR Auction Revenue Rights Infeasible Uplift Amount	$ 69,255.94	$ 36,984.83
29	FTR Auction Revenue Rights Stage 2 Distribution Amount	$ (414,275.12)	$ (221,235.83)
30	DA Congestion Rebate on Option B GFA	$ -	$ -
	RSG & Make Whole Payments		
31	DA Revenue Sufficiency Guarantee Distribution Amount	$ 124,783.52	$ 66,638.29
32	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	$ (53,497.55)	$ (28,569.36)
33	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	$ 224,357.82	$ 119,814.07
34	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	$ -	$ -
35	RT Price Volatility Make Whole Payment	$ (173,335.11)	$ (92,566.35)
	Revenue Neutrality Uplift		
36	RT Revenue Neutrality Uplift Amount	$ 526,753.20	$ 281,302.63
	Other Charges		
37	RT Misc Amount	$ 167,019.66	$ 89,193.70
38	RT Net Inadvertent Amount	$ 31,542.92	$ 16,844.90
39	RT Uninstructed Deviation Amount	$ -	$ -
40	RT Demand Response Allocation Uplift Amount	$ 9.31	$ 4.97
41	DA Ramp Product	$ (1,262.20)	$ (674.05)
42	RT Ramp Product	$ (2.08)	$ (1.11)
	ASM Charges		
43	RT ASM Non-Excessive Energy Amount	$ 3,205,716.51	$ 1,711,952.54
44	RT ASM Excessive Energy Amount	$ 5,379.16	$ 2,872.64
	Grandfathered Charge Types		
45	DA Congestion Rebate on COGA	$ -	$ -
46	DA Losses Rebate on COGA	$ -	$ -
47	RT Congestion Rebate on COGA	$ -	$ -
48	RT Loss Rebate on COGA	$ -	$ -
49	**TOTAL CHARGES**	$ 41,405,614.81	$ 22,111,888.88
50	Less Schedule 16 & 17 (Lines 13, 14, 15)	$ (646,971.37)	
51	Congestion and Losses Adjustment	$ (46,683.36)	
52	No DA generation sch., but still had output	$ (938.37)	
53	MISO RSG Bad Debt	$ -	

Percent of Minnesota Sales to System (2,481,395,298 / 4,646,536,462) = 0.534031169

Fuel Costs Allocated to Minnesota ($109,053,170) x 0.534031169 = $58,237,792

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
July 2015 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						**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 8,918,536.64	$ (3,250,491.24)	$ -	$ 5,668,045.40			353,622	(130,866)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 244,346.54	$ (136.71)	$ -	$ 244,209.83			9,264	(9)
4	RT Asset Energy Amount	555.19	$ 282,243.21	$ (201,613.10)	$ 47,888.68	$ 128,518.79			10,970	(8,992)
5	RT Distribution of Losses Amount	555.24	$ 1,409.78	$ (119,684.63)	$ (1,065.16)	$ (119,340.01)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 114,887.60	$ -	$ -	$ 114,887.60			-	-
8	RT Loss Amount		$ 2,176.02	$ -	$ -	$ 2,176.02			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ (182.98)	$ -	$ (182.98)			-	(10)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 9,563,599.79**	**$ (3,572,108.66)**	**$ 46,823.52**	**$ 6,038,314.65**			**373,856**	**(139,878)**
	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	$ 34,479.29	$ -	$ -	$ 34,479.29			-	-
16	RT Mkt Admin Amount	555.18	$ 2,869.68	$ -	$ (9.25)	$ 2,860.43			-	-
17	FTR Mkt Admin Amount	555.13	$ 710.08	$ -	$ -	$ 710.08			-	-
18	**TOTAL**		**$ 38,059.05**	**$ -**	**$ (9.25)**	**$ 38,049.80**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 19,179.98	$ -	$ 19,179.98				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (4,200.91)	$ -	$ -	$ (4,200.91)				
23	FTR Hourly Allocation Amount	555.14	$ 24,309.37	$ (21,759.57)	$ -	$ 2,549.80			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (637.34)	$ -	$ (637.34)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (63,931.52)	$ -	$ (63,931.52)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 627.77	$ (1,405.49)	$ -	$ (777.72)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 1,405.49	$ (627.77)	$ -	$ 777.72			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 23,531.71	$ (231,866.38)	$ -	$ (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	$ -	$ (23,106.24)	$ 3,859.38	$ (19,246.86)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 259,016.28**	**$ (347,951.52)**	**$ 3,859.38**	**$ (85,075.86)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 12,175.03	$ -	$ (70.64)	$ 12,104.39			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 20,307.86	$ -	$ (485.40)	$ 19,822.46			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (6,567.87)	$ -	$ (6,567.87)			-	-
40	**TOTAL**		**$ 32,482.89**	**$ (6,567.87)**	**$ (556.04)**	**$ 25,358.98**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 35,840.39	$ (2,219.39)	$ 6,328.01	$ 39,949.01			-	-
42	**TOTAL**		**$ 35,840.39**	**$ (2,219.39)**	**$ 6,328.01**	**$ 39,949.01**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (641.33)	$ (641.33)			-	-
44	RT Net Inadvertent Amount	555.27	$ 2,173.43	$ (3,343.44)	$ (660.28)	$ (1,830.29)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ (0.03)	$ (0.03)			-	-
47	**TOTAL**		**$ 2,173.43**	**$ (3,343.44)**	**$ (1,301.64)**	**$ (2,471.65)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
July 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 304,376.84	$ (193,877.01)	$ (36,270.13)	$ 74,229.70			14,323	(9,422)
49	RT ASM Excessive Energy Amount	555.56	$ 4,278.02	$ -	$ (2.35)	$ 4,275.67			-	(128)
50	**TOTAL**		**$ 308,654.86**	**$ (193,877.01)**	**$ (36,272.48)**	**$ 78,505.37**			**14,323**	**(9,550)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 10,239,826.69	$ (4,126,067.89)	$ 18,871.50	$ 6,132,630.30	$ (66,314.55)	$ 6,066,315.75	388,179	(149,428)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (38,059.05)	$ -	$ 9.25	$ (38,049.80)				
58	**Less: Congestion and Losses Adjustment**				$ 250.81	$ 250.81				
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**		**$ 10,201,767.64**	**$ (4,126,067.89)**	**$ 19,131.56**	**$ 6,094,831.31**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 6,094,831.31**						
63	Net KWH for retail = ((G) + (H)) * 1,000			238,751,149						**238,751,149**
64	July 2015 covers time period of 6/23/2015 -- 7/23/2015 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS . . .**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 6,075,699.75	238,751,149						
67	**Congestion and Losses Adjustment**		$ 250.81							
68	**MISO RSG Bad Debt**		$ -							
69	**July Adjustments**		$ 18,880.75	380,499						
70	**Total MISO**		$ 6,094,831.31	239,131,647						
								. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
August 2015 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						**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 9,747,440.80	$ (5,966,740.61)	$ -	$ 3,780,700.19			375,795	(245,237)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 151,960.88	$ (11,456.33)	$ -	$ 140,504.55			6,767	(489)
4	RT Asset Energy Amount	555.19	$ 306,618.77	$ (592,845.52)	$ 6,180.90	$ (280,045.85)			12,469	(25,266)
5	RT Distribution of Losses Amount	555.24	$ 712.62	$ (177,204.50)	$ 1,806.82	$ (174,685.06)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 149,461.22	$ -	$ -	$ 149,461.22			-	-
8	RT Loss Amount		$ 7,545.25	$ -	$ -	$ 7,545.25			-	-
9	RT Non-Asset Energy Amount	555.26	$ 32,600.18	$ (275.13)	$ -	$ 32,325.05			1,149	(16)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 10,396,339.72**	**$ (6,748,522.09)**	**$ 7,987.72**	**$ 3,655,805.35**			**396,181**	**(271,009)**
	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	$ 41,607.66	$ -	$ -	$ 41,607.66			-	-
16	RT Mkt Admin Amount	555.18	$ 5,137.34	$ -	$ (154.63)	$ 4,982.71			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,381.44	$ -	$ -	$ 1,381.44			-	-
18	**TOTAL**		**$ 48,126.44**	**$ -**	**$ (154.63)**	**$ 47,971.81**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 30,406.31	$ -	$ 30,406.31				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (5,301.84)	$ -	$ -	$ (5,301.84)				
23	FTR Hourly Allocation Amount	555.14	$ 58,204.29	$ (103,996.50)	$ 0.17	$ (45,792.04)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (1,651.86)	$ (0.06)	$ (1,651.92)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (10,192.28)	$ -	$ (10,192.28)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 1,637.22	$ (3,899.92)	$ (0.11)	$ (2,262.81)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 3,899.92	$ (1,637.22)	$ 0.11	$ 2,262.81			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 23,531.71	$ (231,866.38)	$ -	$ (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	$ (33.26)	$ (33.26)	$ 5,313.17			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ 904.83	$ (23,107.68)	$ 904.75	$ (21,298.10)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 296,218.98**	**$ (369,775.98)**	**$ 871.60**	**$ (72,685.40)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 11,666.47	$ -	$ 0.75	$ 11,667.22			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 66,252.88	$ -	$ (92.43)	$ 66,160.45			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (8,407.68)	$ 19.20	$ (8,388.48)			-	-
40	**TOTAL**		**$ 77,919.35**	**$ (8,407.68)**	**$ (72.48)**	**$ 69,439.19**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 45,787.08	$ (7,328.30)	$ (789.50)	$ 37,669.28			-	-
42	**TOTAL**		**$ 45,787.08**	**$ (7,328.30)**	**$ (789.50)**	**$ 37,669.28**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (23.17)	$ (23.17)			-	-
44	RT Net Inadvertent Amount	555.27	$ 3,668.15	$ (4,745.72)	$ 487.55	$ (590.02)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ 4.76	$ (0.03)	$ -	$ 4.73			-	-
47	**TOTAL**		**$ 3,672.91**	**$ (4,745.75)**	**$ 464.38**	**$ (608.46)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
August 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 728,487.72	$ (210,832.74)	$ 18,631.48	$ 536,286.46			31,031	(9,720)
49	RT ASM Excessive Energy Amount	555.56	$ 456.96	$ (184.72)	$ -	$ 272.24			-	(128)
50	**TOTAL**		**$ 728,944.68**	**$ (211,017.46)**	**$ 18,631.48**	**$ 536,558.70**			**31,031**	**(9,848)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 11,597,009.16	$ (7,349,797.26)	$ 26,938.57	$ 4,274,150.47	$ (79,671.26)	$ 4,194,479.21	427,212	(280,857)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (48,126.44)	$ -	$ 154.63	$ (47,971.81)				
58	**Less: Congestion and Losses Adjustment**				$ 24.29	$ 24.29				
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**		**$ 11,548,882.72**	**$ (7,349,797.26)**	**$ 27,117.49**	**$ 4,226,202.95**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 4,226,202.95**						
63	Net KWH for retail = ((G) + (H)) * 1,000			146,354,747						**146,354,747**
64	August 2015 covers time period of 7/24/2015 -- 8/23/2015 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS . . .**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 4,199,085.46	146,354,747						
67	**Congestion and Losses Adjustment**		$ 24.29							
68	**MISO RSG Bad Debt**		$ -							
69	**August Adjustments**		$ 27,093.20	1,030,087						
70	**Total MISO**		$ 4,226,202.95	147,384,834						
								. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
September 2015 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						[PROTECTED DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	$ 7,920,776.24	$ (5,733,281.00)	$ -	$ 2,187,495.24			345,269	(250,197)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 187,040.20	$ (5,811.41)	$ -	$ 181,228.79			8,985	(187)
4	RT Asset Energy Amount	555.19	$ 108,421.38	$ (462,426.79)	$ (12,025.22)	$ (366,030.63)			8,041	(19,307)
5	RT Distribution of Losses Amount	555.24	$ 849.48	$ (149,925.84)	$ 2,560.37	$ (146,515.99)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 312,785.86	$ -	$ -	$ 312,785.86			-	-
8	RT Loss Amount		$ 21,823.45	$ -	$ -	$ 21,823.45			-	-
9	RT Non-Asset Energy Amount	555.26	$ 19,552.88	$ -	$ -	$ 19,552.88			668	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 8,571,249.49**	**$ (6,351,445.04)**	**$ (9,464.85)**	**$ 2,210,339.60**			**362,964**	**(269,692)**
	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	$ 40,628.05	$ -	$ -	$ 40,628.05			-	-
16	RT Mkt Admin Amount	555.18	$ 4,370.22	$ -	$ (291.87)	$ 4,078.35			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,675.68	$ -	$ -	$ 1,675.68			-	-
18	**TOTAL**		**$ 46,673.95**	**$ -**	**$ (291.87)**	**$ 46,382.08**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 37,466.59	$ -	$ 37,466.59				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 22,327.79	$ -	$ -	$ 22,327.79				
23	FTR Hourly Allocation Amount	555.14	$ 130,250.27	$ (165,961.52)	$ (0.20)	$ (35,711.45)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (5,184.55)	$ 0.09	$ (5,184.46)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (33,770.58)	$ -	$ (33,770.58)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 5,062.14	$ (11,157.73)	$ 0.11	$ (6,095.48)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 11,157.73	$ (5,062.14)	$ (0.11)	$ 6,095.48			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 21,934.87	$ (259,176.50)	$ -	$ (237,241.63)			-	-
30	FTR Annual Transaction Amount	555.38	$ 259,228.48	$ (22,761.14)	$ -	$ 236,467.34			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 8,670.17	$ -	$ (33.26)	$ 8,636.91			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (46,320.53)	$ 904.77	$ (45,415.76)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 458,631.45**	**$ (511,928.10)**	**$ 871.40**	**$ (52,425.25)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 11,537.65	$ -	$ (122.97)	$ 11,414.68			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (43.00)	$ -	$ (43.00)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 36,331.67	$ -	$ 521.65	$ 36,853.32			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (9,834.15)	$ -	$ (9,834.15)			-	-
40	**TOTAL**		**$ 47,869.32**	**$ (9,877.15)**	**$ 398.68**	**$ 38,390.85**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 42,711.32	$ (1,386.34)	$ (2,344.01)	$ 38,980.97			-	-
42	**TOTAL**		**$ 42,711.32**	**$ (1,386.34)**	**$ (2,344.01)**	**$ 38,980.97**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (4,314.17)	$ (4,314.17)			-	-
44	RT Net Inadvertent Amount	555.27	$ 1,486.50	$ (1,859.93)	$ 2,089.44	$ 1,716.01			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ 0.02	$ 0.02			-	-
47	**TOTAL**		**$ 1,486.50**	**$ (1,859.93)**	**$ (2,224.71)**	**$ (2,598.14)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
September 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 460,062.40	$ (257,991.64)	$ -	$ 202,070.76			23,157	(14,486)
49	RT ASM Excessive Energy Amount	555.56	$ 646.23	$ (273.49)	$ -	$ 372.74			-	(164)
50	**TOTAL**		**$ 460,708.63**	**$ (258,265.13)**	**$ -**	**$ 202,443.50**			**23,157**	**(14,650)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 9,629,330.66	$ (7,134,761.69)	$ (13,055.36)	$ 2,481,513.61	$ (182,462.38)	$ 2,299,051.23	386,121	(284,342)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (46,673.95)	$ -	$ 291.87	$ (46,382.08)				
58	**Less: Congestion and Losses Adjustment**				$ (3,346.59)	$ (3,346.59)				
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**		**$ 9,582,656.71**	**$ (7,134,761.69)**	**$ (16,110.08)**	**$ 2,431,784.94**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,431,784.94**						
63	Net KWH for retail = ((G) + (H)) * 1,000			101,779,269						**101,779,269**

64 September 2015 covers time period of 8/24/2015 -- 9/22/2015 ** increased for losses of 2.8%

		Net Retail	Net MISO KWH	**[PROTECTED DATA BEGINS . . .** per kWh	Net Intersystem	Total
66	**MISO Book Totals**	$ 2,447,895.02	101,779,269			
67	**Congestion and Losses Adjustment**	$ (3,346.59)				
68	**MISO RSG Bad Debt**	$ -				
69	**September Adjustments**	$ (12,763.49)	(1,111,502)			
70	**Total MISO**	$ 2,431,784.94	100,667,767			

. . . PROTECTED DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
October 2015 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						**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 6,630,973.31	$ (4,352,583.24)	$ -	$ 2,278,390.07			349,554	(245,443)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 112,706.48	$ -	$ -	$ 112,706.48			5,409	-
4	RT Asset Energy Amount	555.19	$ 139,044.78	$ (376,084.67)	$ 13,239.95	$ (223,799.94)			3,975	(22,492)
5	RT Distribution of Losses Amount	555.24	$ 31,302.36	$ (146,027.03)	$ (2,739.56)	$ (117,464.23)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 292,597.50	$ -	$ -	$ 292,597.50			-	-
8	RT Loss Amount		$ 2,428.32	$ -	$ -	$ 2,428.32			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ (2,861.86)	$ -	$ (2,861.86)			-	(230)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 7,209,052.75**	**$ (4,877,556.80)**	**$ 10,500.39**	**$ 2,341,996.34**			**358,938**	**(268,166)**
	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	$ 43,199.85	$ -	$ -	$ 43,199.85			-	-
16	RT Mkt Admin Amount	555.18	$ 4,659.67	$ -	$ (43.03)	$ 4,616.64			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,548.16	$ -	$ -	$ 1,548.16			-	-
18	**TOTAL**		**$ 49,407.68**	**$ -**	**$ (43.03)**	**$ 49,364.65**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ (63,115.84)	$ -	$ (63,115.84)				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (53,055.65)	$ -	$ -	$ (53,055.65)				
23	FTR Hourly Allocation Amount	555.14	$ 42,596.23	$ (82,289.83)	$ 0.02	$ (39,693.58)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (12,932.33)	$ -	$ (12,932.33)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (10,253.05)	$ -	$ (10,253.05)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 12,887.52	$ (9,959.23)	$ (0.02)	$ 2,928.27			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 9,959.23	$ (12,887.52)	$ 0.02	$ (2,928.27)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 21,934.87	$ (259,176.50)	$ -	$ (237,241.63)			-	-
30	FTR Annual Transaction Amount	555.38	$ 259,228.48	$ (22,761.14)	$ -	$ 236,467.34			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 8,670.17	$ -	$ -	$ 8,670.17			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (46,544.39)	$ -	$ (46,544.39)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 302,220.85**	**$ (519,919.83)**	**$ 0.02**	**$ (217,698.96)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 15,599.81	$ -	$ (1,879.71)	$ 13,720.10			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (565.87)	$ -	$ (565.87)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 27,781.17	$ -	$ (209.87)	$ 27,571.30			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (10,114.98)	$ 0.15	$ (10,114.83)			-	-
40	**TOTAL**		**$ 43,380.98**	**$ (10,680.85)**	**$ (2,089.43)**	**$ 30,610.70**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 49,859.20	$ (5,698.48)	$ 235.83	$ 44,396.55			-	-
42	**TOTAL**		**$ 49,859.20**	**$ (5,698.48)**	**$ 235.83**	**$ 44,396.55**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ 519.46	$ 519.46			-	-
44	RT Net Inadvertent Amount	555.27	$ 18,378.04	$ (21,277.36)	$ (1,417.09)	$ (4,316.41)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ -	$ -			-	-
47	**TOTAL**		**$ 18,378.04**	**$ (21,277.36)**	**$ (897.63)**	**$ (3,796.95)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
October 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 488,371.44	$ (172,075.73)	$ 10.46	$ 316,306.17			28,420	(9,898)
49	RT ASM Excessive Energy Amount	555.56	$ 395.89	$ (119.10)	$ -	$ 276.79			-	(85)
50	**TOTAL**		**$ 488,767.33**	**$ (172,194.83)**	**$ 10.46**	**$ 316,582.96**			**28,420**	**(9,983)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 8,161,066.83	$ (5,607,328.15)	$ 7,716.61	$ 2,561,455.29	$ (197,902.49)	$ 2,363,552.80	387,358	(278,149)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (49,407.68)	$ -	$ 43.03	$ (49,364.65)				
58	**Less: Congestion and Losses Adjustment**				$ (3,543.39)	$ (3,543.39)				
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**		**$ 8,111,659.15**	**$ (5,607,328.15)**	**$ 4,216.25**	**$ 2,508,547.25**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,508,547.25**						
63	Net KWH for retail = ((G) + (H)) * 1,000			109,209,186						**109,209,186**
64	October 2015 covers time period of 9/23/2015 -- 10/22/2015 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS . . .**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 2,504,331.00	109,209,186						
67	**Congestion and Losses Adjustment**		$ (3,543.39)							
68	**MISO RSG Bad Debt**		$ -							
69	**October Adjustments**		$ 7,759.64	82,570						
70	**Total MISO**		$ 2,508,547.25	109,291,756						
								. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
November 2015 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						**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 6,108,125.95	$ (3,877,439.88)	$ -	$ 2,230,686.07			396,272	(261,953)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ 48,786.61	$ (64,339.64)	$ -	$ (15,553.03)			2,315	(3,527)
4	RT Asset Energy Amount	555.19	$ 228,198.40	$ (316,294.39)	$ 110,769.38	$ 22,673.39			12,037	(23,883)
5	RT Distribution of Losses Amount	555.24	$ 4,439.57	$ (133,064.95)	$ 2,087.03	$ (126,538.35)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 286,442.88	$ -	$ -	$ 286,442.88			-	-
8	RT Loss Amount		$ 16,640.30	$ -	$ -	$ 16,640.30			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ (91.61)	$ -	$ (91.61)			-	(16)
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 6,692,633.71**	**$ (4,391,230.47)**	**$ 112,856.41**	**$ 2,414,259.65**			**410,624**	**(289,380)**
	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	$ 50,738.20	$ -	$ -	$ 50,738.20			-	-
16	RT Mkt Admin Amount	555.18	$ 5,721.24	$ -	$ (345.06)	$ 5,376.18			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,394.40	$ -	$ -	$ 1,394.40			-	-
18	**TOTAL**		**$ 57,853.84**	**$ -**	**$ (345.06)**	**$ 57,508.78**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 19,694.53	$ -	$ 19,694.53				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (14,770.94)	$ -	$ -	$ (14,770.94)				
23	FTR Hourly Allocation Amount	555.14	$ 58,029.34	$ (193,181.29)	$ 13.41	$ (135,138.54)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (5,041.53)	$ (13.49)	$ (5,055.02)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (13,174.94)	$ -	$ (13,174.94)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 4,459.81	$ (38,338.01)	$ 0.08	$ (33,878.12)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 38,338.01	$ (5,023.19)	$ (0.08)	$ 33,314.74			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 21,934.87	$ (259,176.50)	$ -	$ (237,241.63)			-	-
30	FTR Annual Transaction Amount	555.38	$ 259,228.48	$ (22,761.14)	$ -	$ 236,467.34			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 8,670.17	$ -	$ -	$ 8,670.17			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (46,544.39)	$ -	$ (46,544.39)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 375,889.74**	**$ (563,546.46)**	**$ (0.08)**	**$ (187,656.80)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 7,164.59	$ -	$ (1,431.08)	$ 5,733.51			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (39.89)	$ -	$ (39.89)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 15,686.69	$ -	$ (2,217.48)	$ 13,469.21			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (16,755.55)	$ -	$ (16,755.55)			-	-
40	**TOTAL**		**$ 22,851.28**	**$ (16,795.44)**	**$ (3,648.56)**	**$ 2,407.28**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 69,638.33	$ (3,397.70)	$ 279.07	$ 66,519.70			-	-
42	**TOTAL**		**$ 69,638.33**	**$ (3,397.70)**	**$ 279.07**	**$ 66,519.70**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ 3,812.74	$ 3,812.74			-	-
44	RT Net Inadvertent Amount	555.27	$ 1,936.52	$ (8,648.34)	$ 1,367.82	$ (5,344.00)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ 0.02	$ 0.02			-	-
47	**TOTAL**		**$ 1,936.52**	**$ (8,648.34)**	**$ 5,180.58**	**$ (1,531.24)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
November 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**	
	ASM Charges									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 350,665.62	$ (179,874.93)	$ -	$ 170,790.69			24,418	(13,357)
49	RT ASM Excessive Energy Amount	555.56	$ 82.32	$ (121.99)	$ -	$ (39.67)			-	(19)
50	**TOTAL**		**$ 350,747.94**	**$ (179,996.92)**	**$ -**	**$ 170,751.02**			**24,418**	**(13,376)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 7,571,551.36	$ (5,163,615.33)	$ 114,322.36	$ 2,522,258.39	$ (263,243.07)	$ 2,259,015.32	435,043	(302,755)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (57,853.84)	$ -	$ 345.06	$ (57,508.78)				
58	**Less: Congestion and Losses Adjustment**				$ (6,693.23)	$ (6,693.23)				
59	**Less: No DA generation sch., but still had output for current month**				$ (938.37)	$ (938.37)				
60	**Less: MISO RSG Bad Debt**				$ -	$ -				
61	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 7,513,697.52**	**$ (5,163,615.33)**	**$ 107,035.82**	**$ 2,457,118.01**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,457,118.01**						
63	Net KWH for retail = ((G) + (H)) * 1,000			132,287,229						**132,287,229**
64	November 2015 covers time period of 10/23/2015 -- 11/22/2015 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS . . .**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 2,350,082.19	132,287,229						
67	**Congestion and Losses Adjustment**		$ (6,693.23)							
68	**MISO RSG Bad Debt**		$ -							
69	**November Adjustments**		$ 113,729.05	4,951,904						
70	**Total MISO**		$ 2,457,118.01	137,239,133						
								. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
December 2015 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						**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 9,218,575.27	$ (5,529,670.50)	$ -	$ 3,688,904.77			502,589	(296,406)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ -	$ (101,711.03)	$ -	$ (101,711.03)			-	(5,722)
4	RT Asset Energy Amount	555.19	$ 626,624.62	$ (114,826.42)	$ 40,813.04	$ 552,611.24			28,566	(6,732)
5	RT Distribution of Losses Amount	555.24	$ 9,165.23	$ (171,170.12)	$ (2,981.56)	$ (164,986.45)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 372,116.65	$ -	$ -	$ 372,116.65			-	-
8	RT Loss Amount		$ (2,941.75)	$ -	$ -	$ (2,941.75)			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ -	$ -	$ -			-	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 10,223,540.02**	**$ (5,917,378.07)**	**$ 37,831.48**	**$ 4,343,993.43**			**531,156**	**(308,859)**
	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	$ 59,940.84	$ -	$ -	$ 59,940.84			-	-
16	RT Mkt Admin Amount	555.18	$ 6,382.31	$ -	$ (142.27)	$ 6,240.04			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,775.68	$ -	$ -	$ 1,775.68			-	-
18	**TOTAL**		**$ 68,098.83**	**$ -**	**$ (142.27)**	**$ 67,956.56**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 390,682.27	$ -	$ 390,682.27				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (56,800.24)	$ -	$ -	$ (56,800.24)				
23	FTR Hourly Allocation Amount	555.14	$ 15,026.34	$ (359,199.67)	$ -	$ (344,173.33)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (10,126.15)	$ (5.52)	$ (10,131.67)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (8,268.30)	$ -	$ (8,268.30)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 9,853.92	$ (30,672.58)	$ 5.52	$ (20,813.14)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 30,672.58	$ (11,075.54)	$ (4.81)	$ 19,592.23			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 13,462.12	$ (240,030.63)	$ -	$ (226,568.51)			-	-
30	FTR Annual Transaction Amount	555.38	$ 240,100.08	$ (13,639.97)	$ -	$ 226,460.11			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 5,664.89	$ -	$ -	$ 5,664.89			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (33,695.66)	$ -	$ (33,695.66)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 257,979.69**	**$ (316,026.23)**	**$ (4.81)**	**$ (58,051.35)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 7,242.13	$ -	$ (619.06)	$ 6,623.07			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 9,981.25	$ -	$ (1,967.19)	$ 8,014.06			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (19,723.82)	$ 13.25	$ (19,710.57)			-	-
40	**TOTAL**		**$ 17,223.38**	**$ (19,723.82)**	**$ (2,573.00)**	**$ (5,073.44)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 77,585.80	$ (1,118.08)	$ 1,272.10	$ 77,739.82			-	-
42	**TOTAL**		**$ 77,585.80**	**$ (1,118.08)**	**$ 1,272.10**	**$ 77,739.82**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ (750.26)	$ (750.26)			-	-
44	RT Net Inadvertent Amount	555.27	$ 6,704.12	$ (11,471.75)	$ (607.61)	$ (5,375.24)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ 3.91	$ 3.91			-	-
47	**TOTAL**		**$ 6,704.12**	**$ (11,471.75)**	**$ (1,353.96)**	**$ (6,121.59)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
December 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 687,882.79	$ (173,282.19)	$ (124.14)	$ 514,476.46			40,382	(10,331)
49	RT ASM Excessive Energy Amount	555.56	$ 268.47	$ (7.84)	$ -	$ 260.63			-	(18)
50	**TOTAL**		**$ 688,151.26**	**$ (173,290.03)**	**$ (124.14)**	**$ 514,737.09**			**40,382**	**(10,349)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 11,339,283.10	$ (6,439,007.98)	$ 34,905.40	$ 4,935,180.52	$ (318,837.82)	$ 4,616,342.70	571,538	(319,209)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (68,098.83)	$ -	$ 142.27	$ (67,956.56)				
58	**Less: Congestion and Losses Adjustment**				$ (5,409.71)	$ (5,409.71)				
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**		**$ 11,271,184.27**	**$ (6,439,007.98)**	**$ 29,637.96**	**$ 4,861,814.25**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 4,861,814.25**						
63	Net KWH for retail = ((G) + (H)) * 1,000			252,329,077						**252,329,077**
64	December 2015 covers time period of 11/23/2015 -- 12/27/2015 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS . . .**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 4,832,176.29	252,329,077						
67	**Congestion and Losses Adjustment**		$ (5,409.71)							
68	**MISO RSG Bad Debt**		$ -							
69	**December Adjustments**		$ 35,047.67	1,274,429						
70	**Total MISO**		$ 4,861,814.25	253,603,507						
								. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
January 2016 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						**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 9,416,986.60	$ (5,831,852.21)	$ -	$ 3,585,134.39			428,940	(268,017)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ -	$ (86,435.80)	$ -	$ (86,435.80)			-	(4,146)
4	RT Asset Energy Amount	555.19	$ 67,809.19	$ (488,966.12)	$ (99,621.58)	$ (520,778.51)			3,453	(22,349)
5	RT Distribution of Losses Amount	555.24	$ 51,095.83	$ (271,715.44)	$ 875.60	$ (219,744.01)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 368,465.41	$ -	$ -	$ 368,465.41			-	-
8	RT Loss Amount		$ 4,997.97	$ -	$ -	$ 4,997.97			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ -	$ -	$ -			-	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 9,909,355.00**	**$ (6,678,969.57)**	**$ (98,745.98)**	**$ 3,131,639.45**			**432,393**	**(294,512)**
	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	$ 53,761.50	$ -	$ -	$ 53,761.50			-	-
16	RT Mkt Admin Amount	555.18	$ 4,988.84	$ -	$ (142.12)	$ 4,846.72			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,373.76	$ -	$ -	$ 1,373.76			-	-
18	**TOTAL**		**$ 60,124.10**	**$ -**	**$ (142.12)**	**$ 59,981.98**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 127,861.52	$ -	$ 127,861.52				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 2,500.57	$ -	$ -	$ 2,500.57				
23	FTR Hourly Allocation Amount	555.14	$ 18,604.91	$ (111,073.90)	$ 1.13	$ (92,467.86)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (23,301.58)	$ (1.79)	$ (23,303.37)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (5,024.40)	$ -	$ (5,024.40)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 23,290.54	$ (2,825.70)	$ 0.66	$ 20,465.50			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 2,825.70	$ (23,822.38)	$ (0.59)	$ (20,997.27)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 13,462.12	$ (240,030.63)	$ -	$ (226,568.51)			-	-
30	FTR Annual Transaction Amount	555.38	$ 240,100.08	$ (13,639.97)	$ -	$ 226,460.11			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 5,664.89	$ -	$ -	$ 5,664.89			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (33,802.51)	$ -	$ (33,802.51)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 306,448.81**	**$ (325,659.55)**	**$ (0.59)**	**$ (19,211.33)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 11,535.28	$ -	$ -	$ 11,535.28			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (5.71)	$ -	$ (5.71)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 9,238.66	$ -	$ 1,478.76	$ 10,717.42			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (8,202.36)	$ -	$ (8,202.36)			-	-
40	**TOTAL**		**$ 20,773.94**	**$ (8,208.07)**	**$ 1,478.76**	**$ 14,044.63**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 73,959.29	$ (693.63)	$ (3,041.20)	$ 70,224.46			-	-
42	**TOTAL**		**$ 73,959.29**	**$ (693.63)**	**$ (3,041.20)**	**$ 70,224.46**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ 116,010.78	$ 116,010.78			-	-
44	RT Net Inadvertent Amount	555.27	$ 19,568.40	$ (35,397.46)	$ (33.49)	$ (15,862.55)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ -	$ -			-	-
47	**TOTAL**		**$ 19,568.40**	**$ (35,397.46)**	**$ 115,977.29**	**$ 100,148.23**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
January 2016 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 678,274.53	$ (102,868.70)	$ -	$ 575,405.83			33,638	(5,707)
49	RT ASM Excessive Energy Amount	555.56	$ -	$ (183.05)	$ -	$ (183.05)			-	(32)
50	**TOTAL**		**$ 678,274.53**	**$ (103,051.75)**	**$ -**	**$ 575,222.78**			**33,638**	**(5,739)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 11,068,504.07	$ (7,151,980.03)	$ 15,526.16	$ 3,932,050.20	$ (252,246.82)	$ 3,679,803.38	466,032	(300,251)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (60,124.10)	$ -	$ 142.12	$ (59,981.98)				
58	**Less: Congestion and Losses Adjustment**				$ (4,672.27)	$ (4,672.27)				
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**		**$ 11,008,379.97**	**$ (7,151,980.03)**	**$ 10,996.01**	**$ 3,867,395.95**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 3,867,395.95**						
63	Net KWH for retail = ((G) + (H)) * 1,000			165,780,811						**165,780,811**
64	(Month) 2016 covers time period of 12/28/2015 -- 1/21/2016 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS . . .**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 3,856,399.94	165,780,811						
67	**Congestion and Losses Adjustment**		$ (4,672.27)							
68	**MISO RSG Bad Debt**		$ -							
69	**(Month) Adjustments**		$ 15,668.28	(6,101,675)						
70	**Total MISO**		$ 3,867,395.95	159,679,135						
								. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
February 2016 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						**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	$ 9,223,549.24	$ (5,812,281.17)	$ -	$ 3,411,268.07			492,756	(318,441)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ -	$ (100,875.05)	$ -	$ (100,875.05)			-	(5,346)
4	RT Asset Energy Amount	555.19	$ 172,182.42	$ (649,994.84)	$ (100,091.75)	$ (577,904.17)			8,965	(33,705)
5	RT Distribution of Losses Amount	555.24	$ 52,079.76	$ (323,069.56)	$ (5,619.81)	$ (276,609.61)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 353,680.42	$ -	$ -	$ 353,680.42			-	-
8	RT Loss Amount		$ 6,790.71	$ -	$ -	$ 6,790.71			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ -	$ -	$ -			-	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 9,808,282.55**	**$ (6,886,220.62)**	**$ (105,711.56)**	**$ 2,816,350.37**			**501,722**	**(357,492)**
	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	$ 66,895.63	$ -	$ -	$ 66,895.63			-	-
16	RT Mkt Admin Amount	555.18	$ 6,794.14	$ -	$ (347.68)	$ 6,446.46			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,986.24	$ -	$ -	$ 1,986.24			-	-
18	**TOTAL**		**$ 75,676.01**	**$ -**	**$ (347.68)**	**$ 75,328.33**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 117,230.73	$ -	$ 117,230.73				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (21,659.83)	$ -	$ -	$ (21,659.83)				
23	FTR Hourly Allocation Amount	555.14	$ 24,943.11	$ (164,214.94)	$ (1.19)	$ (139,273.02)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (3,128.49)	$ (3.09)	$ (3,131.58)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (3,256.35)	$ -	$ (3,256.35)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 3,122.71	$ (6,230.35)	$ 4.28	$ (3,103.36)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 6,230.35	$ (3,122.71)	$ (4.28)	$ 3,103.36			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 13,462.12	$ (240,030.63)	$ -	$ (226,568.51)			-	-
30	FTR Annual Transaction Amount	555.38	$ 240,100.08	$ (13,639.97)	$ -	$ 226,460.11			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 5,664.89	$ -	$ -	$ 5,664.89			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (33,802.51)	$ -	$ (33,802.51)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 271,863.43**	**$ (350,195.22)**	**$ (4.28)**	**$ (78,336.07)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 12,927.84	$ -	$ (137.29)	$ 12,790.55			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (15,877.85)	$ -	$ (15,877.85)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 3,476.98	$ -	$ (1,938.50)	$ 1,538.48			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (12,535.10)	$ (53.43)	$ (12,588.53)			-	-
40	**TOTAL**		**$ 16,404.82**	**$ (28,412.95)**	**$ (2,129.22)**	**$ (14,137.35)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 77,840.36	$ (11,822.02)	$ 1,850.19	$ 67,868.53			-	-
42	**TOTAL**		**$ 77,840.36**	**$ (11,822.02)**	**$ 1,850.19**	**$ 67,868.53**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ 12,127.42	$ -	$ 330.76	$ 12,458.18			-	-
44	RT Net Inadvertent Amount	555.27	$ 53,095.37	$ (47,202.30)	$ (3,656.88)	$ 2,236.19			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ -	$ -			-	-
47	**TOTAL**		**$ 65,222.79**	**$ (47,202.30)**	**$ (3,326.12)**	**$ 14,694.37**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
February 2016 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 525,157.16	$ (168,884.58)	$ (29,567.62)	$ 326,704.96			30,111	(10,160)
49	RT ASM Excessive Energy Amount	555.56	$ 351.86	$ (47.58)	$ -	$ 304.28			-	(16)
50	**TOTAL**		**$ 525,509.02**	**$ (168,932.16)**	**$ (29,567.62)**	**$ 327,009.24**			**30,111**	**(10,177)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							. . . PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 10,840,798.98	$ (7,492,785.27)	$ (139,236.29)	$ 3,208,777.42	$ (331,587.83)	$ 2,877,189.59	531,832	(367,669)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (75,676.01)	$ -	$ 347.68	$ (75,328.33)				
58	**Less: Congestion and Losses Adjustment**				$ (2,678.85)	$ (2,678.85)				
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**		**$ 10,765,122.97**	**$ (7,492,785.27)**	**$ (141,567.46)**	**$ 3,130,770.24**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 3,130,770.24**						
63	Net KWH for retail = ((G) + (H)) * 1,000			164,163,376						**164,163,376**

64 February 2015 covers time period of 1/22/2016 -- 2/21/2016 ** increased for losses of 2.8%

[PROTECTED DATA BEGINS . . .

		Net Retail	Net MISO KWH	per kWh	Net Intersystem	Total
66	**MISO Book Totals**	$ 3,272,337.70	164,163,376			
67	**Congestion and Losses Adjustment**	$ (2,678.85)				
68	**MISO RSG Bad Debt**	$ -				
69	**February Adjustments**	$ (138,888.61)	(6,638,946)			
70	**Total MISO**	$ 3,130,770.24	157,524,430			

. . . PROTECTED DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
March 2016 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						**[PROTECTED DATA BEGINS ...**			
1	DA Asset Energy Amount	555.02	$ 6,304,075.71	$ (4,112,555.28)	$ -	$ 2,191,520.43			417,490	(277,235)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ -	$ (79,254.31)	$ -	$ (79,254.31)			-	(4,784)
4	RT Asset Energy Amount	555.19	$ 294,404.59	$ (118,029.72)	$ 381,764.82	$ 558,139.69			22,651	(7,667)
5	RT Distribution of Losses Amount	555.24	$ 54,720.92	$ (143,126.56)	$ 58,174.02	$ (30,231.62)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 268,612.23	$ -	$ -	$ 268,612.23			-	-
8	RT Loss Amount		$ 26,663.56	$ -	$ -	$ 26,663.56			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ -	$ -	$ -			-	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 6,948,477.01**	**$ (4,452,965.87)**	**$ 439,938.84**	**$ 2,935,449.98**			**440,142**	**(289,687)**
	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	$ 52,634.44	$ -	$ -	$ 52,634.44			-	-
16	RT Mkt Admin Amount	555.18	$ 5,248.51	$ -	$ (963.58)	$ 4,284.93			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,900.88	$ -	$ -	$ 1,900.88			-	-
18	**TOTAL**		**$ 59,783.83**	**$ -**	**$ (963.58)**	**$ 58,820.25**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 119,513.73	$ -	$ 119,513.73				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 11,477.95	$ -	$ -	$ 11,477.95				
23	FTR Hourly Allocation Amount	555.14	$ 31,062.45	$ (84,853.81)	$ (2.63)	$ (53,793.99)			-	-
24	FTR Monthly Allocation Amount	555.15	$ 44.27	$ (6,595.07)	$ 1.99	$ (6,548.81)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ 2,594.23	$ (4,215.64)	$ -	$ (1,621.41)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 6,295.98	$ (4,246.66)	$ 0.64	$ 2,049.96			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 4,246.66	$ (6,295.98)	$ (0.64)	$ (2,049.96)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 9,219.79	$ (185,434.17)	$ -	$ (176,214.38)			-	-
30	FTR Annual Transaction Amount	555.38	$ 185,409.52	$ (9,205.00)	$ -	$ 176,204.52			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 2,780.53	$ (114.11)	$ -	$ 2,666.42			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (34,881.99)	$ -	$ (34,881.99)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 253,131.38**	**$ (216,328.70)**	**$ (0.64)**	**$ 36,802.04**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 9,352.08	$ -	$ 9.21	$ 9,361.29			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (889.64)	$ -	$ (889.64)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 3,900.12	$ -	$ 992.33	$ 4,892.45			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (12,865.85)	$ -	$ (12,865.85)			-	-
40	**TOTAL**		**$ 13,252.20**	**$ (13,755.49)**	**$ 1,001.54**	**$ 498.25**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 26,415.33	$ (28,341.67)	$ (46,439.67)	$ (48,366.01)			-	-
42	**TOTAL**		**$ 26,415.33**	**$ (28,341.67)**	**$ (46,439.67)**	**$ (48,366.01)**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ 3,307.60	$ 3,307.60			-	-
44	RT Net Inadvertent Amount	555.27	$ 69,190.49	$ (19,046.54)	$ 30,528.78	$ 80,672.73			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ -	$ -			-	-
47	**TOTAL**		**$ 69,190.49**	**$ (19,046.54)**	**$ 33,836.38**	**$ 83,980.33**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
March 2016 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 332,606.26	$ (206,455.56)	$ -	$ 126,150.70			22,417	(15,880)
49	RT ASM Excessive Energy Amount	555.56	$ 8.25	$ (4.17)	$ -	$ 4.08			-	(4)
50	**TOTAL**		**$ 332,614.51**	**$ (206,459.73)**	**$ -**	**$ 126,154.78**			**22,417**	**(15,884)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							... PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 7,702,864.75	$ (4,936,898.00)	$ 427,372.87	$ 3,193,339.62	$ (259,407.15)	$ 2,933,932.47	462,558	(305,571)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (59,783.83)	$ -	$ 963.58	$ (58,820.25)				
58	**Less: Congestion and Losses Adjustment**				$ (5,046.88)	$ (5,046.88)				
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**		**$ 7,643,080.92**	**$ (4,936,898.00)**	**$ 423,289.57**	**$ 3,129,472.49**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 3,129,472.49**						
63	Net KWH for retail = ((G) + (H)) * 1,000			156,987,490						**156,987,490**
64	March 2015 covers time period of 2/22/2016 -- 3/23/2016 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS ...**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 2,706,182.92	156,987,490						
67	**Congestion and Losses Adjustment**		$ (5,046.88)							
68	**MISO RSG Bad Debt**		$ -							
69	**March Adjustments**		$ 428,336.45	18,777,780						
70	**Total MISO**		$ 3,129,472.49	175,765,270						
								... PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
April 2016 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						**[PROTECTED DATA BEGINS ...**			
1	DA Asset Energy Amount	555.02	$ 5,707,095.91	$ (3,162,312.62)	$ -	$ 2,544,783.29			366,095	(205,096)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ -	$ (72,736.13)	$ -	$ (72,736.13)			-	(4,402)
4	RT Asset Energy Amount	555.19	$ 130,754.99	$ (199,537.30)	$ (185,718.43)	$ (254,500.74)			13,333	(13,255)
5	RT Distribution of Losses Amount	555.24	$ 8,010.24	$ (57,524.21)	$ 23,313.13	$ (26,200.84)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 186,514.22	$ -	$ -	$ 186,514.22			-	-
8	RT Loss Amount		$ 22,614.60	$ -	$ -	$ 22,614.60			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ -	$ -	$ -			-	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 6,054,989.96**	**$ (3,492,110.26)**	**$ (162,405.30)**	**$ 2,400,474.40**			**379,428**	**(222,752)**
	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	$ 41,352.68	$ -	$ -	$ 41,352.68			-	-
16	RT Mkt Admin Amount	555.18	$ 4,663.92	$ -	$ 149.80	$ 4,813.72			-	-
17	FTR Mkt Admin Amount	555.13	$ 2,115.84	$ -	$ -	$ 2,115.84			-	-
18	**TOTAL**		**$ 48,132.44**	**$ -**	**$ 149.80**	**$ 48,282.24**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 110,384.92	$ -	$ 110,384.92				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 43,903.46	$ -	$ -	$ 43,903.46				
23	FTR Hourly Allocation Amount	555.14	$ 42,944.66	$ (146,270.31)	$ 0.61	$ (103,325.04)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (8,197.03)	$ (0.61)	$ (8,197.64)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ (36,489.21)	$ (36,489.21)			-	-
26	FTR Monthly Transaction Amount	555.35	$ 2,693.09	$ (8,240.90)	$ -	$ (5,547.81)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 8,194.79	$ (12,174.32)	$ 36,489.21	$ 32,509.68			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 12,174.32	$ (8,194.79)	$ (35,473.65)	$ (31,494.12)			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 9,219.79	$ (185,434.17)	$ -	$ (176,214.38)			-	-
30	FTR Annual Transaction Amount	555.38	$ 185,409.52	$ (9,205.00)	$ -	$ 176,204.52			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 2,666.42	$ -	$ -	$ 2,666.42			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (34,485.21)	$ -	$ (34,485.21)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 307,206.05**	**$ (301,816.81)**	**$ (35,473.65)**	**$ (30,084.41)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 7,679.44	$ -	$ (231.03)	$ 7,448.41			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ -	$ -			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 13,133.22	$ -	$ 597.74	$ 13,730.96			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (22,285.46)	$ (27.00)	$ (22,312.46)			-	-
40	**TOTAL**		**$ 20,812.66**	**$ (22,285.46)**	**$ 339.71**	**$ (1,133.09)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 37,743.88	$ (34,663.74)	$ 20,909.28	$ 23,989.42			-	-
42	**TOTAL**		**$ 37,743.88**	**$ (34,663.74)**	**$ 20,909.28**	**$ 23,989.42**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ 11,092.44	$ -	$ 16,283.15	$ 27,375.59			-	-
44	RT Net Inadvertent Amount	555.27	$ 28,431.69	$ (7,310.79)	$ (18,153.96)	$ 2,966.94			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ -	$ -			-	-
47	**TOTAL**		**$ 39,524.13**	**$ (7,310.79)**	**$ (1,870.81)**	**$ 30,342.53**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
April 2016 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 378,799.25	$ (192,305.61)	$ 915.49	$ 187,409.13			22,160	(15,215)
49	RT ASM Excessive Energy Amount	555.56	$ 26.97	$ -	$ 434.65	$ 461.62			-	(12)
50	**TOTAL**		**$ 378,826.22**	**$ (192,305.61)**	**$ 1,350.14**	**$ 187,870.75**			**22,160**	**(15,226)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							... PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 6,887,235.34	$ (4,050,492.67)	$ (177,000.83)	$ 2,659,741.84	$ (244,244.86)	$ 2,415,496.98	401,588	(237,979)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (48,132.44)	$ -	$ (149.80)	$ (48,282.24)				
58	**Less: Congestion and Losses Adjustment**				$ (363.16)	$ (363.16)				
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**		**$ 6,839,102.90**	**$ (4,050,492.67)**	**$ (177,513.79)**	**$ 2,611,096.44**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,611,096.44**						
63	Net KWH for retail = ((G) + (H)) * 1,000			163,608,978						**163,608,978**
64	April 2015 covers time period of 3/24/2016 -- 4/21/2016 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS ...**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 2,788,610.23	163,608,978						
67	**Congestion and Losses Adjustment**		$ (363.16)							
68	**MISO RSG Bad Debt**		$ -							
69	**April Adjustments**		$ (177,150.63)	(9,689,247)						
70	**Total MISO**		$ 2,611,096.44	153,919,730						
								... PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
May 2016 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						[PROTECTED DATA BEGINS ...			
1	DA Asset Energy Amount	555.02	$ 5,805,695.16	$ (2,775,652.30)	$ -	$ 3,030,042.86			373,662	(197,226)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ -	$ (71,705.06)	$ -	$ (71,705.06)			-	(3,952)
4	RT Asset Energy Amount	555.19	$ 123,163.74	$ (443,570.61)	$ (105,606.77)	$ (426,013.64)			3,392	(31,872)
5	RT Distribution of Losses Amount	555.24	$ 18,479.91	$ (86,486.90)	$ 10,461.40	$ (57,545.59)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 135,141.95	$ -	$ -	$ 135,141.95			-	-
8	RT Loss Amount		$ 14,303.30	$ -	$ -	$ 14,303.30			-	-
9	RT Non-Asset Energy Amount	555.26	$ -	$ -	$ -	$ -			-	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 6,096,784.06**	**$ (3,377,414.87)**	**$ (95,145.37)**	**$ 2,624,223.82**			**377,053**	**(233,050)**
	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	$ 42,390.95	$ -	$ -	$ 42,390.95			-	-
16	RT Mkt Admin Amount	555.18	$ 5,775.32	$ -	$ (408.23)	$ 5,367.09			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,736.64	$ -	$ -	$ 1,736.64			-	-
18	**TOTAL**		**$ 49,902.91**	**$ -**	**$ (408.23)**	**$ 49,494.68**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ (106,800.92)	$ -	$ (106,800.92)				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ (77,762.13)	$ -	$ -	$ (77,762.13)				
23	FTR Hourly Allocation Amount	555.14	$ 124,725.56	$ (146,242.41)	$ (55.77)	$ (21,572.62)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (7,623.39)	$ -	$ (7,623.39)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ (46,028.31)	$ -	$ (46,028.31)			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 6,750.66	$ (10,628.78)	$ 55.77	$ (3,822.35)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 10,628.78	$ (6,440.78)	$ (55.77)	$ 4,132.23			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 9,219.79	$ (185,434.17)	$ -	$ (176,214.38)			-	-
30	FTR Annual Transaction Amount	555.38	$ 185,409.52	$ (9,205.00)	$ -	$ 176,204.52			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 2,666.42	$ -	$ -	$ 2,666.42			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ -	$ (34,663.76)	$ -	$ (34,663.76)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 261,638.60**	**$ (553,067.52)**	**$ (55.77)**	**$ (291,484.69)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 14,106.10	$ -	$ 64.08	$ 14,170.18			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (18,304.26)	$ -	$ (18,304.26)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 5,445.04	$ -	$ 494.69	$ 5,939.73			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (28,766.61)	$ (5.62)	$ (28,772.23)			-	-
40	**TOTAL**		**$ 19,551.14**	**$ (47,070.87)**	**$ 553.15**	**$ (26,966.58)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 51,962.48	$ (12,085.52)	$ 84,617.43	$ 124,494.39			-	-
42	**TOTAL**		**$ 51,962.48**	**$ (12,085.52)**	**$ 84,617.43**	**$ 124,494.39**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ 8,885.55	$ -	$ (2,356.99)	$ 6,528.56			-	-
44	RT Net Inadvertent Amount	555.27	$ 20,942.21	$ (21,829.46)	$ (57,772.33)	$ (58,659.58)			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ -	$ -	$ -	$ -			-	-
47	DA Ramp Product	555.63	$ -	$ (33.26)	$ -	$ (33.26)			-	-
48	RT Ramp Product	555.64	$ 90.69	$ (252.30)	$ -	$ (161.61)			-	-
49	**TOTAL**		**$ 29,918.45**	**$ (22,115.02)**	**$ (60,129.32)**	**$ (52,325.89)**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
May 2016 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									
50	RT ASM Non-Excessive Energy Amount	555.55	$ 329,354.54	$ (215,451.66)	$ (911.40)	$ 112,991.48			25,739	(13,885)
51	RT ASM Excessive Energy Amount	555.56	$ 71.95	$ (251.23)	$ (473.48)	$ (652.76)			-	(37)
52	**TOTAL**		**$ 329,426.49**	**$ (215,702.89)**	**$ (1,384.88)**	**$ 112,338.72**			**25,739**	**(13,922)**
	Grandfathered Charge Types									
53	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -			-	-
54	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
55	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
56	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
57	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							... PROTECTED DATA ENDS]			
58	**TOTAL MISO DAY 2 CHARGES**		$ 6,839,184.13	$ (4,227,456.69)	$ (71,952.99)	$ 2,539,774.45	$ (139,615.12)	$ 2,400,159.33	402,793	(246,972)
59	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (49,902.91)	$ -	$ 408.23	$ (49,494.68)				
60	**Less: Congestion and Losses Adjustment**				$ (4,158.53)	$ (4,158.53)				
61	**Less: No DA generation sch., but still had output for current month**				$ -	$ -				
62	**Less: MISO RSG Bad Debt**				$ -	$ -				
63	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 6,789,281.22**	**$ (4,227,456.69)**	**$ (75,703.29)**	**$ 2,486,121.24**				
64	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,486,121.24**						
65	Net KWH for retail = ((G) + (H)) * 1,000			155,820,813						**155,820,813**
66	May 2015 covers time period of 4/22/2016 -- 5/23/2016 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS ...**			
67			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
68	**MISO Book Totals**		$ 2,561,824.53	155,820,813						
69	**Congestion and Losses Adjustment**		$ (4,158.53)							
70	**MISO RSG Bad Debt**		$ -							
71	**May Adjustments**		$ (71,544.76)	(9,063,186)						
72	**Total MISO**		$ 2,486,121.24	146,757,626						
								... PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
June 2016 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						**[PROTECTED DATA BEGINS ...**			
1	DA Asset Energy Amount	555.02	$ 6,875,503.97	$ (3,857,104.97)	$ -	$ 3,018,399.00			360,896	(202,246)
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -			-	-
3	DA Non-asset Energy Amount	555.09	$ -	$ (83,135.15)	$ -	$ (83,135.15)			-	(3,561)
4	RT Asset Energy Amount	555.19	$ 133,721.47	$ (381,553.76)	$ (20,367.59)	$ (268,199.88)			12,733	(16,680)
5	RT Distribution of Losses Amount	555.24	$ 37,850.67	$ (77,487.32)	$ 1,031.26	$ (38,605.39)			-	-
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -			-	-
7	DA Loss Amount		$ 218,075.24	$ -	$ -	$ 218,075.24			-	-
8	RT Loss Amount		$ 35,858.04	$ -	$ -	$ 35,858.04			-	-
9	RT Non-Asset Energy Amount	555.26	$ 236.31	$ (0.48)	$ -	$ 235.83			12	-
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -			-	-
11	**TOTAL**		**$ 7,301,245.70**	**$ (4,399,281.68)**	**$ (19,336.33)**	**$ 2,882,627.69**			**373,640**	**(222,487)**
	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	$ 40,979.01	$ -	$ -	$ 40,979.01			-	-
16	RT Mkt Admin Amount	555.18	$ 5,118.08	$ -	$ (246.88)	$ 4,871.20			-	-
17	FTR Mkt Admin Amount	555.13	$ 1,980.00	$ -	$ -	$ 1,980.00			-	-
18	**TOTAL**		**$ 48,077.09**	**$ -**	**$ (246.88)**	**$ 47,830.21**			**-**	**-**
	Congest & FTRs									
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -			-	-
20	DA Congestion		$ -	$ 94,014.13	$ -	$ 94,014.13				
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -			-	-
22	RT Congestion		$ 29,134.62	$ -	$ -	$ 29,134.62				
23	FTR Hourly Allocation Amount	555.14	$ 86,258.82	$ (218,290.09)	$ -	$ (132,031.27)			-	-
24	FTR Monthly Allocation Amount	555.15	$ -	$ (7,198.97)	$ -	$ (7,198.97)			-	-
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -			-	-
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -			-	-
27	FTR Full Funding Guarantee Amount	555.36	$ 7,152.85	$ (10,582.86)	$ -	$ (3,430.01)			-	-
28	FTR Guarantee Uplift Amount	555.37	$ 10,582.86	$ (7,240.49)	$ -	$ 3,342.37			-	-
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ 4,230.91	$ (153,963.12)	$ -	$ (149,732.21)			-	-
30	FTR Annual Transaction Amount	555.38	$ 153,943.97	$ (4,128.92)	$ -	$ 149,815.05			-	-
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 7,591.90	$ -	$ -	$ 7,591.90			-	-
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ 89.91	$ (29,983.89)	$ -	$ (29,893.98)			-	-
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -			-	-
34	**TOTAL**		**$ 298,985.84**	**$ (337,374.21)**	**$ -**	**$ (38,388.37)**			**-**	**-**
	RSG & Make Whole Payments									
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 8,806.60	$ -	$ (591.76)	$ 8,214.84			-	-
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ (17,771.33)	$ -	$ (17,771.33)			-	-
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amou	555.29	$ 15,343.30	$ -	$ 304.68	$ 15,647.98			-	-
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -			-	-
39	RT Price Volatility Make Whole Payment	555.42	$ -	$ (17,241.66)	$ 19.43	$ (17,222.23)			-	-
40	**TOTAL**		**$ 24,149.90**	**$ (35,012.99)**	**$ (267.65)**	**$ (11,130.74)**			**-**	**-**
	Revenue Neutrality Uplift									
41	RT Revenue Neutrality Uplift Amount	555.28	$ 16,820.60	$ (41,628.26)	$ 8,094.74	$ (16,712.92)			-	-
42	**TOTAL**		**$ 16,820.60**	**$ (41,628.26)**	**$ 8,094.74**	**$ (16,712.92)**			**-**	**-**
	Other Charges									
43	RT Misc Amount	555.25	$ -	$ -	$ 2,735.68	$ 2,735.68			-	-
44	RT Net Inadvertent Amount	555.27	$ 54,730.25	$ (12,581.25)	$ (6,219.86)	$ 35,929.14			-	-
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -			-	-
46	RT Demand Response Allocation Uplift Amount	555.59	$ 0.66	$ -	$ -	$ 0.66			-	-
	DA Ramp Product	555.63	$ -	$ (1,228.94)	$ -	$ (1,228.94)			-	-
	RT Ramp Product	555.64	$ 332.08	$ (172.55)	$ -	$ 159.53			-	-
47	**TOTAL**		**$ 55,062.99**	**$ (13,982.74)**	**$ (3,484.18)**	**$ 37,596.07**			**-**	**-**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - System
June 2016 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									
48	RT ASM Non-Excessive Energy Amount	555.55	$ 386,910.30	$ (324,016.13)	$ -	$ 62,894.17			22,182	(17,582)
49	RT ASM Excessive Energy Amount	555.56	$ 79.82	$ (53.23)	$ -	$ 26.59			5	(16)
50	**TOTAL**		**$ 386,990.12**	**$ (324,069.36)**	**$ -**	**$ 62,920.76**			**22,187**	**(17,598)**
	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**		**$ -**	**$ -**	**$ -**	**$ -**			**-**	**-**
							... PROTECTED DATA ENDS]			
56	**TOTAL MISO DAY 2 CHARGES**		$ 8,131,332.24	$ (5,151,349.24)	$ (15,240.30)	$ 2,964,742.70	$ (431,700.81)	$ 2,533,041.89	395,827	(240,085)
57	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (48,077.09)	$ -	$ 246.88	$ (47,830.21)				
58	**Less: Congestion and Losses Adjustment**				$ (11,045.85)	$ (11,045.85)				
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**		**$ 8,083,255.15**	**$ (5,151,349.24)**	**$ (26,039.27)**	**$ 2,905,866.64**				
62	Net MISO Charges for Retail = (B) + (C) + (D)			**$ 2,905,866.64**						
63	Net KWH for retail = ((G) + (H)) * 1,000			155,742,002						**155,742,002**
64	June 2015 covers time period of 5/24/2016 -- 6/22/2016 ** increased for losses of 2.8%						**[PROTECTED DATA BEGINS ...**			
65			**Net Retail**	**Net MISO KWH**			**per kWh**	**Net Intersystem**	**Total**	
66	**MISO Book Totals**		$ 2,931,905.91	155,742,002						
67	**Congestion and Losses Adjustment**		$ (11,045.85)							
68	**MISO RSG Bad Debt**		$ -							
69	**June Adjustments**		$ (14,993.42)	(2,387,480)						
70	**Total MISO**		$ 2,905,866.64	153,354,522						
								... PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group - Net Retail - System
July 2015 through June 2016 includes any adjustments

No.	Charge Type Description	(A) Acct	(B) JULY 2015	(C) AUGUST	(D) SEPTEMBER	(E) OCTOBER	(F) NOVEMBER	(G) DECEMBER	(H) JANUARY 2016	(I) FEBRUARY	(J) MARCH	(K) APRIL	(L) MAY	(M) JUNE	YEAR TO DATE 2015 - 2016
	Day Ahead & Real Time Asset & Non Asset Energy & Loss														
1	DA Asset Energy Amount	555.02	$ 5,668,045.40	$ 3,780,700.19	$ 2,187,495.24	$ 2,278,390.07	$ 2,230,686.07	$ 3,688,904.77	$ 3,585,134.39	$ 3,411,268.07	$ 2,191,520.43	$ 2,544,783.29	$ 3,030,042.86	$ 3,018,399.00	$ 37,615,369.78
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	DA Non-asset Energy Amount	555.09	$ 244,209.83	$ 140,504.55	$ 181,228.79	$ 112,706.48	$ (15,553.03)	$ (101,711.03)	$ (86,435.80)	$ (100,875.05)	$ (79,254.31)	$ (72,736.13)	$ (71,705.06)	$ (83,135.15)	$ 67,244.09
4	RT Asset Energy Amount	555.19	$ 128,518.79	$ (280,045.85)	$ (366,030.63)	$ (223,799.94)	$ 22,673.39	$ 552,611.24	$ (520,778.51)	$ (577,904.17)	$ 558,139.69	$ (254,500.74)	$ (426,013.64)	$ (268,199.88)	$ (1,655,330.25)
5	RT Distribution of Losses Amount	555.24	$ (119,340.01)	$ (174,685.06)	$ (146,515.99)	$ (117,464.23)	$ (126,538.35)	$ (164,986.45)	$ (219,744.01)	$ (276,609.61)	$ (30,231.62)	$ (26,200.84)	$ (57,545.59)	$ (38,605.39)	$ (1,498,467.15)
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	DA Loss Amount		$ 114,887.60	$ 149,461.22	$ 312,785.86	$ 292,597.50	$ 286,442.88	$ 372,116.65	$ 368,465.41	$ 353,680.42	$ 268,612.23	$ 186,514.22	$ 135,141.95	$ 218,075.24	$ 3,058,781.18
8	RT Loss Amount		$ 2,176.02	$ 7,545.25	$ 21,823.45	$ 2,428.32	$ 16,640.30	$ (2,941.75)	$ 4,997.97	$ 6,790.71	$ 26,663.56	$ 22,614.60	$ 14,303.30	$ 35,858.04	$ 158,899.77
9	RT Non-Asset Energy Amount	555.26	$ (182.98)	$ 32,325.05	$ 19,552.88	$ (2,861.86)	$ (91.61)	$ -	$ -	$ -	$ -	$ -	$ -	$ 235.83	$ 48,977.31
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	**TOTAL**		**$ 6,038,314.65**	**$ 3,655,805.35**	**$ 2,210,339.60**	**$ 2,341,996.34**	**$ 2,414,259.65**	**$ 4,343,993.43**	**$ 3,131,639.45**	**$ 2,816,350.37**	**$ 2,935,449.98**	**$ 2,400,474.40**	**$ 2,624,223.82**	**$ 2,882,627.69**	**$ 37,795,474.73**
	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	$ 34,479.29	$ 41,607.66	$ 40,628.05	$ 43,199.85	$ 50,738.20	$ 59,940.84	$ 53,761.50	$ 66,895.63	$ 52,634.44	$ 41,352.68	$ 42,390.95	$ 40,979.01	$ 568,608.10
16	RT Mkt Admin Amount	555.18	$ 2,860.43	$ 4,982.71	$ 4,078.35	$ 4,616.64	$ 5,376.18	$ 6,240.04	$ 4,846.72	$ 6,446.46	$ 4,284.93	$ 4,813.72	$ 5,367.09	$ 4,871.20	$ 58,784.47
17	FTR Mkt Admin Amount	555.13	$ 710.08	$ 1,381.44	$ 1,675.68	$ 1,548.16	$ 1,394.40	$ 1,775.68	$ 1,373.76	$ 1,986.24	$ 1,900.88	$ 2,115.84	$ 1,736.64	$ 1,980.00	$ 19,578.80
18	**TOTAL**		**$ 38,049.80**	**$ 47,971.81**	**$ 46,382.08**	**$ 49,364.65**	**$ 57,508.78**	**$ 67,956.56**	**$ 59,981.98**	**$ 75,328.33**	**$ 58,820.25**	**$ 48,282.24**	**$ 49,494.68**	**$ 47,830.21**	**$ 646,971.37**
	Congest & FTRs														
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DA Congestion		$ 19,179.98	$ 30,406.31	$ 37,466.59	$ (63,115.84)	$ 19,694.53	$ 390,682.27	$ 127,861.52	$ 117,230.73	$ 119,513.73	$ 110,384.92	$ (106,800.92)	$ 94,014.13	$ 896,517.95
21	RT FBT Congestion Amount	555.20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	RT Congestion		$ (4,200.91)	$ (5,301.84)	$ 22,327.79	$ (53,055.65)	$ (14,770.94)	$ (56,800.24)	$ 2,500.57	$ (21,659.83)	$ 11,477.95	$ 43,903.46	$ (77,762.13)	$ 29,134.62	$ (124,207.15)
23	FTR Hourly Allocation Amount	555.14	$ 2,549.80	$ (45,792.04)	$ (35,711.45)	$ (39,693.58)	$ (135,138.54)	$ (344,173.33)	$ (92,467.86)	$ (139,273.02)	$ (53,793.99)	$ (103,325.04)	$ (21,572.62)	$ (132,031.27)	$ (1,140,422.94)
24	FTR Monthly Allocation Amount	555.15	$ (637.34)	$ (1,651.92)	$ (5,184.46)	$ (12,932.33)	$ (5,055.02)	$ (10,131.67)	$ (23,303.37)	$ (3,131.58)	$ (6,548.81)	$ (8,197.64)	$ (7,623.39)	$ (7,198.97)	$ (91,596.50)
25	FTR Yearly Allocation Amount	555.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (36,489.21)	$ -	$ -	$ (36,489.21)
26	FTR Monthly Transaction Amount	555.35	$ (63,931.52)	$ (10,192.28)	$ (33,770.58)	$ (10,253.05)	$ (13,174.94)	$ (8,268.30)	$ (5,024.40)	$ (3,256.35)	$ (1,621.41)	$ (5,547.81)	$ (46,028.31)	$ -	$ (201,068.95)
27	FTR Full Funding Guarantee Amount	555.36	$ (777.72)	$ (2,262.81)	$ (6,095.48)	$ 2,928.27	$ (33,878.12)	$ (20,813.14)	$ 20,465.50	$ (3,103.36)	$ 2,049.96	$ 32,509.68	$ (3,822.35)	$ (3,430.01)	$ (16,229.58)
28	FTR Guarantee Uplift Amount	555.37	$ 777.72	$ 2,262.81	$ 6,095.48	$ (2,928.27)	$ 33,314.74	$ 19,592.23	$ (20,997.27)	$ 3,103.36	$ (2,049.96)	$ (31,494.12)	$ 4,132.23	$ 3,342.37	$ 15,151.32
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ (208,334.67)	$ (208,334.67)	$ (237,241.63)	$ (237,241.63)	$ (237,241.63)	$ (226,568.51)	$ (226,568.51)	$ (226,568.51)	$ (176,214.38)	$ (176,214.38)	$ (176,214.38)	$ (149,732.21)	$ (2,486,475.11)
30	FTR Annual Transaction Amount	555.38	$ 184,165.97	$ 184,165.97	$ 236,467.34	$ 236,467.34	$ 236,467.34	$ 226,460.11	$ 226,460.11	$ 226,460.11	$ 176,204.52	$ 176,204.52	$ 176,204.52	$ 149,815.05	$ 2,435,542.90
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 5,379.69	$ 5,313.17	$ 8,636.91	$ 8,670.17	$ 8,670.17	$ 5,664.89	$ 5,664.89	$ 5,664.89	$ 2,666.42	$ 2,666.42	$ 2,666.42	$ 7,591.90	$ 69,255.94
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ (19,246.86)	$ (21,298.10)	$ (45,415.76)	$ (46,544.39)	$ (46,544.39)	$ (33,695.66)	$ (33,802.51)	$ (33,802.51)	$ (34,881.99)	$ (34,485.21)	$ (34,663.76)	$ (29,893.98)	$ (414,275.12)
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	**TOTAL**		**$ (85,075.86)**	**$ (72,685.40)**	**$ (52,425.25)**	**$ (217,698.96)**	**$ (187,656.80)**	**$ (58,051.35)**	**$ (19,211.33)**	**$ (78,336.07)**	**$ 36,802.04**	**$ (30,084.41)**	**$ (291,484.69)**	**$ (38,388.37)**	**$ (1,094,296.45)**
	RSG & Make Whole Payments														
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	$ 12,104.39	$ 11,667.22	$ 11,414.68	$ 13,720.10	$ 5,733.51	$ 6,623.07	$ 11,535.28	$ 12,790.55	$ 9,361.29	$ 7,448.41	$ 14,170.18	$ 8,214.84	$ 124,783.52
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ -	$ -	$ (43.00)	$ (565.87)	$ (39.89)	$ -	$ (5.71)	$ (15,877.85)	$ (889.64)	$ -	$ (18,304.26)	$ (17,771.33)	$ (53,497.55)
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	$ 19,822.46	$ 66,160.45	$ 36,853.32	$ 27,571.30	$ 13,469.21	$ 8,014.06	$ 10,717.42	$ 1,538.48	$ 4,892.45	$ 13,730.96	$ 5,939.73	$ 15,647.98	$ 224,357.82
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	RT Price Volatility Make Whole Payment	555.42	$ (6,567.87)	$ (8,388.48)	$ (9,834.15)	$ (10,114.83)	$ (16,755.55)	$ (19,710.57)	$ (8,202.36)	$ (12,588.53)	$ (12,865.85)	$ (22,312.46)	$ (28,772.23)	$ (17,222.23)	$ (173,335.11)
40	**TOTAL**		**$ 25,358.98**	**$ 69,439.19**	**$ 38,390.85**	**$ 30,610.70**	**$ 2,407.28**	**$ (5,073.44)**	**$ 14,044.63**	**$ (14,137.35)**	**$ 498.25**	**$ (1,133.09)**	**$ (26,966.58)**	**$ (11,130.74)**	**$ 122,308.68**
	Revenue Neutrality Uplift														
41	RT Revenue Neutrality Uplift Amount	555.28	$ 39,949.01	$ 37,669.28	$ 38,980.97	$ 44,396.55	$ 66,519.70	$ 77,739.82	$ 70,224.46	$ 67,868.53	$ (48,366.01)	$ 23,989.42	$ 124,494.39	$ (16,712.92)	$ 526,753.20
42	**TOTAL**		**$ 39,949.01**	**$ 37,669.28**	**$ 38,980.97**	**$ 44,396.55**	**$ 66,519.70**	**$ 77,739.82**	**$ 70,224.46**	**$ 67,868.53**	**$ (48,366.01)**	**$ 23,989.42**	**$ 124,494.39**	**$ (16,712.92)**	**$ 526,753.20**
	Other Charges														
43	RT Misc Amount	555.25	$ (641.33)	$ (23.17)	$ (4,314.17)	$ 519.46	$ 3,812.74	$ (750.26)	$ 116,010.78	$ 12,458.18	$ 3,307.60	$ 27,375.59	$ 6,528.56	$ 2,735.68	$ 167,019.66
44	RT Net Inadvertent Amount	555.27	$ (1,830.29)	$ (590.02)	$ 1,716.01	$ (4,316.41)	$ (5,344.00)	$ (5,375.24)	$ (15,862.55)	$ 2,236.19	$ 80,672.73	$ 2,966.94	$ (58,659.58)	$ 35,929.14	$ 31,542.92
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	RT Demand Response Allocation Uplift Amount	555.59	$ (0.03)	$ 4.73	$ 0.02	$ -	$ 0.02	$ 3.91	$ -	$ -	$ -	$ -	$ -	$ 0.66	$ 9.31
47	DA Ramp Product	555.63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (33.26)	$ (1,228.94)	$ (1,262.20)
48	RT Ramp Product	555.64	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (161.61)	$ 159.53	$ (2.08)
49	**TOTAL**		**$ (2,471.65)**	**$ (608.46)**	**$ (2,598.14)**	**$ (3,796.95)**	**$ (1,531.24)**	**$ (6,121.59)**	**$ 100,148.23**	**$ 14,694.37**	**$ 83,980.33**	**$ 30,342.53**	**$ (52,325.89)**	**$ 37,596.07**	**$ 197,307.61**

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group - Net Retail - System
July 2015 through June 2016 includes any adjustments

	Charge Type Description	(A) Acct	(B) JULY 2015	(C) AUGUST	(D) SEPTEMBER	(E) OCTOBER	(F) NOVEMBER	(G) DECEMBER	(H) JANUARY 2016	(I) FEBRUARY	(J) MARCH	(K) APRIL	(L) MAY	(M) JUNE	YEAR TO DATE 2015 - 2016
	ASM Charges														
50	RT ASM Non-Excessive Energy Amount	555.55	$ 74,229.70	$ 536,286.46	$ 202,070.76	$ 316,306.17	$ 170,790.69	$ 514,476.46	$ 575,405.83	$ 326,704.96	$ 126,150.70	$ 187,409.13	$ 112,991.48	$ 62,894.17	$ 3,205,716.51
51	RT ASM Excessive Energy Amount	555.56	$ 4,275.67	$ 272.24	$ 372.74	$ 276.79	$ (39.67)	$ 260.63	$ (183.05)	$ 304.28	$ 4.08	$ 461.62	$ (652.76)	$ 26.59	$ 5,379.16
52	**TOTAL**		**$ 78,505.37**	**$ 536,558.70**	**$ 202,443.50**	**$ 316,582.96**	**$ 170,751.02**	**$ 514,737.09**	**$ 575,222.78**	**$ 327,009.24**	**$ 126,154.78**	**$ 187,870.75**	**$ 112,338.72**	**$ 62,920.76**	**$ 3,211,095.67**
	Grandfathered Charge Types														
53	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
58	**TOTAL MISO DAY 2 CHARGES**		$ 6,132,630.30	$ 4,274,150.47	$ 2,481,513.61	$ 2,561,455.29	$ 2,522,258.39	$ 4,935,180.52	$ 3,932,050.20	$ 3,208,777.42	$ 3,193,339.62	$ 2,659,741.84	$ 2,539,774.45	$ 2,964,742.70	$ 41,405,614.81
59	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (38,049.80)	$ (47,971.81)	$ (46,382.08)	$ (49,364.65)	$ (57,508.78)	$ (67,956.56)	$ (59,981.98)	$ (75,328.33)	$ (58,820.25)	$ (48,282.24)	$ (49,494.68)	$ (47,830.21)	$ (646,971.37)
60	**Less: Congestion and Losses Adjustment**		$ 250.81	$ 24.29	$ (3,346.59)	$ (3,543.39)	$ (6,693.23)	$ (5,409.71)	$ (4,672.27)	$ (2,678.85)	$ (5,046.88)	$ (363.16)	$ (4,158.53)	$ (11,045.85)	$ (46,683.36)
61	**Less: No DA generation sch., but still had output for current month**		$ -	$ -	$ -	$ -	$ (938.37)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (938.37)
62	**Less: MISO RSG Bad Debt**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	**TOTAL FOR MN COST OF ENERGY ADJUSTMENT**		**$ 6,094,831.31**	**$ 4,226,202.95**	**$ 2,431,784.94**	**$ 2,508,547.25**	**$ 2,457,118.01**	**$ 4,861,814.25**	**$ 3,867,395.95**	**$ 3,130,770.24**	**$ 3,129,472.49**	**$ 2,611,096.44**	**$ 2,486,121.24**	**$ 2,905,866.64**	**$ 40,711,021.71**

SOUTHWEST POWER POOL (SPP) ENERGY COSTS

Otter Tail began incurring Southwest Power Pool (SPP) energy market charges on October 1, 2015 as a result of Western Area Power Administration (WAPA) joining SPP. Additional SPP market exposure was incurred as a result of the expiration of an integrated transmission agreement with Central Power Electric Cooperative effective January 1, 2016. SPP charges include monthly day ahead and real time *energy charges* assessed by SPP, as well as other energy-market related charges. Otter Tail has included the monthly day ahead and real time *energy charges* assessed by SPP in the monthly fuel clause, consistent with paragraph 2 of the Energy Adjustment Rider, Rate Schedule 13.01 (Part E Section 1 Attachment B):

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.*

The SPP energy charges for 2015/2016 reporting period included in the Energy Adjustment Rider are shown in Lines 1-5 of Part E Section 11 Attachment I-2. The SPP charges to date have been relatively minor. The remaining charges in lines 6-29 are additional SPP market related charges. *These charges are currently not included in the Energy Adjustment Rider*. In Otter Tail's current general rate case, Docket No. E017/GR-15-1033, Otter Tail has requested the inclusion of the remaining SPP market charges shown on Lines 6-29 for recovery in the Energy Adjustment Rider, Rate Schedule 13.01, as these costs are comparable to costs incurred from MISO for loads served in MISO.

Further Information on Otter Tail Load in SPP

Otter Tail maintains load served within the WAPA Balancing Authority (BA). Prior to WAPA joining SPP, Otter Tail would schedule energy out of the MISO system and into the WAPA system. This was an energy export out of MISO and therefore was charged under the MISO DA Non-Asset Energy Amount charge type. In response to WAPA joining the SPP market, Otter Tail determined it was in our customers best interest to pseudo tie that load in the WAPA BA (now SPP BA) out of SPP and back into MISO. Pseudo tying load allows for MISO to serve and regulate load outside their BA as if it were inside their BA. As a result, this eliminated the need for a daily export of energy and the DA Non-Asset Energy charge for Otter Tail load in WAPA/SPP BA dropped to zero. WAPA still maintains some of its municipal and agency loads within MISO, which requires WAPA to inject energy into MISO for which Otter Tail receives credit. While these credits have always been included in prior MISO reporting, they are now much more visible as they are no longer netted against the charges associated with energy exports used to serve Otter Tail load in the WAPA/SPP BA.

Otter Tail Power Company
Detail of Southwest Power Pool (SPP) Charges by Charge Group - System
October 2015 to June 2016 Includes Any Adjustments
(Revenue) Expense

No.	Charge Type Description	Acct	2015 OCTOBER	NOVEMBER	DECEMBER	2016 JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	2015/2016 YEAR TO DATE
	Day Ahead & Real Time Asset & Non Asset Energy											
1	DA Asset Energy Amount	555.00	$ -	$ 2,182.63	$ -	$ -	$ -	$ -	$ 43,386.29	$ -	$ -	**$ 45,568.92**
2	DA Non-asset Energy Amount	555.03	$ 0.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 0.04**
3	RT Asset Energy Amount	555.09	$ (3,147.48)	$ (7,297.09)	$ (10,693.47)	$ 24,249.49	$ 8,890.30	$ 46,797.86	$ 9,474.25	$ (1,033.69)	$ 3,684.61	**$ 70,924.78**
4	RT Non-Asset Energy Amount	555.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
5	**TOTAL (1)**		**$ (3,147.44)**	**$ (5,114.46)**	**$ (10,693.47)**	**$ 24,249.49**	**$ 8,890.30**	**$ 46,797.86**	**$ 52,860.54**	**$ (1,033.69)**	**$ 3,684.61**	**$ 116,493.74**
	RSG & Make Whole Payments											
6	DA Make-Whole-Payment Distribution Amount	555.02	$ 937.32	$ 468.28	$ (14.02)	$ -	$ 0.73	$ 0.14	$ 331.66	$ 4.77	$ -	**$ 1,728.88**
7	RT Make-Whole-Payment Distribution Amount	555.10	$ 188.02	$ 157.47	$ 1,030.62	$ 754.44	$ 87.90	$ 799.00	$ 511.80	$ 69.37	$ 255.48	**$ 3,854.10**
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.00	$ (8.20)	$ -	$ 1.17	$ (3.47)	$ -	$ -	$ -	$ -	$ -	**$ (10.50)**
9	**TOTAL**		**$ 1,117.14**	**$ 625.75**	**$ 1,017.77**	**$ 750.97**	**$ 88.63**	**$ 799.14**	**$ 843.46**	**$ 74.14**	**$ 255.48**	**$ 5,572.48**
	Revenue Neutrality Uplift											
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	$ 1,412.34	$ 785.69	$ (148.35)	$ (83.90)	$ (68.97)	$ 20.81	$ 526.75	$ (0.68)	$ (0.57)	**$ 2,443.12**
11	**TOTAL**		**$ 1,412.34**	**$ 785.69**	**$ (148.35)**	**$ (83.90)**	**$ (68.97)**	**$ 20.81**	**$ 526.75**	**$ (0.68)**	**$ (0.57)**	**$ 2,443.12**
	Other Charges											
12	DA Regulation-Down Distribution Amount	555.04	$ 415.29	$ 208.56	$ (16.38)	$ 69.75	$ 41.81	$ 218.56	$ 179.31	$ (5.27)	$ 4.17	**$ 1,115.80**
13	DA Regulation-Up Distribution Amount	555.05	$ 488.90	$ 328.83	$ (24.25)	$ 79.02	$ 50.20	$ 285.64	$ 274.39	$ (5.09)	$ 16.71	**$ 1,494.35**
14	DA Spinning Reserve Distribution Amount	555.06	$ 586.46	$ 411.91	$ (41.56)	$ 52.47	$ 32.72	$ 342.63	$ 422.91	$ 1.12	$ 18.53	**$ 1,827.19**
15	DA Supplemental Reserve Distribution Amount	555.07	$ 134.93	$ 91.77	$ (4.56)	$ 19.20	$ 8.79	$ 75.61	$ 84.78	$ (1.28)	$ 2.20	**$ 411.44**
16	RT Contingency Reserve Deployment Failure Amount	555.08	$ (0.90)	$ (1.83)	$ 0.16	$ (0.90)	$ (13.56)	$ (1.19)	$ (0.83)	$ 0.20	$ (0.21)	**$ (19.06)**
17	RT Over-Collected Losses Distribution Amount	555.11	$ (389.22)	$ (16.45)	$ (305.40)	$ (2,432.04)	$ (3,029.04)	$ (3,300.11)	$ (4,860.10)	$ (3,339.43)	$ (2,571.16)	**$ (20,242.95)**
18	RT Regulation-Down Distribution Amount	555.12	$ (7.38)	$ (9.43)	$ (2.06)	$ (21.97)	$ (8.30)	$ 3.35	$ (25.02)	$ 0.18	$ (0.22)	**$ (70.85)**
19	RT Regulation Non-Performance Distribution Amount	555.13	$ (35.21)	$ (13.05)	$ 1.79	$ (10.40)	$ (4.80)	$ (54.99)	$ (38.63)	$ 1.04	$ (0.31)	**$ (154.56)**
20	RT Regulation-Up Distribution Amount	555.14	$ 5.63	$ 9.35	$ (3.54)	$ (16.11)	$ (9.26)	$ (23.51)	$ (26.23)	$ (0.27)	$ (2.12)	**$ (66.06)**
21	RT Spinning Reserve Distribution Amount	555.16	$ (3.85)	$ (1.15)	$ 0.88	$ (0.26)	$ (0.86)	$ (11.78)	$ (12.15)	$ 0.27	$ 0.07	**$ (28.83)**
22	RT Supplemental Reserve Distribution Amount	555.17	$ 0.02	$ 0.01	$ (0.01)	$ (0.58)	$ -	$ 0.12	$ 0.08	$ -	$ -	**$ (0.36)**
23	RT Pseudo Tie Congestion Amount	555.20	$ -	$ -	$ -	$ 14,462.92	$ (1,725.75)	$ (20,101.43)	$ 3,389.43	$ 33,155.42	$ (39,443.73)	**$ (10,263.14)**
24	RT Pseudo Tie Loss Amount	555.21	$ -	$ -	$ -	$ 9,795.87	$ 1,655.08	$ (1,863.39)	$ (8,636.61)	$ (14,202.13)	$ (18,567.46)	**$ (31,818.64)**
25	Miscellaneous Amount	555.23	$ -	$ -	$ -	$ -	$ (1,084.72)	$ (8.97)	$ (106.70)	$ 0.10	$ (120.55)	**$ (1,320.84)**
26	ARR Closeout Yearly Amount	555.26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,442.58)	**$ (9,442.58)**
27	**TOTAL**		**$ 1,194.67**	**$ 1,008.52**	**$ (394.93)**	**$ 21,996.97**	**$ (4,087.69)**	**$ (24,439.46)**	**$ (9,355.37)**	**$ 15,604.86**	**$ (70,106.66)**	**$ (68,579.09)**
	Grandfathered Charge Types											
28	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	$ 0.76	$ 5.52	$ 7.68	$ 14.14	$ 7.22	$ 50.04	$ 76.68	$ 0.13	$ 9.24	**$ 171.41**
28	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22				0	$ (0.02)	$ -	$ (2.26)	$ -	$ -	**$ (2.28)**
29	**TOTAL**		**$ 0.76**	**$ 5.52**	**$ 7.68**	**$ 14.14**	**$ 7.20**	**$ 50.04**	**$ 74.42**	**$ 0.13**	**$ 9.24**	**$ 169.13**
30	**TOTAL SPP CHARGES**		**$ 577.47**	**$ (2,688.98)**	**$ (10,211.30)**	**$ 46,927.67**	**$ 4,829.47**	**$ 23,228.39**	**$ 44,949.80**	**$ 14,644.76**	**$ (66,157.90)**	**$ 56,099.38**
	Summary:											
31	DA & RT Asset Energy Amounts Total (Line 5) **(1)**		$ (3,147.44)	$ (5,114.46)	$ (10,693.47)	$ 24,249.49	$ 8,890.30	$ 46,797.86	$ 52,860.54	$ (1,033.69)	$ 3,684.61	**$ 116,493.74**
32	RSG, RNU, Other, Grandfather Charges (Line 9 + Line 11 + Line 23 + Line 2		$ 3,724.91	$ 2,425.48	$ 482.17	$ 22,678.18	$ (4,060.83)	$ (23,569.47)	$ (7,910.74)	$ 15,678.45	$ (69,842.51)	**$ (60,394.36)**
33	**TOTAL SPP CHARGES**		**$ 577.47**	**$ (2,688.98)**	**$ (10,211.30)**	**$ 46,927.67**	**$ 4,829.47**	**$ 23,228.39**	**$ 44,949.80**	**$ 14,644.76**	**$ (66,157.90)**	**$ 56,099.38**

(1) DA and RT Energy Charges currently included in the monthly MN Energy Adjustment Rider calculation.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-625

OTTER TAIL
POWER COMPANY

PART F – MINN. R. 7825.2820 ANNUAL INDEPENDENT AUDITORS' REPORT

OTTER TAIL POWER COMPANY

SCHEDULE OF COSTS OF ENERGY ADJUSTMENT FACTORS
FOR MINNESOTA CUSTOMERS
FOR THE PERIOD FROM JULY 1, 2015, THROUGH JUNE 30, 2016

Deloitte.

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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, 2015, through June 30, 2016. This Schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the Schedule based on our examination.

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

In our opinion, such Schedule presents, in all material respects, the fuel clause adjustment factors of the Company for the period from July 1, 2015, through June 30, 2016, 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 on 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
- MN Docket Nos. E017/MR-15-1034 and E017/GR-15-1033 dated April 14, 2016
- MN Docket Nos. E-999/CI-03-802, E-999/AA-12-757, E-999/AA-13-599, and E-999/AA-14-579 dated June 2, 2016

Deloitte & Touche LLP

August 22, 2016

OTTER TAIL POWER COMPANY

SCHEDULE OF COSTS OF ENERGY ADJUSTMENT FACTORS
FOR MINNESOTA CUSTOMERS
FOR THE PERIOD FROM JULY 1, 2015, THROUGH JUNE 30, 2016

Based on Costs in the Two-Month Period Ended	Effective for the Monthly Bill Dated on or After	Adjustment per KWH
July 31, 2015	September 1, 2015	$ 0.00307
August 31, 2015	October 2, 2015	0.00563
September 30, 2015	November 2, 2015	0.00096
October 31, 2015	December 1, 2015	(0.00166)
November 30, 2015	January 4, 2016	(0.00030)
December 31, 2015	February 1, 2016	0.00098
January 31, 2016	March 2, 2016	0.00072
February 29, 2016	April 1, 2016	(0.00189)
February 29, 2016	April 16, 2016	(0.00336)
March 31, 2016	May 2, 2016	(0.00366)
April 30, 2016	June 2, 2016	(0.00410)
May 31, 2016	July 1, 2016	(0.00599)
June 30, 2016	August 2, 2016	(0.00281)

See accompanying note to the schedule of costs of energy adjustment factors.

NOTE TO THE SCHEDULE OF COSTS OF ENERGY ADJUSTMENT FACTORS FOR THE YEAR ENDED JUNE 30, 2016

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 kWh 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 cost associated with retail sales has been interpreted to mean actual kWh sales of electricity.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-625

PART G – MINN. R. 7825.2830 ANNUAL FIVE-YEAR PROJECTION REPORT

PUBLIC DOCUMENT
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION

SUPPORTING DOCUMENTATION

Fuel cost by source and system use purchased power cost is projected by month for July 2016 through December 2021.

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
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION

July 2016 - December 2021

	Jul 2016	Aug	Sep	Oct	Nov	Dec	Total
2016	**[PROTECTED 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

. . . PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION

July 2016 - December 2021

	Jan 2017	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2017	**[PROTECTED 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

. . . PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION

July 2016 - December 2021

	Jan 2018	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2018	**[PROTECTED 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

. . . PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION

July 2016 - December 2021

	Jan 2019	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2019	**[PROTECTED 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

. . . PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION

July 2016 - December 2021

	Jan 2020	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2020	**[PROTECTED 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

. . . PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION

July 2016 - December 2021

	Jan 2021	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2021	**[PROTECTED 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

. . . PROTECTED DATA ENDS]

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-625

OTTER TAIL POWER COMPANY

PART H - ADDITIONAL REPORTING REQUIREMENTS

PUBLIC DOCUMENT
NOT PUBLIC (OR PRIVILEGED) 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. R. 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,**

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

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

In Docket No. E999/AA-14-579 Otter Tail requested that consideration be given to drop this compliance reporting requirement from future Annual Automatic Adjustment filings.

In the June 2, 2016 Order (item 9.6) of Docket No. E999/AA-14-579, the Commission:

Accepts Otter Tail's compliance filing on its electric service agreement with Enbridge Energy, and permits Otter Tail to stop reporting this information.

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, some bilateral purchases are designed to settle in the real-time market while the Company clears its load in the day-ahead market. Therefore, a virtual transaction might be used to convert the real-time purchase to the day-ahead market so that the purchase more accurately hedges the Company's load. For the most recent AAA period (July 2015 through June 2016), the Company did not use any virtual transactions on behalf of retail customers. The Company does not use virtual transactions in the Asset-Based sales category. As of January 1, 2015, the Company discontinued all Non-Asset Based (non-retail) 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, 2014 and 2015.

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 Not Public)

OTTER TAIL POWER COMPANY
GENERATION MAINTENANCE EXPENSE

		Test Year 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015
STEAM POWER MAINTENANCE:								
SUPERVISION AND ENGINEERING	402 - 510	$ 721,308	883,656	$ 778,527	$ 816,833	$ 758,277	$ 773,643	$ 811,657
STRUCTURES	402 - 511	560,715	642,272	597,892	717,803	770,212	708,960	1,221,739
BOILER	402 - 512	6,231,149	5,511,489	7,404,372	6,655,306	6,172,350	7,236,561	6,587,242
ELECTRIC	402 - 513	3,061,762	792,083	1,155,193	1,390,201	1,139,056	4,755,818	3,051,732
MISCELLANEOUS	402 - 514	1,180,678	947,125	1,005,810	1,113,359	1,037,412	1,555,138	1,532,144
Total Steam Power Maintenance		11,755,612	8,776,625	10,941,794	10,693,502	9,877,307	15,030,120	13,204,515
HYDRO POWER MAINTENANCE:								
SUPERVISION & ENGINEERING	402 - 541	4,861	5,498	3,653	2,907	3,188	4,133	430
STRUCTURES	402 - 542	7,809	2,307	23,082	3,651	9,994	1,155	118
RESERVOIRS - DAMS	402 - 543	381,374	224,410	332,332	281,218	220,302	221,334	253,790
ELECTRIC	402 - 544	94,084	37,586	8,707	8,739	27,164	18,516	4,457
MISCELLANEOUS EXPENSE	402 - 545	6,349	7,445	18,714	319		2,089	390
Total Hydro Maintenance		494,478	277,245	386,488	296,834	260,648	247,227	259,185
IC POWER MAINTENANCE WITHOUT WIND:								
SUPERVISION AND ENGINEERING	402 - 551	22,680	32,388	37,446	24,123	40,378	22,937	55,466
STRUCTURES	402 - 552	18,168	79,869	5,010	65,536	39,732	37,245	62,819
GENERATING AND ELECTRIC	402 - 553	562,318	1,095,287	343,525	524,580	602,805	583,072	676,059
MISCELLANEOUS EXPENSE	402 - 554	9,334	(6,203)	1,937	15,771	47,467	23,537	24,682
Total IC Maintenance without wind		612,501	1,201,341	387,918	630,010	730,382	666,791	819,026
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	5,125
MISCELLANEOUS EXPENSE	402 - 554	-	-	1,173	6,704	10,429	118,912	60,925
		-	-	9,372	33,090	100,053	326,133	66,050
Additional Contracted Wind Maintenance*		280,129	249,942	288,570	258,442	446,807	316,763	298,064
Total Maintenance		$ 13,142,720	$ 10,505,153	$ 12,014,142	$ 11,911,878	$ 11,415,197	$ 16,587,034	$ 14,646,839
		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 Not Public) contains a monthly and year to date breakdown of MISO Day 2 Charges – System between Retail, Asset Based Wholesale, and Non-Asset Based Wholesale.

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 8 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 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**										**PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(353,622)	$ (8,918,536.64)	130,866	$ 3,250,491.24	0	$ -	1,099	$ 44,072.46				
2	DA Non-asset Energy Amount	555.09	(9,264)	$ (244,346.54)	9	$ 136.71	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(15,167)	$ (371,325.97)	11,241	$ 242,807.18	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	10	$ 182.98	0	$ -	0	$ -				
5	**SUBTOTAL**		**(378,054)**	**$ (9,534,209.15)**	**142,127**	**$ 3,493,618.11**	**0**	**$ -**	**1,099**	**$ 44,072.46**				
	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	$ (3,032.34)	0	$ 122,372.35	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (114,887.60)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (2,176.02)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (120,095.96)**	**0**	**$ 122,372.35**	**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	$ (34,479.29)	0	$ -	0	$ (75.22)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (3,021.10)	0	$ 160.67	0	$ (80.47)	0	$ -				
18	FTR Mkt Admin Amount	555.13	0	$ (710.08)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (38,210.47)**	**0**	**$ 160.67**	**0**	**$ (155.69)**	**0**	**$ -**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (19,179.98)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 4,200.91	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (24,309.37)	0	$ 21,759.57	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 637.34	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 63,931.52	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (627.77)	0	$ 1,405.49	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (1,405.49)	0	$ 627.77	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (23,531.71)	0	$ 231,866.38	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	$ (3,859.38)	0	$ 23,106.24	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (262,875.66)**	**0**	**$ 347,951.52**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (12,175.03)	0	$ 70.64	0	$ (53.59)	0	$ 0.31				
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	$ (21,264.95)	0	$ 1,442.49	0	$ (93.62)	0	$ 6.24				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 16,482.98				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 6,567.87	0	$ -	0	$ 29.00				
41	**SUBTOTAL**		**0**	**$ (33,439.98)**	**0**	**$ 8,081.00**	**0**	**$ (147.21)**	**0**	**$ 16,518.53**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (303.02)	0	$ 944.35	0	$ (2.09)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (2,494.91)	0	$ 4,325.20	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (44,017.55)	0	$ 4,068.54	0	$ (193.92)	0	$ 17.86				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ -	0	$ 0.03	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (46,815.48)**	**0**	**$ 9,338.12**	**0**	**$ (196.01)**	**0**	**$ 17.86**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(14,370)	$ (304,781.99)	11,038	$ 230,552.29	(419)	$ (9,086.93)	726	$ 15,205.91				
49	RT ASM Excessive Energy Amount	555.56	(1)	$ (4,278.02)	128	$ 2.35	0	$ -	0	$ -				
50	**SUBTOTAL**		**(14,371)**	**$ (309,060.01)**	**11,166**	**$ 230,554.64**	**(419)**	**$ (9,086.93)**	**726**	**$ 15,205.91**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 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**		**(392,425)**	**$ (10,344,706.71)**	**153,293**	**$ 4,212,076.41**	**(419)**	**$ (9,585.84)**	**1,824**	**$ 75,814.76**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (38,210.47)**		**$ 160.67**								
58	**Congestion and Losses Adjustment**			**$ 250.81**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (10,306,747.05)**		**$ 4,211,915.74**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (6,094,831.31)**									
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)**									**$ 66,228.92**				
65	**Less: Fuel Cost**								**1,406**	**$ 52,049.19**				
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**									**$ 22.43**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 14,157.30**				
												. . . PROTECTED DATA ENDS]		

OTTER TAIL POWER COMPANY
Electric Utility - Minnesota
2015/2016 AAA Report

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
August 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**										PROTECTED DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(375,795)	$ (9,747,440.80)	245,237	$ 5,966,740.61	0	$ -	985	$ 27,903.21				
2	DA Non-asset Energy Amount	555.09	(6,767)	$ (151,960.88)	489	$ 11,456.33	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(15,847)	$ (384,794.15)	28,475	$ 664,840.00	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(1,149)	$ (32,600.18)	16	$ 275.13	0	$ -	0	$ -				
5	**SUBTOTAL**		**(399,558)**	**$ (10,316,796.01)**	**274,218**	**$ 6,643,312.07**	**0**	**$ -**	**985**	**$ 27,903.21**				
	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	$ (3,711.99)	0	$ 178,397.05	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (149,461.22)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (7,545.25)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (160,718.46)**	**0**	**$ 178,397.05**	**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	$ (41,607.66)	0	$ -	0	$ (66.40)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (5,197.20)	0	$ 214.49	0	$ (719.47)	0	$ 1.95				
18	FTR Mkt Admin Amount	555.13	0	$ (1,381.44)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (48,186.30)**	**0**	**$ 214.49**	**0**	**$ (785.87)**	**0**	**$ 1.95**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (30,406.31)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 5,301.84	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (58,206.79)	0	$ 103,998.83	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 1,651.92	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 10,192.28	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (1,637.28)	0	$ 3,900.09	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (3,900.09)	0	$ 1,637.28	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (23,531.71)	0	$ 231,866.38	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	$ 66.52	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (1,809.58)	0	$ 23,107.68	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (297,126.46)**	**0**	**$ 369,811.86**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (11,667.22)	0	$ -	0	$ (383.89)	0	$ -				
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	$ (68,134.62)	0	$ 1,974.17	0	$ (2,242.50)	0	$ 64.81				
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	$ (34.33)	0	$ 8,422.81	0	$ (1.12)	0	$ 277.24				
41	**SUBTOTAL**		**0**	**$ (79,836.17)**	**0**	**$ 10,396.98**	**0**	**$ (2,627.51)**	**0**	**$ 342.05**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (407.67)	0	$ 430.84	0	$ (22.76)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (4,536.26)	0	$ 5,126.28	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (47,217.20)	0	$ 9,547.92	0	$ (1,553.89)	0	$ 314.09				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (4.76)	0	$ 0.03	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (52,165.89)**	**0**	**$ 15,105.07**	**0**	**$ (1,576.65)**	**0**	**$ 314.09**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(31,903)	$ (747,374.16)	9,730	$ 211,087.70	(340)	$ (118,673.86)	10,344	$ 174,773.85				
49	RT ASM Excessive Energy Amount	555.56	0	$ (456.96)	128	$ 184.72	0	$ -	7	$ -				
50	**SUBTOTAL**		**(31,903)**	**$ (747,831.12)**	**9,858**	**$ 211,272.42**	**(340)**	**$ (118,673.86)**	**10,351**	**$ 174,773.85**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
August 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**		**(431,461)**	**$ (11,702,660.41)**	**284,076**	**$ 7,428,509.94**	**(340)**	**$ (123,663.89)**	**11,336**	**$ 203,335.15**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (48,186.30)**		**$ 214.49**								
58	**Congestion and Losses Adjustment**			**$ 24.29**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (11,654,498.40)**		**$ 7,428,295.45**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (4,226,202.95)**									
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)**									**$ 79,671.26**				
65	**Less: Fuel Cost**								**10,996**	**$ 212,869.84**				
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**									**$ 119.42**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ (133,318.00)**				

. . . PROTECTED DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
September 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**										PROTECTED DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(345,269)	$ (7,920,776.24)	250,197	$ 5,733,281.00	0	$ -	449	$ 9,918.94				
2	DA Non-asset Energy Amount	555.09	(8,985)	$ (187,040.20)	187	$ 5,811.41	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(12,692)	$ (218,736.53)	25,070	$ 584,767.16	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(668)	$ (19,552.88)	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(367,615)**	**$ (8,346,105.85)**	**275,454**	**$ 6,323,859.57**	**0**	**$ -**	**449**	**$ 9,918.94**				
	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	$ (6,595.09)	0	$ 153,111.08	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (312,785.86)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (21,823.45)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (341,204.40)**	**0**	**$ 153,111.08**	**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	$ (40,628.05)	0	$ -	0	$ (30.69)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (4,460.26)	0	$ 381.91	0	$ (631.81)	0	$ 0.40				
18	FTR Mkt Admin Amount	555.13	0	$ (1,675.68)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (46,763.99)**	**0**	**$ 381.91**	**0**	**$ (662.50)**	**0**	**$ 0.40**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (37,466.59)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (22,327.79)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (130,252.17)	0	$ 165,963.62	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (0.09)	0	$ 5,184.55	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 33,770.58	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (5,062.35)	0	$ 11,157.83	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (11,157.83)	0	$ 5,062.35	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (21,934.87)	0	$ 259,176.50	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (259,228.48)	0	$ 22,761.14	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (8,670.17)	0	$ 33.26	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (904.77)	0	$ 46,320.53	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (459,538.52)**	**0**	**$ 511,963.77**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (11,551.35)	0	$ 136.67	0	$ (283.08)	0	$ 3.35				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 43.00	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (38,533.16)	0	$ 1,679.84	0	$ (944.74)	0	$ 41.06				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 16,718.47				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 9,834.15	0	$ -	0	$ 241.17				
41	**SUBTOTAL**		**0**	**$ (50,084.51)**	**0**	**$ 11,693.66**	**0**	**$ (1,227.82)**	**0**	**$ 17,004.05**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (1,457.94)	0	$ 5,772.11	0	$ (4.35)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (4,236.24)	0	$ 2,520.23	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (45,103.64)	0	$ 6,122.67	0	$ (1,105.85)	0	$ 150.00				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (0.02)	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (50,797.84)**	**0**	**$ 14,415.01**	**0**	**$ (1,110.20)**	**0**	**$ 150.00**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(23,157)	$ (460,062.40)	14,486	$ 257,991.64	(300)	$ (5,196.67)	8,903	$ 162,457.19				
49	RT ASM Excessive Energy Amount	555.56	0	$ (646.23)	164	$ 273.49	0	$ -	45	$ 552.14				
50	**SUBTOTAL**		**(23,157)**	**$ (460,708.63)**	**14,650**	**$ 258,265.13**	**(300)**	**$ (5,196.67)**	**8,948**	**$ 163,009.33**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
September 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**		**(390,772)**	**$ (9,755,203.74)**	**290,104**	**$ 7,273,690.13**	**(300)**	**$ (8,197.19)**	**9,396**	**$ 190,082.72**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (46,763.99)**		**$ 381.91**								
58	**Congestion and Losses Adjustment**			**$ (3,346.59)**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (9,705,093.16)**		**$ 7,273,308.22**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (2,431,784.94)**									
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)**									**$ 181,885.53**				
65	**Less: Fuel Cost**								**9,097**	**$ 182,127.90**				
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**									**$ 104.51**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ (346.88)**				
												. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
October 2015 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										**PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(349,554)	$ (6,630,973.31)	245,443	$ 4,352,583.24	0	$ -	2,405	$ 53,958.15				
2	DA Non-asset Energy Amount	555.09	(5,409)	$ (112,706.48)	0	$ -	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(8,510)	$ (246,709.34)	26,946	$ 470,509.28	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	230	$ 2,861.86	0	$ -	0	$ -				
5	**SUBTOTAL**		**(363,473)**	**$ (6,990,389.13)**	**272,619**	**$ 4,825,954.38**	**0**	**$ -**	**2,405**	**$ 53,958.15**				
	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	$ (36,104.80)	0	$ 153,569.03	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (292,597.50)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (2,428.32)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (331,130.62)**	**0**	**$ 153,569.03**	**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	$ (43,199.85)	0	$ -	0	$ (166.91)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (4,826.19)	0	$ 209.55	0	$ (693.58)	0	$ -				
18	FTR Mkt Admin Amount	555.13	0	$ (1,548.16)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (49,574.20)**	**0**	**$ 209.55**	**0**	**$ (860.49)**	**0**	**$ -**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ 63,115.84	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 53,055.65	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (42,596.26)	0	$ 82,289.84	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 12,932.33	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 10,253.05	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (12,887.52)	0	$ 9,959.25	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (9,959.25)	0	$ 12,887.52	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (21,934.87)	0	$ 259,176.50	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (259,228.48)	0	$ 22,761.14	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (8,670.17)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 46,544.39	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (302,220.90)**	**0**	**$ 519,919.86**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (15,609.06)	0	$ 1,888.96	0	$ (341.47)	0	$ 41.28				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 565.87	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (28,756.41)	0	$ 1,185.11	0	$ (629.07)	0	$ 25.77				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 32,181.60				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (0.15)	0	$ 10,114.98	0	$ -	0	$ 221.37				
41	**SUBTOTAL**		**0**	**$ (44,365.62)**	**0**	**$ 13,754.92**	**0**	**$ (970.54)**	**0**	**$ 32,470.02**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (1,039.08)	0	$ 519.62	0	$ (3.47)	0	$ 0.35				
43	RT Net Inadvertent Amount	555.27	0	$ (19,790.95)	0	$ 24,107.36	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (54,511.09)	0	$ 10,114.54	0	$ (1,192.66)	0	$ 221.15				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (0.01)	0	$ 0.01	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (75,341.13)**	**0**	**$ 34,741.53**	**0**	**$ (1,196.13)**	**0**	**$ 221.50**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(28,421)	$ (488,384.59)	9,898	$ 172,078.42	(1,995)	$ (47,720.62)	7,569	$ 162,421.38				
49	RT ASM Excessive Energy Amount	555.56	0	$ (395.89)	85	$ 119.10	0	$ -	0	$ -				
50	**SUBTOTAL**		**(28,421)**	**$ (488,780.48)**	**9,983**	**$ 172,197.52**	**(1,995)**	**$ (47,720.62)**	**7,569**	**$ 162,421.38**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
October 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**		**(391,894)**	**$ (8,281,802.08)**	**282,602**	**$ 5,720,346.79**	**(1,995)**	**$ (50,747.78)**	**9,974**	**$ 249,071.05**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (49,574.20)**		**$ 209.55**								
58	**Congestion and Losses Adjustment**			**$ (3,543.39)**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (8,228,684.49)**		**$ 5,720,137.24**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (2,508,547.25)**									
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)**									**$ 198,323.27**				
65	**Less: Fuel Cost**								**7,979**	**$ 191,642.16**				
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**									**$ 132.25**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 6,548.86**				
												. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
November 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**										PROTECTED DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(396,272)	$ (6,108,125.95)	261,953	$ 3,877,439.88	0	$ -	407	$ 8,494.20				
2	DA Non-asset Energy Amount	555.09	(2,315)	$ (48,786.61)	3,527	$ 64,339.64	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(18,884)	$ (380,923.67)	25,779	$ 358,250.28	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	16	$ 91.61	0	$ -	0	$ -				
5	**SUBTOTAL**		**(417,472)**	**$ (6,537,836.23)**	**291,275**	**$ 4,300,121.41**	**0**	**$ -**	**407**	**$ 8,494.20**				
	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	$ (11,302.62)	0	$ 137,840.97	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (286,442.88)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (16,640.30)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (314,385.80)**	**0**	**$ 137,840.97**	**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	$ (50,738.20)	0	$ -	0	$ (32.11)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (5,769.36)	0	$ 393.18	0	$ (1,377.48)	0	$ -				
18	FTR Mkt Admin Amount	555.13	0	$ (1,394.40)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (57,901.96)**	**0**	**$ 393.18**	**0**	**$ (1,409.59)**	**0**	**$ -**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (19,694.53)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 14,770.94	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (58,044.55)	0	$ 193,183.09	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 5,055.02	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 13,174.94	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (4,473.36)	0	$ 38,351.48	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (38,351.48)	0	$ 5,036.74	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (21,934.87)	0	$ 259,176.50	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (259,228.48)	0	$ 22,761.14	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (8,670.17)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 46,544.39	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (375,931.97)**	**0**	**$ 563,588.77**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (7,211.83)	0	$ 1,478.32	0	$ (362.77)	0	$ 74.36				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 39.89	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (16,424.64)	0	$ 2,955.43	0	$ (826.56)	0	$ 148.58				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 14,410.01				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 16,755.55	0	$ -	0	$ 843.50				
41	**SUBTOTAL**		**0**	**$ (23,636.47)**	**0**	**$ 21,229.19**	**0**	**$ (1,189.33)**	**0**	**$ 15,476.45**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (3,812.74)	0	$ -	0	$ (288.97)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (4,018.97)	0	$ 9,362.97	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (73,223.36)	0	$ 6,703.66	0	$ (3,685.88)	0	$ 337.29				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (0.02)	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (81,055.09)**	**0**	**$ 16,066.63**	**0**	**$ (3,974.85)**	**0**	**$ 337.29**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(24,418)	$ (350,665.62)	13,357	$ 179,874.93	(261)	$ (5,030.49)	17,092	$ 250,862.75				
49	RT ASM Excessive Energy Amount	555.56	0	$ (82.32)	19	$ 121.99	0	$ -	10	$ -				
50	**SUBTOTAL**		**(24,418)**	**$ (350,747.94)**	**13,376**	**$ 179,996.92**	**(261)**	**$ (5,030.49)**	**17,102**	**$ 250,862.75**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
November 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**		**(441,890)**	**$ (7,741,495.46)**	**304,651**	**$ 5,219,237.07**	**(261)**	**$ (11,604.26)**	**17,509**	**$ 275,170.69**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (57,901.96)**		**$ 393.18**								
58	**Congestion and Losses Adjustment**			**$ (6,693.23)**										
59	**No DA generation sch., but still had output for current month**			**$ (938.37)**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (7,675,961.90)**		**$ 5,218,843.89**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (2,457,118.01)**									
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)**									**$ 263,566.43**				
65	**Less: Fuel Cost**								**17,249**	**$ 356,020.09**				
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**									**$ 213.12**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ (92,666.78)**				

. . . PROTECTED DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
December 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**										PROTECTED DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(502,589)	$ (9,218,575.27)	296,406	$ 5,529,670.50	0	$ -	187	$ 4,542.16				
2	DA Non-asset Energy Amount	555.09	0	$ -	5,722	$ 101,711.03	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(36,652)	$ (784,701.36)	13,533	$ 232,090.12	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(539,242)**	**$ (10,003,276.63)**	**315,661**	**$ 5,863,471.65**	**0**	**$ -**	**187**	**$ 4,542.16**				
	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	$ (12,290.95)	0	$ 177,277.40	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (372,116.65)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ 2,941.75	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (381,465.85)**	**0**	**$ 177,277.40**	**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	$ (59,940.84)	0	$ -	0	$ (14.24)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (6,685.05)	0	$ 445.01	0	$ (1,153.39)	0	$ 3.13				
18	FTR Mkt Admin Amount	555.13	0	$ (1,775.68)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (68,401.57)**	**0**	**$ 445.01**	**0**	**$ (1,167.63)**	**0**	**$ 3.13**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (390,682.27)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 56,800.24	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (15,026.34)	0	$ 359,199.67	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (0.06)	0	$ 10,131.73	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 8,268.30	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (9,859.50)	0	$ 30,672.64	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (30,672.64)	0	$ 11,080.41	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (13,462.12)	0	$ 240,030.63	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (240,100.08)	0	$ 13,639.97	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (5,664.89)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 33,695.66	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (257,985.39)**	**0**	**$ 316,036.74**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (7,246.59)	0	$ 623.52	0	$ (299.01)	0	$ 25.70				
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	$ (10,305.41)	0	$ 2,291.35	0	$ (425.31)	0	$ 94.39				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 7,499.74				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (16.75)	0	$ 19,727.32	0	$ (0.68)	0	$ 814.58				
41	**SUBTOTAL**		**0**	**$ (17,568.75)**	**0**	**$ 22,642.19**	**0**	**$ (725.00)**	**0**	**$ 8,434.41**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (236.68)	0	$ 986.94	0	$ (13.02)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (7,016.54)	0	$ 12,391.78	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (82,774.25)	0	$ 5,034.43	0	$ (3,417.64)	0	$ 207.65				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (3.91)	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (90,031.38)**	**0**	**$ 18,413.15**	**0**	**$ (3,430.66)**	**0**	**$ 207.65**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(40,383)	$ (687,925.70)	10,342	$ 173,449.24	(143)	$ (2,869.10)	14,776	$ 313,795.37				
49	RT ASM Excessive Energy Amount	555.56	0	$ (268.47)	18	$ 7.84	0	$ -	5	$ 47.49				
50	**SUBTOTAL**		**(40,383)**	**$ (688,194.17)**	**10,361**	**$ 173,457.08**	**(143)**	**$ (2,869.10)**	**14,781**	**$ 313,842.86**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
December 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**		**(579,625)**	**$ (11,506,923.74)**	**326,021**	**$ 6,571,743.22**	**(143)**	**$ (8,192.39)**	**14,968**	**$ 327,030.21**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (68,401.57)**		**$ 445.01**								
58	**Congestion and Losses Adjustment**			**$ (5,409.71)**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (11,433,112.46)**		**$ 6,571,298.21**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (4,861,814.25)**									
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)**									**$ 318,837.82**				
65	**Less: Fuel Cost**								**14,826**	**$ 295,306.87**				
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**									**$ 172.10**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 23,358.85**				

. . . PROTECTED DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
January 2016 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										**PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(428,940)	$ (9,416,986.60)	268,017	$ 5,831,852.21	0	$ -	355	$ 8,387.48				
2	DA Non-asset Energy Amount	555.09	0	$ -	4,146	$ 86,435.80	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(5,315)	$ (112,958.33)	30,312	$ 633,736.84	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(434,255)**	**$ (9,529,944.93)**	**302,475**	**$ 6,552,024.85**	**0**	**$ -**	**355**	**$ 8,387.48**				
	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	$ (55,176.20)	0	$ 274,920.21	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (368,465.41)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (4,997.97)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (428,639.58)**	**0**	**$ 274,920.21**	**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	$ (53,761.50)	0	$ -	0	$ (28.18)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (5,184.13)	0	$ 337.41	0	$ (925.23)	0	$ 2.12				
18	FTR Mkt Admin Amount	555.13	0	$ (1,373.76)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (60,319.39)**	**0**	**$ 337.41**	**0**	**$ (953.41)**	**0**	**$ 2.12**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (127,861.52)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (2,500.57)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (18,618.05)	0	$ 111,085.91	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 23,303.37	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 5,024.40	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (23,292.79)	0	$ 2,827.29	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (2,827.29)	0	$ 23,824.56	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (13,462.12)	0	$ 240,030.63	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (240,100.08)	0	$ 13,639.97	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (5,664.89)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 33,802.51	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (306,465.79)**	**0**	**$ 325,677.12**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (11,535.28)	0	$ -	0	$ (335.80)	0	$ -				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 5.71	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (12,109.18)	0	$ 1,391.76	0	$ (352.46)	0	$ 40.41				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 11,936.84				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 8,202.36	0	$ -	0	$ 238.88				
41	**SUBTOTAL**		**0**	**$ (23,644.46)**	**0**	**$ 9,599.83**	**0**	**$ (688.26)**	**0**	**$ 12,216.13**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (116,010.78)	0	$ -	0	$ (13.89)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (19,990.19)	0	$ 35,852.74	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (75,221.76)	0	$ 4,997.30	0	$ (2,190.48)	0	$ 145.32				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ -	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (211,222.73)**	**0**	**$ 40,850.04**	**0**	**$ (2,204.37)**	**0**	**$ 145.32**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(33,638)	$ (678,274.53)	5,707	$ 102,868.70	(202)	$ (3,822.47)	11,545	$ 239,126.87				
49	RT ASM Excessive Energy Amount	555.56	0	$ -	32	$ 183.05	0	$ -	21	$ 37.41				
50	**SUBTOTAL**		**(33,638)**	**$ (678,274.53)**	**5,739**	**$ 103,051.75**	**(202)**	**$ (3,822.47)**	**11,566**	**$ 239,164.28**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
January 2016 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**		**(467,893)**	**$ (11,238,511.41)**	**308,214**	**$ 7,306,461.21**	**(202)**	**$ (7,668.51)**	**11,921**	**$ 259,915.33**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (60,319.39)**		**$ 337.41**								
58	**Congestion and Losses Adjustment**			**$ (4,672.27)**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (11,173,519.75)**		**$ 7,306,123.80**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (3,867,395.95)**									
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)**									**$ 252,246.82**				
65	**Less: Fuel Cost**								**11,719**	**$ 219,620.31**				
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**									**$ 131.94**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 32,494.57**				
												. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
February 2016 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**										**PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(492,756)	$ (9,223,549.24)	318,441	$ 5,812,281.17	0	$ -	114	$ 2,606.24				
2	DA Non-asset Energy Amount	555.09	0	$ -	5,346	$ 100,875.05	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(11,811)	$ (233,617.09)	41,943	$ 811,521.26	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(504,567)**	**$ (9,457,166.33)**	**365,730**	**$ 6,724,677.48**	**0**	**$ -**	**114**	**$ 2,606.24**				
	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	$ (74,107.58)	0	$ 350,717.19	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (353,680.42)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (6,790.71)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (434,578.71)**	**0**	**$ 350,717.19**	**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	$ (66,895.63)	0	$ -	0	$ (9.37)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (6,925.16)	0	$ 478.70	0	$ (1,419.50)	0	$ 99.51				
18	FTR Mkt Admin Amount	555.13	0	$ (1,986.24)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (75,807.03)**	**0**	**$ 478.70**	**0**	**$ (1,428.87)**	**0**	**$ 99.51**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (117,230.73)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 21,659.83	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (26,830.32)	0	$ 166,103.34	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 3,131.58	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 3,256.35	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (3,130.97)	0	$ 6,234.33	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (6,234.33)	0	$ 3,130.97	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (13,462.12)	0	$ 240,030.63	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (240,100.08)	0	$ 13,639.97	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (5,664.89)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 33,802.51	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (273,762.88)**	**0**	**$ 352,098.95**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (12,927.84)	0	$ 137.29	0	$ (456.88)	0	$ 4.85				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 15,877.85	0	$ -	0	$ 29.97				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (4,237.71)	0	$ 2,699.23	0	$ (149.51)	0	$ 95.29				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 6,173.70				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 12,588.53	0	$ -	0	$ 445.05				
41	**SUBTOTAL**		**0**	**$ (17,165.55)**	**0**	**$ 31,302.90**	**0**	**$ (606.39)**	**0**	**$ 6,748.86**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (18,301.12)	0	$ 5,842.94	0	$ (0.01)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (60,842.51)	0	$ 58,606.32	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (93,916.34)	0	$ 26,047.81	0	$ (3,320.09)	0	$ 920.65				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ -	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (173,059.97)**	**0**	**$ 90,497.07**	**0**	**$ (3,320.10)**	**0**	**$ 920.65**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(30,111)	$ (525,157.16)	11,407	$ 198,452.20	(99)	$ (1,920.93)	16,922	$ 326,370.90				
49	RT ASM Excessive Energy Amount	555.56	0	$ (351.86)	16	$ 47.58	0	$ -	32	$ 598.37				
50	**SUBTOTAL**		**(30,111)**	**$ (525,509.02)**	**11,424**	**$ 198,499.78**	**(99)**	**$ (1,920.93)**	**16,953**	**$ 326,969.27**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
February 2016 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**		**(534,678)**	**$ (10,957,049.49)**	**377,154**	**$ 7,748,272.07**	**(99)**	**$ (7,276.29)**	**17,067**	**$ 337,344.53**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (75,807.03)**		**$ 478.70**								
58	**Congestion and Losses Adjustment**			**$ (2,678.85)**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (10,878,563.61)**		**$ 7,747,793.37**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (3,130,770.24)**									
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)**									**$ 330,068.24**				
65	**Less: Fuel Cost**								**16,969**	**$ 324,471.58**				
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**									**$ 180.78**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 5,415.88**				
												. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
March 2016 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**										**PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(417,490)	$ (6,304,075.71)	277,235	$ 4,112,555.28	0	$ -	1,680	$ 33,129.32				
2	DA Non-asset Energy Amount	555.09	0	$ -	4,784	$ 79,254.31	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(43,051)	$ (707,486.44)	9,289	$ 149,346.75	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(460,541)**	**$ (7,011,562.15)**	**291,309**	**$ 4,341,156.34**	**0**	**$ -**	**1,680**	**$ 33,129.32**				
	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	$ (151,408.82)	0	$ 181,640.44	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (268,612.23)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (26,663.56)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (446,684.61)**	**0**	**$ 181,640.44**	**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	$ (52,634.44)	0	$ -	0	$ (124.77)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (5,391.89)	0	$ 1,106.96	0	$ (1,016.51)	0	$ 0.06				
18	FTR Mkt Admin Amount	555.13	0	$ (1,900.88)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (59,927.21)**	**0**	**$ 1,106.96**	**0**	**$ (1,141.28)**	**0**	**$ 0.06**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (119,513.73)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (11,477.95)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (31,073.23)	0	$ 84,867.22	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (46.26)	0	$ 6,595.07	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ (2,594.23)	0	$ 4,215.64	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (6,302.12)	0	$ 4,252.16	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (4,252.16)	0	$ 6,302.12	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (9,219.79)	0	$ 185,434.17	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (185,409.52)	0	$ 9,205.00	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (2,780.53)	0	$ 114.11	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 34,881.99	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (253,155.79)**	**0**	**$ 216,353.75**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (9,365.84)	0	$ 4.55	0	$ (265.44)	0	$ 0.12				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 889.64	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (4,944.84)	0	$ 52.39	0	$ (140.00)	0	$ 1.39				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 3,779.53				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 12,865.85	0	$ -	0	$ 364.90				
41	**SUBTOTAL**		**0**	**$ (14,310.68)**	**0**	**$ 13,812.43**	**0**	**$ (405.44)**	**0**	**$ 4,145.94**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (3,307.65)	0	$ 0.05	0	$ (6.43)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (109,254.96)	0	$ 28,582.23	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (40,417.91)	0	$ 88,783.92	0	$ (1,146.04)	0	$ 2,517.68				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ -	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (152,980.52)**	**0**	**$ 117,366.20**	**0**	**$ (1,152.47)**	**0**	**$ 2,517.68**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(22,417)	$ (332,606.26)	15,880	$ 206,455.56	(758)	$ (12,644.24)	12,454	$ 235,355.35				
49	RT ASM Excessive Energy Amount	555.56	0	$ (8.25)	4	$ 4.17	0	$ (2.00)	15	$ 149.34				
50	**SUBTOTAL**		**(22,417)**	**$ (332,614.51)**	**15,884**	**$ 206,459.73**	**(758)**	**$ (12,646.24)**	**12,470**	**$ 235,504.69**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
March 2016 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**		**(482,958)**	**$ (8,271,235.47)**	**307,193**	**$ 5,077,895.85**	**(758)**	**$ (15,345.43)**	**14,150**	**$ 275,297.69**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (59,927.21)**		**$ 1,106.96**								
58	**Congestion and Losses Adjustment**			**$ (5,046.88)**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (8,206,261.38)**		**$ 5,076,788.89**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (3,129,472.49)**									
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)**									**$ 259,952.26**				
65	**Less: Fuel Cost**								**13,392**	**$ 247,548.52**				
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**									**$ 173.15**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 12,230.59**				
												. . . PROTECTED DATA ENDS]		

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
April 2016 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**										**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(366,095)	$ (5,707,095.91)	205,096	$ 3,162,312.62	0	$ -	327	$ 7,001.24				
2	DA Non-asset Energy Amount	555.09	0	$ -	4,402	$ 72,736.13	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(15,842)	$ (175,390.11)	25,454	$ 429,890.85	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(381,938)**	**$ (5,882,486.02)**	**234,952**	**$ 3,664,939.60**	**0**	**$ -**	**327**	**$ 7,001.24**				
	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	$ (61,161.52)	0	$ 87,362.36	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (186,514.22)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (22,614.60)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (270,290.34)**	**0**	**$ 87,362.36**	**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	$ (41,352.68)	0	$ -	0	$ (24.12)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (5,135.69)	0	$ 321.97	0	$ (828.18)	0	$ 648.45				
18	FTR Mkt Admin Amount	555.13	0	$ (2,115.84)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (48,604.21)**	**0**	**$ 321.97**	**0**	**$ (852.30)**	**0**	**$ 648.45**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (110,384.92)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (43,903.46)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (42,946.06)	0	$ 146,271.10	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 8,197.64	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ 36,489.21	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ (2,693.09)	0	$ 8,240.90	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (44,684.61)	0	$ 12,174.93	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (12,174.93)	0	$ 43,669.05	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (9,219.79)	0	$ 185,434.17	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (185,409.52)	0	$ 9,205.00	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (2,666.42)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 34,485.21	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (343,697.88)**	**0**	**$ 373,782.29**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (7,681.75)	0	$ 233.34	0	$ (187.68)	0	$ 5.69				
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	$ (13,774.79)	0	$ 43.83	0	$ (336.55)	0	$ 1.01				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 26,379.09				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (33.58)	0	$ 22,346.04	0	$ (0.80)	0	$ 546.38				
41	**SUBTOTAL**		**0**	**$ (21,490.12)**	**0**	**$ 22,623.21**	**0**	**$ (525.03)**	**0**	**$ 26,932.17**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (27,375.60)	0	$ 0.01	0	$ (0.04)	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (46,594.72)	0	$ 43,627.78	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (90,341.64)	0	$ 66,352.22	0	$ (2,208.67)	0	$ 1,622.18				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ -	0	$ -	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (164,311.96)**	**0**	**$ 109,980.01**	**0**	**$ (2,208.71)**	**0**	**$ 1,622.18**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(22,216)	$ (379,714.74)	15,217	$ 192,305.61	(668)	$ (13,086.87)	10,879	$ 224,911.27				
49	RT ASM Excessive Energy Amount	555.56	(2)	$ (500.45)	68	$ 38.83	0	$ (28.14)	91	$ 29.74				
50	**SUBTOTAL**		**(22,218)**	**$ (380,215.19)**	**15,285**	**$ 192,344.44**	**(668)**	**$ (13,115.01)**	**10,969**	**$ 224,941.01**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
April 2016 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**		**(404,156)**	**$ (7,111,095.72)**	**250,236**	**$ 4,451,353.88**	**(668)**	**$ (16,701.05)**	**11,296**	**$ 261,145.05**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (48,604.21)**		**$ 321.97**								
58	**Congestion and Losses Adjustment**			**$ (363.16)**										
59	**No DA generation sch., but still had output for current month**			**$ -**										
60	**MISO RSG Bad Debt**			**$ -**										
61	**Total for MN Energy Adjustment Rider**			**$ (7,062,128.35)**		**$ 4,451,031.91**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (2,611,096.44)**									
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)**									**$ 244,444.00**				
65	**Less: Fuel Cost**								**10,628**	**$ 214,794.70**				
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**									**$ 52.33**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 29,596.97**				
														... PROTECTED DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
May 2016 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**										[PROTECTED DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(373,662)	$ (5,805,695.16)	197,226	$ 2,775,652.30	0	$ -	146	$ 3,253.93				
2	DA Non-asset Energy Amount	555.09	0	$ -	3,952	$ 71,705.06	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(5,044)	$ (151,984.05)	42,587	$ 577,997.69	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	0	$ -	0	$ -	0	$ -	0	$ -				
5	**SUBTOTAL**		**(378,705)**	**$ (5,957,679.21)**	**243,765**	**$ 3,425,355.05**	**0**	**$ -**	**146**	**$ 3,253.93**				
	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	$ (64,046.80)	0	$ 121,592.39	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (135,141.95)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (14,303.30)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (213,492.05)**	**0**	**$ 121,592.39**	**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	$ (42,390.95)	0	$ -	0	$ (10.90)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (5,851.47)	0	$ 484.38	0	$ (528.57)	0	$ -				
18	FTR Mkt Admin Amount	555.13	0	$ (1,736.64)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (49,979.06)**	**0**	**$ 484.38**	**0**	**$ (539.47)**	**0**	**$ -**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ 106,800.92	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 77,762.13	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (124,725.66)	0	$ 146,298.28	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 7,623.39	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ -	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ -	0	$ 46,028.31	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (6,806.43)	0	$ 10,628.78	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (10,628.78)	0	$ 6,496.55	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (9,219.79)	0	$ 185,434.17	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (185,409.52)	0	$ 9,205.00	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (2,666.42)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ -	0	$ 34,663.76	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (261,694.47)**	**0**	**$ 553,179.16**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (14,170.77)	0	$ 0.59	0	$ (249.42)	0	$ 0.01				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 18,304.26	0	$ -	0	$ -				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (6,097.28)	0	$ 157.55	0	$ (107.13)	0	$ 2.71				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 3,355.58				
40	RT Price Volatility Make Whole Payment	555.42	0	$ -	0	$ 28,772.23	0	$ -	0	$ 506.81				
41	**SUBTOTAL**		**0**	**$ (20,268.05)**	**0**	**$ 47,234.63**	**0**	**$ (356.55)**	**0**	**$ 3,865.11**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (8,885.55)	0	$ 2,356.99	0	$ -	0	$ -				
43	RT Net Inadvertent Amount	555.27	0	$ (35,368.53)	0	$ 94,028.11	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (155,457.32)	0	$ 30,962.93	0	$ (2,737.89)	0	$ 545.29				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ -	0	$ -	0	$ -	0	$ -				
47	DA Ramp Product	555.63	0	$ -	0	$ 33.26	0	$ -	0	$ -				
48	RT Ramp Prodcut	555.64	0	$ (90.69)	0	$ 252.30	0	$ -	0	$ -				
49	**SUBTOTAL**		**0**	**$ (199,802.09)**	**0**	**$ 127,633.59**	**0**	**$ (2,737.89)**	**0**	**$ 545.29**				
	ASM Charges													
50	RT ASM Non-Excessive Energy Amount	555.55	(25,739)	$ (329,354.54)	13,941	$ 216,363.06	(73)	$ (1,667.31)	6,977	$ 137,146.81				
51	RT ASM Excessive Energy Amount	555.56	(56)	$ (71.95)	37	$ 724.71	(69)	$ -	18	$ 105.20				
52	**SUBTOTAL**		**(25,795)**	**$ (329,426.49)**	**13,978**	**$ 217,087.77**	**(141)**	**$ (1,667.31)**	**6,995**	**$ 137,252.01**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
May 2016 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													
53	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
54	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
55	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
56	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
57	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
58	**TOTAL MISO DAY 2 CHARGES**		**(404,501)**	**$ (7,032,341.42)**	**257,743**	**$ 4,492,566.97**		**$ (5,301.22)**	**7,141**	**$ 144,916.34**				
59	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (49,979.06)**		**$ 484.38**								
60	**Congestion and Losses Adjustment**			**$ (4,158.53)**										
61	**No DA generation sch., but still had output for current month**			**$ -**										
62	**MISO RSG Bad Debt**			**$ -**										
63	**Total for MN Energy Adjustment Rider**			**$ (6,978,203.83)**		**$ 4,492,082.59**								
64	**Net Retail for MN Energy Adjustment Rider**				**$ (2,486,121.24)**									
65	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
66	**NET MISO (Rev-Cost and MWh)**									**$ 139,615.12**				
67	**Less: Fuel Cost**								**7,000**	**$ 144,747.79**				
68	**Less: Misc Cost Adjustment**									**$ -**				
69	**Plus: Capacity Revenue**													
70	**Plus: Bilateral Sales**													
71	**Less: Bilateral Purchases**													
72	**Less: Schedule 24 for Asset Based Sales**									**$ 86.34**				
73														
74	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ (5,219.01)**				

... PROTECTED DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
June 2016 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**										**[PROTECTED DATA BEGINS . . .**			
1	DA Asset Energy Amount	555.02	(360,896)	$ (6,875,503.97)	202,246	$ 3,857,104.97	0	$ -	1,689	$ 46,002.95				
2	DA Non-asset Energy Amount	555.09	0	$ -	3,561	$ 83,135.15	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(18,154)	$ (227,558.93)	24,489	$ 495,758.81	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(12)	$ (236.31)	0	$ 0.48	0	$ -	0	$ -				
5	**SUBTOTAL**		**(379,061)**	**$ (7,103,299.21)**	**230,296**	**$ 4,435,999.41**	**0**	**$ -**	**1,689**	**$ 46,002.95**				
	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	$ (62,044.68)	0	$ 100,650.07	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (218,075.24)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (35,858.04)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (315,977.96)**	**0**	**$ 100,650.07**	**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	$ (40,979.01)	0	$ -	0	$ (124.24)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (5,399.31)	0	$ 528.11	0	$ (1,332.97)	0	$ 90.21				
18	FTR Mkt Admin Amount	555.13	0	$ (1,980.00)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (48,358.32)**	**0**	**$ 528.11**	**0**	**$ (1,457.21)**	**0**	**$ 90.21**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (94,014.13)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ (29,134.62)	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (86,258.82)	0	$ 218,290.09	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ -	0	$ 7,198.97	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	$ (7,152.85)	0	$ 10,582.86	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (10,582.86)	0	$ 7,240.49	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (4,230.91)	0	$ 153,963.12	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (153,943.97)	0	$ 4,128.92	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (7,591.90)	0	$ -	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (89.91)	0	$ 29,983.89	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (298,985.84)**	**0**	**$ 337,374.21**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (8,806.60)	0	$ 591.76	0	$ (479.83)	0	$ 32.24				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 17,771.33	0	$ -	0	$ 70.13				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (15,878.86)	0	$ 230.88	0	$ (865.17)	0	$ 12.47				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 8,843.38				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (19.43)	0	$ 17,241.66	0	$ (1.05)	0	$ 939.76				
41	**SUBTOTAL**		**0**	**$ (24,704.89)**	**0**	**$ 35,835.63**	**0**	**$ (1,346.05)**	**0**	**$ 9,897.98**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (3,311.53)	0	$ 575.85	0	$ -	0	$ 5.92				
43	RT Net Inadvertent Amount	555.27	0	$ (69,433.48)	0	$ 33,504.34	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (43,768.33)	0	$ 60,481.25	0	$ (2,385.31)	0	$ 3,296.22				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (0.66)	0	$ -	0	$ -	0	$ -				
47	DA Ramp Product	555.63	0	$ -	0	$ 1,228.94	0	$ -	0	$ -				
48	RT Ramp Prodcut	555.64	0	$ (332.08)	0	$ 172.55	0	$ -	0	$ -				
49	**SUBTOTAL**		**0**	**$ (116,846.08)**	**0**	**$ 95,962.93**	**0**	**$ (2,385.31)**	**0**	**$ 3,302.14**				
	ASM Charges													
50	RT ASM Non-Excessive Energy Amount	555.55	(22,182)	$ (386,910.30)	17,582	$ 324,016.13	(413)	$ (8,181.96)	17,755	$ 385,771.63				
51	RT ASM Excessive Energy Amount	555.56	(5)	$ (79.82)	16	$ 53.23	(5)	$ -	6	$ 6.43				
52	**SUBTOTAL**		**(22,187)**	**$ (386,990.12)**	**17,598**	**$ 324,069.36**	**(417)**	**$ (8,181.96)**	**17,762**	**$ 385,778.06**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
June 2016 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													
53	DA Congestion Rebate on COGA	555.05	0	$ -	0	$ -	0	$ -	0	$ -				
54	DA Losses Rebate on COGA	555.06	0	$ -	0	$ -	0	$ -	0	$ -				
55	RT Congestion Rebate on COGA	555.22	0	$ -	0	$ -	0	$ -	0	$ -				
56	RT Loss Rebate on COGA	555.23	0	$ -	0	$ -	0	$ -	0	$ -				
57	**SUBTOTAL**		**0**	**$ -**	**0**	**$ -**	**0**	**$ -**	**0**	**$ -**				
58	**TOTAL MISO DAY 2 CHARGES**		**(401,249)**	**$ (8,295,162.42)**	**247,894**	**$ 5,330,419.72**		**$ (13,370.53)**	**19,450**	**$ 445,071.34**				
59	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (48,358.32)**		**$ 528.11**								
60	**Congestion and Losses Adjustment**			**$ (11,045.85)**										
61	**No DA generation sch., but still had output for current month**			**$ -**										
62	**MISO RSG Bad Debt**			**$ -**										
63	**Total for MN Energy Adjustment Rider**			**$ (8,235,758.25)**		**$ 5,329,891.61**								
64	**Net Retail for MN Energy Adjustment Rider**				**$ (2,905,866.64)**									
65	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
66	**NET MISO (Rev-Cost and MWh)**									**$ 431,700.81**				
67	**Less: Fuel Cost**								**19,033**	**$ 335,553.22**				
68	**Less: Misc Cost Adjustment**									**$ -**				
69	**Plus: Capacity Revenue**													
70	**Plus: Bilateral Sales**													
71	**Less: Bilateral Purchases**													
72	**Less: Schedule 24 for Asset Based Sales**									**$ 212.05**				
73														
74	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ 95,935.54**				

... PROTECTED DATA ENDS]

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2015 - June 2016 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**										[PROTECTED DATA BEGINS . . .			
1	DA Asset Energy Amount	555.02	(4,762,941)	$ (91,877,334.80)	2,898,363	$ 54,261,965.02	0	$ -	9,842	$ 249,270.28				
2	DA Non-asset Energy Amount	555.09	(32,741)	$ (744,840.71)	36,125	$ 677,596.62	0	$ -	0	$ -				
3	RT Asset Energy Amount	555.19	(206,970)	$ (3,996,185.97)	305,119	$ 5,651,516.22	0	$ -	0	$ -				
4	RT Non-Asset Energy Amount	555.26	(1,829)	$ (52,389.37)	273	$ 3,412.06	0	$ -	0	$ -				
5	**SUBTOTAL**		**(5,004,481)**	**$ (96,670,750.85)**	**3,239,880**	**$ 60,594,489.92**	**0**	**$ -**	**9,842**	**$ 249,270.28**				
	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	$ (540,983.39)	0	$ 2,039,450.54	0	$ -	0	$ -				
8	RT FBT Loss Amount	555.21	0	$ -	0	$ -	0	$ -	0	$ -				
9	DA Loss Amount		0	$ (3,058,781.18)	0	$ -	0	$ -	0	$ -				
10	RT Loss Amount		0	$ (158,899.77)	0	$ -	0	$ -	0	$ -				
11	DA Losses Rebate on Option B GFA	555.08	0	$ -	0	$ -	0	$ -	0	$ -				
12	**SUBTOTAL**		**0**	**$ (3,758,664.34)**	**0**	**$ 2,039,450.54**	**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	$ (568,608.10)	0	$ -	0	$ (707.15)	0	$ -				
17	RT Mkt Admin Amount	555.18	0	$ (63,846.81)	0	$ 5,062.34	0	$ (10,707.16)	0	$ 845.83				
18	FTR Mkt Admin Amount	555.13	0	$ (19,578.80)	0	$ -	0	$ -	0	$ -				
19	**SUBTOTAL**		**0**	**$ (652,033.71)**	**0**	**$ 5,062.34**	**0**	**$ (11,414.31)**	**0**	**$ 845.83**				
	Congestion & FTRs													
20	DA FBT Congestion Amount	555.03	0	$ -	0	$ -	0	$ -	0	$ -				
21	DA Congestion		0	$ -	0	$ (896,517.95)	0	$ -	0	$ -				
22	RT FBT Congestion Amount	555.20	0	$ -	0	$ -	0	$ -	0	$ -				
23	RT Congestion		0	$ 124,207.15	0	$ -	0	$ -	0	$ -				
24	FTR Hourly Allocation Amount	555.14	0	$ (658,887.62)	0	$ 1,799,310.56	0	$ -	0	$ -				
25	FTR Monthly Allocation Amount	555.15	0	$ (46.41)	0	$ 91,642.91	0	$ -	0	$ -				
26	FTR Yearly Allocation Amount	555.17	0	$ -	0	$ 36,489.21	0	$ -	0	$ -				
27	FTR Monthly Transaction Amount	555.35	0	$ (5,287.32)	0	$ 206,356.27	0	$ -	0	$ -				
28	FTR Full Funding Guarantee Amount	555.36	0	$ (125,917.55)	0	$ 142,147.13	0	$ -	0	$ -				
29	FTR Guarantee Uplift Amount	555.37	0	$ (142,147.13)	0	$ 126,995.81	0	$ -	0	$ -				
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	$ (185,144.67)	0	$ 2,671,619.78	0	$ -	0	$ -				
31	FTR Annual Transaction Amount	555.38	0	$ (2,624,084.53)	0	$ 188,541.63	0	$ -	0	$ -				
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	$ (69,469.83)	0	$ 213.89	0	$ -	0	$ -				
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	$ (6,663.64)	0	$ 420,938.76	0	$ -	0	$ -				
34	DA Congestion Rebate on Option B GFA	555.07	0	$ -	0	$ -	0	$ -	0	$ -				
35	**SUBTOTAL**		**0**	**$ (3,693,441.55)**	**0**	**$ 4,787,738.00**	**0**	**$ -**	**0**	**$ -**				
	RSG & Make Whole Payments													
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	$ (129,949.16)	0	$ 5,165.64	0	$ (3,698.86)	0	$ 187.91				
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	$ -	0	$ 53,497.55	0	$ -	0	$ 100.10				
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	$ (240,461.85)	0	$ 16,104.03	0	$ (7,112.62)	0	$ 534.13				
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	$ -	0	$ -	0	$ -	0	$ 147,760.92				
40	RT Price Volatility Make Whole Payment	555.42	0	$ (104.24)	0	$ 173,439.35	0	$ (3.65)	0	$ 5,468.64				
41	**SUBTOTAL**		**0**	**$ (370,515.25)**	**0**	**$ 248,206.57**	**0**	**$ (10,815.13)**	**0**	**$ 154,051.70**				
	RNU & Misc Charges													
42	RT Misc Amount	555.25	0	$ (184,449.36)	0	$ 17,429.70	0	$ (355.03)	0	$ 6.27				
43	RT Net Inadvertent Amount	555.27	0	$ (383,578.26)	0	$ 352,035.34	0	$ -	0	$ -				
44	RT Revenue Neutrality Uplift Amount	555.28	0	$ (845,970.39)	0	$ 319,217.19	0	$ (25,138.32)	0	$ 10,295.38				
45	RT Uninstructed Deviation Amount	555.31	0	$ -	0	$ -	0	$ -	0	$ -				
46	RT Demand Response Allocation Uplift Amount	555.59	0	$ (9.38)	0	$ 0.07	0	$ -	0	$ -				
	DA Ramp Product	555.63	0	$ -	0	$ 1,262.20	0	$ -	0	$ -				
	RT Ramp Product	555.64	0	$ (422.77)	0	$ 424.85	0	$ -	0	$ -				
47	**SUBTOTAL**		**0**	**$ (1,414,430.16)**	**0**	**$ 690,369.35**	**0**	**$ (25,493.35)**	**0**	**$ 10,301.65**				
	ASM Charges													
48	RT ASM Non-Excessive Energy Amount	555.55	(318,956)	$ (5,671,211.99)	148,585	$ 2,465,495.48	(5,669)	$ (229,901.45)	135,942	$ 2,628,199.28				
49	RT ASM Excessive Energy Amount	555.56	(64)	$ (7,140.22)	716	$ 1,761.06	(73)	$ (30.14)	250	$ 1,526.12				
50	**SUBTOTAL**		**(319,020)**	**$ (5,678,352.21)**	**149,301**	**$ 2,467,256.54**	**(5,742)**	**$ (229,931.59)**	**136,191**	**$ 2,629,725.40**				

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
July 2015 - June 2016 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**		**(5,323,501)**	**$ (112,238,188.07)**	**3,389,182**	**$ 70,832,573.26**		**$ (277,654.38)**	**146,034**	**$ 3,044,194.86**				
57	**Less Schedule 16 & 17 (Lines 16, 17, 18)**			**$ (652,033.71)**		**$ 5,062.34**								
58	**Congestion and Losses Adjustment**			**$ (46,683.36)**		**$ -**								
59	**No DA generation sch., but had usage for current month**			**$ (938.37)**		**$ -**								
60	**MISO RSG Bad Debt**			**$ -**		**$ -**								
61	**Total for MN Energy Adjustment Rider**			**$ (111,538,532.63)**		**$ 70,827,510.92**								
62	**Net Retail for MN Energy Adjustment Rider**				**$ (40,711,021.71)**									
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]									**$ 2,766,540.48**				
65	**Less: Fuel Cost**								**140,292**	**$ 2,776,752.17**				
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**									**$ 1,600.42**				
71														
72	**TOTAL ASSET or NON ASSET BASED WHOLESALE**									**$ (11,812.11)**				

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

. . . PROTECTED 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 (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 of 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.

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 $ 4,774 for the 2015/2016 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 cost of ($31,995) for the AAA period (Schedule 1 of Part H Section 4 Attachment L, column R, line 12). Prior to August of 2015, Otter Tail's three oil-fueled peaking units, Lake Preston and the Jamestown units #1 and #2, were qualified to provide supplemental reserves to the MISO ASM market. However, testing in July and August of 2015 indicated those unit are no longer able to meet the required operating specifications to be eligible to provide such reserves. As of September 2015, Otter Tail has not provided supplemental reserves in the MISO energy markets.

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 ($18,263) 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 four 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 ($3,646) 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 ($942) 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. Otter Tail has been able to maximize the capabilities of our units to a greater extent, which ultimately has led to greater operational efficiencies for Otter Tail. Otter Tail will 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 ($50,820) (column R, line 18) of net ASM charge cost.

Schedule 2 of Part H Section 4 Attachment L provides a summary of hourly MWh related to ASM products for the period of July 2015 through June 2016.

III. 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 last general rate case, Docket E017/GR-10-239, Otter Tail passes on ASM charges and credits 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, has 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 relative to current market conditions.

SUMMARY OF 12 ASM CHARGE TYPES (Dollars)
Revenue (Cost)

Line No.		(A) Jul-15	(B) Aug-15	(C) Sep-15	(D) 3rd Qtr 2015 Total	(E) Oct-15	(F) Nov-15	(G) Dec-15	(H) 4th Qtr 2015 Total	(I) Jan-16	(J) Feb-16	(K) Mar-16	(L) 1st Qtr 2016 Total	(M) Apr-16	(N) May-16	(O) Jun-16	(P) 2nd Qtr 2016 Total	(Q) 12-Month Total	(R) MN Amount @ 0.534031169
1	Day Ahead Regulation Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,919	$ 33,164	$ 35,083	$ 35,083	$ 18,736
2	Real Time Regulation Amount	$ 233	$ 281	$ 148	$ 662	$ 1,923	$ 988	$ 1,399	$ 4,310	$ 443	$ 886	$ 4,382	$ 5,712	$ 7,377	$ 6,778	$ 4,565	$ 18,720	$ 29,404	$ 15,702
3	Regulation Cost Distribution Amount	$ (7,548)	$ (7,907)	$ (7,489)	$ (22,944)	$ (8,771)	$ (8,768)	$ (10,239)	$ (27,778)	$ (6,687)	$ (8,013)	$ (7,821)	$ (22,521)	$ (8,559)	$ (10,714)	$ (6,171)	$ (25,444)	$ (98,686)	$ (52,701)
4	**Regulation Subtotal**	**$ (7,315)**	**$ (7,625)**	**$ (7,341)**	**$ (22,281)**	**$ (6,848)**	**$ (7,781)**	**$ (8,840)**	**$ (23,468)**	**$ (6,244)**	**$ (7,126)**	**$ (3,439)**	**$ (16,809)**	**$ (1,182)**	**$ (2,017)**	**$ 31,558**	**$ 28,360**	**$ (34,199)**	**$ (18,263)**
5	Day Ahead Spinning Reserve Amount	$ 11,001	$ 17,190	$ 2,387	$ 30,578	$ 1,462	$ 8,399	$ 12,402	$ 22,263	$ 7,344	$ 7,534	$ 16,583	$ 31,461	$ 20,788	$ 19,055	$ 18,172	$ 58,015	$ 142,317	$ 76,002
6	Real Time Spinning Reserve Amount	$ 86	$ (1,319)	$ 3,908	$ 2,676	$ 1,859	$ (1,408)	$ (1,533)	$ (1,082)	$ (21)	$ 1,780	$ 2,288	$ 4,047	$ 1,895	$ (2,200)	$ (11,109)	$ (11,415)	$ (5,774)	$ (3,083)
7	Spinning Reserve Cost Distribution Amount	$ (12,871)	$ (11,591)	$ (8,738)	$ (33,201)	$ (11,437)	$ (9,653)	$ (11,028)	$ (32,118)	$ (8,455)	$ (8,111)	$ (9,947)	$ (26,513)	$ (11,474)	$ (11,878)	$ (12,421)	$ (35,773)	$ (127,605)	$ (68,145)
8	**Spinning Reserve Subtotal**	**$ (1,784)**	**$ 4,280**	**$ (2,443)**	**$ 54**	**$ (8,117)**	**$ (2,662)**	**$ (159)**	**$ (10,937)**	**$ (1,132)**	**$ 1,203**	**$ 8,924**	**$ 8,996**	**$ 11,209**	**$ 4,976**	**$ (5,358)**	**$ 10,827**	**$ 8,939**	**$ 4,774**
9	Day Ahead Supplemental Reserve Amount	$ 13,227	$ 8,877	$ -	$ 22,104	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,104	$ 11,804
10	Real Time Supplemental Reserve Amount	$ (16,492)	$ (9,586)	$ -	$ (26,078)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,078)	$ (13,927)
11	Supplemental Reserve Cost Distribution Amount	$ (3,630)	$ (5,495)	$ (5,847)	$ (14,972)	$ (7,466)	$ (6,244)	$ (5,721)	$ (19,431)	$ (3,787)	$ (3,504)	$ (3,874)	$ (11,166)	$ (3,707)	$ (3,635)	$ (3,026)	$ (10,368)	$ (55,938)	$ (29,873)
12	**Supplemental Reserve Subtotal**	**$ (6,896)**	**$ (6,204)**	**$ (5,847)**	**$ (18,947)**	**$ (7,466)**	**$ (6,244)**	**$ (5,721)**	**$ (19,431)**	**$ (3,787)**	**$ (3,504)**	**$ (3,874)**	**$ (11,166)**	**$ (3,707)**	**$ (3,635)**	**$ (3,026)**	**$ (10,368)**	**$ (59,912)**	**$ (31,995)**
13	Contingency Reserve Deployment Failure Charge Amount	$ (1,207)	$ -	$ -	$ (1,207)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (556)	$ -	$ (556)	$ (1,763)	$ (942)
14	Real Time Excessive Deficient Energy Deployment Charge Amount	$ (44)	$ (60)	$ (162)	$ (267)	$ (285)	$ (64)	$ (139)	$ (488)	$ (72)	$ (32)	$ (300)	$ (404)	$ (2,154)	$ (1,098)	$ (2,418)	$ (5,670)	$ (6,828)	$ (3,646)
15	Net Regulation Adjustment Amount	$ (3)	$ 1	$ 4	$ 2	$ (358)	$ (29)	$ (56)	$ (443)	$ (17)	$ (6)	$ (92)	$ (115)	$ (92)	$ (14)	$ (736)	$ (843)	$ (1,399)	$ (747)
16	Real Time Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	**Other Charge Subtotal**	**$ (1,254)**	**$ (60)**	**$ (158)**	**$ (1,472)**	**$ (643)**	**$ (93)**	**$ (194)**	**$ (931)**	**$ (89)**	**$ (39)**	**$ (392)**	**$ (519)**	**$ (2,246)**	**$ (1,668)**	**$ (3,154)**	**$ (7,068)**	**$ (9,991)**	**$ (5,335)**
18	**TOTAL**	**$ (17,249)**	**$ (9,608)**	**$ (15,789)**	**$ (42,646)**	**$ (23,074)**	**$ (16,780)**	**$ (14,914)**	**$ (54,768)**	**$ (11,252)**	**$ (9,466)**	**$ 1,220**	**$ (19,499)**	**$ 4,074**	**$ (2,344)**	**$ 20,020**	**$ 21,750**	**$ (95,163)**	**$ (50,820)**

Summary of 12 ASM Charge Types (MWh)
Revenue (Cost)

Line No.		(A) Jul-15	(B) Aug-15	(C) Sep-15	(D) 3rd Qtr 2015 Total	(E) Oct-15	(F) Nov-15	(G) Dec-15	(H) 4th Qtr 2015 Total	(I) Jan-16	(J) Feb-16	(K) Mar-16	(L) 1st Qtr 2016 Total	(M) Apr-16	(N) May-16	(O) Jun-16	(P) 2nd Qtr 2016 Total	(Q) 12-Month Total	(R) MN Amount @ 0.534031169
1	Day Ahead Regulation 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	200.90	3,511.10	3,712.00	3,712.00	1,982.32
2	Real Time Regulation Amount	7.38	2.69	8.85	18.93	71.98	33.18	44.18	149.33	24.18	24.38	168.75	217.30	195.50	364.53	780.50	1,340.52	1,726.08	921.78
3	Regulation Cost Distribution 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
4	**Regulation Subtotal**	**7.38**	**2.69**	**8.85**	**18.93**	**71.98**	**33.18**	**44.18**	**149.33**	**24.18**	**24.38**	**168.75**	**217.30**	**195.50**	**565.43**	**4,291.60**	**5,052.52**	**5,438.08**	**2,904.10**
5	Day Ahead Spinning Reserve Amount	3,229.80	5,866.70	586.00	9,682.50	393.70	3,686.10	5,920.10	9,999.90	2,936.00	5,083.90	8,487.90	16,507.80	6,665.10	4,798.80	3,230.00	14,693.90	50,884.10	27,173.70
6	Real Time Spinning Reserve Amount	(26.27)	(326.23)	33.54	(318.96)	(190.71)	(1,205.88)	(1,199.44)	(2,596.02)	(146.71)	(170.87)	291.33	(26.25)	(796.60)	(2,581.08)	(2,514.49)	(5,892.16)	(8,833.39)	(4,717.31)
7	Spinning Reserve Cost Distribution 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
8	**Spinning Reserve Subtotal**	**3,203.53**	**5,540.47**	**619.54**	**9,363.54**	**202.99**	**2,480.23**	**4,720.66**	**7,403.88**	**2,789.29**	**4,913.04**	**8,779.23**	**16,481.55**	**5,868.50**	**2,217.72**	**715.51**	**8,801.74**	**42,050.71**	**22,456.39**
9	Day Ahead Supplemental Reserve Amount	7,098.20	2,840.40	0.00	9,938.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9,938.60	5,307.52
10	Real Time Supplemental Reserve Amount	(5,562.56)	(2,690.40)	0.00	(8,252.96)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(8,252.96)	(4,407.34)
11	Supplemental Reserve Cost Distribution 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
12	**Supplemental Reserve Subtotal**	**1,535.64**	**150.00**	**0.00**	**1,685.64**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1,685.64**	**900.18**
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**	**4,746.55**	**5,693.16**	**628.39**	**11,068.11**	**274.97**	**2,513.40**	**4,764.84**	**7,553.21**	**2,813.47**	**4,937.41**	**8,947.98**	**16,698.85**	**6,064.00**	**2,783.15**	**5,007.11**	**13,854.26**	**49,174.42**	**26,260.68**

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

Monthly 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
July '15 through June '16	$	52,282.71
Average monthly increase from prior period	$	75.92

Monthly 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
July '15 through June '16	$	0.07479
Average monthly increase from prior period	$	0.00142

MINNESOTA PUBLIC UTILITIES COMMISSION (MNPUC) ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND SETTING FURTHER REQUIREMENTS DOCKET NO. E999/AA-08-995

In the Minnesota Public Utilities Commission's March 15, 2010, Order the MNPUC ordered:

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

While Otter Tail has not understood or construed Ordering Point 12 to create an annual reporting requirement within annual AAA dockets, Otter Tail takes contractor performance seriously and has processes and procedures in place to select its vendors and contractors, and subsequently manage their work. A key step in mitigating delays is the selection of qualified contractors and ensuring that appropriate contractual terms are in place to address poor performance. This is combined with project management processes and procedures to hold contractors accountable. Otter Tail believes its current program serves Otter Tail's needs very well. A summary of Otter Tail's processes and procedures specifically related to Procurement, Contracting and Quality Assurance are listed below.

Procurement and Contracting

Standardized contracts are used as much as possible, with formal legal review required of all contracts over $250,000 and for any contracts that have material changes to template language to key risk articles. Formal legal review is also required for certain contracts regardless of contract value. Request for proposals as part of a competitive bidding/selection process is the norm. Otter Tail believes that the use of competition in the contractor selection process helps Otter Tail achieve reasonable pricing and contractual terms.

Otter Tail strives to have appropriate contractual assurances in place for each transaction by using Otter Tail standardized base contracts. A required step in Otter Tail's contracting process is the development of a Contract Risk Assessment (CRA). The CRA is a worksheet listing the main risks in the particular transaction(s) the contractor is hired for, what sections of the contract the risk is covered, and a narrative describing how each particular risk is addressed in the contract. The CRA allows for an appropriate contract to be developed as the transaction is negotiated. The CRA documentation enhances the risk assessment of a project and is a useful tool for Otter Tail subject matter experts (SME), Sourcing, Legal, and Insurance personnel in developing risk mitigation strategies. The CRA helps ensure the SME is aware of the risks of the work being done by the contractor and how the risk is addressed in the contract. It also assists the SME in holding the contractor responsible.

Depending on the nature of the project additional financial assurances may be sought, including retainage, liquidated damages, performance guarantees, letters of credit, and bonds. For instance, retainage - the withholding of a portion of each invoice during a large construction project - is often an effective way to ensure performance. The leverage that retainage provides helps ensure Otter Tail's work remains a priority for the contractor, which is especially critical if there is an issue that requires immediate attention. Time-sensitive project contracts include a work schedule with milestone dates that are often linked to liquidated damages for delays, all of which helps Otter Tail hold contractors accountable.

The contract approval process ensures the contract is reviewed at the appropriate levels within Otter Tail. The CRA is included with the contract as the contract moves through various levels of organizational approvals. During this process risks and key terms are reviewed.

For major procurements on large construction projects, Otter Tail often holds internal pre-Request For Proposal and pre-contract execution meetings between the SME, Project Management, Sourcing, Legal and Insurance personnel. These meetings allow for robust discussion of project risks and ultimately help to Otter Tail identify vendors well suited for the project and to negotiate contracts with appropriate terms protecting Otter Tail. Otter Tail also conducts contractor pre-bid meetings to answer any questions prospective contractors may have before submitting their bid and to discuss risk mitigation options.

Quality Assurance (QA) Quality Control (QC)/ Project Management

Each SME is responsible for reviewing the Scope of Work and monitoring the quality of the work of the contractor. The size and nature of the project will often dictate what resources are used to ensure quality work is completed. On large projects, Otter Tail uses a separate quality assurance SME and a quality assurance firm. For the smaller construction projects, Otter Tail uses the SME and possibly an outside firm. Formal quality assurance/quality control programs are developed for the larger projects, many times with the input of the contractor selected to complete the work. These plans are vetted by Otter Tail's engineering staff, outside quality assurance firms, and senior Otter Tail engineering management.

The scope of Project Management (PM) required depends on the size and complexity of the project / transaction. Otter Tail's larger projects require that a Risk Register is completed by the Project Manager. The Risk Register is a worksheet or table listing the risks associated with the respective project as a whole. These are items that, if they occur, may cause the project to be delayed, cost more than expected, or to be postponed altogether. Each risk is analyzed and an estimated cost as well approximate probability of occurring is listed. The Risk Register assists Project Management in proactively managing the project and increasing the quality of work performed by all involved, including contractors. If needed, items identified in the Risk Register are incorporated into the contractual terms of the contractor. There are other requirements, all of which assist in the project being well run and the respective contractors held accountable.

Contract articles define the contractor's responsibilities for staying on schedule, working safely, and staying within the agreed upon price. Otter Tail also requires daily updates on work progress that are discussed in pre-scheduled meetings.

Given the size and nature of Otter Tail's business and the types of projects Otter Tail is involved in, the sourcing strategies and resources outlined above help Otter Tail to prudently scale and deploy resources as needed to effectively manage contractor performance and achieve desired performance outcomes.

Use of Risk Management Provisions

During the 2015/2016 reporting period, Otter Tail did in fact seek Liquidated Damages (LDs) from a contractor doing work during a scheduled outage. The following describes the situation:

During a scheduled outage at the Big Stone Plant in the spring of 2015, normal maintenance inspections of the turbine blades identified some cracks in the blades located in the high pressure section of the steam turbine that ultimately required the blades to be replaced. By discovering and addressing the cracks in the blades at this time, the risk of an unscheduled turbine failure in the future was mitigated. As a result, the planned outage was extended in order to complete the necessary repairs. The contractor performing the work had a target Substantial Completion Date of July 16, 2015 in their Major Supply Agreement, as amended by change-order, to complete the necessary repairs. The contractor did not achieve Substantial Completion until July 31, 2015 due to an issue of the contractor initially ordering the incorrect replacement blades.

The supplier contract included provisions for the supplier to pay the Big Stone Plant Owners liquidated damages of $15,000 per day for 14 days ($210,000 Total Plant, OTP Share 53.9%, MN Share approximately 50% = $57,000). The supplier did pay the LDs through a reduction in the overall contract price, reducing the amount ultimately capitalized from this overhaul project. Otter Tail estimates that replacement energy costs were approximately $180,000 (MN Share) for the two week period.

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 seven forced outages in excess of 24 hours over the July 2015 – June 2016 period; three at the Big Stone Plant, two at Coyote Station and two 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 6, Attachment M (marked as Not Public), 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. Description of Equipment Failure
e. Change in Energy Costs
f. Steps Taken to Alleviate Reoccurrence

Of the seven forced outages experienced during the reporting period, two of those outages were tube leaks. Other than outages relating to tube leaks, Otter Tail's plants experienced five forced outages: two at Big Stone, two at Coyote, and one at Hoot Lake units #2 and #3. Otter Tail estimates that the aggregate cost of the replacement power for these outages was **PROTECTED DATA BEGINS…**

…**PROTECTED DATA ENDS.**

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 ($772,311) (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 $1,866,607 (system basis) for a net congestion revenue of $1,094,296 (system basis).

Part H Section 3 Attachment K (marked as Not Public) reflect year to date (July 2015 - June 2016) 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 6 Attachment N (marked as Not Public) for Otter Tail's Generation Deliverability Results for MISO Planning Year 2015/2016. The MISO planning year starts on June 1 and ends on May 31.

Please see Attachment O (marked as Not Public) 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 2015/2016, 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 2015/2016, 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 resources 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
8/5/2015	8/7/2015	Gas Recirc Fan vibration	1.32	Ash buildup on fans was suspected cause. The fan was cleaned during prior scheduled outage but vibration following initial startup indicated the need for further inspection and further cleaning.		Procedures put into place to fully inspect work prior to start up.
9/26/2015	9/29/2015	SSH tube leak	3.00	Secondary super heat section (installed in 2011) experienced a boiler tube failure which caused additional tube failures. Initial inspection indicated overheat condition. This was after AQCS boiler modifications in which thousands of cuts and welds were made.		Possible root cause was debris from welding new tubes entering the line and causing a plug, even though new tube welding was performed by contractor with signficant QAQC experience during the major outage. No overheat failures have been seen since this outage.
3/16/2016	3/16/2016	BFP B isolation valve packing leak	2.84	Isolation valve packing leak.		Impossible to avoid this type of outage without a major investment in redundant valving which will be impractical due to space limitations.

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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
11/11/2015	11/13/2015	A Circ Water Pump breaker failure	1.61	Burned up coil in the breaker caused the failure.		Plant already performs annual maintenance on these breakers and the coils are tested.
6/8/2016	6/10/2016	Windbox leak	1.62	Leak was caused by fuel oil leak on cyclone burner.		Operations conduct cyclone inspections during unit startup looking for fuel oil leaks.

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Hoot Lake 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
	Hoot Lake Plant #2					
11/3/2015	11/5/2015	Steam leak on turbine flange	1.96	A steam leak was observed on the steam chest/pipe connecting flanges.		This outage was taken during a reserve shutdown to replace the flange gasket. The gasket had been replaced during the 2014 overhaul. The Unit had been through multiple starts before this anomalous leak. No procedural changes.
	Hoot Lake Plant #3					
9/2/2015	9/3/2015	Tube leak	1.35	Leak developed during a cold start between the membrane and the walltube.		OTP evaluating whether any procedural changes would be effective.

. . . PROTECTED DATA ENDS]

Otter Tail's Generation Deliverability Results for MISO Planning Year 2015/2016

Plan Year: 2015-2016 Asset Owner: All

Resource Name	LRZ	Asset Owner	Type	Effective ICAP	GVTC	Total IS	NRIS	ERIS	XEFORd	Wind %	TL% Inc	UCAP (Total)	UCAP (ERIS)
BIG STONE DIESEL	Zone 1	OTPW	LMR (BTMG)	1.1	1.1	1.1	0	1.1	0.13998		4.1	1	1
DAYTON HOLLOW I	Zone 1	OTPW	LMR (BTMG)	0.5	0.5	0.5	0	0.5	0		4.1	0.5	0.5
DAYTON HOLLOW II	Zone 1	OTPW	LMR (BTMG)	0.5	0.5	0.5	0	0.5	0		4.1	0.5	0.5
FERGUS CONTROL CENTE	Zone 1	OTPW	LMR (BTMG)	2	2	2	0	2	0.13998		4.1	1.8	1.8
GARRISON HYDRO PLANT	Zone 1	OTPW	LMR (ER)	4.7	4.7	5.1	0	5.1	0.01900			5	5
GARRISON HYDRO PLT 2	Zone 1	OTPW	LMR (ER)	4.1	4.1	4.5	0	4.5	0.01900			4.4	4.4
HOOT LAKE DIESEL 2A	Zone 1	OTPW	LMR (BTMG)	0.2	0.2	0.2	0	0.2	0.13998		4.1	0.2	0.2
HOOT LAKE DIESEL 3A	Zone 1	OTPW	LMR (BTMG)	0.1	0.1	0.1	0	0.1	0.13998		4.1	0.1	0.1
HOOT LAKE HYDRO	Zone 1	OTPW	LMR (BTMG)	0.4	0.4	0.4	0	0.4	0		4.1	0.4	0.4
OTP.ASHTAIII	Zone 1	OTPW	CP_NODE	62.4	62.4	9999	0	9999	0	0.22066		13.8	13.8
OTP.ASHTUBULA	Zone 1	OTPW	CP_NODE	48	48	9999	0	9999	0	0.21934		10.5	10.5
OTP.BIGSTON1	Zone 1	OTPW	CP_NODE	254.8	254.8	318.7	318.7	0	0.08010			234.4	0
OTP.COYOT1	Zone 1	OTPW	CP_NODE	151	151	174	174	0	0.14350			129.3	0
OTP.EDGLYEDGL	Zone 1	OTPW	CP_NODE	21	21	21	4.2	16.8	0	0.15445		3.2	0
OTP.HETLA	Zone 1	OTPW	CP_NODE	19.6	19.6	29	21	8	0.06570			18.3	0
OTP.HOOTL2	Zone 1	OTPW	CP_NODE	59.5	59.5	65	65	0	0.05770			56.1	0
OTP.HOOTL3	Zone 1	OTPW	CP_NODE	81	81	88	88	0	0.00830			80.3	0
OTP.JAMSPK1	Zone 1	OTPW	CP_NODE	21.4	21.4	29	21	8	0.11180			19	0
OTP.JAMSPK2	Zone 1	OTPW	CP_NODE	21.1	21.1	29	21	8	0.14540			18	0
OTP.LANGDN1	Zone 1	OTPW	CP_NODE	40.5	40.5	9999	0	9999	0	0.21294		8.6	8.6
OTP.LANGDN2	Zone 1	OTPW	CP_NODE	19.5	19.5	9999	0	9999	0	0.21891		4.3	4.3
OTP.MPWR	Zone 1	OTPW	CP_NODE	49.5	49.5	9999	0	9999	0	0.25518		12.6	12.6
OTP.SLWAYO1	Zone 1	OTPW	CP_NODE	43	43	50	50	0	0.00610			42.7	0
PISGAH HYDRO	Zone 1	OTPW	LMR (BTMG)	0.6	0.6	0.6	0	0.6	0		4.1	0.6	0.6
TAPLIN GORGE HYDRO	Zone 1	OTPW	LMR (BTMG)	0.4	0.4	0.4	0	0.4	0		4.1	0.4	0.4
WRIGHT HYDRO	Zone 1	OTPW	LMR (BTMG)	0.1	0.1	0.1	0	0.1	0		4.1	0.1	0.1
				[PROTECTED 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)										
												…PROTECTED DATA ENDS]	

PUBLIC DOCUMENT - NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

Plan Year: 2015-2016

PRC Type	CP Node	LMR Resource Name	MISO UCAP (MW)	Resource Plan Capacity Ratings	Difference	% Difference	Explanation
external	Garrison Hydro Plant_1		5	5	0	0%	
external	Garrison Hydro Plant_2		4.4	4.4	0	0%	
local	OTP.ASHTUBULA		10.5	10.5	0	0%	
aggregate	OTP.BIGSTON1		234.4	234.4	0	0%	
aggregate	OTP.COYOT1		129.3	129.3	0	0%	
aggregate	OTP.EDGLYEDGL		3.2	3.2	0	0%	
aggregate	OTP.HETLA1		18.3	18.3	0	0%	
aggregate	OTP.HOOTL2		56.1	56.1	0	0%	
aggregate	OTP.HOOTL3		80.3	80.3	0	0%	
aggregate	OTP.JAMSPK1		19	19	0	0%	
aggregate	OTP.JAMSPK2		18	18	0	0%	
local	OTP.LANGDN1		8.6	8.6	0	0%	
local	OTP.LANGDN2		4.3	4.3	0	0%	
local	OTP.MPWR		12.6	12.6	0	0%	
local	OTP.ASHTAIII		13.8	13.8	0	0%	
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	0.5	0.5	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	0.2	0.2	0	0%	
btmg(local)	OTP.OTP	Hoot Lake Diesel 3A	0.1	0.1	0	0%	
btmg(local)	OTP.OTP	Hoot Lake Hydro	0.4	0.4	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	0.1	0.1	0	0%	
aggregate	OTP.SLWAYO1		42.7	42.7	0	0%	
			[PROTECTED 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	Stevens Community Medical Cntr					
						…PROTECTED 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) (Part D Section 5 Attachment A) increased from $809,139 (System-wide) in the 2014-2015 AAA period to $854,949 (System-wide) in the 2015-2016 AAA period. These cost increases equate to a 5.7% 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 $409,427 for the 2015-2016 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 (AttachmentPtoAAA_2015-2016_NOT PUBLIC.accdb) (marked as Not Public). *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 WAPA balancing authority, now part of SPP as a result of WAPA joining SPP in October 2015). 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:

[PROTECTED DATA BEGINS . . .

Source	Sink	FTR Revenue	Congestion Cost	(Rev) Cost Net Congestion Cost

. . . **PROTECTED DATA ENDS]**

[PROTECTED DATA BEGINS . . .

. . . **PROTECTED 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	336	Jamestown	ND	In-Service Stand Alone
345	115	336	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	140	Rugby	ND	In-Service Stand Alone
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. Otter Tail Power carries one 345/115 112 MVA transformer as a spare. In addition, the Wilton 230/115 kV transformer can be considered 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 should a need arise.

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, have invested in on site spare generator step-up transformers at each location. This provides a way to reduce the down-time of these generators in the event of a transformer failure.

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 DA LMP_YR 2015-2016

Note that we included the dates from June 23, 2015 - June 22, 2016 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 23, 2015 to June 22, 2016 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, 2015 – June 22, 2016 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 2015-2016 for each path.

REFERENCE GUIDE FOR ACCESS TABLE NAMED Path Detail

Note that we included the dates from June 23, 2015 - June 22, 2016 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, 2015 - June 22, 2016 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 2015 Actual

Line No.	Account Description	FERC Account	2009 Test Year Amount	2015 Actual Year Expense
1	Maintenance Supervision and Engineering	568.0	$ 448,117	$ 217,105
2	Maintenance of Computer Hardware, Software, etc	569.1; 569.2; 569.3	826,293	910,691
3	Maintenance of Station Equipment	570.0	1,170,884	1,109,533
4	Maintenance of Overhead System	571.0	1,183,741	1,541,400
5	Maintenance of Underground Lines	572.0	220	0
6	Maintenance of Computer Software	576.3	285,036	265,641
7	Total System Historical Transmission Maintenance Expense		$ 3,914,291	$ 4,044,369
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	$ 4,044,369
10	Jurisdictional D2 Allocation Factor (2009 Rate Case)		47.889095%	47.889095%
11	Total MN Jurisdictional Transmission Maintenance Expense		$ 1,942,672	$ 1,936,812

The 2015 above numbers are on a calendar year basis.

MN PUC ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS IN 2013/2014 (FYE11) ANNUAL AUTOMATIC ADJUSTMENT REPORTS - DOCKET NO. E999/AA-14-579

In the Minnesota Public Utilities Commission's June 2, 2016 Order, the following was ordered for Otter Tail Power Company and other electric utilities:

4. **The Commission accepts Otter Tail's identification of and explanation for its higher Revenue Sufficiency Guarantee Make-Whole Payments in May 2013. The Commission disallows recovery of $37,058.**

   In Otter Tail's Energy Adjustment effective July 1, 2016, a credit of ($37,058) is a line item on the monthly calculation (Part E Section 2 Attachment D).

9. **The Commission accepts the uncontested comments, conclusions and recommendations in the Department's Response Comments at 35-40 (August 26, 2015) and takes the following actions:**

   6) **Accepts Otter Tail's compliance filing on its electric service agreement with Enbridge Energy (January 26, 2007 Order) and permits Otter Tail to stop reporting this information.**

      Part H Section 1 Otter Tail Power Company Compliance Report as Required by Order in Docket E017/M-06-1332

   18) **Accepts Otter Tail's reporting with respect to fuel costs associated with coal shortages during FYE14. Requires Otter Tail to report in future AAA filings any coal conservation measures taken in response to coal delivery issues during the relevant reporting period, along with a discussion of Otter Tail's efforts to minimize coal, coal delivery and any replacement power costs if needed to address issues with coal supplies for Otter Tail.**

       There were no coal conservation measures taken or coal delivery issues for Otter Tail coal units during the current reporting period (July 2015 to June 2016). See Part D section 1-4 Rule 7825.2800 Policies and Actions.

   21) **Requires the Companies to continue to provide in the initial filing of all future electric AAA reports the Minnesota jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable.**

       See Part H Section 8 Docket No E999/AA-11-792, 18 for response.

   22) **Requires the Companies to provide in the initial filing of all future electric AAA reports, information to support MISO Schedule 10 cost increases of five percent or higher over the prior year's costs, including an explanation of benefits received by customers for these added costs.**

       See Part H Section 8 Docket No E999/AA-11-792, 18 for response.

25) Accepts Otter Tail's MISO Day 2 reporting for FYE14. Requires Otter Tail to provide in future AAA filings information and narrative to explain why the selected option for Financial Transmission Rights and ARRs is better for rate payers than the alternative.

The company's two largest generating stations (Big Stone and Coyote), have grandfathered transmission rights. These grandfathered transmission rights allow the company to choose between two different congestion hedging instruments on an annual, ARR market year, basis; namely Option A and Option B.

Option A is the equivalent of holding an FTR between Otter Tail's generating stations and Otter Tail's load zone. Option A treatment is not dependent on accurately forecasting the clearing of day-ahead (DA) schedules from the generating stations.

Option B status allows the company to receive a refund of congestion costs incurred on the energy scheduled between generator and load. However, the MISO scheduling rules under Option B require that the companion, Option B, financial schedule, be less than or equal to the DA clearing from the unit. If the Option B financial schedule exceeds the DA, cleared, MWs from the unit, the hourly congestion hedge is lost.

Otter Tail chose to switch its grandfathered status from Option B to Option A beginning June 2013.

The transition from Option B to Option A was made due to increased volatility and difficulty in predicting DA, cleared, MW values from Otter Tail's Big Stone and Coyote generating stations and the resulting elimination of the rebate of congestion between the generation and the load for those hours, often during hours when the congestion hedge is needed the most.

Otter Tail preserves the right to change the grandfathered status on a yearly basis. This enables Otter Tail to revert back to Option B should system conditions change. The choice between Option A and Option B grandfathered rights treatment is reviewed on a yearly basis.

Since the volatility and difficulty in predicting the DA, cleared, MW values from Big Stone and Coyote generation units remain; Otter Tail continues to choose Option A treatment.

ANNUAL AUTOMATIC ADJUSTMENT REPORT

DOCKET NO. E999/AA-16-625

PART I – MINN. R. 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)

OTTER TAIL POWER COMPANY

September 1, 2016

Notice of Availability of Reports

To: All Intervenors in Otter Tail Power Company
Retail Rate Proceedings
Docket No. E017/GR-10-239
Docket No. E017/GR-15-1033

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 Minn. R. 7825.2800 to 7825.2830. The subject matter of the reports filed includes the following:

Minn. R. 7825.2800 Policies and Actions
Minn. R. 7825.2810 Automatic Adjustment Charges
Minn. R. 7825.2820 Annual Independent Auditors' Report
Minn. R. 7825.2830 Annual Five-Year Projection Report
Minn. R. 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.

Minn. R. 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: 2016 Annual Automatic Adjustment of Charges Report - Electric
Minnesota Rules 7825.2800 – 7825.2840
Docket No. E999/AA-16-625

I, Jana C. Hrdlicka, 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: September 1, 2016

/s/ JANA C. HRDLICKA

Jana C. Hrdlicka
Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8879

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 2016
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 2016
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 2016
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James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2016

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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	GEN_SL_Otter Tail Power Company_AAA Service List 2016
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2016
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 2016
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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 2016
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 2016
Ben	Passer	Passer@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 220 Saint Paul, MN 55102	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2016
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 2016
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	332 Minnesota St, Ste W1390 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Otter Tail Power Company_AAA Service List 2016

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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 2016
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