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February 27, 2026



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

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

**RE: In the Matter of Otter Tail Power Company's Petition for Approval
of the Annual True-Up for its Energy Adjustment Rider, Rate
Schedule 13.01
Docket No. E017/AA-24-65**

Dear Ms. Bergman:

Otter Tail Power Company (Otter Tail Power) hereby submits to the Minnesota Public Utilities Commission (Commission) its 2025 True-Up of Energy Adjustment rates in response to decisions rendered by the Commission in Docket No. E999/CI-03-802 and where applicable, in compliance with annual reporting requirements pursuant to Minn. R. 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges.

Various portions and attachments to this filing contain information that Otter Tail Power considers trade secret. Otter Tail Power 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 218-739-8728 or at agrenier@otpc.com.

Sincerely,

/s/ *AMBER GRENIER*
Amber Grenier
Manager, Regulatory Economics

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.

- Attachment 3: Monthly Forecast to Actual Expense (Revenue);
- Attachment 7: Monthly Cost Components by Fuel-Type;
- Attachment 13: Forced Outage Information Change in Energy Costs Column;
- Attachment 14: Wind Curtailment Summary Report;
- Attachment 19: Segments Eligible for Auction Revenue Rights (ARRs)
- Attachment 20: ARR Segements Awarded
- Attachment 21: ARR Segments Converted to FTRs
- Appendix D: Additional Reporting Requirements
 - Section 1.1 – Order Point 7.A.1.a: Eenergy Hedging
 - Section 1.2 – Order Point 7.A.1.b: Eenergy Hedging
 - Section 7.2 – Order Point 22: Plant Outages
 - Section 9.4 – Order Point 4.D: ARR Nomination/FTR Conversion Strategies
 - Section 9.5 – Order Point 5.A: Strategies to Address Congestion/Curtailment of Energy
 - Section 9.6 – Order Point 5.B: Merit of Each Congestion/Curtailment of Energy Strategy
- Appendix E: Self Commit Annual Compliance on pages 3, 7, 8, 15, 22, as marked, include plant-specific information in the body text, and
 - Tables 1, 3, 4, 6, 7, 8, 9, 10, 11, 12, 13 and 15 in the filing letter – Plant specific economic information;
 - Figures 1-6 in the filing letter – Plant specific economic information;
 - Attachment 1 in its entirety – Plant specific economic information;
 - Attachment 2 in its entirety – Plant specific economic information;
 - Attachment 3 in its entirety – Plant specific economic information;
 - Attachment 4 in its entirety – Plant specific operating information;
 - Attachment 5 in its entirety – Plant specific economic information;
 - Attachment 6 in its entirety – Plant specific economic information; and
 - Attachment 7 in its entirety – Facility specific economic information.

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: February 27, 2026

**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

**In the Matter of Otter Tail Power
Company's Petition for Approval of
the Annual True-Up for its Energy
Adjustment Rider, Rate Schedule
13.01**

Docket No. E017/AA-24-65

SUMMARY OF FILING

Otter Tail Power Company (Otter Tail Power or Company) submits this Petition to the Minnesota Public Utilities Commission (Commission) for approval of its annual true-up rate for its Energy Adjustment Rider (EAR) under Otter Tail Power's Rate Schedule Section 13.01 for calendar year 2025.

**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

**In the Matter of Otter Tail Power
Company's Petition for Approval of
the Annual True-Up for its Energy
Adjustment Rider, Rate Schedule
13.01**

**Docket No. E017/AA-24-65
PETITION**

I. INTRODUCTION

Otter Tail Power Company (Otter Tail Power or the Company) submits this Petition to the Minnesota Public Utilities Commission (Commission) for approval of its Annual Fuel Cost Adjustment (FCA) True-Up of annual costs and collections recovered through its Energy Adjustment Rider (EAR) under Rate Schedule Section 13.01 for the period of January 1 to December 31, 2025. Otter Tail Power also provides various annual reports in compliance with Minn. R. 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges and as required by prior Commission Orders.

In this filing, Otter Tail Power submits for approval its proposed true-up of final FCA costs and collections for calendar year 2025, along with analysis of various factors that contributed to the variances that occurred between forecasted costs for 2025 and actual costs for 2025. Otter Tail Power will demonstrate that its FCA costs for 2025 were reasonable and prudent given market conditions that existed in 2025.

On a system-wide basis, Otter Tail Power's actual EAR recovery able costs for 2025 totaled \$127,206,362, compared to the forecasted amount of \$140,775,337. Actual costs have been adjusted to include the proposed return of the 2025 portion of Midcontinent Independent System Operator (MISO) Planning Resource Auction (PRA) revenues.

Using the ratio of Minnesota jurisdictional kWh sales subject to the EAR to total system kWh sales, Minnesota's allocated share of 2025 system costs is \$60,092,464. Total revenues collected from Minnesota customers for 2025 under the Commission-approved forecasted EAR rates were \$65,602,211, resulting in an over-collection of \$5,509,747 prior to incorporating the impacts of Otter Tail Power's two 2025 supplemental filings and the associated refunds implemented beginning September 2025.

Accounting for the refunds implemented September 2025 through December 2025 and the projected refunds scheduled for January 2026 through April 2026, the Company projects a net under-collection of \$2,553,919 for the 2025 recovery year. Table 1 summarizes the calculation of the 2025 projected Minnesota under-recovery.

Table 1
Minnesota Under Recovery Calculation

Line	Item	Amount
1	Total 2025 Recovery from Forecasted EAR	\$65,602,211
2	Actual 2025 Energy Costs	\$60,092,464
3	2025 Over/(Under) Recovery Before Refunds	\$5,509,747
4	Collected 2025 Supplemental Refund (September-December 2025)	(\$5,205,435)
5	Projected 2025 Supplemental Refund (January-April 2026)	(\$2,858,231)
6	Current 2025 Projected Over/(Under)	(\$2,553,919)

In addition to the 2025 balance, Otter Tail Power includes in this filing the remaining balance associated with prior recovery periods. The final balance for the 2023 FCA True-Up,¹ which concluded August 31, 2025, is an under-recovery of \$807,136. The Company continues to implement the adjustments approved in its 2024 Annual FCA True-Up² filing related to the 2024 costs with a projected under-recovery of \$358,088. Based on forecasted sales from January through August 2026, the Company estimates that the combined net under-recovery for all periods will total \$3,719,144 as of August 31, 2026. Table 2 summarizes the aggregated balances for all included periods.

Table 2
Aggregated Over/Under-Recovery Balances

Line	Item	Amount
1	Current 2025 Projected Over/(Under)	(\$2,553,919)
2	Collected Over/(Under) of 2023 Costs	(\$807,136)
3	Projected Collected Over/(Under) of 2024 Costs	(\$358,088)
4	Current Projected Over/(Under) to Customers	(\$3,719,144)

Otter Tail Power proposes to recover the 2025 net under-recovery balance over the twelve-month period from September 1, 2026, through August 31, 2027, consistent with Otter Tail Power's EAR Rate Schedule, Section 13.01, which provides that the annual true-up shall be applied to the subsequent twelve-month period.

¹ 2023 FCA True-Up, Docket No. E017/AA-22-214

² 2024 FCA True-Up, Docket No. E017/AA-23-181

In accordance with Minnesota Rules 7825.2800 through 7825.2840 governing automatic adjustment of charges, Otter Tail Power also submits the required reports and schedules, along with all materials required under prior Commission Orders in Annual Automatic Adjustment (AAA) dockets.

The Company additionally includes its Annual Self-Commitment and Self Scheduling Report (Self-Commitment Report). On December 29, 2025, The Minnesota Department of Commerce, Division of Energy Resources; Minnesota Power; Otter Tail Power; and Northern States Power Company jointly proposed incorporating the entirety of the Self-Commitment Report into each utility's FCA True-Up filing rather than submitting it as a stand-alone report. Consolidating the reports allows plant operations information to be evaluated in the context of relevant fuel cost data, improving administrative efficiency and facilitating a more comprehensive review.

II. SUMMARY OF FILING

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

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, Otter Tail Power provides the following general information.

A. Name, Address, and Telephone Number of Utility

(Minn. Rules 7829.1300, subp. 3(A))

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

(Minn. Rules 7829.1300, subp. 3(B))

Lauren Donofrio
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8774
ldonofrio@otpc.com

C. Date of Filing and Proposed Effective Date of True-Up

(Minn. Rules 7829.1300, subp. 3(C))

Consistent with the filing requirement in Minn. R. 7825.2840, the date of this filing is February 27, 2026. Otter Tail Power proposes to implement the True-Up rate effective September 1, 2026. The information contained in this filing is submitted in compliance with the aforementioned rules concerning Automatic Adjustment of Charges. Attachment 4 includes Otter Tail Power's proposed customer notice.

D. Statute Controlling Schedule for Processing the Filing

(Minn. Rules 7829.1300, subp. 3(D))

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

(Minn. Rules 7829.1300, subp. 3(E))

Amber Grenier
Manager, Regulatory Economics
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F. Impact on Rates

(Minn. Rules 7829.1300, subp. 3(F))

The True-Up rate has no effect on Otter Tail Power's base rates. The additional information required under this rule is included throughout the Petition.

G. Service List

(Minn. Rules 7829.0700)

Otter Tail Power requests that the following persons be placed on the Commission's official service list for this matter and that any trade secret comments, requests, or information be provided to the following on behalf of Otter Tail Power:

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H. Service on Other Parties

(Minn. Rules 7829.1300, subp. 2; Minn. Rules 7829.0600)

Pursuant to Minn. Rule 7829.1300, subp. 2, Otter Tail Power served a copy of this Petition on the Department and the Residential Utilities Division of the Office of the Attorney General. A summary of the filing prepared in accordance with Minn. Rule 7829.1300, subp. 1 was served on all parties on Otter Tail Power's general service list.

IV. DESCRIPTION OF FILING

A. Purpose

The primary purpose of this filing is to: (1) demonstrate that Otter Tail Power's 2025 fuel and purchased power costs were reasonable and prudent; (2) provide the information necessary support for the Commission to make that determination; (3) obtain approval to implement Otter Tail Power's 2025 true-up rate; and 4) obtain approval of all compliance reporting required in accordance with Minnesota Rules 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges, as well as requirements established in prior Commission Orders from past AAA Dockets.

B. Background

On May 1, 2024, Otter Tail Power filed its Initial Petition for approval of the 2025 Annual Forecasted Rates for its EAR, Rate Schedule Section 13.01 in Docket No. E017/AA-24-65. In its November 12, 2024 Order, the Commission authorized Otter Tail Power to implement its updated 2025 FCA forecast based on forecasted

sales of 5,885,378 MWh, fuel costs of \$140,775,337, and net system FCA costs of \$23.92 per MWh.

On March 1, 2025, Otter Tail Power filed its 2024 True-up filing in Docket 23-181 requesting to collect a net under-recovered balance for 2024 and prior periods of (\$774,941). The true-up was approved by the Commission's Order dated July 28, 2025, and the Commission ordered collection of that balance over the September 2025 to August 2026 timeframe, with an increase in the EAR by a rate of \$0.00030 per kilowatt hour (kWh).

On July 28, 2025, Otter Tail Power made a supplemental filing to its 2025 FCA forecast rates in Docket E017/AA-24-65 to return an over-collection of approximately \$5.4 million that accumulated from January 2025 through June 2025. The reduction in EAR rates to begin refunding this amount was (\$0.00640) per kWh beginning September 2025 and through December 2025.

On November 26, 2025, Otter Tail Power made an additional supplemental filing to return an over-collection of approximately \$2.8 million that accumulated from July 2025 through October 2025. The reduction in EAR rates to begin refunding this additional supplemental amount was (\$0.00290) per kWh beginning January 2026 through April 2026.

V. 2025 FORECAST VERSUS ACTUAL

A. Summary

On a system-wide basis, Otter Tail Power's actual FCA costs for 2025 totaled \$127,206,362, or \$13,568,975 lower than the forecasted amount of \$140,775,337. The actual average fuel cost of \$21.49 per MWh was 10.08 percent lower than the approved rate of \$23.90 per MWh. Total system sales in 2025 were marginally higher than forecast. Table 3 below summarized the 2025 Total Company forecast to actuals.

Table 3
2025 FCA Summary (Total System)

	Actual	Forecast	Variance	Variance %
Average Cost Per MWh	\$21.49	\$23.90	\$2.41	(10.08%)
MWh Sales	5,920,133	5,885,378	34,755	0.59%
Total Cost (Fuel & Purchased Power)	\$127,206,362	\$140,775,337	(\$13,568,975)	(9.64%)

The Company provides more detailed analysis of variances between forecast and actuals for the primary components of fuel costs later in this Annual FCA True-Up filing. Specifically, the analysis provides additional data and discussion on the following items:

1. Total forecast costs for 2025 compared to actual costs.
2. Forecasted kWh sales for 2025 compared to actual kWh sales.
3. Forecasted rates for 2025 compared to actual rates.
4. Forecasted market prices for 2025 compared to actual market prices.
5. Forecasted generation and associated fuel costs compared to actual generation and associated costs, a discussion on changes in plant operations implemented in 2025, as well as a review of overall plant availability and associated forced outages.
6. Forecasted purchased power costs authorized for FCA recovery including PPAs and market purchases compared to actual results.
7. Forecasted MISO and SPP wholesale market charges compared to actual results.
8. Forecasted asset-based sales compared to actual results.
9. Reagent expenses and steam and water sales.
10. MISO Planning Resource Auction revenues

Otter Tail Power provides additional analysis associated with total FCA collections for 2025 relative to actual costs incurred and quantifies the applicable true-up balance subject to collection as authorized by the Commission.

B. Actual to Forecast of Monthly Fuel & Purchased Power Costs

Table 4 below summarizes Otter Tail Power's actual monthly FCA costs for 2025 compared to forecasted costs. Attachment 2 to this filing provides a further categorical breakdown of forecasted and actual monthly costs for 2025. Further discussion and analysis of these results follow.

Table 4
Monthly Fuel & Purchased Power Costs (Total System)
Actual to Forecast Comparison

Month	Actual	Forecast	Variance
January 2025	\$17,030,492	\$16,159,551	\$870,941
February 2025	\$14,016,294	\$15,444,844	(\$1,428,550)
March 2025	\$10,541,716	\$11,986,371	(\$1,444,655)
April 2025	\$7,880,698	\$11,240,560	(\$3,359,863)
May 2025	\$7,273,901	\$10,171,210	(\$2,897,309)
June 2025	\$11,885,082	\$8,661,062	\$3,224,020
July 2025	\$8,684,774	\$9,131,039	(\$446,265)
August 2025	\$6,608,830	\$9,555,026	(\$2,946,196)
September 2025	\$7,131,027	\$9,429,229	(\$2,298,202)
October 2025	\$6,797,770	\$10,021,653	(\$3,223,883)
November 2025	\$9,397,071	\$12,365,264	(\$2,968,193)
December 2025	\$19,958,708	\$16,609,529	\$3,349,179
Total	\$127,206,362	\$140,775,337	(\$13,568,975)

C. Actual to Forecast of kWh Sales

Otter Tail Power developed its 2025 FCA forecast using the most current sales forecast available at the time of its May 1, 2024 Initial Filing. Actual 2025 kWh sales were approximately 0.5 percent higher relative to forecast. Weather contributed to these results with heating degree days (HDD) for 2025 at 97.1 percent³ of normal and cooling degree days (CDD) at 102.5 percent of normal, reflecting slightly warmer winter conditions and higher cooling needs during the summer months. Table 5 below presents a comparison of actual billed kWh sales to the forecast for 2025.

³ Actual 2025 HDD = 6,117 (97.1% of Normal); Actual 2025 CDD = 492 (102.5% of Normal).

Table 5
2025 Monthly kWh Sales (Total System)
Actual to Forecast Comparison

Month	Actual	Forecast⁴	Variance
January 2025	602,284,529	595,596,123	6,688,406
February 2025	589,770,866	546,423,644	43,347,222
March 2025	533,208,522	526,495,043	6,713,479
April 2025	506,015,599	465,141,417	40,874,182
May 2025	442,130,258	439,648,648	2,481,610
June 2025	435,216,071	431,882,951	3,333,121
July 2025	459,046,318	455,028,148	4,018,170
August 2025	460,094,059	451,076,646	9,017,413
September 2025	463,456,819	423,712,379	39,744,441
October 2025	428,629,031	459,000,219	(30,371,188)
November 2025	473,057,393	515,733,969	(42,676,576)
December 2025	527,223,809	575,638,690	(48,414,881)
Total	5,920,133,274	5,885,377,876	34,755,398

D. Comparison of Forecasted Rates to Actual Costs Per kWh

Table 6 summarizes the approved forecasted monthly fuel rate per kWh, the actual fuel costs per kWh, and the resulting variances. Detailed monthly and annual cost information is provided in Attachment 2.

⁴ November 12, 2024, Order in Docket No. E017/AA-24-65.

Table 6
Total FCA Cost Per kWh (Total System)
2025 Initial Forecast to Actual Comparison

Month	Actual	Initial Forecast⁵	Variance
January 2025	\$0.02828	\$0.02713	\$0.00115
February 2025	\$0.02377	\$0.02827	(\$0.00450)
March 2025	\$0.01977	\$0.02277	(\$0.00300)
April 2025	\$0.01557	\$0.02417	(\$0.00859)
May 2025	\$0.01645	\$0.02314	(\$0.00668)
June 2025	\$0.02731	\$0.02005	\$0.00725
July 2025	\$0.01892	\$0.02007	(\$0.00115)
August 2025	\$0.01436	\$0.02118	(\$0.00682)
September 2025	\$0.01539	\$0.02225	(\$0.00687)
October 2025	\$0.01586	\$0.02183	(\$0.00597)
November 2025	\$0.01987	\$0.02398	(\$0.00411)
December 2025	\$0.03786	\$0.02885	\$0.00900

Table 7 provides the revised rates that Otter Tail Power implemented beginning in September 2025 and remaining in effect through December 2025. As detailed in the Company's July 28, 2025 Supplemental Filing in this docket, these rates include recovery of the 2025 over-collection during the first six months of 2025.

Table 7
Total FCA Cost Per kWh
Revised Forecast to Actual Comparison

Month	Actual	Revised Rates⁶	Variance
September 2025	\$0.02225	\$0.01665	(\$0.0056)
October 2025	\$0.02183	\$0.01623	(\$0.0056)
November 2025	\$0.02398	\$0.01838	(\$0.0056)
December 2025	\$0.02885	\$0.02325	(\$0.0056)

⁵ November 12, 2024 Order in Docket No. E017/AA-24-65.

⁶ Otter Tail Power's Supplement Filing, July 28, 2025 in Docket No. E017/AA-24-65.

Table 8 shows the revised rates implemented by Otter Tail Power beginning in January 2026 and remaining in effect through June 2026. As outlined in Otter Tail Power's November 26, 2025 Supplemental Filing in this docket, these rates incorporate the return of the over-collection accrued from July 2025 through October 2025.

Table 8
Total FCA Cost Per kWh
2026 Approved Rates to Revised Rates Comparison

Month	Approved Rates⁷	Revised Rates⁸	Variance
January 2026	\$0.03115	\$0.02855	(\$0.00260)
February 2026	\$0.02780	\$0.02520	(\$0.00260)
March 2026	\$0.02486	\$0.02226	(\$0.00260)
April 2026	\$0.02243	\$0.01983	(\$0.00260)
May 2026	\$0.02218	\$0.02248	(\$0.00030)
June 2026	\$0.02487	\$0.02517	(\$0.00030)

E. Detailed Variance Explanations

Attachment 3 contains detailed forecast-to-actual comparisons for each 2025 fuel cost component. The attachment includes monthly variance analyses for total costs, MWhs, and cost per MWh, along with corresponding full-year results for each component.

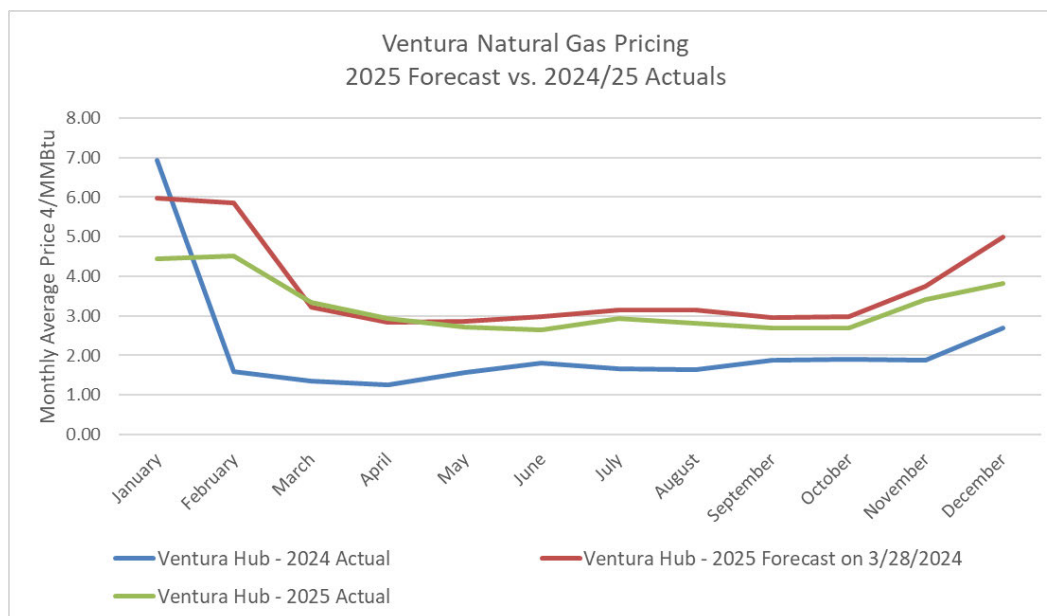
1. Natural Gas Prices

Natural gas pricing often drives MISO Locational Marginal Prices (LMPs) because natural gas units frequently operate as the marginal, price-setting units within the MISO market. Otter Tail Power developed its 2025 forecast using natural gas forward prices captured on March 28, 2024, which at the time indicated higher than expected prices for 2025. The chart below compares the forecasted monthly prices used in the Company's modeling to the actual 2025 monthly average Ventura Hub natural gas prices. These forward prices were used as core inputs in Otter Tail Power's FCA modeling to estimate plant dispatch levels and expected market purchases reflected in forecasted rates. The graph below presents a comparison of actual Ventura

⁷ Otter Tail Power's Approved 2026 Forecasted rate in Docket No. E017/AA-25-65 with Otter Tail Power's Approved 2024 True-Up in Docket No. E017/AA-23-181.

⁸ Otter Tail Power's Supplement Filing, November 26, 2025 in Docket No. E017/AA-24-65.

Hub natural gas prices from 2024 and 2025 to the 2025 forecast prices used in the FCA forecast.

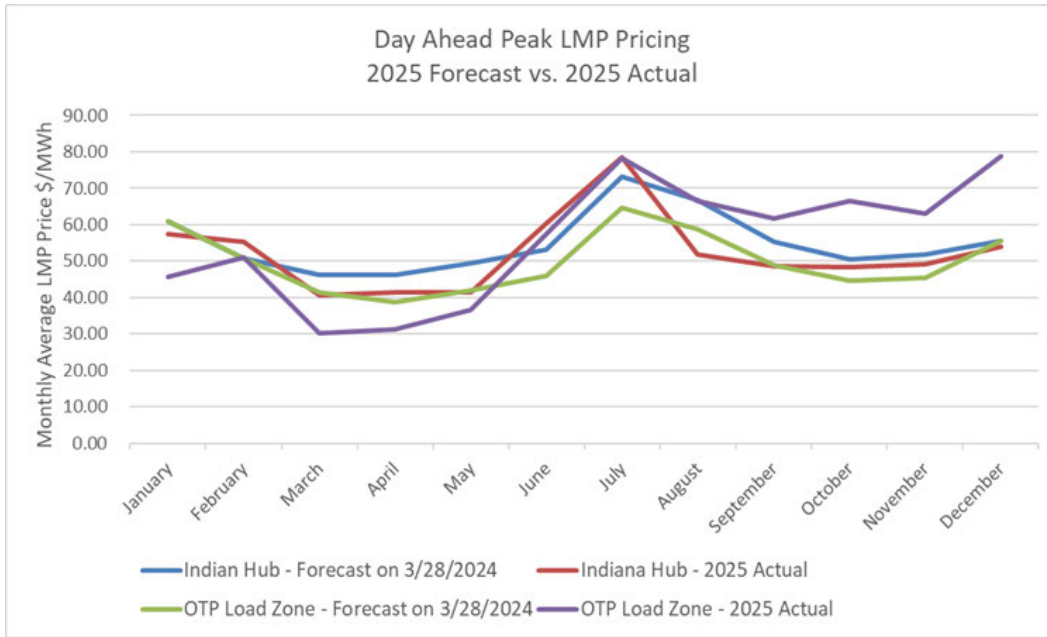


Appendix D, Section 1 of this filing provides further discussion of 2025 natural gas pricing.

2. Locational Marginal Prices

Forecasted LMSPs are a key input in Otter Tail Power's Encompass model used to develop 2025 forecasted rates. The model uses these prices to estimate economic dispatch within MISO will dispatch generating resources based on their respective operating costs to meet forecasted load. by comparing forecasted market prices to plant operating costs to determine whether units will be dispatched or whether market purchases will meet load.

To forecast LMPs for the Otter Tail Power load zone, the Company relies on daily forward Indiana Hub price curves published by Intercontinental Exchange, Inc. (ICE). Otter Tail Power evaluates historical pricing relationships between the Indiana Hub and its load zone, considers historical and current market conditions, and incorporates future market trends when developing its load zone forecast. For the 2025 forecast, the Company used the March 28, 2024, Indiana Hub forward price curve. The graph below presents a comparison of actual Day-Ahead Peak LMPs from 2025 to the 2025 forecast Peak LMPs used in the FCA forecast.



Appendix D, Section 1 provides further discussion of 2025 market conditions and explains how LMP pricing was incorporated into the Company's forecast of generation output.

As noted earlier, the Encompass model that Otter Tail Power used to develop its 2025 fuel forecasts modeled plant dispatch and associated fuel costs based on the operating parameters and associated costs of running the plants. In the model, the dispatch of plants is influenced by (1) the amount of load to be served, which varies seasonally; (2) energy acquired from long term PPAs or other forward purchases; and (3) forecasted LMPs estimating the cost at which Otter Tail Power could acquire energy from the market. Plant availability is another factor, as planned outages and estimated forced outage rates were also inputs into the model. The model attempts to balance all these variables to achieve the lowest cost portfolio of resources to meet load and other market requirements.

3. Baseload Generation Utilization

Actual baseload generation for 2025 was 5.26 percent lower than forecasted while associated fuel costs were 1.39 percent higher than forecast. Table 9 summarizes the baseload generation output and related fuel costs for 2025 compared to forecast.

Table 9
2025 Baseload Generation (Total System)
Forecast to Actual Comparison

	Actual	Forecast	Variance	Percentage
Big Stone Plant MWhs	1,134,191	1,038,184	96,008	9.25%
Coyote Station MWhs	747,631	948,192	(200,561)	(21.15%)
Total Baseload Generation -MWhs	1,881,823	1,986,376	(104,554)	(5.26%)
Total Baseload Fuel Costs	\$52,066,689	\$51,353,824	712,865	1.39%

4. Plant Availability

Big Stone Plant experienced three forced outages in 2025. The first forced outage was due to a furnace wall tube leak repair and lasted 2.65 days. The second was a steam leak due to an issue with a 101 LP Valve to BFP, which lasted 1.03 days. The final outage was a cyclone tube leak that lasted 1.51 days. The estimated change in energy costs due to these outages in 2025 was approximately **[Protected Data Begins... ..Protected Data Ends]** as summarized in Attachment 13.

Coyote Station had five forced outages in 2025, of which two were related to tube leaks. One was related to crack in the metal casing of the wind box causing excessive heat. Another forced outage was related to a summer storm. Another outage was related to a pendant wash. The estimated change in energy costs due to these outages in 2025 was approximately **[Protected Data Begins... ..Protected Data Ends]** as summarized in Attachment 13.

5. Wind Generation

Output from Otter Tail Power's owned wind generation fleet was approximately 12.91 percent lower than forecasted for 2025. As shown in Table 10, all Company-owned wind generation facilities – except Langdon and Merricourt – experienced reductions in generation output ranging from 16 to 44 percent.

Table 10
2025 OTP Owned Wind Generation (Total System)
Forecast to Actual Comparison

	Actual MWhs	Forecast MWhs	Variance	Variance %
Langdon Wind	172,664	166,414	6,250	3.76%
Ashtabula Wind	88,586	151,488	(62,902)	(41.52%)
Ashtabula Wind III	119,861	213,843	(93,983)	(43.95%)
Luverne Wind	151,404	179,397	(27,993)	(15.60%)
Merricourt Wind	583,545	570,410	13,135	2.30%
Total Wind	1,116,060	1,281,553	(165,492)	(12.91%)

6. Gas and Oil Peaking Units, Hydro and Solar Generation

Attachment 3 provides a detailed comparison of forecasted and actual results for all applicable generating facilities. A portion of Otter Tail Power's generation is supplied by its natural gas peaking unit located in Solway, Minnesota; the Astoria Station in Astoria, South Dakota; several small oil peaking units; limited hydro resources; and small-scale solar facilities. MISO dispatches these units as needed to meet system load within their respective geographic areas.

Hoot Lake Solar, a 50 MW solar facility located in Fergus Falls, Minnesota, commenced operation in the fall of 2023. For 2025, the Company forecasted the solar facility would produce approximately 73,000 MWhs; actual generation totaled 87,000 MWhs.

7. Market Purchases and Power Purchase Agreements

Otter Tail Power included three long-term wind Power Purchase Agreements (PPAs) in its resource portfolio to meet the Company's load requirements in 2025. Additional energy was supplied through shared service agreements and small cogeneration agreements. The majority of the Company's purchased power was obtained through transactions in the MISO Day Ahead (DA) and Real Time (RT) markets, and supplemented by forward bilateral energy purchases. The Company executes forward bilateral energy purchases to hedge market price volatility during periods of peak load or when generating units are unavailable due to major planned outages.

Table 11 below provides a summary of these various resources and their respective MWh contributions to Otter Tail Power's overall resource needs in 2025 relative to forecast, as well as a summary of the overall forecasted and actual costs.

Table 11
2025 Purchased Power Summary (Total System)
Forecast to Actual Comparison

	Actual	Forecast	Variance	Variance %
Wind PPAs MWhs	114,648	116,650	(2,002)	(1.72%)
Shared Loads/ Small Cogen MWhs	151,886	154,810	(2,924)	(1.89%)
Bilateral & MISO Market purchases MWhs	2,086,924	2,391,998	(305,074)	(12.75%)
Total Purchases MWhs	2,661,475	2,355,460	306,015	12.99%
Total Purchases Cost	\$102,409,214	\$96,130,445	\$6,278,769	6.53%
Average Cost per MWh	\$38.48	\$40.81	(\$2.33)	(5.71%)

Otter Tail Power's wind PPAs generated approximately 1.7 percent less than forecast for 2025, and output from shared load and small co-generation agreements was also slightly below expectations. These resources continue to play a supplemental role in meeting the Company's overall energy needs.

Market conditions in 2025 differed materially from assumptions used when rates were established. Market prices were higher than forecast, and system sales grew during the year. As shown in Table 11, bilateral and market-based purchases totaled 2,086,924 MWh – 12.75 percent lower than the forecasted 2,391,998 MWh. However, when combined with other purchased power resources, the overall purchased power portfolio totaled 2,661,475, approximately 12.99 percent higher than the forecasted 2,335,460 MWh. This higher overall purchased power volume, together with elevated market prices, resulted in total purchased power costs that were approximately \$6.2 million (OTP Total) higher than forecast. The average cost of purchased power was \$38.48 per MWh, compared to the forecasted \$40.81 per MWh.

8. MISO and SPP Wholesale Market Charges

Wholesale market charges consist of the various non-energy charges and credits assessed by MISO and SPP as part of their market settlement processes. These charges exclude the primary costs associated with energy generation and load, which are reflected in the purchased power category discussed above. Together, MISO and SPP administer nearly 70 distinct wholesale market charge types.

As summarized in Table 12, Otter Tail Power had initially forecast approximately \$13 million in net wholesale market revenue credits for 2025. Actual results, however, produced a net revenue credit of approximately \$62 million. This significant favorable variance was driven primarily by strong Financial Transmission Rights (FTR) hourly allocation revenues and Auction Revenue Rights (ARRs) in the MISO market, which more than offset small unfavorable variances in day-ahead and real-time congestion and loss charges. Detailed forecast-to-actual comparisons for all MISO and SPP charge types are provided in Attachment 3.

Table 12
2025 MISO and SPP Wholesales Market Charges
Forecast to Actual Comparison
Expense (Revenue)

	Actual	Forecast	Variance	Variance %
MISO Market Charges	(\$58,731,212)	(\$11,265,769)	(\$47,465,442)	421.32%
SPP Market Charges	(\$955,900)	(\$1,327,608)	\$371,708	(28.00%)
Total Market Charges	(\$62,259,431)	(\$13,067,870)	(\$49,191,560)	376.43%

9. Asset Based Sales

Plant availability, market prices, and load levels all influence whether MISO dispatches generation units as net sellers into the market. In 2025, Otter Tail Power realized approximately \$19.4 million (OTP Total) in asset-based sales, producing a margin of roughly \$6.9 million (OTP Total). These revenues are fully credited back to customers under EAR Tariff Section 13.01. The Company's Encompass model had forecasted \$8.4 million of sales for 2025; actual sales were higher primarily because dispatch conditions created more opportunities for excess generation to be sold into the market. However,

lower-than-expected average LMPs reduced the unit value of those sales and associated margins. Table 13 below provides the detailed forecast-to-actual comparison for 2025.

Table 13
2025 Asset Based Sales
Forecast to Actual Comparison
Expense (Revenue)

	Actual	Forecast	Variance	Variance %
Fuel Costs of Asset Based Sales	\$12,488,597	\$3,578,780	\$8,909,817	248.96%
Margin on Asset Based Sales	(\$6,933,113)	(\$4,865,641)	(\$2,067,472)	42.49%
Total Asset Based Sales	(\$19,421,710)	(\$8,444,421)	(\$4,804,348)	129.99%

10. Ancillary Services

MISO occasionally calls upon Otter Tail Power's generation units to provide services in the Ancillary Services Market (ASM), which generates a small amount of revenue for the Company. In 2025, ASM revenues totals \$2.6 million – approximately 442 percent higher than forecast. These revenues represent a minor component of overall FCA costs. Detailed forecast-to-actual results for ASM revenues are included in Attachment 2 and Attachment 3.

11. Wind Curtailment Costs

Certain provisions in Otter Tail Power's wind PPAs require curtailment payments when facilities are shut down during periods of negative LMPs. Curtailment costs for 2025 were \$41,596, approximately 67 percent lower than forecast. As with ASM revenues, these costs make up a small portion of total FCA costs. Forecast-to-actual details for curtailment costs are provided in Attachment 2 and Attachment 3.

12. Reagent Costs

Actual reagent expenses for 2025 exceeded forecasted levels by approximately 25.87 percent. Because reagent consumption is directly correlated with baseload unit operations, variations in unit run times can significantly affect annual costs. Forecast-to-actual details for reagent costs are provided in Attachment 2 and Attachment 3.

13. Steam and Water Sales

Actual steam and water sales for 2025 were approximately 5.56 percent lower than the amounts included in the 2025 FCA forecast. The total net margin from steam and water sales was approximately \$1.2 million (OTP Total) for the year. Forecast-to-actual details for steam and water sales are provided in Attachment 2 and Attachment 3.

14. MISO Planning Resource Auction Revenues

In Docket No. E017/AA-24-065, the Commission approved Otter Tail Power's request to include actual MISO PRA costs and revenues in this annual true-up filing for the 2025 calendar year. Otter Tail Power recognized \$6.3 million (OTP Total) in 2025 MISO PRA Revenues as shown in Attachment 2.

15. Hoot Lake Solar Adjustment for 100 Percent of Output

In Docket No. E017/M-20-844, the Commission approved Otter Tail Power's request to fully allocate the output and costs of the Hoot Lake Solar project to Minnesota. Under the current EAR mechanism, Minnesota EAR rates are calculated using total system costs divided by total system sales. Because Otter Tail Power serves customers in three states, the zero-fuel-cost output of Hoot Lake Solar would otherwise be spread across all jurisdictions, diluting the benefit to Minnesota. To ensure that Minnesota customers receive the full value of this resource, the Company applies an adjustment that grosses up the Hoot Lake Solar output in the EAR calculation so that 100 percent of the benefit is attributed to Minnesota.

From a forecasting perspective, Otter Tail Power estimates the monthly avoided cost by multiplying the forecasted Hoot Lake Solar output by the forecasted cost per MWh of market purchases. For actual results, the Company uses revenue recorded through two primary MISO settlement charge types – Day-Ahead Asset Energy Amount and Non-Excessive Energy Amount – to determine actual Hoot Lake Solar revenues. The difference between total Hoot Lake Solar revenue and the portion allocated to Minnesota under the standard EAR method is grossed up monthly using Minnesota's share of total system sales to credit 100 percent of the revenue to the EAR. The resulting credit for 2025 was approximately \$3.7 million (OTP Total). The detailed adjustment calculation is provided in Attachment 18 and is reflected in Attachment 2.

F. Net True-Up Balance

Attachment 1 provides the monthly detail of total system sales, total system FCA costs, monthly cost recovery, and remaining true-up balances from both 2023 and 2024 recovery periods. Because existing true-up adjustments will remain in rates until August 2026, the proposed 2025 true-up balance reflects an estimated under-collection of \$3,719,144, as summarized in Table 14. Attachment 1 provides the calculation of the annual true-up rate of \$0.00130 per kWh.

Table 14
2025 Annual True-Up Balance
MN Share

Line	Item	Amount
1	Total 2025 Recovery from Forecasted EAR:	\$65,602,211
2	Actual 2025 Energy Costs (MN Share)	\$60,092,464
3	2025 Over/(Under) Recovery Before Refund	\$5,509,747
4	Collected Over/(Under) of 2023 Costs	(\$807,136)
5	Projected Collected Over/(Under) of 2024 Costs	(\$358,088)
6	Collected 2025 July Supplemental Refund (September - December 2025)	(\$5,205,435)
7	Projected 2025 November Supplemental Refund (January - April 2026)	(\$2,858,231)
8	Current Projected Over/(Under) to Customers	(\$3,719,144)

Line 1 of Table 10 shows that total collections based on approved rates were approximately \$65.6 million, resulting in an over-collection of approximately \$5.5 million for the 2025 recovery year. This amount reflects only the 2025 activity and does not include balance from prior periods.

Line 4 presents the final balance of the 2023 True-Up in Docket No. E017/AA-22-214, which concluded on August 31, 2025, following the rate adjustments implemented in September 2024. Line 5 reflects the projected balance of the 2024 True-Up in Docket No. E017/AA-23-181 that began September 1, 2025, and recovery will continue to August 31, 2026. Line 6 and 7 present the collected and projected refunds to customers resulting from the Company's supplemental filings made in 2025. As noted above, Attachment 1 provides the detailed monthly calculations supporting the amounts summarized in Table 10.

For reference, Otter Tail Power's current EAR, Section 13.01, Page 3, includes these two paragraphs describing the annual true-up:

In addition, subject to Commission approval, there shall be an annual true-up for any amount collected over or under the actual cost of energy for the twelve months ending December 31 of each year as reported in the Annual Automatic Adjustment True-up report to be filed by March 1 following the most recent reporting period. The annual true-up shall be based on a historic twelve-month period, comparing actual costs per kWh to the forecasted costs per kWh and shall be applied to the subsequent twelve months. The annual true-up will be effective on billings beginning the first of the month following Commission approval of the true-up, or as ordered by the Commission. In years when the over- or under-recovery amount is small (resulting in a true-up rate rounded to less than 0.001¢), the true-up balance will carry over to the next year's true-up.

The annual true-up rate for each class shall be calculated as follows. The over- or under-recovery amount as shown in the current year Annual Automatic Adjustment True-up report will be divided by the forecasted Minnesota Kilowatt-Hours subject to the fuel adjustment clause for the proposed twelve-month recovery period the true-up rate will be in effect and then multiplied by the applicable EAF ratio. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each class that will be applied to Customers' bills in the same manner as the monthly cost of energy adjustment.

This annual true-up for 2025 is being filed on or before March 1, 2026. Any remaining balances associated with the prior recovery period annual true-up filings (and supplemental true-up filings) are included as part of the true-up rate requested in this filing per Ordering point 10 of the June 12, 2019 Order in Docket E999/CI-03-802.

VI. ANNUAL COMPLIANCE/REPORTING REQUIREMENTS

In Appendix A, Otter Tail Power provides annual reporting requirements specified in the Rule sections described below to satisfy compliance obligations stemming from either these Rules or prior Commission Orders. Rule variances for these rules were approved by the Commission Order dated June 12, 2019, in Docket No. E999/CI-03-802.

A. 7825.2810 Annual Report of Automatic Adjustment of Charges

Appendix A, Section 2 contains a summary of the annual reporting (by month) of all actual electric automatic adjustment charges for the prior year of January 1 to December 31, 2025. It includes the following:

Appendix A, Section 2.1	Subpt. 1.A. Commission Approved Base Cost of Fuel
Appendix A, Section 2.2	Subpt. 1.B. Billing Adjustment Amounts Charged Customers for Each Type of Energy Cost
Appendix A, Section 2.3	Subpt. 1.D. Total Cost of Fuel Delivered to Customers
Appendix A, Section 2.4	Subpt. 1.E. Revenue Collected from Customer for Energy Delivered
Appendix A, Section 2.5	Subpt. 1.G. The Amount of Refunds

B. 7825.2820 Annual Auditor's Report

Appendix B contains the Independent Accountants' Report for the period of January 1 to December 31, 2025.

C. 7825.2830 Annual Five-Year Projection

Otter Tail Power submitted its Five-Year Projection as part of its 2026 Forecasted FCA rates filing submitted May 1, 2024, in Docket No. E017/AA-25-65.

D. 7825.2840 Notice of Reports Availability

Appendix C contains the Notice of Reports Availability, Certificate of Service, and Service Lists.

E. Additional Reporting Requirements

Appendix D, Section 1	Passing MISO Day 2 Costs Through Fuel Clause Order Docket No. E017/M-05-284
Appendix D, Section 2	Wind Curtailment Summary Docket No. E017/M-03-970 and Docket No. E,G999/AA-06-1208
Appendix D, Section 3	Use of Virtual Transactions for Retail and Generation Maintenance Expenses Docket No. E,G999/AA-06-1208
Appendix D, Section 4	MISO Day 2 Charges Docket No. E,G999/AA-07-1130
Appendix D, Section 5	MISO Ancillary Services Market Docket No. E017/M-08-528
Appendix D, Section 6	Contingency Plans to Mitigate Against the Risk of Delays or Lack of Performance when Contractors Perform Poorly Contractors Docket No. E999/AA-08-995

Appendix D, Section 7	Offsetting Revenues or Compensation, Identification of Forced Outages and Planned Outages, Congestion and Firm Transmission Rights Docket No. E999/AA-09-961 and E999/AA-10-884
Appendix D, Section 8	Selected Option for Financial Transmission Rights and ARRs Docket No. E999/AA-14-579
Appendix D, Section 9	Discussion of ARR Nomination and FTR Conversion Strategies and List of Strategies Considered and Implemented to Address Congestion and Curtailment of Energy Docket No. E017/AA-23-181

F. Annual Self-Commitment and Self Scheduling Report

Appendix E contains the 2025 Self-Commitment and Self Scheduling Report.

VII. CONCLUSION

Otter Tail Power's fuel clause expenses for 2025 were lower than forecasted resulting in over-collections throughout much of the year. In response to materially different market conditions that emerged early in 2025 and continued into the fall, the Company proactively implemented rate adjustments for the periods September through December 2025 and January through April 2026. These timely adjustments mitigated the potential for a larger over-collection balance at year-end.

Although actual costs in December 2025 were higher than forecast, the early refund measures already implemented result in an under collection for the 2025 calendar year. Otter Tail Power's actual costs for 2025 were reasonable and prudent reflecting the operational and market conditions experienced throughout the year, as described in this filing. The Company respectfully requests Commission approval of the proposed true-up balance.

Otter Tail Power also requests approval of all reporting and compliance components of this Annual Automatic Adjustment of Charges Report, as required under applicable rules and prior Commission orders.

Dated: February 27, 2026

Respectfully submitted,

OTTER TAIL POWER COMPANY

By: /s/ *AMBER GRENIER*

Amber Grenier

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OTTER TAIL POWER COMPANY
FUEL CLAUSE ADJUSTMENT FORECAST PETITION ATTACHMENTS

Attachment 1	True-Up for kWh Subject to Energy Adjustment
Attachment 2	Forecast to Actual by Category
Attachment 3	Forecast to Actual Detail by Month with Variance (Not Public)
Attachment 4	Energy Adjustment Rider Rate Schedule/ Notice of Annual FCA True-Up
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Attachment 6	Energy Costs by Primary Energy Source
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Attachment 8	MISO Module E
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OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
True-up for kWh Subject to Energy Adjustment Rider (EAR)
Annual True-up Period January through December

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	Description	January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25	2025 Year End
1	Total System Sales (kWh)	602,284,529	589,770,866	533,208,522	506,015,599	442,130,258	435,216,071	459,046,318	460,094,059	463,456,819	428,629,031	473,057,393	527,223,809	5,920,133,274
2	Total System Energy Cost	\$ 17,030,492	\$ 14,016,294	\$ 10,541,716	\$ 7,880,698	\$ 7,273,901	\$ 11,885,082	\$ 8,684,774	\$ 6,608,830	\$ 7,131,027	\$ 6,797,770	\$ 9,397,071	\$ 19,958,708	\$ 127,206,362
3	MN kWh Sales Subject to Energy Adjustment Rider (EAR)	281,790,149	275,665,229	238,419,928	235,499,832	215,161,537	211,367,002	226,854,329	229,644,117	216,384,071	203,633,936	221,261,461	240,997,683	2,796,679,274
4	MN FCA Revenue excluding true-up(s) (Line 22 - Line 11 - Line 15)	\$ 7,883,271	\$ 7,640,349	\$ 6,566,343	\$ 5,474,431	\$ 5,210,656	\$ 4,815,961	\$ 3,119,795	\$ 4,423,557	\$ 5,052,293	\$ 4,382,487	\$ 4,980,612	\$ 6,052,457	\$ 65,602,211
5	True-up Year	2023	2023	2023	2023	2023	2023	2023	2023	2024	2024	2024	2024	
6	Annual True-up Rate	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ 0.000300	\$ 0.000300	\$ 0.000300	\$ 0.000300	
7	Annual True-up	\$ (563,580)	\$ (551,330)	\$ (476,840)	\$ (471,000)	\$ (430,323)	\$ (422,734)	\$ (453,709)	\$ (459,288)	\$ 64,915	\$ 61,090	\$ 66,378	\$ 72,299	\$ (3,564,121)
8	True-up Year	2024	2024	2024	2024	2024	2024							
9	Provisional Refund Rate	\$ (0.007200)	\$ (0.007200)	\$ (0.007200)	\$ (0.007200)	\$ (0.007200)	\$ (0.007200)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
10	Provisional Refund	\$ (2,028,889)	\$ (1,984,790)	\$ (1,716,623)	\$ (1,695,599)	\$ (1,549,163)	\$ (1,521,842)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (10,496,906)
11	True-up Year	2025	2025	2025	2025	2025	2025							
12	Provisional Refund Rate	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.005900)	\$ (0.005900)	\$ (0.005900)	\$ (0.005900)	
13	Provisional Refund	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (1,276,666)	\$ (1,201,440)	\$ (1,305,443)	\$ (1,421,886)	\$ (5,205,435)
14	Total Minnesota EAR Revenue Collection	\$ 5,290,802	\$ 5,104,229	\$ 4,372,880	\$ 3,307,832	\$ 3,231,170	\$ 2,871,384	\$ 2,666,086	\$ 3,964,269	\$ 3,840,542	\$ 3,242,137	\$ 3,741,548	\$ 4,702,870	\$ 46,335,748
15	2023 FCA Forecast / True Up (Docket No E017/AA-22-214) Approved 2023 True-up Amount - Over/(Under) Collection Amount Collected/(Refunded) September 2023 - August 2024 Amount Collected/(Refunded) January 2024 - December 2024 Amount Collected/(Refunded) January 2025 - August 2025 2023 Balance of Over/(Under) Collection											MN FCA Revenue (Line 7)	\$ 65,602,211	
16												Actual Energy Cost	\$ 60,092,464	
17												Over/(Under) Recovery for 2025	\$ 5,509,747	
18												Over/(Under) Balance for 2023	\$ (807,136)	
19												Collected Over/(Under) Balance for 2024	\$ (906,855)	
20												Projected Remaining Over/(Under) Balance for 2024	\$ 548,767	
21												Amount Collected/(Refunded) for 2025 from Supplemental Filings	\$ (5,205,435)	
22												Projected Amount Collected/(Refunded) for 2025 from Supplemental Filings	\$ (2,858,231)	
23												Net Over/(Under) Recovery	\$ (3,719,144)	
24												September 2026 - August 2027 kWh	2,761,945,088	
25	2024 FCA Forecast / True Up (Docket No E017/AA-23-181) Over/(Under) Recovery for 2024 Amount Collected/(Refunded) July 2024 - December 2024 Amount Collected/(Refunded) January 2025 - August 2025 Amount Collected/(Refunded) September 2025 - December 2025 Projected Amount Collected/(Refunded) January 2026 - August 2026 2024 Balance of Over/(Under) Collection											Annual True-up Factor		\$ (0.001300)
26														
27														
28														
29														
30														
31														
32														
33														
34														
35	2025 FCA Forecast / True Up (Docket No E017/AA-24-65) Over/(Under) Recovery for 2025 Amount Collected/(Refunded) September 2025 - December 2025 Projected Amount Collected/(Refunded) January 2026 - August 2026 2025 Projected Balance of Over/(Under) Collection													
36														
37														
38														
39														
40														
41														
42														
43														

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
COST OF ENERGY CALCULATION

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.		FORECASTED COSTS													Year End Total
		January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25		
1	Plant Generation	\$ 7,937,031	\$ 5,767,222	\$ 4,945,425	\$ 2,718,426	\$ 2,677,236	\$ 5,060,461	\$ 8,352,822	\$ 7,930,418	\$ 5,207,405	\$ 4,678,563	\$ 5,685,885	\$ 6,970,888	\$ 67,931,783	
2	Wholesale Market Charges	\$ (1,615,793)	\$ (1,270,395)	\$ (1,112,763)	\$ (742,475)	\$ (722,917)	\$ (1,207,406)	\$ (1,015,817)	\$ (1,047,762)	\$ (889,843)	\$ (884,425)	\$ (957,587)	\$ (1,126,193)	\$ (12,593,377)	
3	Purchased Power	\$ 11,795,627	\$ 11,007,991	\$ 8,430,639	\$ 9,716,285	\$ 8,696,267	\$ 6,183,907	\$ 4,168,752	\$ 4,179,648	\$ 6,277,254	\$ 6,616,896	\$ 7,782,501	\$ 11,274,678	\$ 96,130,445	
4	Wind Curtailment	\$ (2,273)	\$ (1,739)	\$ 19,907	\$ 3,354	\$ 19,240	\$ 42,165	\$ 10,958	\$ (8,199)	\$ 819	\$ 25,136	\$ 11,356	\$ 6,995	\$ 127,718	
5	Fuel costs of Asset-Based Sales	\$ (749,893)	\$ (30,982)	\$ (36,986)	\$ (25,936)	\$ (20,823)	\$ (468,814)	\$ (783,337)	\$ (557,404)	\$ (397,426)	\$ (161,884)	\$ (72,412)	\$ (272,883)	\$ (3,578,780)	
6	MISO ASM	\$ (83,106)	\$ (5,455)	\$ (29,868)	\$ (44,363)	\$ (63,896)	\$ (80,545)	\$ (108,381)	\$ (11,307)	\$ (101,317)	\$ 9,654	\$ (26,411)	\$ 70,500	\$ (474,493)	
7	Asset-Based Margins	\$ (1,187,587)	\$ (26,327)	\$ (40,117)	\$ (14,579)	\$ (21,727)	\$ (591,857)	\$ (1,128,821)	\$ (721,094)	\$ (456,183)	\$ (168,099)	\$ (84,987)	\$ (424,262)	\$ (4,865,641)	
8	Hoot Lake Solar Generation Credit	\$ (172,659)	\$ (237,314)	\$ (338,811)	\$ (361,014)	\$ (401,656)	\$ (403,177)	\$ (556,580)	\$ (408,260)	\$ (360,012)	\$ (218,094)	\$ (147,757)	\$ (131,274)	\$ (3,736,608)	
9	Steam Plant Reagents	\$ 342,259	\$ 341,542	\$ 278,164	\$ 82,404	\$ 106,224	\$ 224,003	\$ 331,233	\$ 337,012	\$ 237,230	\$ 173,385	\$ 300,288	\$ 345,136	\$ 3,098,881	
10	Steam and Water Sales: Net Margin	\$ (104,055)	\$ (99,700)	\$ (129,220)	\$ (91,541)	\$ (96,739)	\$ (97,674)	\$ (139,790)	\$ (138,027)	\$ (88,698)	\$ (49,480)	\$ (125,612)	\$ (104,055)	\$ (1,264,591)	
11	MISO Planning Resource Auction Results	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	
12															
13	Fuel Costs and Purchase Power for System Use	\$ 16,159,551	\$ 15,444,844	\$ 11,986,371	\$ 11,240,560	\$ 10,171,210	\$ 8,661,062	\$ 9,131,039	\$ 9,555,026	\$ 9,429,229	\$ 10,021,653	\$ 12,365,264	\$ 16,609,529	\$ 140,775,337	
14		-	-	-	-	-	-	-	-	-	-	-	-	-	
15															
16	Energy for System Use (kWh)	595,596,123	546,423,644	526,495,043	465,141,417	439,648,648	431,882,951	455,028,148	451,076,646	423,712,379	459,000,219	515,733,969	575,638,690	5,885,377,876	
17															
18															
19	Approved Forecast Cost per kWh	\$ 0.027132	\$ 0.028265	\$ 0.022766	\$ 0.024166	\$ 0.023135	\$ 0.020054	\$ 0.020067	\$ 0.021183	\$ 0.022254	\$ 0.021834	\$ 0.023976	\$ 0.028854	\$ 0.023920	
20															
21	2023 True-up Rate	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ (0.002000)	\$ -	\$ -	\$ -	\$ -		
22	2024 Provisional Refund Rate	\$ (0.007200)	\$ (0.007200)	\$ (0.007200)	\$ (0.007200)	\$ (0.007200)	\$ (0.007200)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -		
23	2024 True-up Rate	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.000300	\$ 0.000300	\$ 0.000300	\$ 0.000300		
24	2025 Provisional Refund Rate	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.005900)	\$ (0.005900)	\$ (0.005900)	\$ (0.005900)		
25	EAR Rate With Approved True Up and Refunds	\$ 0.017932	\$ 0.019065	\$ 0.013566	\$ 0.014966	\$ 0.013935	\$ 0.010854	\$ 0.018067	\$ 0.019183	\$ 0.016654	\$ 0.016234	\$ 0.018376	\$ 0.023254		

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)												
Line No.		ACTUAL COSTS													Year End Total												
		January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25														
1	Plant Generation	\$	5,306,732	\$	4,780,496	\$	4,234,039	\$	2,760,020	\$	3,149,091	\$	10,382,899	\$	10,969,031	\$	7,934,144	\$	6,538,465	\$	4,803,549	\$	7,411,149	\$	6,777,951	\$	75,047,565
2	Wholesale Market Charges	\$	(801,661)	\$	381,127	\$	73,290	\$	(862,481)	\$	(956,824)	\$	(794,242)	\$	137,321	\$	(19,030)	\$	(1,915,605)	\$	(7,748,295)	\$	(3,540,132)	\$	(4,962,096)	\$	(21,008,627)
3	Purchased Power	\$	12,622,848	\$	10,104,823	\$	7,043,760	\$	7,002,109	\$	6,324,114	\$	5,646,964	\$	5,155,948	\$	4,236,993	\$	5,516,944	\$	12,236,896	\$	7,145,370	\$	19,372,446	\$	102,409,214
4	Wind Curtailment	\$	(21,031)	\$	1,198	\$	9,876	\$	1,619	\$	10,898	\$	25,660	\$	(1,061)	\$	(3,629)	\$	(742)	\$	13,535	\$	16,080	\$	(10,808)	\$	41,596
5	Fuel costs of Asset-Based Sales	\$	383,527	\$	(728,806)	\$	(601,568)	\$	(535,736)	\$	(718,962)	\$	(1,258,198)	\$	(2,549,053)	\$	(1,753,188)	\$	(1,461,815)	\$	(972,665)	\$	(1,179,773)	\$	(1,114,359)	\$	(12,488,597)
6	MISO ASM	\$	(343,498)	\$	(266,143)	\$	(139,916)	\$	-786	\$	(117,761)	\$	(139,327)	\$	(359,452)	\$	(418,707)	\$	(153,884)	\$	(259,288)	\$	(234,179)	\$	(142,751)	\$	(2,572,319)
7	Asset Based Margins	\$	(252,408)	\$	(352,477)	\$	(4,870)	\$	(198,168)	\$	(83,451)	\$	(376,628)	\$	(2,339,456)	\$	(963,955)	\$	(573,413)	\$	(871,023)	\$	(345,740)	\$	(571,521)	\$	(6,933,113)
8	Hoot Lake Solar Generation Credit	\$	(140,751)	\$	(116,073)	\$	(195,528)	\$	(243,008)	\$	(264,456)	\$	(330,035)	\$	(598,363)	\$	(663,960)	\$	(450,612)	\$	(451,215)	\$	(193,618)	\$	(95,684)	\$	(3,743,304)
9	Steam Plant Reagents	\$	394,795	\$	338,274	\$	269,000	\$	109,859	\$	105,300	\$	363,685	\$	529,282	\$	349,612	\$	304,969	\$	262,755	\$	449,628	\$	423,445	\$	3,900,605
10	Steam and Water Sales: Net Margin	\$	(118,060)	\$	(118,051)	\$	(82,100)	\$	(74,837)	\$	(95,379)	\$	(112,403)	\$	(118,440)	\$	(112,208)	\$	(96,631)	\$	(53,081)	\$	(97,881)	\$	(115,243)	\$	(1,194,314)
11	MISO Planning Resource Auction Results	\$	-	\$	(10,075)	\$	(64,266)	\$	(81,465)	\$	(78,669)	\$	(1,523,294)	\$	(2,140,783)	\$	(1,977,242)	\$	(576,649)	\$	(163,398)	\$	(33,833)	\$	397,328	\$	(6,252,344)
12																											
13	Fuel Costs and Purchase Power for System Use	\$	17,030,492	\$	14,016,294	\$	10,541,716	\$	7,880,698	\$	7,273,901	\$	11,885,082	\$	8,684,774	\$	6,608,830	\$	7,131,027	\$	6,797,770	\$	9,397,071	\$	19,958,708	\$	127,206,362
14			-		-		-		-		-		-		-		-		-		-		-		-		-
15																											
16	Energy for System Use (kWh)		602,284,529		589,770,866		533,208,522		506,015,599		442,130,258		435,216,071		459,046,318		460,094,059		463,456,819		428,629,031		473,057,393		527,223,809		5,920,133,274
17																											
18																											
19	Actual Cost per kWh	\$	0.028276	\$	0.023766	\$	0.019770	\$	0.015574	\$	0.016452	\$	0.027308	\$	0.018919	\$	0.014364	\$	0.015387	\$	0.015859	\$	0.019865	\$	0.037856	\$	0.021487

(1) Includes PPAs, shared loads, Bilateral purchases, MISO and SPP Market purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		January 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 5,441,054	\$ 4,258,935	\$ (1,182,119)	-21.73%	217,742	171,123	(46,619)	-21.41%	\$ 24.99	\$ 24.89
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	122,906	135,946	13,040	10.61%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,699	775	(924)	-54.36%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ 21,752	\$ 6,020	\$ (15,732)	-72.33%	83	-	(83)	-100.00%	\$ 262.07	\$ -
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 2,474,225	\$ 1,041,777	\$ (1,432,449)	-57.89%	70,547	21,970	(48,578)	-68.86%	\$ 35.07	\$ 47.42
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	3,101	3,595	494	15.95%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 7,937,031	\$ 5,306,732	\$ (2,630,299)	-33.14%	416,079	333,410	(82,669)	-19.87%	\$ 19.08	\$ 15.92
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (388,069)	\$ (778,267)	\$ (390,198)	100.55%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 735,943	\$ 1,324,175	\$ 588,232	79.93%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 44,342	\$ 149,927	\$ 105,585	238.11%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 74,914	\$ 86,587	\$ 11,673	15.58%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 8,518	\$ 10,957	\$ 2,438	28.63%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 1,312	\$ 2,096	\$ 784	59.74%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 2,501,918	\$ 439,642	\$ (2,062,277)	-82.43%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 293,472	\$ 274,887	\$ (18,585)	-6.33%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (3,781,124)	\$ (844,923)	\$ 2,936,201	-77.65%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (90,468)	\$ (52,369)	\$ 38,099	-42.11%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ (312,193)	\$ (241,774)	\$ 70,420	-22.56%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ 217,668	\$ 232,957	\$ 15,288	7.02%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ (245,430)	\$ (47,079)	\$ 198,351	-80.82%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 5,401,650	\$ 3,172,567	\$ (2,229,083)	-41.27%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,551,558)	\$ (3,196,807)	\$ 2,354,752	-42.42%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 8,627	\$ 13,564	\$ 4,936	57.21%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (158,203)	\$ (204,339)	\$ (46,136)	29.16%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 15,706	\$ 17,029	\$ 1,323	8.42%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ -	\$ (47)	\$ (47)	0.00%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		January 2025									
		Expense (Revenue)			MWh			Cost per MWh			
		Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 9,382	\$ (18,905)	-66.83%	-	0.00%	\$ -	\$ -		
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%	-	0.00%	\$ -	\$ -		
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (24,599)	\$ 29,505	-54.53%	-	0.00%	\$ -	\$ -		
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 236,085	\$ 107,629	83.79%	-	0.00%	\$ -	\$ -		
79	555.25 RT Misc Amount	\$ (20,051)	\$ (3,315)	\$ 16,736	-83.46%	-	0.00%	\$ -	\$ -		
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ (69,163)	\$ (69,274)	-61990.54%	-	0.00%	\$ -	\$ -		
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 1,459	\$ 7,673	\$ 6,214	426.04%	-	0.00%	\$ -	\$ -		
83	555.63 DA Ramp Product	\$ (274)	\$ (8,058)	\$ (7,784)	2837.24%	-	0.00%	\$ -	\$ -		
84	555.64 RT Ramp Product	\$ (28)	\$ (1,263)	\$ (1,235)	4438.81%	-	0.00%	\$ -	\$ -		
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 21,159	\$ (878)	-3.99%	-	0.00%	\$ -	\$ -		
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ (973,035)	\$ (973,035)	0.00%	-	0.00%	\$ -	\$ -		
93											
94	Total MISO Wholesale Market Charges	\$ (1,397,504)	\$ (545,992)	\$ 866,407	-62.00%	-	0.00%	\$ -	\$ -		
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ -	\$ (1,092)	-100.00%	-	0.00%	\$ -	\$ -		
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ -	\$ (244)	-100.00%	-	0.00%	\$ -	\$ -		
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ -	\$ (16)	-100.00%	-	0.00%	\$ -	\$ -		
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ -	\$ (59)	-100.00%	-	0.00%	\$ -	\$ -		
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ -	\$ (72)	-100.00%	-	0.00%	\$ -	\$ -		
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ -	\$ (11)	-100.00%	-	0.00%	\$ -	\$ -		
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	0.00%	\$ -	\$ -		
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (19,919)	\$ (20,927)	\$ (1,009)	5.06%	-	0.00%	\$ -	\$ -		
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ -	\$ (3)	-100.00%	-	0.00%	\$ -	\$ -		
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	0.00%	\$ -	\$ -		
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	0.00%	\$ -	\$ -		
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
116	555.20 RT Pseudo Tie Congestion Amount	\$ (39,627)	\$ (242,234)	\$ (202,606)	511.28%	-	0.00%	\$ -	\$ -		
117	555.21 RT Pseudo Tie Loss Amount	\$ (14,971)	\$ 7,492	\$ 22,463	-150.04%	-	0.00%	\$ -	\$ -		
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%	-	0.00%	\$ -	\$ -		
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ -	\$ (0)	-100.00%	-	0.00%	\$ -	\$ -		
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ -	\$ (7)	-100.00%	-	0.00%	\$ -	\$ -		
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ -	\$ (35)	-100.00%	-	0.00%	\$ -	\$ -		
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ -	\$ (36)	-100.00%	-	0.00%	\$ -	\$ -		
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	0.00%	\$ -	\$ -		
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
128	555.36 ARR_Auction Transaction AO Amount	\$ (145,367)	\$ -	\$ 145,367	-100.00%	-	0.00%	\$ -	\$ -		
129	555.37 RT URD Distribution AO Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ -	\$ (26)	-100.00%	-	0.00%	\$ -	\$ -		
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ (0)	\$ -	\$ 0	-100.00%	-	0.00%	\$ -	\$ -		
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
133											
134	Total SPP Wholesale Market Charges	\$ (218,289)	\$ (255,669)	\$ (37,380)	17.12%	-	0.00%	\$ -	\$ -		
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (16,203)	\$ (110,524)	\$ (94,321)	582.11%	-	0.00%	\$ -	\$ -		
138	DA ASM Spinning Reserve Amount	\$ (2,321)	\$ (16,760)	\$ (14,439)	622.01%	-	0.00%	\$ -	\$ -		
139	DA ASM Short-Term Reserve Amount	\$ (122,191)	\$ (57,579)	\$ 64,612	-52.88%	-	0.00%	\$ -	\$ -		
140	DA ASM Supplemental Reserve Amount	\$ (18,339)	\$ (391,405)	\$ (373,066)	2034.30%	-	0.00%	\$ -	\$ -		
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%	-	0.00%	\$ -	\$ -		
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 15,819	\$ 11,890	302.63%	-	0.00%	\$ -	\$ -		
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 7,763	\$ 6,324	439.46%	-	0.00%	\$ -	\$ -		
144	RT ASM Net Regulation Adjustment Amount	\$ (13,267)	\$ (57,866)	\$ (44,599)	336.17%	-	0.00%	\$ -	\$ -		
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 17,466	\$ 38,108	\$ 20,642	118.19%	-	0.00%	\$ -	\$ -		
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (3,487)	\$ (2,191)	\$ 1,296	-37.17%	-	0.00%	\$ -	\$ -		
147	RT ASM Regulation Cost Distribution Amount	\$ 16,341	\$ 20,665	\$ 4,324	26.46%	-	0.00%	\$ -	\$ -		
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ 649	\$ 12,795	\$ 12,146	1871.40%	-	0.00%	\$ -	\$ -		
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 42,671	\$ 182,204	\$ 139,533	327.00%	-	0.00%	\$ -	\$ -		
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		January 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 4,230	\$ 12,663	\$ 8,433	199.39%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 2,595	\$ 2,810	\$ 216	8.31%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (83,106)	\$ (343,498)	\$ (260,392)	313.33%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (1,698,898)	\$ (1,145,159)	\$ 553,740	-32.59%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 11,795,627	\$ 12,622,848	\$ 827,221	7.01%	219,536	283,263	63,727	29.03%	\$ 53.73	\$ 44.56
172											
173	Wind Curtailment	\$ (2,273)	\$ (21,031)	\$ (18,758)	825.18%		(536)	(536)	0.00%	\$ -	\$ 39.22
174											
175	Asset Based Sales	\$ (1,937,481)	\$ 131,119	\$ 2,068,599	-106.77%	(27,238)	(17,252)	9,986	-36.66%	\$ 71.13	\$ (7.60)
176	Fuel Costs	\$ 749,893	\$ (383,527)	\$ (1,133,420)	-151.14%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (1,187,587)	\$ (252,408)	\$ 935,179	-78.75%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (172,659)	\$ (140,751)	\$ 31,908	-18.48%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 342,259	\$ 394,795	\$ 52,535	15.35%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (104,055)	\$ (118,060)	\$ (14,005)	13.46%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 16,159,551	\$ 17,030,492	\$ 870,941	5.39%	608,377	598,884	(9,493)	-1.56%	\$ 26.56	\$ 28.44

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)										
		February 2025										
		Expense (Revenue)				MWh				Cost per MWh		
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual	
1	Plant Generation											
2	Coal	[PROTECTED DATA BEGINS...										
3	Big Stone											
4	Coyote											
5										...PROTECTED DATA ENDS]		
6	Total Coal	\$ 5,573,862	\$ 4,014,885	\$ (1,558,977)	-27.97%	214,599	155,741	(58,858)	-27.43%	\$ 25.97	\$ 25.78	
7												
8	Wind	[PROTECTED DATA BEGINS...										
9	Langdon Wind											
10	Ashtabula Wind											
11	Ashtabula III											
12	Luverne Wind											
13	Merricourt											
14										...PROTECTED DATA ENDS]		
15	Total Wind	\$ -	\$ -	\$ -	0.00%	121,564	111,634	(9,930)	-8.17%	\$ -	\$ -	
16												
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,534	487	(1,047)	-68.22%	\$ -	\$ -	
18												
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...										
20	Jamestown 1											
21	Jamestown 2											
22	Lake Preston											
23										...PROTECTED DATA ENDS]		
24	Total Oil - Peaking Units	\$ -	\$ 8,785	\$ 8,785	0.00%	-	-	-	0.00%	\$ -	\$ -	
25												
26	Natural Gas	[PROTECTED DATA BEGINS...										
27	Solway											
28	Astoria											
29										...PROTECTED DATA ENDS]		
30	Total Natural Gas	\$ 193,360	\$ 756,826	\$ 563,466	291.41%	2,437	14,493	12,056	494.71%	\$ 79.34	\$ 52.22	
31												
32	Solar	[PROTECTED DATA BEGINS...										
33	Blue Jay											
34	Blue Heron											
35	Hoot Lake											
36										...PROTECTED DATA ENDS]		
37	Total Solar	\$ -	\$ -	\$ -	0.00%	4,307	3,136	(1,171)	-27.18%	\$ -	\$ -	
38												
39	Total OTP-Owned	\$ 5,767,222	\$ 4,780,496	\$ (986,726)	-17.11%	344,441	285,492	(58,949)	-17.11%	\$ 16.74	\$ 16.74	
40												
41	Wholesale Market Charges											
42	MISO Wholesale Market Charges											
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
47	555.24 RT Distribution of Losses Amount	\$ (359,452)	\$ (357,367)	\$ 2,085	-0.58%	-	-	-	0.00%	\$ -	\$ -	
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
49	DA Loss Amount	\$ 681,673	\$ 1,183,091	\$ 501,418	73.56%	-	-	-	0.00%	\$ -	\$ -	
50	RT Loss Amount	\$ 41,072	\$ 121,520	\$ 80,447	195.87%	-	-	-	0.00%	\$ -	\$ -	
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
55	555.01 DA Mkt Admin Amount	\$ 87,588	\$ 96,276	\$ 8,688	9.92%	-	-	-	0.00%	\$ -	\$ -	
56	555.18 RT Mkt Admin Amount	\$ 12,001	\$ 10,773	\$ (1,228)	-10.23%	-	-	-	0.00%	\$ -	\$ -	
57	555.13 FTR Mkt Admin Amount	\$ 1,702	\$ 1,607	\$ (94)	-5.54%	-	-	-	0.00%	\$ -	\$ -	
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
59	DA Congestion	\$ 2,317,421	\$ 616,619	\$ (1,700,803)	-73.39%	-	-	-	0.00%	\$ -	\$ -	
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
61	RT Congestion	\$ 271,831	\$ 129,828	\$ (142,002)	-52.24%	-	-	-	0.00%	\$ -	\$ -	
62	555.14 FTR Hourly Allocation Amount	\$ (3,502,296)	\$ (969,909)	\$ 2,532,387	-72.31%	-	-	-	0.00%	\$ -	\$ -	
63	555.15 FTR Monthly Allocation Amount	\$ (83,797)	\$ (44,466)	\$ 39,330	-46.94%	-	-	-	0.00%	\$ -	\$ -	
64	555.17 FTR Yearly Allocation Amount	\$ 0	\$ -	\$ (0)	-100.00%	-	-	-	0.00%	\$ -	\$ -	
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
66	555.36 FTR Full Funding Guarantee Amount	\$ (7,533)	\$ 18,583	\$ 26,116	-346.68%	-	-	-	0.00%	\$ -	\$ -	
67	555.37 FTR Guarantee Uplift Amount	\$ (11,112)	\$ (24,051)	\$ (12,939)	116.44%	-	-	-	0.00%	\$ -	\$ -	
68	555.38 FTR Annual Transaction Amount	\$ 5,401,650	\$ 3,172,567	\$ (2,229,083)	-41.27%	-	-	-	0.00%	\$ -	\$ -	
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,551,558)	\$ (3,196,807)	\$ 2,354,752	-42.42%	-	-	-	0.00%	\$ -	\$ -	
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 8,627	\$ 13,561	\$ 4,934	57.19%	-	-	-	0.00%	\$ -	\$ -	
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (158,203)	\$ (204,327)	\$ (46,124)	29.16%	-	-	-	0.00%	\$ -	\$ -	
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -	
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 11,430	\$ 18,597	\$ 7,167	62.71%	-	-	-	0.00%	\$ -	\$ -	
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (2,949)	\$ (1,507)	\$ 1,441	-48.88%	-	-	-	0.00%	\$ -	\$ -	

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		February 2025									
		Expense (Revenue)			MWh			Cost per MWh			
		Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 9,997	\$ (18,290)	-64.66%	-	0.00%	\$ -	\$ -		
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%	-	0.00%	\$ -	\$ -		
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (27,801)	\$ 26,302	-48.61%	-	0.00%	\$ -	\$ -		
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 43,494	\$ (84,962)	-66.14%	-	0.00%	\$ -	\$ -		
79	555.25 RT Misc Amount	\$ (20,051)	\$ (0)	\$ 20,051	-100.00%	-	0.00%	\$ -	\$ -		
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ 3,549	\$ 3,437	3075.39%	-	0.00%	\$ -	\$ -		
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 2,641	\$ 16,533	\$ 13,892	525.97%	-	0.00%	\$ -	\$ -		
83	555.63 DA Ramp Product	\$ (1,572)	\$ (9,859)	\$ (8,288)	527.37%	-	0.00%	\$ -	\$ -		
84	555.64 RT Ramp Product	\$ (547)	\$ (182)	\$ 365	-66.75%	-	0.00%	\$ -	\$ -		
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 39,515	\$ 17,477	79.31%	-	0.00%	\$ -	\$ -		
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ (16,283)	\$ (16,283)	0.00%	-	0.00%	\$ -	\$ -		
93											
94	Total MISO Wholesale Market Charges	\$ (1,033,614)	\$ 534,893	\$ 1,575,873	-152.46%	-	0.00%	\$ -	\$ -		
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ -	\$ (1,092)	-100.00%	-	0.00%	\$ -	\$ -		
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ -	\$ (244)	-100.00%	-	0.00%	\$ -	\$ -		
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ -	\$ (16)	-100.00%	-	0.00%	\$ -	\$ -		
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ -	\$ (59)	-100.00%	-	0.00%	\$ -	\$ -		
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ -	\$ (72)	-100.00%	-	0.00%	\$ -	\$ -		
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ -	\$ (11)	-100.00%	-	0.00%	\$ -	\$ -		
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	0.00%	\$ -	\$ -		
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (18,450)	\$ (16,677)	\$ 1,772	-9.61%	-	0.00%	\$ -	\$ -		
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ -	\$ (3)	-100.00%	-	0.00%	\$ -	\$ -		
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	0.00%	\$ -	\$ -		
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	0.00%	\$ -	\$ -		
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
116	555.20 RT Pseudo Tie Congestion Amount	\$ (36,705)	\$ (149,740)	\$ (113,035)	307.95%	-	0.00%	\$ -	\$ -		
117	555.21 RT Pseudo Tie Loss Amount	\$ (13,867)	\$ 12,651	\$ 26,518	-191.23%	-	0.00%	\$ -	\$ -		
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%	-	0.00%	\$ -	\$ -		
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ -	\$ (0)	-100.00%	-	0.00%	\$ -	\$ -		
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ -	\$ (7)	-100.00%	-	0.00%	\$ -	\$ -		
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ -	\$ (35)	-100.00%	-	0.00%	\$ -	\$ -		
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ -	\$ (36)	-100.00%	-	0.00%	\$ -	\$ -		
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	0.00%	\$ -	\$ -		
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
128	555.36 ARR_Auction Transaction AO Amount	\$ (169,354)	\$ -	\$ 169,354	-100.00%	-	0.00%	\$ -	\$ -		
129	555.37 RT URD Distribution AO Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ -	\$ (26)	-100.00%	-	0.00%	\$ -	\$ -		
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ (0)	\$ -	\$ 0	-100.00%	-	0.00%	\$ -	\$ -		
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
133											
134	Total SPP Wholesale Market Charges	\$ (236,781)	\$ (153,766)	\$ 83,015	-35.06%	-	0.00%	\$ -	\$ -		
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (23,100)	\$ (87,328)	\$ (64,228)	278.04%	-	0.00%	\$ -	\$ -		
138	DA ASM Spinning Reserve Amount	\$ (8,272)	\$ (23,499)	\$ (15,226)	184.06%	-	0.00%	\$ -	\$ -		
139	DA ASM Short-Term Reserve Amount	\$ (3,406)	\$ (196,079)	\$ (192,673)	5656.68%	-	0.00%	\$ -	\$ -		
140	DA ASM Supplemental Reserve Amount	\$ (3,401)	\$ (132,484)	\$ (129,083)	3795.36%	-	0.00%	\$ -	\$ -		
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%	-	0.00%	\$ -	\$ -		
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 8,902	\$ 4,973	126.57%	-	0.00%	\$ -	\$ -		
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 11,203	\$ 9,764	678.57%	-	0.00%	\$ -	\$ -		
144	RT ASM Net Regulation Adjustment Amount	\$ (13,522)	\$ (58,418)	\$ (44,896)	332.03%	-	0.00%	\$ -	\$ -		
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 18,806	\$ 36,159	\$ 17,353	92.28%	-	0.00%	\$ -	\$ -		
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (262)	\$ (2,721)	\$ (2,458)	936.66%	-	0.00%	\$ -	\$ -		
147	RT ASM Regulation Cost Distribution Amount	\$ 12,678	\$ 23,791	\$ 11,113	87.65%	-	0.00%	\$ -	\$ -		
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (413)	\$ 61,276	\$ 61,689	-14940.50%	-	0.00%	\$ -	\$ -		
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 3,002	\$ 78,008	\$ 75,006	2498.24%	-	0.00%	\$ -	\$ -		
150	RT ASM Short-Term Reserve Amount	\$ -	\$ 228	\$ 228	0.00%	-	0.00%	\$ -	\$ -		

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		February 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 1,549	\$ 10,502	\$ 8,953	578.05%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 2,136	\$ 4,317	\$ 2,180	102.05%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (5,455)	\$ (266,143)	\$ (260,688)	4779.29%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (1,275,850)	\$ 114,985	\$ 1,390,834	-109.01%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 11,007,991	\$ 10,104,823	\$ (903,168)	-8.20%	220,262	265,105	44,843	20.36%	\$ 49.98	\$ 38.12
172											
173	Wind Curtailment	\$ (1,739)	\$ 1,198	\$ 2,938	-168.89%		31	31	0.00%	\$ -	\$ 39.22
174											
175	Asset Based Sales	\$ (57,309)	\$ (1,079,284)	\$ (1,021,975)	1783.27%	(1,166)	(17,731)	(16,565)	1420.77%	\$ 49.15	\$ 60.87
176	Fuel Costs	\$ 30,982	\$ 726,806	\$ 695,824	2245.90%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (26,327)	\$ (352,477)	\$ (326,150)	1238.84%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (237,314)	\$ (116,073)	\$ 121,241	-51.09%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 341,542	\$ 338,274	\$ (3,268)	-0.96%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (99,700)	\$ (118,051)	\$ (18,351)	18.41%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (10,075)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 15,444,844	\$ 14,016,294	\$ (1,428,550)	-9.25%	563,537	532,897	(30,640)	-5.44%	\$ 27.41	\$ 26.30

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		March 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 4,390,246	\$ 3,706,591	\$ (683,655)	-15.57%	181,330	138,023	(43,306)	-23.88%	\$ 24.21	\$ 26.85
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	117,516	114,050	(3,465)	-2.95%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,699	850	(849)	-49.98%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 555,179	\$ 527,448	\$ (27,731)	-4.99%	17,166	10,360	(6,806)	-39.65%	\$ 32.34	\$ 50.91
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	7,694	7,813	119	1.55%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 4,945,425	\$ 4,234,039	\$ (711,386)	-14.38%	325,403	271,096	(54,307)	-16.69%	\$ 15.20	\$ 15.62
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (346,303)	\$ (58,101)	\$ 288,202	-83.22%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 656,736	\$ 725,463	\$ 68,726	10.46%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 39,570	\$ 54,921	\$ 15,351	38.80%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 72,459	\$ 78,214	\$ 5,755	7.94%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 10,862	\$ 9,364	\$ (1,498)	-13.79%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 1,349	\$ 1,511	\$ 162	12.00%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 2,232,647	\$ 531,444	\$ (1,701,203)	-76.20%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 261,887	\$ 141,235	\$ (120,652)	-46.07%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (3,374,177)	\$ (1,156,159)	\$ 2,218,019	-65.74%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (80,731)	\$ (9,350)	\$ 71,381	-88.42%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (164,934)	\$ (19,499)	\$ 145,436	-88.18%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 164,936	\$ 19,499	\$ (145,437)	-88.18%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 4,869,311	\$ 3,744,795	\$ (1,124,517)	-23.09%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,028,146)	\$ (3,768,316)	\$ 1,259,830	-25.06%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 21,712	\$ 17,077	\$ (4,635)	-21.35%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (169,360)	\$ (152,445)	\$ 16,915	-9.99%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 13,575	\$ 12,884	\$ (691)	-5.09%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (5,836)	\$ (8,435)	\$ (2,598)	-44.52%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

(A)		(B)		(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		Expense (Revenue)				March 2025						
		Forecast	Actual	Difference		Forecast	Actual	MWh Difference		Cost per MWh		
										Forecast	Actual	
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 6,866	\$ (21,421)	-75.73%			-	0.00%	\$ -	\$ -	
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%			-	0.00%	\$ -	\$ -	
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (18,124)	\$ 35,980	-66.50%			-	0.00%	\$ -	\$ -	
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 117,592	\$ (10,865)	-8.46%			-	0.00%	\$ -	\$ -	
79	555.25 RT Misc Amount	\$ (20,051)	\$ -	\$ 20,051	-100.00%			-	0.00%	\$ -	\$ -	
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ 63,073	\$ 62,962	56341.48%			-	0.00%	\$ -	\$ -	
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 3,162	\$ 6,583	\$ 3,421	108.18%			-	0.00%	\$ -	\$ -	
83	555.63 DA Ramp Product	\$ (5,418)	\$ (17,637)	\$ (12,220)	225.56%			-	0.00%	\$ -	\$ -	
84	555.64 RT Ramp Product	\$ (296)	\$ (1,805)	\$ (1,509)	509.94%			-	0.00%	\$ -	\$ -	
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 16,572	\$ (5,466)	-24.80%			-	0.00%	\$ -	\$ -	
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 1,844	\$ 1,844	0.00%			-	0.00%	\$ -	\$ -	
93												
94	Total MISO Wholesale Market Charges	\$ (1,002,607)	\$ 249,976	\$ 1,257,001	-125.37%			-	0.00%	\$ -	\$ -	
95												
96	SPP Wholesale Market Charges											
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ 0	\$ (1,092)	-99.98%			-	0.00%	\$ -	\$ -	
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ 1	\$ (243)	-99.65%			-	0.00%	\$ -	\$ -	
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ 0	\$ (16)	-99.94%			-	0.00%	\$ -	\$ -	
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ 0	\$ (58)	-99.91%			-	0.00%	\$ -	\$ -	
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ -	\$ (72)	-100.00%			-	0.00%	\$ -	\$ -	
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ 0	\$ (11)	-99.91%			-	0.00%	\$ -	\$ -	
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%			-	0.00%	\$ -	\$ -	
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (17,775)	\$ (9,312)	\$ 8,463	-47.61%			-	0.00%	\$ -	\$ -	
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ -	\$ (3)	-100.00%			-	0.00%	\$ -	\$ -	
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ -	\$ 2	-100.00%			-	0.00%	\$ -	\$ -	
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%			-	0.00%	\$ -	\$ -	
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%			-	0.00%	\$ -	\$ -	
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%			-	0.00%	\$ -	\$ -	
116	555.20 RT Pseudo Tie Congestion Amount	\$ (35,362)	\$ (161,875)	\$ (126,513)	357.76%			-	0.00%	\$ -	\$ -	
117	555.21 RT Pseudo Tie Loss Amount	\$ (13,360)	\$ (5,500)	\$ 7,859	-58.83%			-	0.00%	\$ -	\$ -	
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%			-	0.00%	\$ -	\$ -	
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ -	\$ (0)	-100.00%			-	0.00%	\$ -	\$ -	
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ 0	\$ (7)	-99.86%			-	0.00%	\$ -	\$ -	
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ 0	\$ (35)	-99.86%			-	0.00%	\$ -	\$ -	
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ -	\$ (36)	-100.00%			-	0.00%	\$ -	\$ -	
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%			-	0.00%	\$ -	\$ -	
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%			-	0.00%	\$ -	\$ -	
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
128	555.36 ARR_Auction Transaction AO Amount	\$ (45,254)	\$ -	\$ 45,254	-100.00%			-	0.00%	\$ -	\$ -	
129	555.37 RT URD Distribution AO Amount	\$ -	\$ 0	\$ 0	0.00%			-	0.00%	\$ -	\$ -	
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ 0	\$ (26)	-99.77%			-	0.00%	\$ -	\$ -	
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	
133												
134	Total SPP Wholesale Market Charges	\$ (110,156)	\$ (176,686)	\$ (66,530)	60.40%			-	0.00%	\$ -	\$ -	
135												
136	MISO ASM											
137	DA ASM Regulation Amount	\$ (38,995)	\$ (92,428)	\$ (53,433)	137.03%			-	0.00%	\$ -	\$ -	
138	DA ASM Spinning Reserve Amount	\$ (21,898)	\$ (34,249)	\$ (12,351)	56.40%			-	0.00%	\$ -	\$ -	
139	DA ASM Short-Term Reserve Amount	\$ (7,216)	\$ (96,507)	\$ (89,291)	1237.36%			-	0.00%	\$ -	\$ -	
140	DA ASM Supplemental Reserve Amount	\$ (2,990)	\$ (11,361)	\$ (8,371)	279.93%			-	0.00%	\$ -	\$ -	
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%			-	0.00%	\$ -	\$ -	
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 12,098	\$ 8,169	207.92%			-	0.00%	\$ -	\$ -	
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 7,057	\$ 5,618	390.39%			-	0.00%	\$ -	\$ -	
144	RT ASM Net Regulation Adjustment Amount	\$ (8,167)	\$ (25,111)	\$ (16,944)	207.48%			-	0.00%	\$ -	\$ -	
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 20,142	\$ 37,040	\$ 16,898	83.90%			-	0.00%	\$ -	\$ -	
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (1,292)	\$ 1,715	\$ 3,007	-232.65%			-	0.00%	\$ -	\$ -	
147	RT ASM Regulation Cost Distribution Amount	\$ 14,752	\$ 26,298	\$ 11,546	78.26%			-	0.00%	\$ -	\$ -	
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ 1	\$ 370	\$ 369	35439.42%			-	0.00%	\$ -	\$ -	
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 3,635	\$ 24,646	\$ 21,011	578.02%			-	0.00%	\$ -	\$ -	
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%			-	0.00%	\$ -	\$ -	

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		March 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 1,786	\$ 7,781	\$ 5,995	335.72%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 1,624	\$ 2,735	\$ 1,111	68.39%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (29,868)	\$ (139,916)	\$ (110,048)	368.45%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (1,142,631)	\$ (66,626)	\$ 1,076,004	-94.17%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 8,430,639	\$ 7,043,760	\$ (1,386,879)	-16.45%	218,727	292,851	74,124	33.89%	\$ 38.54	\$ 24.05
172											
173	Wind Curtailment	\$ 19,907	\$ 9,876	\$ (10,031)	-50.39%		252	252	0.00%	\$ -	\$ 39.22
174											
175	Asset Based Sales	\$ (77,103)	\$ (606,438)	\$ (529,335)	686.53%	(1,485)	(20,244)	(18,759)	1263.66%	\$ 51.94	\$ 29.96
176	Fuel Costs	\$ 36,986	\$ 601,568	\$ 564,582	1526.47%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (40,117)	\$ (4,870)	\$ 35,247	-87.86%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (338,811)	\$ (195,528)	\$ 143,283	-42.29%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 278,164	\$ 269,000	\$ (9,165)	-3.29%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (129,220)	\$ (82,100)	\$ 47,120	-36.47%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (64,266)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 11,986,371	\$ 10,541,716	\$ (1,444,655)	-12.05%	542,646	543,955	1,309	0.24%	\$ 22.09	\$ 19.38

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		April 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 1,904,206	\$ 2,276,320	\$ 372,114	19.54%	45,780	82,156	36,376	79.46%	\$ 41.59	\$ 27.71
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	110,770	97,811	(12,959)	-11.70%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,644	993	(651)	-39.62%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 814,220	\$ 483,700	\$ (330,520)	-40.59%	27,526	10,794	(16,732)	-60.79%	\$ 29.58	\$ 44.81
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	9,547	8,112	(1,435)	-15.03%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 2,718,426	\$ 2,760,020	\$ 41,594	1.53%	195,267	199,866	4,599	2.36%	\$ 13.92	\$ 13.81
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (310,271)	\$ (189,736)	\$ 120,536	-38.85%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 588,405	\$ 618,340	\$ 29,935	5.09%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 35,453	\$ 30,693	\$ (4,760)	-13.43%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 64,615	\$ 73,548	\$ 8,933	13.83%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 10,089	\$ 10,783	\$ 694	6.88%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 1,843	\$ 873	\$ (969)	-52.60%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 2,000,347	\$ 837,346	\$ (1,163,001)	-58.14%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 234,638	\$ (97,402)	\$ (332,040)	-141.51%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (3,023,105)	\$ (1,967,189)	\$ 1,055,916	-34.93%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (72,332)	\$ (28,503)	\$ 43,829	-60.59%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (115,820)	\$ (5,357)	\$ 110,464	-95.37%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 113,975	\$ 5,357	\$ (108,619)	-95.30%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 3,914,118	\$ (3,768,316)	\$ (7,682,434)	-196.27%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (3,922,956)	\$ 3,744,795	\$ 7,667,751	-195.46%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 24,084	\$ 17,288	\$ (6,796)	-28.22%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (84,610)	\$ (151,645)	\$ (67,034)	79.23%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 11,314	\$ 10,863	\$ (451)	-3.98%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (2,162)	\$ (17)	\$ 2,146	-99.22%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		April 2025									
		Expense (Revenue)			MWh			Cost per MWh			
		Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 7,219	\$ (21,069)	-74.48%	-	-	0.00%	\$ -	\$ -	-
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%	-	-	0.00%	\$ -	\$ -	-
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (7,315)	\$ 46,788	-86.48%	-	-	0.00%	\$ -	\$ -	-
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 152,579	\$ 24,123	18.78%	-	-	0.00%	\$ -	\$ -	-
79	555.25 RT Misc Amount	\$ (20,051)	\$ (403)	\$ 19,648	-97.99%	-	-	0.00%	\$ -	\$ -	-
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ 6,323	\$ 6,211	5558.36%	-	-	0.00%	\$ -	\$ -	-
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 18,011	\$ 3,423	\$ (14,588)	-80.99%	-	-	0.00%	\$ -	\$ -	-
83	555.63 DA Ramp Product	\$ (3,066)	\$ (27,463)	\$ (24,397)	795.77%	-	-	0.00%	\$ -	\$ -	-
84	555.64 RT Ramp Product	\$ 426	\$ (1,279)	\$ (1,705)	-400.36%	-	-	0.00%	\$ -	\$ -	-
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 19,255	\$ (2,782)	-12.62%	-	-	0.00%	\$ -	\$ -	-
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 30,961	\$ 30,961	0.00%	-	-	0.00%	\$ -	\$ -	-
93											
94	Total MISO Wholesale Market Charges	\$ (684,492)	\$ (760,181)	\$ (67,031)	9.79%	-	-	0.00%	\$ -	\$ -	-
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ -	\$ (1,092)	-100.00%	-	-	0.00%	\$ -	\$ -	-
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ -	\$ (244)	-100.00%	-	-	0.00%	\$ -	\$ -	-
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ -	\$ (16)	-100.00%	-	-	0.00%	\$ -	\$ -	-
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ -	\$ (59)	-100.00%	-	-	0.00%	\$ -	\$ -	-
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ -	\$ (72)	-100.00%	-	-	0.00%	\$ -	\$ -	-
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ -	\$ (11)	-100.00%	-	-	0.00%	\$ -	\$ -	-
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	-	0.00%	\$ -	\$ -	-
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (15,925)	\$ (7,116)	\$ 8,809	-55.31%	-	-	0.00%	\$ -	\$ -	-
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ -	\$ (3)	-100.00%	-	-	0.00%	\$ -	\$ -	-
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	-	0.00%	\$ -	\$ -	-
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	-	0.00%	\$ -	\$ -	-
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	-	0.00%	\$ -	\$ -	-
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	-	0.00%	\$ -	\$ -	-
116	555.20 RT Pseudo Tie Congestion Amount	\$ (31,683)	\$ (93,453)	\$ (61,770)	194.96%	-	-	0.00%	\$ -	\$ -	-
117	555.21 RT Pseudo Tie Loss Amount	\$ (11,970)	\$ (1,730)	\$ 10,239	-85.55%	-	-	0.00%	\$ -	\$ -	-
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%	-	-	0.00%	\$ -	\$ -	-
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ -	\$ (0)	-100.00%	-	-	0.00%	\$ -	\$ -	-
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ -	\$ (7)	-100.00%	-	-	0.00%	\$ -	\$ -	-
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ -	\$ (35)	-100.00%	-	-	0.00%	\$ -	\$ -	-
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ -	\$ (36)	-100.00%	-	-	0.00%	\$ -	\$ -	-
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	-	0.00%	\$ -	\$ -	-
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	-	0.00%	\$ -	\$ -	-
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
128	555.36 ARR_Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
129	555.37 RT URD Distribution AO Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ -	\$ (26)	-100.00%	-	-	0.00%	\$ -	\$ -	-
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
133											
134	Total SPP Wholesale Market Charges	\$ (57,983)	\$ (102,300)	\$ (44,317)	76.43%	-	-	0.00%	\$ -	\$ -	-
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (35,261)	\$ (87,032)	\$ (51,771)	146.82%	-	-	0.00%	\$ -	\$ -	-
138	DA ASM Spinning Reserve Amount	\$ (49,831)	\$ (58,568)	\$ (8,737)	17.53%	-	-	0.00%	\$ -	\$ -	-
139	DA ASM Short-Term Reserve Amount	\$ (24,956)	\$ (52,495)	\$ (27,539)	110.35%	-	-	0.00%	\$ -	\$ -	-
140	DA ASM Supplemental Reserve Amount	\$ (9,979)	\$ (12,200)	\$ (2,221)	22.26%	-	-	0.00%	\$ -	\$ -	-
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%	-	-	0.00%	\$ -	\$ -	-
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 9,342	\$ 5,413	137.78%	-	-	0.00%	\$ -	\$ -	-
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 13,179	\$ 11,740	815.87%	-	-	0.00%	\$ -	\$ -	-
144	RT ASM Net Regulation Adjustment Amount	\$ (2,378)	\$ (33,675)	\$ (31,297)	1315.97%	-	-	0.00%	\$ -	\$ -	-
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 21,501	\$ 37,055	\$ 15,554	72.34%	-	-	0.00%	\$ -	\$ -	-
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ 6,093	\$ 13,892	\$ 7,799	128.01%	-	-	0.00%	\$ -	\$ -	-
147	RT ASM Regulation Cost Distribution Amount	\$ 22,137	\$ 25,692	\$ 3,555	16.06%	-	-	0.00%	\$ -	\$ -	-
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ 1,453	\$ (6,624)	\$ (8,077)	-555.99%	-	-	0.00%	\$ -	\$ -	-
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 12,102	\$ 38,207	\$ 26,105	215.70%	-	-	0.00%	\$ -	\$ -	-
150	RT ASM Short-Term Reserve Amount	\$ -	\$ 42,019	\$ 42,019	0.00%	-	-	0.00%	\$ -	\$ -	-

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		April 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 3,909	\$ 69,378	\$ 65,469	1674.87%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 2,098	\$ 4,616	\$ 2,518	120.00%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (44,363)	\$ 2,786	\$ 47,149	-106.28%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (786,838)	\$ (859,695)	\$ (72,857)	9.26%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 9,716,285	\$ 7,002,109	\$ (2,714,176)	-27.93%	291,384	262,806	(28,578)	-9.81%	\$ 33.35	\$ 26.64
172											
173	Wind Curtailment	\$ 3,354	\$ 1,619	\$ (1,735)	-51.73%		41	41	0.00%	\$ -	\$ 39.22
174											
175	Asset Based Sales	\$ (40,515)	\$ (733,905)	\$ (693,390)	1711.44%	(699)	(15,419)	(14,720)	2104.63%	\$ 57.93	\$ 47.60
176	Fuel Costs	\$ 25,936	\$ 535,736	\$ 509,800	1965.61%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (14,579)	\$ (198,168)	\$ (183,589)	1259.27%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (361,014)	\$ (243,008)	\$ 118,005	-32.69%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 82,404	\$ 109,859	\$ 27,456	33.32%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (91,541)	\$ (74,837)	\$ 16,705	-18.25%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (81,465)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 11,240,560	\$ 7,880,698	\$ (3,359,863)	-29.89%	485,952	447,294	(38,658)	-7.96%	\$ 23.13	\$ 17.62

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		May 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 2,167,486	\$ 1,951,107	\$ (216,379)	-9.98%	73,070	70,396	(2,674)	-3.66%	\$ 29.66	\$ 27.72
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	103,761	104,767	1,006	0.97%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,699	1,106	(593)	-34.90%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 509,751	\$ 1,197,984	\$ 688,233	135.01%	17,690	31,809	14,119	79.81%	\$ 28.82	\$ 37.66
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	10,348	9,104	(1,243)	-12.01%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 2,677,236	\$ 3,149,091	\$ 471,855	17.62%	206,567	217,182	10,615	5.14%	\$ 12.96	\$ 14.50
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (291,757)	\$ (135,498)	\$ 156,259	-53.56%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 553,295	\$ 428,065	\$ (125,231)	-22.63%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 33,337	\$ 94,934	\$ 61,597	184.77%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 59,755	\$ 49,047	\$ (10,708)	-17.92%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 10,761	\$ 6,876	\$ (3,885)	-36.10%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 2,017	\$ 871	\$ (1,146)	-56.82%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 1,880,988	\$ 1,031,418	\$ (849,569)	-45.17%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 220,638	\$ 92,400	\$ (128,238)	-58.12%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (2,842,718)	\$ (2,432,505)	\$ 410,213	-14.43%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (68,016)	\$ (84,820)	\$ (16,804)	24.71%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (94,024)	\$ (17,992)	\$ 76,032	-80.86%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 75,511	\$ 17,992	\$ (57,519)	-76.17%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 3,914,118	\$ (3,768,316)	\$ (7,682,434)	-196.27%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (3,922,956)	\$ 3,744,795	\$ 7,667,751	-195.46%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 24,084	\$ 16,984	\$ (7,100)	-29.48%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (84,610)	\$ (152,046)	\$ (67,436)	79.70%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 17,005	\$ 8,877	\$ (8,128)	-47.80%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (15,944)	\$ (13,506)	\$ 2,438	-15.29%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		May 2025									
		Expense (Revenue)			MWh			Cost per MWh			
		Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 5,519	\$ (22,768)	-80.49%	-	0.00%	\$ -	\$ -		
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%	-	0.00%	\$ -	\$ -		
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (3,441)	\$ 50,662	-93.64%	-	0.00%	\$ -	\$ -		
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 219,498	\$ 91,042	70.87%	-	0.00%	\$ -	\$ -		
79	555.25 RT Misc Amount	\$ (20,051)	\$ 122	\$ 20,173	-100.61%	-	0.00%	\$ -	\$ -		
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ (1,259)	\$ (1,371)	-1226.62%	-	0.00%	\$ -	\$ -		
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 30,220	\$ 3,110	\$ (27,110)	-89.71%	-	0.00%	\$ -	\$ -		
83	555.63 DA Ramp Product	\$ (5,096)	\$ (27,913)	\$ (22,817)	447.73%	-	0.00%	\$ -	\$ -		
84	555.64 RT Ramp Product	\$ (1,622)	\$ (265)	\$ 1,357	-83.66%	-	0.00%	\$ -	\$ -		
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 20,232	\$ (1,806)	-8.19%	-	0.00%	\$ -	\$ -		
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 41,026	\$ 41,026	0.00%	-	0.00%	\$ -	\$ -		
93											
94	Total MISO Wholesale Market Charges	\$ (668,489)	\$ (912,589)	\$ (259,840)	38.87%	-	0.00%	\$ -	\$ -		
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ -	\$ (1,092)	-100.00%	-	0.00%	\$ -	\$ -		
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ -	\$ (244)	-100.00%	-	0.00%	\$ -	\$ -		
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ -	\$ (16)	-100.00%	-	0.00%	\$ -	\$ -		
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ -	\$ (59)	-100.00%	-	0.00%	\$ -	\$ -		
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ -	\$ (72)	-100.00%	-	0.00%	\$ -	\$ -		
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ -	\$ (11)	-100.00%	-	0.00%	\$ -	\$ -		
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	0.00%	\$ -	\$ -		
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (14,975)	\$ (5,787)	\$ 9,188	-61.36%	-	0.00%	\$ -	\$ -		
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ -	\$ (3)	-100.00%	-	0.00%	\$ -	\$ -		
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	0.00%	\$ -	\$ -		
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	0.00%	\$ -	\$ -		
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
116	555.20 RT Pseudo Tie Congestion Amount	\$ (29,793)	\$ (33,984)	\$ (4,191)	14.07%	-	0.00%	\$ -	\$ -		
117	555.21 RT Pseudo Tie Loss Amount	\$ (11,255)	\$ (4,464)	\$ 6,791	-60.34%	-	0.00%	\$ -	\$ -		
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%	-	0.00%	\$ -	\$ -		
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ -	\$ (0)	-100.00%	-	0.00%	\$ -	\$ -		
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ -	\$ (7)	-100.00%	-	0.00%	\$ -	\$ -		
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ -	\$ (35)	-100.00%	-	0.00%	\$ -	\$ -		
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ -	\$ (36)	-100.00%	-	0.00%	\$ -	\$ -		
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	0.00%	\$ -	\$ -		
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
128	555.36 ARR_Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
129	555.37 RT URD Distribution AO Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ -	\$ (26)	-100.00%	-	0.00%	\$ -	\$ -		
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ (0)	\$ -	\$ 0	-100.00%	-	0.00%	\$ -	\$ -		
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
133											
134	Total SPP Wholesale Market Charges	\$ (54,429)	\$ (44,235)	\$ 10,194	-18.73%	-	0.00%	\$ -	\$ -		
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (60,234)	\$ (88,048)	\$ (27,814)	46.18%	-	0.00%	\$ -	\$ -		
138	DA ASM Spinning Reserve Amount	\$ (55,514)	\$ (81,549)	\$ (26,035)	46.90%	-	0.00%	\$ -	\$ -		
139	DA ASM Short-Term Reserve Amount	\$ (24,834)	\$ (111,179)	\$ (86,346)	347.70%	-	0.00%	\$ -	\$ -		
140	DA ASM Supplemental Reserve Amount	\$ (18,688)	\$ (20,809)	\$ (2,121)	11.35%	-	0.00%	\$ -	\$ -		
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%	-	0.00%	\$ -	\$ -		
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 27,545	\$ 23,616	601.09%	-	0.00%	\$ -	\$ -		
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 3,911	\$ 2,472	171.79%	-	0.00%	\$ -	\$ -		
144	RT ASM Net Regulation Adjustment Amount	\$ (2,524)	\$ (32,337)	\$ (29,813)	1181.17%	-	0.00%	\$ -	\$ -		
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 28,465	\$ 36,385	\$ 7,920	27.82%	-	0.00%	\$ -	\$ -		
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ 1,473	\$ 15,933	\$ 14,460	981.35%	-	0.00%	\$ -	\$ -		
147	RT ASM Regulation Cost Distribution Amount	\$ 26,450	\$ 26,699	\$ 249	0.94%	-	0.00%	\$ -	\$ -		
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (58)	\$ 6,559	\$ 6,617	-11324.44%	-	0.00%	\$ -	\$ -		
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 17,390	\$ 29,647	\$ 12,257	70.48%	-	0.00%	\$ -	\$ -		
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		May 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 13,080	\$ 66,226	\$ 53,146	406.31%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 2,346	\$ 3,257	\$ 911	38.84%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (63,896)	\$ (117,761)	\$ (53,865)	84.30%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (786,813)	\$ (1,074,585)	\$ (287,772)	36.57%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 8,696,267	\$ 6,324,114	\$ (2,372,153)	-27.28%	250,914	230,995	(19,920)	-7.94%	\$ 34.66	\$ 27.38
172											
173	Wind Curtailment	\$ 19,240	\$ 10,898	\$ (8,342)	-43.36%		278	278	0.00%	\$ -	\$ 39.22
174											
175	Asset Based Sales	\$ (42,550)	\$ (802,414)	\$ (759,864)	1785.81%	(706)	(21,940)	(21,234)	3008.09%	\$ 60.28	\$ 36.57
176	Fuel Costs	\$ 20,823	\$ 718,962	\$ 698,139	3352.73%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (21,727)	\$ (83,451)	\$ (61,724)	284.09%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (401,656)	\$ (264,456)	\$ 137,200	-34.16%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 106,224	\$ 105,300	\$ (924)	-0.87%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (96,739)	\$ (95,379)	\$ 1,360	-1.41%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (78,669)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 10,171,210	\$ 7,273,901	\$ (2,897,309)	-28.49%	456,776	426,515	(30,261)	-6.62%	\$ 22.27	\$ 17.05

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		June 2025									
		Expense (Revenue)				MWh			Cost per MWh		
		Forecast	Actual	Difference		Forecast	Actual	Difference	Forecast	Actual	
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5											...PROTECTED DATA ENDS]
6	Total Coal	\$ 3,761,004	\$ 7,764,175	\$ 4,003,171	106.44%	147,493	189,149	41,656	28.24%	\$ 25.50	\$ 41.05
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14											...PROTECTED DATA ENDS]
15	Total Wind	\$ -	\$ -	\$ -	0.00%	88,051	61,218	(26,833)	-30.47%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,644	1,718	74	4.47%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23											...PROTECTED DATA ENDS]
24	Total Oil - Peaking Units	\$ -	\$ 190,131	\$ 190,131	0.00%	-	502	502	0.00%	\$ -	\$ 378.68
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29											...PROTECTED DATA ENDS]
30	Total Natural Gas	\$ 1,299,457	\$ 2,428,592	\$ 1,129,135	86.89%	45,579	69,080	23,501	51.56%	\$ 28.51	\$ 35.16
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36											...PROTECTED DATA ENDS]
37	Total Solar	\$ -	\$ -	\$ -	0.00%	10,500	7,357	(3,143)	-29.93%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 5,060,461	\$ 10,382,899	\$ 5,322,437	105.18%	293,267	329,023	35,756	12.19%	\$ 17.26	\$ 31.56
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (288,048)	\$ (96,839)	\$ 191,209	-66.38%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 546,261	\$ 559,070	\$ 12,809	2.34%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 32,913	\$ 43,329	\$ 10,415	31.65%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 63,208	\$ 41,158	\$ (22,050)	-34.88%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 10,390	\$ 6,258	\$ (4,132)	-39.77%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 2,110	\$ 871	\$ (1,238)	-58.70%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 1,857,073	\$ 1,625,052	\$ (232,021)	-12.49%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 217,832	\$ 38,964	\$ (178,868)	-82.11%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (2,806,576)	\$ (1,984,996)	\$ 821,580	-29.27%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (67,151)	\$ (52,946)	\$ 14,205	-21.15%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ 20,928	\$ 23,609	\$ 2,681	12.81%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ (24,985)	\$ (23,609)	\$ 1,376	-5.51%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 5,059,516	\$ (2,703,234)	\$ (7,762,751)	-153.43%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,238,471)	\$ 2,369,047	\$ 7,607,518	-145.22%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 5,762	\$ 530	\$ (5,231)	-90.80%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (161,345)	\$ (254,778)	\$ (93,434)	57.91%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 15,248	\$ 10,403	\$ (4,845)	-31.78%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (9,871)	\$ (17,625)	\$ (7,755)	78.56%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)		
Line No.		Expense (Revenue)				June 2025			MWh			Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference	Forecast	Actual			
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 16,300	\$ (11,987)	-42.38%				0.00%	\$ -	\$ -		
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%				0.00%	\$ -	\$ -		
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (10,202)	\$ 43,901	-81.14%				0.00%	\$ -	\$ -		
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 68,821	\$ (59,636)	-46.42%				0.00%	\$ -	\$ -		
79	555.25 RT Misc Amount	\$ (20,051)	\$ (939)	\$ 19,112	-95.32%				0.00%	\$ -	\$ -		
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ 4,581	\$ 4,469	3999.49%				0.00%	\$ -	\$ -		
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 21,152	\$ 2,043	\$ (19,109)	-90.34%				0.00%	\$ -	\$ -		
83	555.63 DA Ramp Product	\$ (4,945)	\$ (17,400)	\$ (12,455)	251.87%				0.00%	\$ -	\$ -		
84	555.64 RT Ramp Product	\$ (1,124)	\$ 638	\$ 1,762	-156.74%				0.00%	\$ -	\$ -		
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 20,376	\$ (1,661)	-7.54%				0.00%	\$ -	\$ -		
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 70,605	\$ 70,605	0.00%				0.00%	\$ -	\$ -		
93													
94	Total MISO Wholesale Market Charges	\$ (916,771)	\$ (309,200)	\$ 580,151	-63.28%	-	-	-	0.00%	\$ -	\$ -		
95													
96	SPP Wholesale Market Charges												
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ -	\$ (1,092)	-100.00%				0.00%	\$ -	\$ -		
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ -	\$ (244)	-100.00%				0.00%	\$ -	\$ -		
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ -	\$ (16)	-100.00%				0.00%	\$ -	\$ -		
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ -	\$ (59)	-100.00%				0.00%	\$ -	\$ -		
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ -	\$ (72)	-100.00%				0.00%	\$ -	\$ -		
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ -	\$ (11)	-100.00%				0.00%	\$ -	\$ -		
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%				0.00%	\$ -	\$ -		
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (14,785)	\$ (4,532)	\$ 10,253	-69.35%				0.00%	\$ -	\$ -		
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ -	\$ (3)	-100.00%				0.00%	\$ -	\$ -		
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ -	\$ 2	-100.00%				0.00%	\$ -	\$ -		
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%				0.00%	\$ -	\$ -		
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%				0.00%	\$ -	\$ -		
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%				0.00%	\$ -	\$ -		
116	555.20 RT Pseudo Tie Congestion Amount	\$ (29,414)	\$ (65,904)	\$ (36,490)	124.06%				0.00%	\$ -	\$ -		
117	555.21 RT Pseudo Tie Loss Amount	\$ (11,112)	\$ 4,039	\$ 15,151	-136.35%				0.00%	\$ -	\$ -		
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%				0.00%	\$ -	\$ -		
119	555.26 ARR Closeout Yearly Amount	\$ (236,793)	\$ (418,641)	\$ (181,848)	76.80%				0.00%	\$ -	\$ -		
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ -	\$ (0)	-100.00%				0.00%	\$ -	\$ -		
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ -	\$ (7)	-100.00%				0.00%	\$ -	\$ -		
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ -	\$ (35)	-100.00%				0.00%	\$ -	\$ -		
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ -	\$ (36)	-100.00%				0.00%	\$ -	\$ -		
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%				0.00%	\$ -	\$ -		
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%				0.00%	\$ -	\$ -		
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
128	555.36 ARR_Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
129	555.37 RT URD Distribution AO Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ -	\$ (26)	-100.00%				0.00%	\$ -	\$ -		
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ (0)	\$ -	\$ 0	-100.00%				0.00%	\$ -	\$ -		
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ (125)	\$ (3)	\$ 122	-97.43%				0.00%	\$ -	\$ -		
133													
134	Total SPP Wholesale Market Charges	\$ (290,635)	\$ (485,042)	\$ (194,406)	66.89%	-	-	-	0.00%	\$ -	\$ -		
135													
136	MISO ASM												
137	DA ASM Regulation Amount	\$ (45,116)	\$ (119,532)	\$ (74,416)	164.94%				0.00%	\$ -	\$ -		
138	DA ASM Spinning Reserve Amount	\$ (31,851)	\$ (43,665)	\$ (11,814)	37.09%				0.00%	\$ -	\$ -		
139	DA ASM Short-Term Reserve Amount	\$ (31,541)	\$ (79,699)	\$ (48,158)	152.68%				0.00%	\$ -	\$ -		
140	DA ASM Supplemental Reserve Amount	\$ (31,054)	\$ (20,379)	\$ 10,675	-34.38%				0.00%	\$ -	\$ -		
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%				0.00%	\$ -	\$ -		
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 5,207	\$ 1,278	32.54%				0.00%	\$ -	\$ -		
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 520	\$ (919)	-63.85%				0.00%	\$ -	\$ -		
144	RT ASM Net Regulation Adjustment Amount	\$ (2,959)	\$ (213)	\$ 2,746	-92.80%				0.00%	\$ -	\$ -		
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 18,966	\$ 39,631	\$ 20,665	108.96%				0.00%	\$ -	\$ -		
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (3,977)	\$ 2,613	\$ 6,590	-165.70%				0.00%	\$ -	\$ -		
147	RT ASM Regulation Cost Distribution Amount	\$ 17,843	\$ 22,256	\$ 4,413	24.73%				0.00%	\$ -	\$ -		
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (244)	\$ 24,661	\$ 24,905	-10225.19%				0.00%	\$ -	\$ -		
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 12,047	\$ 20,582	\$ 8,534	70.84%				0.00%	\$ -	\$ -		
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -		

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		June 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 5,046	\$ 7,364	\$ 2,318	45.93%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 3,543	\$ 1,327	\$ (2,217)	-62.56%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (80,545)	\$ (139,327)	\$ (58,782)	72.98%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (1,287,952)	\$ (933,569)	\$ 354,383	-27.52%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 6,183,907	\$ 5,646,964	\$ (536,943)	-8.68%	175,617	218,431	42,815	24.38%	\$ 35.21	\$ 25.85
172											
173	Wind Curtailment	\$ 42,165	\$ 25,660	\$ (16,504)	-39.14%		654	654	0.00%	\$ -	\$ 39.22
174											
175	Asset Based Sales	\$ (1,060,671)	\$ (1,634,826)	\$ (574,155)	54.13%	(17,887)	(33,636)	(15,749)	88.05%	\$ 59.30	\$ 48.60
176	Fuel Costs	\$ 468,814	\$ 1,258,198	\$ 789,384	168.38%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (591,857)	\$ (376,628)	\$ 215,229	-36.37%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (403,177)	\$ (330,035)	\$ 73,142	-18.14%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 224,003	\$ 363,685	\$ 139,682	62.36%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (97,674)	\$ (112,403)	\$ (14,729)	15.08%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (1,523,294)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 8,661,062	\$ 11,885,082	\$ 3,224,020	37.22%	450,997	514,473	63,476	14.07%	\$ 19.20	\$ 23.10

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		July 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 5,300,564	\$ 6,835,590	\$ 1,535,026	28.96%	214,984	241,636	26,651	12.40%	\$ 24.66	\$ 28.29
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	78,446	66,088	(12,359)	-15.75%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,699	1,858	159	9.35%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ -	\$ 128,050	\$ 128,050	0.00%	-	304	304	0.00%	\$ -	\$ 420.58
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 3,052,258	\$ 4,005,390	\$ 953,132	31.23%	104,423	112,027	7,604	7.28%	\$ 29.23	\$ 35.75
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	12,129	8,531	(3,597)	-29.66%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 8,352,822	\$ 10,969,031	\$ 2,616,209	31.32%	411,681	430,445	18,763	4.56%	\$ 20.29	\$ 25.48
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (307,544)	\$ (656,281)	\$ (348,737)	113.39%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 583,232	\$ 1,664,365	\$ 1,081,132	185.37%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 35,141	\$ 70,518	\$ 35,377	100.67%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 73,261	\$ 59,725	\$ (13,536)	-18.48%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 10,987	\$ 7,840	\$ (3,147)	-28.64%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 2,180	\$ 1,122	\$ (1,058)	-48.52%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 1,982,762	\$ 2,243,383	\$ 260,621	13.14%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 232,576	\$ 238,802	\$ 6,227	2.68%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (2,996,528)	\$ (2,824,690)	\$ 171,838	-5.73%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (71,696)	\$ (52,898)	\$ 18,798	-26.22%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ 15,263	\$ (16,030)	\$ (31,293)	-205.02%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ (24,637)	\$ 16,030	\$ 40,667	-165.06%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 5,059,516	\$ (2,703,234)	\$ (7,762,751)	-153.43%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,238,471)	\$ 2,369,047	\$ 7,607,518	-145.22%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 5,762	\$ 530	\$ (5,231)	-90.80%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (161,345)	\$ (254,779)	\$ (93,434)	57.91%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 13,037	\$ 10,261	\$ (2,776)	-21.29%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (10,631)	\$ (628)	\$ 10,003	-94.10%	-	-	-	0.00%	\$ -	\$ -

Line No.		Expense (Revenue)				July 2025				Cost per MWh			
		Forecast	Actual	Difference		Forecast	Actual	MWh	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 16,501	\$ (11,786)	-41.67%		-	0.00%	\$ -	\$ -	\$ -	-	
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (139,413)	\$ (85,310)	157.68%		-	0.00%	\$ -	\$ -	\$ -	-	
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 192,588	\$ 64,132	49.93%		-	0.00%	\$ -	\$ -	\$ -	-	
79	555.25 RT Misc Amount	\$ (20,051)	\$ 19,079	\$ 39,130	-195.15%		-	0.00%	\$ -	\$ -	\$ -	-	
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ (12,453)	\$ (12,564)	-11243.38%		-	0.00%	\$ -	\$ -	\$ -	-	
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 22,098	\$ 44,111	\$ 22,013	99.61%		-	0.00%	\$ -	\$ -	\$ -	-	
83	555.63 DA Ramp Product	\$ (3,129)	\$ (14,515)	\$ (11,386)	363.89%		-	0.00%	\$ -	\$ -	\$ -	-	
84	555.64 RT Ramp Product	\$ (2,822)	\$ (845)	\$ 1,978	-70.07%		-	0.00%	\$ -	\$ -	\$ -	-	
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 21,929	\$ (108)	-0.49%		-	0.00%	\$ -	\$ -	\$ -	-	
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ (28,453)	\$ (28,453)	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
93													
94	Total MISO Wholesale Market Charges	\$ (958,355)	\$ 202,927	\$ 1,143,541	-119.32%		-	-	0.00%	\$ -	\$ -	-	
95													
96	SPP Wholesale Market Charges												
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ 14	\$ (1,079)	-98.76%		-	0.00%	\$ -	\$ -	\$ -	-	
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ (0)	\$ (244)	-100.20%		-	0.00%	\$ -	\$ -	\$ -	-	
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ 0	\$ (16)	-99.17%		-	0.00%	\$ -	\$ -	\$ -	-	
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ 1	\$ (57)	-97.83%		-	0.00%	\$ -	\$ -	\$ -	-	
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ 1	\$ (71)	-98.44%		-	0.00%	\$ -	\$ -	\$ -	-	
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ 0	\$ (10)	-98.01%		-	0.00%	\$ -	\$ -	\$ -	-	
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ (0)	\$ 2	-97.33%		-	0.00%	\$ -	\$ -	\$ -	-	
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (15,785)	\$ (4,764)	\$ 11,021	-69.82%		-	0.00%	\$ -	\$ -	\$ -	-	
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ -	\$ (3)	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ (0)	\$ 2	-98.58%		-	0.00%	\$ -	\$ -	\$ -	-	
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ 0	\$ 3	-101.21%		-	0.00%	\$ -	\$ -	\$ -	-	
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
116	555.20 RT Pseudo Tie Congestion Amount	\$ (31,405)	\$ (59,063)	\$ (27,658)	88.07%		-	0.00%	\$ -	\$ -	\$ -	-	
117	555.21 RT Pseudo Tie Loss Amount	\$ (11,864)	\$ (1,796)	\$ 10,068	-84.86%		-	0.00%	\$ -	\$ -	\$ -	-	
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
119	555.26 ARR Closeout Yearly Amount	\$ (2)	\$ -	\$ 2	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ 0	\$ 0	51.58%		-	0.00%	\$ -	\$ -	\$ -	-	
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ 0	\$ (7)	-96.43%		-	0.00%	\$ -	\$ -	\$ -	-	
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ 0	\$ (35)	-98.73%		-	0.00%	\$ -	\$ -	\$ -	-	
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ 1	\$ (34)	-96.28%		-	0.00%	\$ -	\$ -	\$ -	-	
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ (0)	\$ 0	-81.70%		-	0.00%	\$ -	\$ -	\$ -	-	
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
128	555.36 ARR Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
129	555.37 RT URD Distribution AO Amount	\$ -	\$ (1)	\$ (1)	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ -	\$ (26)	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	
133													
134	Total SPP Wholesale Market Charges	\$ (57,462)	\$ (65,606)	\$ (8,144)	14.17%		-	-	0.00%	\$ -	\$ -	-	
135													
136	MISO ASM												
137	DA ASM Regulation Amount	\$ (49,749)	\$ (132,678)	\$ (82,929)	166.70%		-	0.00%	\$ -	\$ -	\$ -	-	
138	DA ASM Spinning Reserve Amount	\$ (27,015)	\$ (28,713)	\$ (1,698)	6.28%		-	0.00%	\$ -	\$ -	\$ -	-	
139	DA ASM Short-Term Reserve Amount	\$ (14,747)	\$ (445,041)	\$ (430,294)	2917.75%		-	0.00%	\$ -	\$ -	\$ -	-	
140	DA ASM Supplemental Reserve Amount	\$ (42,416)	\$ (127,515)	\$ (85,099)	200.63%		-	0.00%	\$ -	\$ -	\$ -	-	
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%		-	0.00%	\$ -	\$ -	\$ -	-	
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 7,792	\$ 3,863	98.33%		-	0.00%	\$ -	\$ -	\$ -	-	
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 7,873	\$ 6,434	447.15%		-	0.00%	\$ -	\$ -	\$ -	-	
144	RT ASM Net Regulation Adjustment Amount	\$ (5,331)	\$ (1,222)	\$ 4,108	-77.07%		-	0.00%	\$ -	\$ -	\$ -	-	
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 15,315	\$ 26,933	\$ 11,618	75.86%		-	0.00%	\$ -	\$ -	\$ -	-	
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (11,968)	\$ 6,747	\$ 18,715	-156.37%		-	0.00%	\$ -	\$ -	\$ -	-	
147	RT ASM Regulation Cost Distribution Amount	\$ 10,586	\$ 20,638	\$ 10,052	94.96%		-	0.00%	\$ -	\$ -	\$ -	-	
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (4,302)	\$ (111,188)	\$ (106,886)	2484.54%		-	0.00%	\$ -	\$ -	\$ -	-	
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 10,423	\$ 343,727	\$ 333,304	3197.82%		-	0.00%	\$ -	\$ -	\$ -	-	
150	RT ASM Short-Term Reserve Amount	\$ -	\$ 28	\$ 28	0.00%		-	0.00%	\$ -	\$ -	\$ -	-	

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		Expense (Revenue)				July 2025				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	MWh	Difference	Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ (5,410)	\$ 60,434	\$ 65,845	-1216.99%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 7,483	\$ 12,531	\$ 5,048	67.46%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (108,381)	\$ (359,652)	\$ (251,271)	231.84%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (1,124,198)	\$ (222,332)	\$ 901,867	-80.22%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 4,168,752	\$ 5,155,948	\$ 987,196	23.68%	99,876	127,082	27,205	27.24%	\$ 41.74	\$ 40.57
172											
173	Wind Curtailment	\$ 10,958	\$ (1,061)	\$ (12,019)	-109.68%		(27)	(27)	0.00%	\$ -	\$ 39.22
174											
175	Asset Based Sales	\$ (1,912,158)	\$ (4,888,509)	\$ (2,976,351)	155.65%	(29,954)	(72,722)	(42,768)	142.78%	\$ 63.84	\$ 67.22
176	Fuel Costs	\$ 783,337	\$ 2,549,053	\$ 1,765,716	225.41%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (1,128,821)	\$ (2,339,456)	\$ (1,210,635)	107.25%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (556,580)	\$ (598,363)	\$ (41,783)	7.51%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 331,233	\$ 529,282	\$ 198,049	59.79%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (139,790)	\$ (118,440)	\$ 21,350	-15.27%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (2,140,783)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 9,131,039	\$ 8,684,774	\$ (446,265)	-4.89%	481,603	484,777	3,174	0.66%	\$ 18.96	\$ 17.91

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		August 2025									
		Expense (Revenue)				MWh			Cost per MWh		
		Forecast	Actual	Difference		Forecast	Actual	Difference	Forecast	Actual	
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5											...PROTECTED DATA ENDS]
6	Total Coal	\$ 5,345,582	\$ 4,648,770	\$ (696,812)	-13.04%	215,183	178,226	(36,957)	-17.17%	\$ 24.84	\$ 26.08
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14											...PROTECTED DATA ENDS]
15	Total Wind	\$ -	\$ -	\$ -	0.00%	77,764	69,283	(8,481)	-10.91%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,699	1,750	52	3.06%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23											...PROTECTED DATA ENDS]
24	Total Oil - Peaking Units	\$ 224,601	\$ 160,977	\$ (63,624)	-28.33%	791	503	(288)	-36.46%	\$ 283.93	\$ 320.27
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29											...PROTECTED DATA ENDS]
30	Total Natural Gas	\$ 2,360,235	\$ 3,124,397	\$ 764,162	32.38%	79,475	95,896	16,420	20.66%	\$ 29.70	\$ 32.58
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36											...PROTECTED DATA ENDS]
37	Total Solar	\$ -	\$ -	\$ -	0.00%	10,028	8,699	(1,329)	-13.26%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 7,930,418	\$ 7,934,144	\$ 3,726	0.05%	384,940	354,356	(30,584)	-7.95%	\$ 20.60	\$ 22.39
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (305,690)	\$ (696,524)	\$ (390,834)	127.85%				0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 579,718	\$ 1,841,930	\$ 1,262,212	217.73%				0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 34,929	\$ 28,511	\$ (6,418)	-18.37%				0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 68,398	\$ 65,554	\$ (2,843)	-4.16%				0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 9,812	\$ 8,289	\$ (1,523)	-15.52%				0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 2,120	\$ 1,146	\$ (974)	-45.95%				0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
59	DA Congestion	\$ 1,970,813	\$ 3,727,454	\$ 1,756,641	89.13%				0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
61	RT Congestion	\$ 231,174	\$ 349,643	\$ 118,469	51.25%				0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (2,978,470)	\$ (4,863,801)	\$ (1,885,331)	63.30%				0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (71,264)	\$ (45,479)	\$ 25,784	-36.18%				0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (4,332)	\$ (253,729)	\$ (249,396)	5756.87%				0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 4,332	\$ 253,729	\$ 249,396	5756.87%				0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 5,059,516	\$ (2,703,234)	\$ (7,762,751)	-153.43%				0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,238,471)	\$ 2,369,047	\$ 7,607,518	-145.22%				0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 5,762	\$ 530	\$ (5,231)	-90.80%				0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (161,345)	\$ (254,779)	\$ (93,434)	57.91%				0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 17,259	\$ 9,034	\$ (8,225)	-47.66%				0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (45,697)	\$ (3,987)	\$ 41,711	-91.28%				0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		August 2025									
		Expense (Revenue)			MWh			Cost per MWh			
		Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 20,619	\$ (7,669)	-27.11%			0.00%	\$ -	\$ -	
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%			0.00%	\$ -	\$ -	
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (74,898)	\$ (20,794)	38.43%			0.00%	\$ -	\$ -	
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 213,814	\$ 85,358	66.45%			0.00%	\$ -	\$ -	
79	555.25 RT Misc Amount	\$ (20,051)	\$ 5	\$ 20,056	-100.03%			0.00%	\$ -	\$ -	
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ 366	\$ 255	227.78%			0.00%	\$ -	\$ -	
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 5,129	\$ (1,822)	\$ (6,951)	-135.53%			0.00%	\$ -	\$ -	
83	555.63 DA Ramp Product	\$ (1,905)	\$ (10,887)	\$ (8,982)	471.62%			0.00%	\$ -	\$ -	
84	555.64 RT Ramp Product	\$ (1,175)	\$ (4,163)	\$ (2,988)	254.16%			0.00%	\$ -	\$ -	
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 18,464	\$ (3,574)	-16.22%			0.00%	\$ -	\$ -	
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 48,656	\$ 48,656	0.00%			0.00%	\$ -	\$ -	
93											
94	Total MISO Wholesale Market Charges	\$ (990,658)	\$ (31,500)	\$ 953,819	-96.28%	-	-	0.00%	\$ -	\$ -	-
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ 340	\$ (752)	-68.83%			0.00%	\$ -	\$ -	
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ 82	\$ (162)	-66.44%			0.00%	\$ -	\$ -	
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ 9	\$ (6)	-40.74%			0.00%	\$ -	\$ -	
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ 30	\$ (28)	-47.92%			0.00%	\$ -	\$ -	
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ 15	\$ (56)	-78.48%			0.00%	\$ -	\$ -	
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ 3	\$ (7)	-69.17%			0.00%	\$ -	\$ -	
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%			0.00%	\$ -	\$ -	
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (15,690)	\$ (5,673)	\$ 10,018	-63.85%			0.00%	\$ -	\$ -	
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ 0	\$ (3)	-93.67%			0.00%	\$ -	\$ -	
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ (1)	\$ 1	-54.95%			0.00%	\$ -	\$ -	
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ (0)	\$ 3	-88.21%			0.00%	\$ -	\$ -	
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%			0.00%	\$ -	\$ -	
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%			0.00%	\$ -	\$ -	
116	555.20 RT Pseudo Tie Congestion Amount	\$ (31,215)	\$ 10,924	\$ 42,140	-135.00%			0.00%	\$ -	\$ -	
117	555.21 RT Pseudo Tie Loss Amount	\$ (11,793)	\$ 6,716	\$ 18,508	-156.95%			0.00%	\$ -	\$ -	
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%			0.00%	\$ -	\$ -	
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ (0)	\$ (0)	-276.84%			0.00%	\$ -	\$ -	
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ 8	\$ 1	13.26%			0.00%	\$ -	\$ -	
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ 15	\$ (21)	-58.90%			0.00%	\$ -	\$ -	
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ 9	\$ (26)	-74.27%			0.00%	\$ -	\$ -	
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ (0)	\$ 0	-89.02%			0.00%	\$ -	\$ -	
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ (0)	\$ 3	-95.84%			0.00%	\$ -	\$ -	
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
128	555.36 ARR_Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
129	555.37 RT URD Distribution AO Amount	\$ -	\$ (14)	\$ (14)	0.00%			0.00%	\$ -	\$ -	
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ 5	\$ (21)	-82.30%			0.00%	\$ -	\$ -	
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ -	\$ (0)	\$ (0)	0.00%			0.00%	\$ -	\$ -	
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
133											
134	Total SPP Wholesale Market Charges	\$ (57,104)	\$ 12,470	\$ 69,573	-121.84%	-	-	0.00%	\$ -	\$ -	-
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (32,345)	\$ (139,085)	\$ (106,740)	330.00%			0.00%	\$ -	\$ -	
138	DA ASM Spinning Reserve Amount	\$ (16,293)	\$ (41,391)	\$ (25,098)	154.04%			0.00%	\$ -	\$ -	
139	DA ASM Short-Term Reserve Amount	\$ (47,614)	\$ (397,379)	\$ (349,765)	734.58%			0.00%	\$ -	\$ -	
140	DA ASM Supplemental Reserve Amount	\$ (28,624)	\$ (110,624)	\$ (82,000)	286.48%			0.00%	\$ -	\$ -	
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%			0.00%	\$ -	\$ -	
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 12,661	\$ 8,732	222.24%			0.00%	\$ -	\$ -	
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 2,088	\$ 649	45.13%			0.00%	\$ -	\$ -	
144	RT ASM Net Regulation Adjustment Amount	\$ (18,024)	\$ (70,603)	\$ (52,579)	291.71%			0.00%	\$ -	\$ -	
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 16,597	\$ 24,690	\$ 8,093	48.76%			0.00%	\$ -	\$ -	
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ 11,411	\$ 31,143	\$ 19,732	172.93%			0.00%	\$ -	\$ -	
147	RT ASM Regulation Cost Distribution Amount	\$ 13,970	\$ 16,889	\$ 2,919	20.89%			0.00%	\$ -	\$ -	
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ 794	\$ (12,535)	\$ (13,329)	-1678.90%			0.00%	\$ -	\$ -	
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 33,142	\$ 270,500	\$ 237,358	716.18%			0.00%	\$ -	\$ -	
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

(A)		(B)		(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)		
Line No.		Expense (Revenue)				August 2025				MWh			Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual			
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 43,012	\$ (16,027)	\$ (59,039)	-137.26%			-	0.00%	\$ -	\$ -	-		
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 3,917	\$ 10,967	\$ 7,050	179.97%			-	0.00%	\$ -	\$ -	-		
153														
154	Total MISO ASM	\$ (11,307)	\$ (418,707)	\$ (407,400)	3603.18%			-	0.00%	\$ -	\$ -	-		
155														
156	Total Wholesale Market Charges	\$ (1,059,069)	\$ (437,737)	\$ 621,332	-58.67%			-	0.00%	\$ -	\$ -	-		
157														
158														
159														
160	Purchased Power	[PROTECTED DATA BEGINS...												
161	Edgeley PPA													
162	Langdon PPA													
163	Ashtabula III PPA													
164	Tribal (WAPA)													
165	WAPA Energy Imbalance													
166	Shared Loads													
167	Small Co-gen													
168	Bilateral purchases													
169	Market Purchases													
170														
171	Total Purchases	\$ 4,179,648	\$ 4,236,993	\$ 57,344	1.37%	114,461	115,579	1,119	0.98%	\$ 36.52	\$ 36.66			
172														
173	Wind Curtailment	\$ (8,199)	\$ (3,629)	\$ 4,570	-55.74%		(93)	(93)	0.00%	\$ -	\$ 39.22			
174														
175	Asset Based Sales	\$ (1,278,498)	\$ (2,717,143)	\$ (1,438,645)	112.53%	(20,711)	(45,207)	(24,496)	118.28%	\$ 61.73	\$ 60.10			
176	Fuel Costs	\$ 557,404	\$ 1,753,188	\$ 1,195,784	214.53%			-	0.00%	\$ -	\$ -			
177	Asset Based Margins	\$ (721,094)	\$ (963,955)	\$ (242,861)	33.68%			-	0.00%	\$ -	\$ -			
178														
179	Hoot Lake Solar Generation Credit	\$ (408,260)	\$ (663,960)	\$ (255,700)	62.63%			-	0.00%	\$ -	\$ -			
180														
181	Steam Plant Reagents	\$ 337,012	\$ 349,612	\$ 12,600	3.74%			-	0.00%	\$ -	\$ -			
182														
183	Steam/Water Sales	\$ (138,027)	\$ (112,208)	\$ 25,819	-18.71%			-	0.00%	\$ -	\$ -			
184														
185	Planning Resource Auction Revenues	\$ -	\$ (1,977,242)	\$ -	0.00%			-	0.00%	\$ -	\$ -			
186														
187	Total System - Plant Level	\$ 9,555,026	\$ 6,608,830	\$ (2,946,196)	-30.83%	478,690	424,636	(54,054)	-11.29%	\$ 19.96	\$ 15.56			

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		September 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 3,921,179	\$ 4,009,158	\$ 87,979	2.24%	154,640	161,927	7,287	4.71%	\$ 25.36	\$ 24.76
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	103,856	66,424	(37,432)	-36.04%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,644	985	(659)	-40.09%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ -	\$ 4,833	\$ 4,833	0.00%	-	-	-	0.00%	\$ -	\$ -
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 1,286,226	\$ 2,524,474	\$ 1,238,248	96.27%	45,592	74,453	28,861	63.30%	\$ 28.21	\$ 33.91
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	7,901	6,850	(1,051)	-13.30%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 5,207,405	\$ 6,538,465	\$ 1,331,060	25.56%	313,633	310,639	(2,994)	-0.95%	\$ 16.60	\$ 21.05
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (291,632)	\$ (218,954)	\$ 72,678	-24.92%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 553,058	\$ 844,655	\$ 291,596	52.72%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 33,323	\$ 40,221	\$ 6,898	20.70%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 62,255	\$ 71,318	\$ 9,062	14.56%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 9,494	\$ 8,172	\$ (1,322)	-13.93%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 1,926	\$ 1,303	\$ (624)	-32.38%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 1,880,181	\$ 1,586,198	\$ (293,983)	-15.64%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 220,543	\$ (115,257)	\$ (335,800)	-152.26%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (2,841,500)	\$ (3,775,638)	\$ (934,139)	32.87%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (67,986)	\$ (209,615)	\$ (141,628)	208.32%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (60,572)	\$ 105,590	\$ 166,162	-274.32%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 60,572	\$ (135,897)	\$ (196,469)	-324.35%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 5,757,546	\$ (3,994,313)	\$ (9,751,858)	-169.38%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,857,971)	\$ 3,735,605	\$ 9,593,576	-163.77%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 13,833	\$ 9,509	\$ (4,325)	-31.26%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (128,220)	\$ (270,127)	\$ (141,907)	110.68%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 13,613	\$ 7,761	\$ (5,852)	-42.99%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (29,039)	\$ (1,598)	\$ 27,442	-94.50%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		September 2025									
		Expense (Revenue)			MWh			Cost per MWh			
		Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 13,069	\$ (15,218)	-53.80%			0.00%	\$ -	\$ -	
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%			0.00%	\$ -	\$ -	
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (25,239)	\$ 28,864	-53.35%			0.00%	\$ -	\$ -	
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 181,810	\$ 53,354	41.53%			0.00%	\$ -	\$ -	
79	555.25 RT Misc Amount	\$ (20,051)	\$ (0)	\$ 20,051	-100.00%			0.00%	\$ -	\$ -	
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ 8,031	\$ 7,920	7086.92%			0.00%	\$ -	\$ -	
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 5,920	\$ 14,655	\$ 8,735	147.54%			0.00%	\$ -	\$ -	
83	555.63 DA Ramp Product	\$ (4,517)	\$ (6,412)	\$ (1,896)	41.98%			0.00%	\$ -	\$ -	
84	555.64 RT Ramp Product	\$ (1,650)	\$ (865)	\$ 785	-47.56%			0.00%	\$ -	\$ -	
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 20,852	\$ (1,186)	-5.38%			0.00%	\$ -	\$ -	
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 139,716	\$ 139,716	0.00%			0.00%	\$ -	\$ -	
93											
94	Total MISO Wholesale Market Charges	\$ (835,438)	\$ (2,046,244)	\$ (1,203,689)	144.08%	-	-	0.00%	\$ -	\$ -	-
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ (2)	\$ (1,094)	-100.14%			0.00%	\$ -	\$ -	
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ (0)	\$ (244)	-100.01%			0.00%	\$ -	\$ -	
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ (0)	\$ (16)	-100.06%			0.00%	\$ -	\$ -	
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ (0)	\$ (59)	-100.10%			0.00%	\$ -	\$ -	
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ (0)	\$ (72)	-100.07%			0.00%	\$ -	\$ -	
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ (0)	\$ (11)	-100.09%			0.00%	\$ -	\$ -	
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%			0.00%	\$ -	\$ -	
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (14,969)	\$ (5,505)	\$ 9,464	-63.22%			0.00%	\$ -	\$ -	
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ -	\$ (3)	-100.00%			0.00%	\$ -	\$ -	
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ 0	\$ 2	-100.47%			0.00%	\$ -	\$ -	
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%			0.00%	\$ -	\$ -	
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%			0.00%	\$ -	\$ -	
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%			0.00%	\$ -	\$ -	
116	555.20 RT Pseudo Tie Congestion Amount	\$ (29,780)	\$ 128,163	\$ 157,943	-530.37%			0.00%	\$ -	\$ -	
117	555.21 RT Pseudo Tie Loss Amount	\$ (11,251)	\$ 7,982	\$ 19,233	-170.95%			0.00%	\$ -	\$ -	
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%			0.00%	\$ -	\$ -	
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ (0)	\$ (0)	-112.63%			0.00%	\$ -	\$ -	
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ (0)	\$ (7)	-100.14%			0.00%	\$ -	\$ -	
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ (0)	\$ (35)	-100.03%			0.00%	\$ -	\$ -	
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ (0)	\$ (36)	-100.17%			0.00%	\$ -	\$ -	
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%			0.00%	\$ -	\$ -	
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%			0.00%	\$ -	\$ -	
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
128	555.36 ARR_Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	
129	555.37 RT URD Distribution AO Amount	\$ -	\$ 0	\$ 0	0.00%			0.00%	\$ -	\$ -	
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ (0)	\$ (26)	-100.08%			0.00%	\$ -	\$ -	
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ (0)	\$ (0)	\$ 0	-81.25%			0.00%	\$ -	\$ -	
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ 0	\$ -	\$ (0)	-100.00%			0.00%	\$ -	\$ -	
133											
134	Total SPP Wholesale Market Charges	\$ (54,405)	\$ 130,639	\$ 185,043	-340.12%	-	-	0.00%	\$ -	\$ -	-
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (46,882)	\$ (131,062)	\$ (84,181)	179.56%			0.00%	\$ -	\$ -	
138	DA ASM Spinning Reserve Amount	\$ (22,593)	\$ (18,494)	\$ 4,099	-18.14%			0.00%	\$ -	\$ -	
139	DA ASM Short-Term Reserve Amount	\$ (32,969)	\$ (23,950)	\$ 9,018	-27.35%			0.00%	\$ -	\$ -	
140	DA ASM Supplemental Reserve Amount	\$ (13,511)	\$ (27,416)	\$ (13,905)	102.92%			0.00%	\$ -	\$ -	
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%			0.00%	\$ -	\$ -	
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 22,849	\$ 18,920	481.55%			0.00%	\$ -	\$ -	
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ (672)	\$ (2,111)	-146.72%			0.00%	\$ -	\$ -	
144	RT ASM Net Regulation Adjustment Amount	\$ (6,808)	\$ (65,459)	\$ (58,650)	861.43%			0.00%	\$ -	\$ -	
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 16,030	\$ 40,894	\$ 24,864	155.11%			0.00%	\$ -	\$ -	
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (11,202)	\$ 3,516	\$ 14,717	-131.39%			0.00%	\$ -	\$ -	
147	RT ASM Regulation Cost Distribution Amount	\$ 10,158	\$ 15,791	\$ 5,632	55.45%			0.00%	\$ -	\$ -	
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (2,523)	\$ (8,761)	\$ (6,238)	247.25%			0.00%	\$ -	\$ -	
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 22,891	\$ 31,400	\$ 8,508	37.17%			0.00%	\$ -	\$ -	
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%			0.00%	\$ -	\$ -	

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		September 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ (25,956)	\$ 838	\$ 26,794	-103.23%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 3,296	\$ 6,644	\$ 3,348	101.58%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (101,317)	\$ (153,884)	\$ (52,567)	51.88%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (991,160)	\$ (2,069,489)	\$ (1,078,329)	108.79%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 6,277,254	\$ 5,516,944	\$ (760,310)	-12.11%	158,290	162,647	4,357	2.75%	\$ 39.66	\$ 33.92
172											
173	Wind Curtailment	\$ 819	\$ (742)	\$ (1,560)	-190.59%		(19)	(19)	0.00%	\$ -	\$ 39.22
174											
175	Asset Based Sales	\$ (853,609)	\$ (2,035,228)	\$ (1,181,619)	138.43%	(15,282)	(42,195)	(26,913)	176.11%	\$ 55.86	\$ 48.23
176	Fuel Costs	\$ 397,426	\$ 1,461,815	\$ 1,064,389	267.82%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (456,183)	\$ (573,413)	\$ (117,230)	25.70%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (360,012)	\$ (450,612)	\$ (90,600)	25.17%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 237,230	\$ 304,969	\$ 67,739	28.55%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (88,698)	\$ (96,631)	\$ (7,934)	8.94%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (576,649)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 9,429,229	\$ 7,131,027	\$ (2,298,202)	-24.37%	456,641	431,073	(25,568)	-5.60%	\$ 20.65	\$ 16.54

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		October 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 3,073,162	\$ 3,041,383	\$ (31,779)	-1.03%	116,984	106,479	(10,505)	-8.98%	\$ 26.27	\$ 28.56
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	126,500	101,085	(25,415)	-20.09%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,699	441	(1,258)	-74.04%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 1,605,401	\$ 1,762,166	\$ 156,765	9.76%	57,702	50,114	(7,587)	-13.15%	\$ 27.82	\$ 35.16
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	5,185	5,332	147	2.84%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 4,678,563	\$ 4,803,549	\$ 124,986	2.67%	308,070	263,452	(44,618)	-14.48%	\$ 15.19	\$ 18.23
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (305,547)	\$ (299,040)	\$ 6,507	-2.13%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 579,445	\$ 755,639	\$ 176,194	30.41%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 34,913	\$ 41,166	\$ 6,254	17.91%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 70,854	\$ 64,637	\$ (6,217)	-8.77%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 11,853	\$ 9,611	\$ (2,243)	-18.92%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 1,872	\$ 970	\$ (902)	-48.17%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 1,969,888	\$ 3,730,861	\$ 1,760,973	89.39%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 231,065	\$ 109,882	\$ (121,183)	-52.45%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (2,977,072)	\$ (11,856,968)	\$ (8,879,895)	298.28%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (71,230)	\$ (122,159)	\$ (50,929)	71.50%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (283,078)	\$ (300,111)	\$ (17,033)	6.02%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 290,732	\$ 300,111	\$ 9,379	3.23%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 5,757,546	\$ (3,994,313)	\$ (9,751,858)	-169.38%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,857,971)	\$ 3,735,605	\$ 9,593,576	-163.77%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 13,833	\$ 9,512	\$ (4,321)	-31.24%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (128,220)	\$ (270,125)	\$ (141,905)	110.67%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 12,188	\$ 12,671	\$ 483	3.96%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (3,284)	\$ (39,185)	\$ (35,901)	1093.24%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		Expense (Revenue)				October 2025					
		Forecast	Actual	Difference		Forecast	Actual	MWh Difference	Forecast	Actual	
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 9,254	\$ (19,033)	-67.28%		-	0.00%	\$ -	\$ -	-
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%		-	0.00%	\$ -	\$ -	-
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (17,830)	\$ 36,274	-67.04%		-	0.00%	\$ -	\$ -	-
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 213,076	\$ 84,619	65.87%		-	0.00%	\$ -	\$ -	-
79	555.25 RT Misc Amount	\$ (20,051)	\$ (2,516)	\$ 17,535	-87.45%		-	0.00%	\$ -	\$ -	-
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ 1,253	\$ 1,142	1021.57%		-	0.00%	\$ -	\$ -	-
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 2,772	\$ 1,614	\$ (1,157)	-41.75%		-	0.00%	\$ -	\$ -	-
83	555.63 DA Ramp Product	\$ (2,280)	\$ (4,425)	\$ (2,144)	94.02%		-	0.00%	\$ -	\$ -	-
84	555.64 RT Ramp Product	\$ (107)	\$ (1,059)	\$ (953)	894.35%		-	0.00%	\$ -	\$ -	-
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 21,643	\$ (395)	-1.79%		-	0.00%	\$ -	\$ -	-
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 191,043	\$ 191,043	0.00%		-	0.00%	\$ -	\$ -	-
93											
94	Total MISO Wholesale Market Charges	\$ (827,347)	\$ (7,774,398)	\$ (6,956,412)	840.81%		-	0.00%	\$ -	\$ -	-
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ 30	\$ (1,062)	-97.22%		-	0.00%	\$ -	\$ -	-
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ 122	\$ (122)	-50.15%		-	0.00%	\$ -	\$ -	-
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ 11	\$ (5)	-31.82%		-	0.00%	\$ -	\$ -	-
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ 40	\$ (18)	-31.32%		-	0.00%	\$ -	\$ -	-
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ 3	\$ (69)	-95.94%		-	0.00%	\$ -	\$ -	-
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ 1	\$ (10)	-91.18%		-	0.00%	\$ -	\$ -	-
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%		-	0.00%	\$ -	\$ -	-
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (15,683)	\$ (8,013)	\$ 7,670	-48.91%		-	0.00%	\$ -	\$ -	-
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ 0	\$ (2)	-84.89%		-	0.00%	\$ -	\$ -	-
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ (2)	\$ 0	-14.17%		-	0.00%	\$ -	\$ -	-
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ (0)	\$ 3	-98.49%		-	0.00%	\$ -	\$ -	-
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%		-	0.00%	\$ -	\$ -	-
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%		-	0.00%	\$ -	\$ -	-
116	555.20 RT Pseudo Tie Congestion Amount	\$ (31,201)	\$ 20,694	\$ 51,895	-166.33%		-	0.00%	\$ -	\$ -	-
117	555.21 RT Pseudo Tie Loss Amount	\$ (11,787)	\$ 13,210	\$ 24,997	-212.07%		-	0.00%	\$ -	\$ -	-
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%		-	0.00%	\$ -	\$ -	-
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ (0)	\$ (0)	-403.16%		-	0.00%	\$ -	\$ -	-
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ 4	\$ (3)	-41.99%		-	0.00%	\$ -	\$ -	-
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ 7	\$ (28)	-78.91%		-	0.00%	\$ -	\$ -	-
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ (0)	\$ (36)	-100.37%		-	0.00%	\$ -	\$ -	-
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ (0)	\$ 1	-92.68%		-	0.00%	\$ -	\$ -	-
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%		-	0.00%	\$ -	\$ -	-
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
128	555.36 ARR_Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
129	555.37 RT URD Distribution AO Amount	\$ -	\$ (9)	\$ (9)	0.00%		-	0.00%	\$ -	\$ -	-
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ 4	\$ (22)	-84.18%		-	0.00%	\$ -	\$ -	-
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ (1)	\$ -	\$ 1	-100.00%		-	0.00%	\$ -	\$ -	-
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-
133											
134	Total SPP Wholesale Market Charges	\$ (57,078)	\$ 26,103	\$ 83,181	-145.73%		-	0.00%	\$ -	\$ -	-
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (18,554)	\$ (110,399)	\$ (91,845)	495.03%		-	0.00%	\$ -	\$ -	-
138	DA ASM Spinning Reserve Amount	\$ (15,139)	\$ (28,804)	\$ (13,664)	90.26%		-	0.00%	\$ -	\$ -	-
139	DA ASM Short-Term Reserve Amount	\$ (7,302)	\$ (57,381)	\$ (50,079)	685.83%		-	0.00%	\$ -	\$ -	-
140	DA ASM Supplemental Reserve Amount	\$ (10,789)	\$ (133,986)	\$ (123,197)	1141.86%		-	0.00%	\$ -	\$ -	-
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%		-	0.00%	\$ -	\$ -	-
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 27,036	\$ 23,107	588.14%		-	0.00%	\$ -	\$ -	-
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ (1,134)	\$ (2,573)	-178.79%		-	0.00%	\$ -	\$ -	-
144	RT ASM Net Regulation Adjustment Amount	\$ (8,232)	\$ (126,844)	\$ (118,612)	1440.87%		-	0.00%	\$ -	\$ -	-
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 21,778	\$ 51,870	\$ 30,092	138.18%		-	0.00%	\$ -	\$ -	-
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (2,034)	\$ (11,462)	\$ (9,427)	463.44%		-	0.00%	\$ -	\$ -	-
147	RT ASM Regulation Cost Distribution Amount	\$ 21,926	\$ 27,193	\$ 5,266	24.02%		-	0.00%	\$ -	\$ -	-
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (53)	\$ (15,737)	\$ (15,683)	29513.42%		-	0.00%	\$ -	\$ -	-
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 13,522	\$ 66,503	\$ 52,981	391.81%		-	0.00%	\$ -	\$ -	-
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%		-	0.00%	\$ -	\$ -	-

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

		(A)			(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)					
Line No.		October 2025																	
		Expense (Revenue)				MWh				Cost per MWh									
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual								
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$	2,386	\$	39,468	\$	37,082		1554.10%			-	0.00%	\$	-	\$	-		
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$	3,395	\$	14,388	\$	10,993		323.82%			-	0.00%	\$	-	\$	-		
153																			
154	Total MISO ASM	\$	9,654	\$	(259,288)	\$	(268,942)		-2785.75%		-	-	-	0.00%	\$	-	\$	-	
155																			
156	Total Wholesale Market Charges	\$	(874,771)	\$	(8,007,582)	\$	(7,132,811)		815.39%		-	-	-	0.00%	\$	-	\$	-	
157																			
158																			
159																			
160	Purchased Power																		
161	Edgeley PPA																		
162	Langdon PPA																		
163	Ashtabula III PPA																		
164	Tribal (WAPA)																		
165	WAPA Energy Imbalance																		
166	Shared Loads																		
167	Small Co-gen																		
168	Bilateral purchases																		
169	Market Purchases																		
170																			
171	Total Purchases	\$	6,616,896	\$	12,236,896	\$	5,619,999		84.93%		176,444	237,051	60,607	34.35%	\$	37.50	\$	51.62	
172																			
173	Wind Curtailment	\$	25,136	\$	13,535	\$	(11,601)		-46.15%			345	345	0.00%	\$	-	\$	39.22	
174																			
175	Asset Based Sales	\$	(329,983)	\$	(1,843,689)	\$	(1,513,706)		458.72%		(6,044)	(22,350)	(16,305)	269.76%	\$	54.59	\$	82.49	
176	Fuel Costs	\$	161,884	\$	972,665	\$	810,781		500.84%					-	0.00%	\$	-	\$	-
177	Asset Based Margins	\$	(168,099)	\$	(871,023)	\$	(702,924)		418.16%					-	0.00%	\$	-	\$	-
178																			
179	Hoot Lake Solar Generation Credit	\$	(218,094)	\$	(451,215)	\$	(233,121)		106.89%					-	0.00%	\$	-	\$	-
180																			
181	Steam Plant Reagents	\$	173,385	\$	262,755	\$	89,370		51.54%					-	0.00%	\$	-	\$	-
182																			
183	Steam/Water Sales	\$	(49,480)	\$	(53,081)	\$	(3,601)		7.28%					-	0.00%	\$	-	\$	-
184																			
185	Planning Resource Auction Revenues	\$	-	\$	(163,398)	\$	-		0.00%					-	0.00%	\$	-	\$	-
186																			
187	Total System - Plant Level	\$	10,021,653	\$	6,797,770	\$	(3,223,883)		-32.17%		478,470	478,498	28	0.01%	\$	20.95	\$	14.21	

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		November 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5											
6	Total Coal	\$ 4,801,357	\$ 4,927,492	\$ 126,135	2.63%	194,759	205,440	10,681	5.48%	\$ 24.65	\$ 23.99
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14											
15	Total Wind	\$ -	\$ -	\$ -	0.00%	104,551	105,248	698	0.67%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,644	397	(1,247)	-75.85%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23											
24	Total Oil - Peaking Units	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29											
30	Total Natural Gas	\$ 884,528	\$ 2,483,657	\$ 1,599,129	180.79%	24,818	60,315	35,496	143.02%	\$ 35.64	\$ 41.18
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36											
37	Total Solar	\$ -	\$ -	\$ -	0.00%	3,433	3,433	0	0.01%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 5,685,885	\$ 7,411,149	\$ 1,725,264	30.34%	329,204	374,833	45,629	13.86%	\$ 17.27	\$ 19.77
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (335,550)	\$ (215,817)	\$ 119,733	-35.68%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 636,345	\$ 1,092,119	\$ 455,774	71.62%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 38,341	\$ 134,743	\$ 96,402	251.43%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 75,430	\$ 64,835	\$ (10,595)	-14.05%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 11,114	\$ 8,876	\$ (2,238)	-20.14%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 1,691	\$ 827	\$ (864)	-51.09%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 2,163,325	\$ 4,698,526	\$ 2,535,201	117.19%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 253,755	\$ 232,574	\$ (21,181)	-8.35%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (3,269,411)	\$ (9,089,125)	\$ (5,819,714)	178.00%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (78,225)	\$ (297,937)	\$ (219,712)	280.87%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (177,407)	\$ (52,646)	\$ 124,762	-70.33%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 181,363	\$ 53,706	\$ (127,657)	-70.39%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 5,757,546	\$ (3,994,313)	\$ (9,751,858)	-169.38%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,857,971)	\$ 3,735,605	\$ 9,593,576	-163.77%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 13,837	\$ 9,513	\$ (4,324)	-31.25%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (128,220)	\$ (270,125)	\$ (141,905)	110.67%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 15,039	\$ 11,764	\$ (3,275)	-21.78%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (8,270)	\$ -	\$ 8,270	-100.00%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		November 2025									
		Expense (Revenue)			MWh			Cost per MWh			
		Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 3,816	\$ (24,472)	-86.51%	-	0.00%	\$ -	\$ -		
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%	-	0.00%	\$ -	\$ -		
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (55,425)	\$ (1,322)	2.44%	-	0.00%	\$ -	\$ -		
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 204,196	\$ 75,740	58.96%	-	0.00%	\$ -	\$ -		
79	555.25 RT Misc Amount	\$ (20,051)	\$ (2,078)	\$ 17,973	-89.64%	-	0.00%	\$ -	\$ -		
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ (882)	\$ (994)	-889.34%	-	0.00%	\$ -	\$ -		
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 327	\$ 1,974	\$ 1,647	503.33%	-	0.00%	\$ -	\$ -		
83	555.63 DA Ramp Product	\$ (7,590)	\$ (13,651)	\$ (6,061)	79.86%	-	0.00%	\$ -	\$ -		
84	555.64 RT Ramp Product	\$ (1,044)	\$ (1,360)	\$ (316)	30.29%	-	0.00%	\$ -	\$ -		
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 21,935	\$ (103)	-0.47%	-	0.00%	\$ -	\$ -		
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 203,645	\$ 203,645	0.00%	-	0.00%	\$ -	\$ -		
93											
94	Total MISO Wholesale Market Charges	\$ (894,750)	\$ (3,589,243)	\$ (2,708,190)	302.68%	-	0.00%	\$ -	\$ -		
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ 20	\$ (1,072)	-98.20%	-	0.00%	\$ -	\$ -		
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ (85)	\$ (328)	-134.68%	-	0.00%	\$ -	\$ -		
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ 1	\$ (15)	-95.92%	-	0.00%	\$ -	\$ -		
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ (28)	\$ (87)	-148.47%	-	0.00%	\$ -	\$ -		
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ (2)	\$ (73)	-102.20%	-	0.00%	\$ -	\$ -		
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ (1)	\$ (11)	-104.84%	-	0.00%	\$ -	\$ -		
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	0.00%	\$ -	\$ -		
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (17,223)	\$ (8,632)	\$ 8,591	-49.88%	-	0.00%	\$ -	\$ -		
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ (0)	\$ (3)	-100.70%	-	0.00%	\$ -	\$ -		
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ 1	\$ 3	-132.72%	-	0.00%	\$ -	\$ -		
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	0.00%	\$ -	\$ -		
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
116	555.20 RT Pseudo Tie Congestion Amount	\$ (34,264)	\$ 44,591	\$ 78,856	-230.14%	-	0.00%	\$ -	\$ -		
117	555.21 RT Pseudo Tie Loss Amount	\$ (12,945)	\$ 13,248	\$ 26,192	-202.34%	-	0.00%	\$ -	\$ -		
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ -	-100.00%	-	0.00%	\$ -	\$ -		
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ 1	\$ 1	733.68%	-	0.00%	\$ -	\$ -		
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ (1)	\$ (8)	-111.96%	-	0.00%	\$ -	\$ -		
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ (2)	\$ (37)	-104.35%	-	0.00%	\$ -	\$ -		
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ -	\$ (36)	-100.00%	-	0.00%	\$ -	\$ -		
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	0.00%	\$ -	\$ -		
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	0.00%	\$ -	\$ -		
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
128	555.36 ARR_Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
129	555.37 RT URD Distribution AO Amount	\$ -	\$ 1	\$ 1	0.00%	-	0.00%	\$ -	\$ -		
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ (0)	\$ (26)	-101.57%	-	0.00%	\$ -	\$ -		
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ 0	\$ (0)	\$ (0)	-133.33%	-	0.00%	\$ -	\$ -		
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		
133											
134	Total SPP Wholesale Market Charges	\$ (62,838)	\$ 49,111	\$ 111,949	-178.16%	-	0.00%	\$ -	\$ -		
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (31,121)	\$ (128,471)	\$ (97,350)	312.81%	-	0.00%	\$ -	\$ -		
138	DA ASM Spinning Reserve Amount	\$ (39,437)	\$ (36,299)	\$ 3,138	-7.96%	-	0.00%	\$ -	\$ -		
139	DA ASM Short-Term Reserve Amount	\$ (19,227)	\$ (88,611)	\$ (69,384)	360.87%	-	0.00%	\$ -	\$ -		
140	DA ASM Supplemental Reserve Amount	\$ (7,222)	\$ (35,930)	\$ (28,708)	397.49%	-	0.00%	\$ -	\$ -		
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%	-	0.00%	\$ -	\$ -		
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 39,340	\$ 35,412	901.32%	-	0.00%	\$ -	\$ -		
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 984	\$ (455)	-31.63%	-	0.00%	\$ -	\$ -		
144	RT ASM Net Regulation Adjustment Amount	\$ (6,275)	\$ (141,477)	\$ (135,202)	2154.61%	-	0.00%	\$ -	\$ -		
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 24,915	\$ 60,765	\$ 35,850	143.89%	-	0.00%	\$ -	\$ -		
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (374)	\$ 1,899	\$ 2,273	-608.43%	-	0.00%	\$ -	\$ -		
147	RT ASM Regulation Cost Distribution Amount	\$ 28,889	\$ 25,760	\$ (3,129)	-10.83%	-	0.00%	\$ -	\$ -		
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (84)	\$ 3,370	\$ 3,454	-4134.93%	-	0.00%	\$ -	\$ -		
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 11,938	\$ 46,991	\$ 35,053	293.63%	-	0.00%	\$ -	\$ -		
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%	-	0.00%	\$ -	\$ -		

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		November 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 1,106	\$ 13,467	\$ 12,361	1117.42%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 1,729	\$ 4,032	\$ 2,303	133.21%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (26,411)	\$ (234,179)	\$ (207,768)	786.66%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (983,998)	\$ (3,774,311)	\$ (2,790,313)	283.57%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 7,782,501	\$ 7,145,370	\$ (637,132)	-8.19%	199,357	169,256	(30,101)	-15.10%	\$ 39.04	\$ 42.22
172											
173	Wind Curtailment	\$ 11,356	\$ 16,080	\$ 4,724	41.60%		610	610	0.00%	\$ -	\$ 26.36
174											
175	Asset Based Sales	\$ (157,399)	\$ (1,525,513)	\$ (1,368,114)	869.20%	(2,796)	(25,586)	(22,790)	814.97%	\$ 56.29	\$ 59.62
176	Fuel Costs	\$ 72,412	\$ 1,179,773	\$ 1,107,361	1529.25%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (84,987)	\$ (345,740)	\$ (260,753)	306.82%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (147,757)	\$ (193,618)	\$ (45,861)	31.04%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 300,288	\$ 449,628	\$ 149,339	49.73%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (125,612)	\$ (97,881)	\$ 27,731	-22.08%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (33,833)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 12,365,264	\$ 9,397,071	\$ (2,968,193)	-24.00%	525,765	519,112	(6,652)	-1.27%	\$ 23.52	\$ 18.10

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		December 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 5,674,123	\$ 4,632,282	\$ (1,041,841)	-18.36%	209,813	181,528	(28,285)	-13.48%	\$ 27.04	\$ 25.52
7											
8	Wind	[PROTECTED DATA BEGINS...									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	125,866	82,504	(43,362)	-34.45%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	1,699	650	(1,048)	-61.70%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ -	\$ 8,910	\$ 8,910	0.00%	-	-	-	0.00%	\$ -	\$ -
25											
26	Natural Gas	[PROTECTED DATA BEGINS...									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 1,296,765	\$ 2,136,759	\$ 839,994	64.78%	26,839	46,914	20,075	74.80%	\$ 48.32	\$ 45.55
31											
32	Solar	[PROTECTED DATA BEGINS...									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	2,544	1,503	(1,040)	-40.89%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 6,970,888	\$ 6,777,951	\$ (192,937)	-2.77%	366,760	313,100	(53,660)	-14.63%	\$ 19.01	\$ 21.65
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (375,189)	\$ (462,951)	\$ (87,762)	23.39%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 711,516	\$ 1,588,238	\$ 876,722	123.22%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 42,870	\$ 103,518	\$ 60,648	141.47%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ 418	\$ 418	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 77,384	\$ 81,246	\$ 3,862	4.99%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 11,136	\$ 9,726	\$ (1,410)	-12.66%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 1,727	\$ 1,047	\$ (680)	-39.38%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 2,418,877	\$ 7,807,586	\$ 5,388,709	222.78%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 283,731	\$ 560,998	\$ 277,267	97.72%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (3,655,624)	\$ (14,707,514)	\$ (11,051,889)	302.33%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (87,465)	\$ (205,732)	\$ (118,267)	135.22%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (97,578)	\$ (391,146)	\$ (293,568)	300.85%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 83,118	\$ 376,019	\$ 292,901	352.39%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 5,401,650	\$ (2,229,651)	\$ (7,631,301)	-141.28%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (5,551,558)	\$ 2,152,157	\$ 7,703,715	-138.77%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 8,628	\$ 7,679	\$ (950)	-11.01%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (158,203)	\$ (320,798)	\$ (162,596)	102.78%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 18,077	\$ 33,346	\$ 15,268	84.46%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (4,882)	\$ -	\$ 4,882	-100.00%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		December 2025									
		Expense (Revenue)			MWh			Cost per MWh			
		Forecast	Actual	Difference	Forecast	Actual	Difference	Forecast	Actual		
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 28,287	\$ 16,196	\$ (12,092)	-42.75%	-	-	0.00%	\$ -	\$ -	-
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (195,680)	\$ -	\$ 195,680	-100.00%	-	-	0.00%	\$ -	\$ -	-
77	555.42 RT Price Volatility Make Whole Payment	\$ (54,103)	\$ (66,960)	\$ (12,857)	23.76%	-	-	0.00%	\$ -	\$ -	-
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 128,456	\$ 372,566	\$ 244,110	190.03%	-	-	0.00%	\$ -	\$ -	-
79	555.25 RT Misc Amount	\$ (20,051)	\$ (0)	\$ 20,051	-100.00%	-	-	0.00%	\$ -	\$ -	-
80	555.27 RT Net Inadvertent Amount	\$ 112	\$ 20,664	\$ 20,552	18391.03%	-	-	0.00%	\$ -	\$ -	-
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 858	\$ 974	\$ 116	13.52%	-	-	0.00%	\$ -	\$ -	-
83	555.63 DA Ramp Product	\$ (2,100)	\$ (11,479)	\$ (9,378)	446.50%	-	-	0.00%	\$ -	\$ -	-
84	555.64 RT Ramp Product	\$ (1,529)	\$ 29	\$ 1,558	-101.92%	-	-	0.00%	\$ -	\$ -	-
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 22,038	\$ 26,230	\$ 4,192	19.02%	-	-	0.00%	\$ -	\$ -	-
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ 258,436	\$ 258,436	0.00%	-	-	0.00%	\$ -	\$ -	-
93											
94	Total MISO Wholesale Market Charges	\$ (1,055,744)	\$ (5,071,177)	\$ (4,013,662)	380.17%	-	-	0.00%	\$ -	\$ -	-
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 1,092	\$ 347	\$ (745)	-68.24%	-	-	0.00%	\$ -	\$ -	-
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 244	\$ 162	\$ (82)	-33.50%	-	-	0.00%	\$ -	\$ -	-
105	555.04 DA Regulation-Down Distribution Amount	\$ 16	\$ 5	\$ (11)	-68.71%	-	-	0.00%	\$ -	\$ -	-
106	555.05 DA Regulation-Up Distribution Amount	\$ 59	\$ 26	\$ (33)	-56.28%	-	-	0.00%	\$ -	\$ -	-
107	555.06 DA Spinning Reserve Distribution Amount	\$ 72	\$ 18	\$ (54)	-74.76%	-	-	0.00%	\$ -	\$ -	-
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 11	\$ 3	\$ (8)	-75.43%	-	-	0.00%	\$ -	\$ -	-
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (2)	\$ -	\$ 2	-100.00%	-	-	0.00%	\$ -	\$ -	-
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (19,257)	\$ (13,396)	\$ 5,861	-30.44%	-	-	0.00%	\$ -	\$ -	-
111	555.12 RT Regulation-Down Distribution Amount	\$ 3	\$ 0	\$ (2)	-82.78%	-	-	0.00%	\$ -	\$ -	-
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (2)	\$ (0)	\$ 2	-92.41%	-	-	0.00%	\$ -	\$ -	-
113	555.14 RT Regulation-Up Distribution Amount	\$ (3)	\$ 0	\$ 3	-103.33%	-	-	0.00%	\$ -	\$ -	-
114	555.16 RT Spinning Reserve Distribution Amount	\$ (1)	\$ -	\$ 1	-100.00%	-	-	0.00%	\$ -	\$ -	-
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	-	0.00%	\$ -	\$ -	-
116	555.20 RT Pseudo Tie Congestion Amount	\$ (38,312)	\$ 72,014	\$ 110,326	-287.97%	-	-	0.00%	\$ -	\$ -	-
117	555.21 RT Pseudo Tie Loss Amount	\$ (14,474)	\$ 49,866	\$ 64,340	-444.52%	-	-	0.00%	\$ -	\$ -	-
118	555.23 Miscellaneous Amount	\$ 9	\$ -	\$ (9)	-100.00%	-	-	0.00%	\$ -	\$ -	-
119	555.26 ARR Closeout Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
120	555.28 RT Demand Reduction Distribution Amount	\$ 0	\$ (9)	\$ (9)	-11860.00%	-	-	0.00%	\$ -	\$ -	-
121	555.29 RT Schedule 1A3 Amount	\$ 7	\$ 7	\$ (0)	-3.92%	-	-	0.00%	\$ -	\$ -	-
122	555.30 RT Schedule 1A4 Amount	\$ 35	\$ 12	\$ (23)	-65.11%	-	-	0.00%	\$ -	\$ -	-
123	555.31 DA Ramp Up Distribution Amount	\$ 36	\$ 8	\$ (28)	-77.59%	-	-	0.00%	\$ -	\$ -	-
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (1)	\$ (0)	\$ 1	-98.17%	-	-	0.00%	\$ -	\$ -	-
126	555.34 RT Ramp Up Distribution Amount	\$ (3)	\$ -	\$ 3	-100.00%	-	-	0.00%	\$ -	\$ -	-
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
128	555.36 ARR_Auction Transaction AO Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
129	555.37 RT URD Distribution AO Amount	\$ -	\$ (2)	\$ (2)	0.00%	-	-	0.00%	\$ -	\$ -	-
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 26	\$ 20	\$ (6)	-23.45%	-	-	0.00%	\$ -	\$ -	-
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ (0)	\$ (0)	\$ (0)	50.00%	-	-	0.00%	\$ -	\$ -	-
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-
133											
134	Total SPP Wholesale Market Charges	\$ (70,449)	\$ 109,081	\$ 179,530	-254.84%	-	-	0.00%	\$ -	\$ -	-
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (26,108)	\$ (118,769)	\$ (92,661)	354.91%	-	-	0.00%	\$ -	\$ -	-
138	DA ASM Spinning Reserve Amount	\$ (15,464)	\$ (39,092)	\$ (23,628)	152.79%	-	-	0.00%	\$ -	\$ -	-
139	DA ASM Short-Term Reserve Amount	\$ (14,550)	\$ (110,739)	\$ (96,189)	661.10%	-	-	0.00%	\$ -	\$ -	-
140	DA ASM Supplemental Reserve Amount	\$ (13,335)	\$ (16,301)	\$ (2,965)	22.24%	-	-	0.00%	\$ -	\$ -	-
141	RT ASM Regulation Amount	\$ 3,383	\$ -	\$ (3,383)	-100.00%	-	-	0.00%	\$ -	\$ -	-
142	RT ASM Spinning Reserve Amount	\$ 3,929	\$ 16,815	\$ 12,886	327.97%	-	-	0.00%	\$ -	\$ -	-
143	RT ASM Supplemental Reserve Amount	\$ 1,439	\$ 1,234	\$ (205)	-14.26%	-	-	0.00%	\$ -	\$ -	-
144	RT ASM Net Regulation Adjustment Amount	\$ (33,803)	\$ (48,740)	\$ (14,937)	44.19%	-	-	0.00%	\$ -	\$ -	-
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 25,893	\$ 68,828	\$ 42,935	165.82%	-	-	0.00%	\$ -	\$ -	-
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (57,869)	\$ 9,826	\$ 67,695	-116.98%	-	-	0.00%	\$ -	\$ -	-
147	RT ASM Regulation Cost Distribution Amount	\$ 26,496	\$ 28,666	\$ 2,170	8.19%	-	-	0.00%	\$ -	\$ -	-
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (40,857)	\$ 10,201	\$ 51,057	-124.97%	-	-	0.00%	\$ -	\$ -	-
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 56,449	\$ 44,819	\$ (11,630)	-20.60%	-	-	0.00%	\$ -	\$ -	-
150	RT ASM Short-Term Reserve Amount	\$ -	\$ -	\$ -	0.00%	-	-	0.00%	\$ -	\$ -	-

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		December 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 154,275	\$ 8,306	\$ (145,969)	-94.62%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 623	\$ 2,196	\$ 1,573	252.36%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ 70,500	\$ (142,751)	\$ (213,251)	-302.48%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (1,055,693)	\$ (5,104,847)	\$ (4,049,154)	383.55%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 11,274,678	\$ 19,372,446	\$ 8,097,769	71.82%	230,592	296,410	65,818	28.54%	\$ 48.89	\$ 65.36
172											
173	Wind Curtailment	\$ 6,995	\$ (10,808)	\$ (17,802)	-254.52%		(376)	(376)	0.00%	\$ -	\$ 28.78
174											
175	Asset Based Sales	\$ (697,145)	\$ (1,685,880)	\$ (988,735)	141.83%	(9,264)	(27,013)	(17,749)	191.59%	\$ 75.25	\$ 62.41
176	Fuel Costs	\$ 272,883	\$ 1,114,359	\$ 841,476	308.37%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (424,262)	\$ (571,521)	\$ (147,259)	34.71%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (131,274)	\$ (95,684)	\$ 35,590	-27.11%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 345,136	\$ 423,445	\$ 78,309	22.69%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (104,055)	\$ (115,243)	\$ (11,188)	10.75%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ 397,328	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 16,609,529	\$ 19,958,708	\$ 3,349,179	20.16%	588,088	582,121	(5,967)	-1.01%	\$ 28.24	\$ 34.29

*** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		Year-to-Date 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
1	Plant Generation										
2	Coal	[PROTECTED DATA BEGINS...]									
3	Big Stone										
4	Coyote										
5										...PROTECTED DATA ENDS]	
6	Total Coal	\$ 51,353,824	\$ 52,066,689	\$ 712,865	1.39%	1,986,376	1,881,823	(104,554)	-5.26%	\$ 25.85	\$ 27.67
7											
8	Wind	[PROTECTED DATA BEGINS...]									
9	Langdon Wind										
10	Ashtabula Wind										
11	Ashtabula III										
12	Luverne Wind										
13	Merricourt										
14										...PROTECTED DATA ENDS]	
15	Total Wind	\$ -	\$ -	\$ -	0.00%	1,281,553	1,116,060	(165,493)	-12.91%	\$ -	\$ -
16											
17	Total Hydro	\$ -	\$ -	\$ -	0.00%	20,000	12,010	(7,990)	-39.95%	\$ -	\$ -
18											
19	Oil - Peaking Units	[PROTECTED DATA BEGINS...]									
20	Jamestown 1										
21	Jamestown 2										
22	Lake Preston										
23										...PROTECTED DATA ENDS]	
24	Total Oil - Peaking Units	\$ 246,353	\$ 507,706	\$ 261,353	106.09%	874	1,309	435	49.78%	\$ 281.86	\$ 387.81
25											
26	Natural Gas	[PROTECTED DATA BEGINS...]									
27	Solway										
28	Astoria										
29										...PROTECTED DATA ENDS]	
30	Total Natural Gas	\$ 16,331,606	\$ 22,473,171	\$ 6,141,565	37.61%	519,795	598,226	78,431	15.09%	\$ 31.42	\$ 37.57
31											
32	Solar	[PROTECTED DATA BEGINS...]									
33	Blue Jay										
34	Blue Heron										
35	Hoot Lake										
36										...PROTECTED DATA ENDS]	
37	Total Solar	\$ -	\$ -	\$ -	0.00%	86,715	73,467	(13,247)	-15.28%	\$ -	\$ -
38											
39	Total OTP-Owned	\$ 67,931,783	\$ 75,047,565	\$ 7,115,782	10.47%	3,895,312	3,682,894	(212,418)	-5.45%	\$ 17.44	\$ 20.38
40											
41	Wholesale Market Charges										
42	MISO Wholesale Market Charges										
43	555.02 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
44	555.04 DA FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
45	555.09 DA Non-asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
46	555.19 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
47	555.24 RT Distribution of Losses Amount	\$ (3,905,053)	\$ (4,165,375)	\$ (260,322)	6.67%	-	-	-	0.00%	\$ -	\$ -
48	555.21 RT FBT Loss Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
49	DA Loss Amount	\$ 7,405,629	\$ 12,625,149	\$ 5,219,520	70.48%	-	-	-	0.00%	\$ -	\$ -
50	RT Loss Amount	\$ 446,204	\$ 914,001	\$ 467,797	104.84%	-	-	-	0.00%	\$ -	\$ -
51	555.26 RT Non-Asset Energy Amount***	\$ -	\$ 418	\$ 418	0.00%	-	-	-	0.00%	\$ -	\$ -
52	555.08 DA Losses Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
53	555.12 DA Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
54	555.32 RT Virtual Energy Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
55	555.01 DA Mkt Admin Amount	\$ 850,121	\$ 832,146	\$ (17,976)	-2.11%	-	-	-	0.00%	\$ -	\$ -
56	555.18 RT Mkt Admin Amount	\$ 127,018	\$ 107,525	\$ (19,494)	-15.35%	-	-	-	0.00%	\$ -	\$ -
57	555.13 FTR Mkt Admin Amount	\$ 21,848	\$ 14,244	\$ (7,604)	-34.80%	-	-	-	0.00%	\$ -	\$ -
58	555.03 DA FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
59	DA Congestion	\$ 25,176,241	\$ 28,875,529	\$ 3,699,289	14.69%	-	-	-	0.00%	\$ -	\$ -
60	555.20 RT FBT Congestion Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
61	RT Congestion	\$ 2,953,142	\$ 1,956,554	\$ (996,588)	-33.75%	-	-	-	0.00%	\$ -	\$ -
62	555.14 FTR Hourly Allocation Amount	\$ (38,048,602)	\$ (56,473,416)	\$ (18,424,815)	-48.42%	-	-	-	0.00%	\$ -	\$ -
63	555.15 FTR Monthly Allocation Amount	\$ (910,360)	\$ (1,206,274)	\$ (295,914)	-32.51%	-	-	-	0.00%	\$ -	\$ -
64	555.17 FTR Yearly Allocation Amount	\$ (312,193)	\$ (241,774)	\$ 70,420	-22.56%	-	-	-	0.00%	\$ -	\$ -
65	555.35 FTR Monthly Transaction Amount	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
66	555.36 FTR Full Funding Guarantee Amount	\$ (751,420)	\$ (675,771)	\$ 75,650	-10.07%	-	-	-	0.00%	\$ -	\$ -
67	555.37 FTR Guarantee Uplift Amount	\$ 668,376	\$ 811,807	\$ 143,430	21.46%	-	-	-	0.00%	\$ -	\$ -
68	555.38 FTR Annual Transaction Amount	\$ 61,353,684	\$ (19,768,996)	\$ (81,122,680)	-132.22%	-	-	-	0.00%	\$ -	\$ -
69	555.39 FTR Auction Revenue Rights Transaction Amount	\$ (62,818,060)	\$ 17,793,773	\$ 80,611,833	-128.33%	-	-	-	0.00%	\$ -	\$ -
70	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 154,551	\$ 116,276	\$ (38,275)	-24.77%	-	-	-	0.00%	\$ -	\$ -
71	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (1,681,880)	\$ (2,760,311)	\$ (1,078,431)	-64.12%	-	-	-	0.00%	\$ -	\$ -
72	555.07 DA Congestion Rebate on Option B GFA	\$ -	\$ -	\$ -	0.00%	-	-	-	0.00%	\$ -	\$ -
73	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	\$ 173,493	\$ 163,490	\$ (10,003)	-5.77%	-	-	-	0.00%	\$ -	\$ -
74	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (138,566)	\$ (86,534)	\$ 52,031	-37.55%	-	-	-	0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.		Year-to-Date 2025									
		Expense (Revenue)				MWh			Cost per MWh		
		Forecast	Actual	Difference		Forecast	Actual	Difference	Forecast	Actual	
75	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 339,449	\$ 134,738	\$ (204,711)	-60.31%				0.00%	\$ -	\$ -
76	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (2,348,157)	\$ -	\$ 2,348,157	-100.00%				0.00%	\$ -	\$ -
77	555.42 RT Price Volatility Make Whole Payment	\$ (649,241)	\$ (471,248)	\$ 177,994	-27.42%				0.00%	\$ -	\$ -
78	555.28 RT Revenue Neutrality Uplift Amount	\$ 1,541,475	\$ 2,216,119	\$ 674,644	43.77%				0.00%	\$ -	\$ -
79	555.25 RT Misc Amount	\$ (240,614)	\$ 9,955	\$ 250,569	-104.14%				0.00%	\$ -	\$ -
80	555.27 RT Net Inadvertent Amount	\$ 1,341	\$ 24,085	\$ 22,744	1696.01%				0.00%	\$ -	\$ -
81	555.31 RT Uninstructed Deviation Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
82	555.59 RT Demand Response Allocation Uplift Amount	\$ 113,750	\$ 100,872	\$ (12,878)	-11.32%				0.00%	\$ -	\$ -
83	555.63 DA Ramp Product	\$ (41,891)	\$ (169,699)	\$ (127,808)	305.10%				0.00%	\$ -	\$ -
84	555.64 RT Ramp Product	\$ (11,518)	\$ (12,419)	\$ (901)	7.82%				0.00%	\$ -	\$ -
85	555.65 RT Schedule 49 Cost Distribution Amount	\$ 264,452	\$ 268,162	\$ 3,710	1.40%				0.00%	\$ -	\$ -
86	555.55 RT ASM Non-Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
87	555.56 RT ASM Excessive Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
88	555.05 DA Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
89	555.06 DA Losses Rebate on COGA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
90	555.22 RT Congestion Rebate on COGA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
91	555.23 RT Loss Rebate on COGA	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
92	Net Congestion and Losses Adjustment & No DA Generation Schedule	\$ -	\$ (31,840)	\$ (31,840)	0.00%				0.00%	\$ -	\$ -
93											
94	Total MISO Wholesale Market Charges	\$ (11,265,769)	\$ (20,052,728)	\$ (8,786,959)	78.00%	-	-	-	0.00%	\$ -	\$ -
95											
96	SPP Wholesale Market Charges										
97	555.19 DA Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
98	555.03 DA Non-asset Energy Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
99	555.09 RT Asset Energy Amount***	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
100	555.00 RT Non-Asset Energy Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
101	555.02 DA Make-Whole-Payment Distribution Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
102	555.10 RT Make-Whole-Payment Distribution Amount	\$ 13,105	\$ 750	\$ (12,356)	-94.28%				0.00%	\$ -	\$ -
103	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
104	555.15 RT Revenue Neutrality Uplift Distribution Amount	\$ 2,925	\$ 281	\$ (2,644)	-90.39%				0.00%	\$ -	\$ -
105	555.04 DA Regulation-Down Distribution Amount	\$ 188	\$ 26	\$ (163)	-86.36%				0.00%	\$ -	\$ -
106	555.05 DA Regulation-Up Distribution Amount	\$ 703	\$ 69	\$ (633)	-90.15%				0.00%	\$ -	\$ -
107	555.06 DA Spinning Reserve Distribution Amount	\$ 860	\$ 36	\$ (824)	-95.82%				0.00%	\$ -	\$ -
108	555.07 DA Supplemental Reserve Distribution Amount	\$ 127	\$ 6	\$ (120)	-94.89%				0.00%	\$ -	\$ -
109	555.08 RT Contingency Reserve Deployment Failure Amount	\$ (22)	\$ (0)	\$ 22	-99.78%				0.00%	\$ -	\$ -
110	555.11 RT Over-Collected Losses Distribution Amount	\$ (200,436)	\$ (110,334)	\$ 90,101	-44.95%				0.00%	\$ -	\$ -
111	555.12 RT Regulation-Down Distribution Amount	\$ 34	\$ 1	\$ (33)	-96.84%				0.00%	\$ -	\$ -
112	555.13 RT Regulation Non-Performance Distribution Amount	\$ (25)	\$ (2)	\$ 23	-91.11%				0.00%	\$ -	\$ -
113	555.14 RT Regulation-Up Distribution Amount	\$ (40)	\$ (0)	\$ 39	-99.27%				0.00%	\$ -	\$ -
114	555.16 RT Spinning Reserve Distribution Amount	\$ (9)	\$ -	\$ 9	-100.00%				0.00%	\$ -	\$ -
115	555.17 RT Supplemental Reserve Distribution Amount	\$ (38)	\$ -	\$ 38	-100.00%				0.00%	\$ -	\$ -
116	555.20 RT Pseudo Tie Congestion Amount	\$ (398,761)	\$ (529,865)	\$ (131,104)	32.88%				0.00%	\$ -	\$ -
117	555.21 RT Pseudo Tie Loss Amount	\$ (150,648)	\$ 101,712	\$ 252,361	-167.52%				0.00%	\$ -	\$ -
118	555.23 Miscellaneous Amount	\$ 113	\$ -	\$ (113)	-100.00%				0.00%	\$ -	\$ -
119	555.26 ARR Closeout Yearly Amount	\$ (236,796)	\$ (418,641)	\$ (181,846)	76.79%				0.00%	\$ -	\$ -
120	555.28 RT Demand Reduction Distribution Amount	\$ 1	\$ (9)	\$ (10)	-1038.95%				0.00%	\$ -	\$ -
121	555.29 RT Schedule 1A3 Amount	\$ 87	\$ 19	\$ (68)	-78.42%				0.00%	\$ -	\$ -
122	555.30 RT Schedule 1A4 Amount	\$ 425	\$ 33	\$ (392)	-92.16%				0.00%	\$ -	\$ -
123	555.31 DA Ramp Up Distribution Amount	\$ 426	\$ 18	\$ (408)	-95.72%				0.00%	\$ -	\$ -
124	555.32 DA Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
125	555.33 RT Ramp Non Performance Distribution Amount	\$ (7)	\$ (0)	\$ 6	-96.80%				0.00%	\$ -	\$ -
126	555.34 RT Ramp Up Distribution Amount	\$ (32)	\$ (0)	\$ 32	-99.65%				0.00%	\$ -	\$ -
127	555.35 RT Ramp Down Distribution Amount	\$ -	\$ -	\$ -	0.00%				0.00%	\$ -	\$ -
128	555.36 ARR_Auction Transaction AO Amount	\$ (359,974)	\$ -	\$ 359,974	-100.00%				0.00%	\$ -	\$ -
129	555.37 RT URD Distribution AO Amount	\$ -	\$ (24)	\$ (24)	0.00%				0.00%	\$ -	\$ -
130	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	\$ 313	\$ 28	\$ (284)	-90.95%				0.00%	\$ -	\$ -
131	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	\$ (2)	\$ (0)	\$ 2	-93.99%				0.00%	\$ -	\$ -
132	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	\$ (125)	\$ (3)	\$ 122	-97.43%				0.00%	\$ -	\$ -
133											
134	Total SPP Wholesale Market Charges	\$ (1,327,608)	\$ (955,900)	\$ 371,708	-28.00%	-	-	-	0.00%	\$ -	\$ -
135											
136	MISO ASM										
137	DA ASM Regulation Amount	\$ (423,667)	\$ (1,345,355)	\$ (921,688)	217.55%				0.00%	\$ -	\$ -
138	DA ASM Spinning Reserve Amount	\$ (305,630)	\$ (451,082)	\$ (145,453)	47.59%				0.00%	\$ -	\$ -
139	DA ASM Short-Term Reserve Amount	\$ (350,553)	\$ (1,716,641)	\$ (1,366,089)	389.70%				0.00%	\$ -	\$ -
140	DA ASM Supplemental Reserve Amount	\$ (200,347)	\$ (1,040,408)	\$ (840,060)	419.30%				0.00%	\$ -	\$ -
141	RT ASM Regulation Amount	\$ 40,593	\$ -	\$ (40,593)	-100.00%				0.00%	\$ -	\$ -
142	RT ASM Spinning Reserve Amount	\$ 47,147	\$ 205,405	\$ 158,259	335.67%				0.00%	\$ -	\$ -
143	RT ASM Supplemental Reserve Amount	\$ 17,267	\$ 54,006	\$ 36,738	212.76%				0.00%	\$ -	\$ -
144	RT ASM Net Regulation Adjustment Amount	\$ (121,290)	\$ (661,964)	\$ (540,674)	445.77%				0.00%	\$ -	\$ -
145	RT ASM Excessive Deficient Energy Deployment Charge Amount	\$ 245,873	\$ 498,358	\$ 252,485	102.69%				0.00%	\$ -	\$ -
146	RT ASM Contingency Reserve Deployment Failure Charge Amount	\$ (73,489)	\$ 70,909	\$ 144,398	-196.49%				0.00%	\$ -	\$ -
147	RT ASM Regulation Cost Distribution Amount	\$ 222,228	\$ 280,338	\$ 58,110	26.15%				0.00%	\$ -	\$ -
148	RT ASM Spinning Reserve Cost Distribution Amount	\$ (45,636)	\$ (35,612)	\$ 10,024	-21.97%				0.00%	\$ -	\$ -
149	RT ASM Supplemental Reserve Cost Distribution Amount	\$ 239,214	\$ 1,177,233	\$ 938,019	392.13%				0.00%	\$ -	\$ -
150	RT ASM Short-Term Reserve Amount	\$ -	\$ 42,275	\$ 42,275	0.00%				0.00%	\$ -	\$ -

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2025 FORECASTED VS ACTUAL COST OF ENERGY

Line No.	(A)	(B) (C) (D) (E) (F) (G) (H) (I) (J) (K)									
		Year-to-Date 2025									
		Expense (Revenue)				MWh				Cost per MWh	
		Forecast	Actual	Difference		Forecast	Actual	Difference		Forecast	Actual
151	RT ASM Short-Term Reserve Cost Distribution Amount	\$ 199,013	\$ 280,400	\$ 81,387	40.90%			-	0.00%	\$ -	\$ -
152	RT ASM Short-Term Reserve Deployment Failure Charge Amount	\$ 34,786	\$ 69,820	\$ 35,034	100.71%			-	0.00%	\$ -	\$ -
153											
154	Total MISO ASM	\$ (474,493)	\$ (2,572,319)	\$ (2,097,826)	442.12%	-	-	-	0.00%	\$ -	\$ -
155											
156	Total Wholesale Market Charges	\$ (13,067,870)	\$ (23,580,947)	\$ (10,513,077)	80.45%	-	-	-	0.00%	\$ -	\$ -
157											
158											
159											
160	Purchased Power	[PROTECTED DATA BEGINS...									
161	Edgeley PPA										
162	Langdon PPA										
163	Ashtabula III PPA										
164	Tribal (WAPA)										
165	WAPA Energy Imbalance										
166	Shared Loads										
167	Small Co-gen										
168	Bilateral purchases										
169	Market Purchases										
170											
171	Total Purchases	\$ 96,130,445	\$ 102,409,214	\$ 6,278,769	6.53%	2,355,460	2,661,475	306,015	12.99%	\$ 40.81	\$ 38.48
172											
173	Wind Curtailment	\$ 127,718	\$ 41,596	\$ (86,122)	-67.43%	-	1,161	1,161	0.00%	\$ -	\$ 35.84
174											
175	Asset Based Sales	\$ (8,444,421)	\$ (19,421,710)	\$ (10,977,289)	129.99%	(133,231)	(361,294)	(228,063)	171.18%	\$ 63.38	\$ 53.76
176	Fuel Costs	\$ 3,578,780	\$ 12,488,597	\$ 8,909,817	248.96%			-	0.00%	\$ -	\$ -
177	Asset Based Margins	\$ (4,865,641)	\$ (6,933,113)	\$ (2,067,472)	42.49%			-	0.00%	\$ -	\$ -
178											
179	Hoot Lake Solar Generation Credit	\$ (3,736,608)	\$ (3,743,304)	\$ (6,696)	0.18%			-	0.00%	\$ -	\$ -
180											
181	Steam Plant Reagents	\$ 3,098,881	\$ 3,900,605	\$ 801,723	25.87%			-	0.00%	\$ -	\$ -
182											
183	Steam/Water Sales	\$ (1,264,591)	\$ (1,194,314)	\$ 70,277	-5.56%			-	0.00%	\$ -	\$ -
184											
185	Planning Resource Auction Revenues	\$ -	\$ (6,252,344)	\$ -	0.00%			-	0.00%	\$ -	\$ -
186											
187	Total System - Plant Level	\$ 140,775,337	\$ 127,206,362	\$ (13,568,975)	-9.64%	6,117,541	5,984,236	(133,305)	-2.18%	\$ 23.01	\$ 21.26

*** These energy related charge types are reported in Market Purchases

Attachment 4

Docket No. E017/AA-24-65

**Clean Version of Tariff Sheet MN 13.01 –
Energy Adjustment Rider**

Notice of Annual FCA True-Up



Fergus Falls, Minnesota

Minnesota Public Utilities Commission
Section 13.01
ELECTRIC RATE SCHEDULE
Energy Adjustment Rider

Page 1 of 4
Nineteenth Revision

ENERGY ADJUSTMENT RIDER

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 an Energy Adjustment Charge calculated by multiplying the customers applicable monthly billing kilowatt hours (kWh) by the billed Energy Adjustment Factor (EAF) per kWh (rounded to the nearest 0.001¢). The Current Period Cost of Energy shall be based upon the forecasted Minnesota cost of energy for the current month, divided by forecasted Minnesota retail Kilowatt-Hour sales. The applicable adjustment will be applied to each Customer's bill beginning with the first day of the calendar month. The forecasted cost of energy shall be determined based on forecasted information for the following items:

1. The forecasted cost of fuel, as recorded in Account 151, used in the Company's generating plants based on the forecasted dispatch of those plants.
2. The forecasted 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 forecasted 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 forecasted Midcontinent ISO (MISO) and Southwest Power Pool (SPP) costs and revenues associated with forecasted retail sales that have been authorized by the Commission to flow through this Energy Adjustment Rider and excluding MISO and SPP costs and revenues that are recoverable in base rates, as prescribed in applicable Commission Orders.
5. Renewable energy purchased for the TailWinds program is not included in the cost of energy adjustment calculation.



Fergus Falls, Minnesota

Minnesota Public Utilities Commission
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ELECTRIC RATE SCHEDULE
Energy Adjustment Rider

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6. The forecasted identifiable fuel costs associated with energy purchased for reasons other than in 2 and 3 above.
7. Less the forecasted fuel-related costs recovered through intersystem sales.
8. Less a credit for forecasted asset-based margins: forecasted 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 forecasted revenues for this calculation are those received from forecasted sales of excess generation; the forecasted 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 forecasted transmission costs incurred that are required to make such sales.
9. The forecasted costs of reagents for the Company to operate its generating plants in compliance with Federal Environmental Protection Agency rules and regulations.
10. The forecasted costs of fuel and reagents resulting from steam and water sales.
11. The proceeds from the forecasted revenues from steam and water sales shall be credited to (flow through) the energy adjustment rider.
12. Less a credit for Minnesota solar generation revenues.
13. Known MISO Planning Resource Auction capacity costs will be added to the energy adjustment rider or revenues will be credited (flow through) the energy adjustment rider.
14. Excluding any Market Energy related costs under Section 14.16.

N



Fergus Falls, Minnesota

Minnesota Public Utilities Commission
Section 13.01
ELECTRIC RATE SCHEDULE
Energy Adjustment Rider

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Fifth Revision

CLASS ENERGY ADJUSTMENT FACTOR (EAF): A separate EAF will be determined for each customer service category defined by customer class. The EAF for each service category is the sum of the Current Period forecasted Cost of Energy multiplied by the applicable EAF Ratio, and the applicable annual true-up.

Service Category	Section	EAF Ratio
Residential	9.01, 9.02, 9.04	1.0555
Farm	9.03	1.0281
General Service	10.01, 10.02, 10.03, 10.07	1.0461
Large General Service non TOD	10.04, 10.06, 14.03	1.0207
Large General Service TOD – Winter On-Peak	10.05, 10.06, 11.01	1.2673
Large General Service TOD – Winter Shoulder	10.05, 10.06, 11.01	1.1106
Large General Service TOD – Winter Off-Peak	10.05, 10.06, 11.01	0.8499
Large General Service TOD – Summer On-Peak	10.05, 10.06, 11.01	1.2664
Large General Service TOD – Summer Shoulder	10.05, 10.06, 11.01	0.9956
Large General Service TOD – Summer Off-Peak	10.05, 10.06, 11.01	0.6896
Irrigation Service	11.02	0.9250
Outdoor Lighting	11.03, 11.04, 11.07	0.8645
OPA	11.05	1.0210
Controlled Service Deferred Load	14.01, 14.06	0.9513
Controlled Service Interruptible	14.04,	0.9883
Controlled Service Off-Peak	14.07, 14.12	0.9164

N

Forecasted Class EAF's are published on OTP's website at <https://www.otpc.com/pricing>.

In addition, subject to Commission approval, there shall be an annual true-up for any amount collected over or under the actual cost of energy for the twelve months ending December 31 of each year as reported in the Annual Automatic Adjustment True-up report to be filed by March 1 following the most recent reporting period. The annual true-up shall be based on a historic twelve-month period, comparing actual costs per kWh to the forecasted costs per kWh and shall be applied to the subsequent twelve months. The annual true-up will be effective on billings beginning the first of the month following Commission approval of the true-up, or as ordered by the Commission. In years when the over- or under-recovery amount is small (resulting in a true-up rate rounded to less than 0.001¢), the true-up balance will carry over to the next year's true-up.



Fergus Falls, Minnesota

Minnesota Public Utilities Commission
Section 13.01
ELECTRIC RATE SCHEDULE
Energy Adjustment Rider

Page 4 of 4
Second Revision

The annual true-up rate for each class shall be calculated as follows. The over- or under-recovery amount as shown in the current year Annual Automatic Adjustment True-up report will be divided by the forecasted Minnesota Kilowatt-Hours subject to the fuel adjustment clause for the proposed twelve month recovery period the true-up rate will be in effect and then multiplied by the applicable EAF ratio. This calculation will produce a true-up rate per Kilowatt-Hour (rounded to the nearest 0.001¢) for each class that will be added to or subtracted from the applicable forecasted class EAF's for the months the true-up factor is in effect and applied to Customers' bills as part of the monthly cost of Energy Adjustment Charge.

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.

Notice of Annual Energy Adjustment True-up

The Energy Adjustment line item on your monthly electric bill reflects the estimated cost of fuel (including transportation) and estimated cost of electricity we purchase to supplement power from our own plants. These energy costs pass through to our customers without markups, so we don't profit from them.

Each year we compare what we estimated these energy costs would be with what we actually paid. If there's a difference, we apply a one-year adjustment to true-up that amount.

For 2025 actual energy costs were higher than estimated. As approved by the Minnesota Public Utilities Commission (Docket No. E017/AA-24-65), this undercollection results in a 12-month charge of \$0.001300 per kilowatt-hour.

We'll include this adjustment as part of the monthly Energy Adjustment on customer bills September 1, 2026, through August 31, 2027.

For more information, contact us at **800-257-4044** or visit **otpc.com**.

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
kWh Sales by Primary Energy Source
Annual True-up Period January 2025 through December 2025

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	Description	January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25	2025 Year End
1	Coal	171,122,765	155,740,925	138,023,193	82,156,005	70,396,125	189,148,818	241,635,613	178,225,927	161,927,123	106,478,618	205,439,823	181,527,616	1,881,822,551
2	Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Gas	21,969,569	14,493,117	10,360,361	10,793,873	31,809,011	69,079,996	112,027,362	95,895,856	74,453,184	50,114,428	60,314,856	46,913,991	598,225,604
4	Wind	135,946,325	111,634,139	114,050,189	97,811,088	104,767,175	61,217,939	66,087,809	69,282,851	66,424,184	101,085,260	105,248,368	82,504,386	1,116,059,713
5	Solar	3,613,547	3,147,953	7,845,535	8,145,483	9,156,811	7,393,643	8,586,171	8,757,881	6,876,818	5,355,923	3,467,844	1,520,488	73,868,097
6	Fuel Oil	-	-	-	-	-	502,091	304,463	502,621	-	-	-	-	1,309,175
7	Purchased Power	29,971,225	29,967,359	19,438,520	24,169,565	23,862,243	21,323,292	16,601,614	12,442,465	14,257,181	20,301,034	35,494,194	22,809,461	270,638,154
8	Market Purchases	252,755,150	235,168,424	273,664,361	238,678,186	207,410,242	197,762,332	110,452,894	103,044,181	148,370,927	217,094,901	134,371,554	273,224,709	2,391,997,860
9														
10	Total	615,378,581	550,151,916	563,382,159	461,754,200	447,401,607	546,428,111	555,695,926	468,151,782	472,309,418	500,430,164	544,336,638	608,500,651	6,333,921,154

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
kWh Sales by Primary Energy Source
Annual True-up Period January 2025 through December 2025

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	Description	January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25	2025 Year End
1	Generation													
2	Coal	\$ 4,258,935	\$ 4,014,885	\$ 3,706,591	\$ 2,276,320	\$ 1,951,107	\$ 7,764,175	\$ 6,835,590	\$ 4,648,770	\$ 4,009,158	\$ 3,041,383	\$ 4,927,492	\$ 4,632,282	\$ 52,066,689
3	Biomass	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
4	Gas	\$ 1,041,777	\$ 756,826	\$ 527,448	\$ 483,700	\$ 1,197,984	\$ 2,428,592	\$ 4,005,390	\$ 3,124,397	\$ 2,524,474	\$ 1,762,166	\$ 2,483,657	\$ 2,136,759	\$ 22,473,171
5	Wind	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
6	Solar	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
7	Fuel Oil	\$ 6,020	\$ 8,785	\$ -	\$ -	\$ -	\$ 190,131	\$ 128,050	\$ 160,977	\$ 4,833	\$ -	\$ -	\$ 8,910	\$ 507,706
8														
9														
10	Total	\$ 5,306,732	\$ 4,780,496	\$ 4,234,039	\$ 2,760,020	\$ 3,149,091	\$ 10,382,899	\$ 10,969,031	\$ 7,934,144	\$ 6,538,465	\$ 4,803,549	\$ 7,411,149	\$ 6,777,951	\$ 75,047,565

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

Input data: BTU Report

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											
2010 Big Stone cost per Mbtu												
2011 Big Stone cost per Mbtu												
2012 Big Stone cost per Mbtu												
2013 Big Stone cost per Mbtu												
2014 Big Stone cost per Mbtu												
2015 Big Stone cost per Mbtu												
2016 Big Stone cost per Mbtu												
2017 Big Stone cost per Mbtu												
2018 Big Stone cost per Mbtu												
2019 Big Stone cost per Mbtu												
2020 Big Stone cost per Mbtu												
2021 Big Stone cost per Mbtu												
2022 Big Stone cost per Mbtu												
2023 Big Stone cost per Mbtu												
2024 Big Stone cost per Mbtu												
2025 Big Stone cost per Mbtu												
2010 Coyote cost per Mbtu												
2011 Coyote cost per Mbtu												
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												
2017 Coyote cost per Mbtu												
2018 Coyote cost per Mbtu												
2019 Coyote cost per Mbtu												
2020 Coyote cost per Mbtu												
2021 Coyote cost per Mbtu												
2022 Coyote cost per Mbtu												
2023 Coyote cost per Mbtu												
2024 Coyote cost per Mbtu												
2025 Coyote cost per Mbtu												
2018 Hoot Lake cost per Mbtu												
2019 Hoot Lake cost per Mbtu												
2020 Hoot Lake cost per Mbtu												
2021 Hoot Lake cost per Mbtu												
	. . . PROTECTED DATA ENDS]											

(1) Effective July 2008 fuel oil burned for generation is included

Cost of delivered natural gas	[PROTECTED DATA BEGINS
2010 Solway Plant cost per Mbtu	
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	
2017 Solway Plant cost per Mbtu	
2018 Solway Plant cost per Mbtu	
2019 Solway Plant cost per Mbtu	
2020 Solway Plant cost per Mbtu	
2021 Solway Plant cost per Mbtu	
2022 Solway Plant cost per Mbtu	

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

Input data: BTU Report

MONTHLY COST COMPONENTS BY FUEL TYPE

	January	February	March	April	May	June	July	August	September	October	November	December
2023 Solway Plant cost per Mbtu												
2024 Solway Plant cost per Mbtu												
2025 Solway Plant cost per Mbtu												
2021 Astoria Plant cost per Mbtu												
2022 Astoria Plant cost per Mbtu												
2023 Astoria Plant cost per Mbtu												
2024 Astoria Plant cost per Mbtu												
2025 Astoria Plant cost per Mbtu												

... PROTECTED DATA ENDS]

Cost of delivered nuclear fuel - not applicable

Cost of delivered oil

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	22.13	21.15	22.22	20.18	16.15	16.15
2017 IC Plants and FF Control Ctr diesel, \$/Mbtu	0.00	20.37	19.32	16.87	20.19	16.72	20.13	20.17	21.67	21.90	17.28	22.11
2018 IC Plants and FF Control Ctr diesel, \$/Mbtu	20.67	16.15	18.70	22.11	18.42	16.57	20.86	19.42	17.50	20.05	20.05	16.61
2019 IC Plants and FF Control Ctr diesel, \$/Mbtu	18.78	17.74	17.13	17.82	16.80	0.00	0.00	0.00	0.00	17.11	17.81	16.72
2020 IC Plants and FF Control Ctr diesel, \$/Mbtu	17.40	17.05	14.38	15.67	15.69	14.92	15.23	14.65	14.28	14.65	14.54	14.28
2021 IC Plants and FF Control Ctr diesel, \$/Mbtu	14.52	14.86	14.78	14.90	0.00	14.87	14.83	0.00	15.70	15.92	15.73	0.00
2022 IC Plants and FF Control Ctr diesel, \$/Mbtu	15.55	16.03	15.72	15.70	15.97	17.16	18.18	22.72	18.98	18.52	20.80	21.36
2023 IC Plants and FF Control Ctr diesel, \$/Mbtu	20.33	15.71	19.37	20.06	20.12	16.47	17.67	19.71	18.95	19.52	25.98	7.53
2024 IC Plants and FF Control Ctr diesel, \$/Mbtu	18.49	19.66	16.90	20.16	18.91	16.89	19.64	18.91	0.00	18.77	0.00	19.06
2025 IC Plants and FF Control Ctr diesel, \$/Mbtu	18.48	17.31	0.00	0.00	0.00	19.11	18.69	18.82	18.81	0.00	0.00	18.57

Cost of wholesale purchases (\$/MWh) without RSG or RNU charges (2)

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	34.24	36.67	29.49	24.10	26.47	27.93
2017 Purchased Power	29.77	25.82	27.00	28.86	28.80	28.26	28.93	26.62	25.05	25.17	31.12	22.29
2018 Purchased Power	36.16	31.00	27.24	29.54	29.23	28.62	38.93	36.53	30.21	28.62	30.66	34.45
2019 Purchased Power	29.84	36.30	34.16	28.04	24.78	22.66	24.02	22.08	27.57	22.86	27.63	24.12
2020 Purchased Power	23.99	26.18	24.00	21.89	18.96	14.65	19.85	20.78	18.99	19.48	12.12	26.77
2021 Purchased Power	24.25	41.25	21.37	15.23	16.15	19.39	32.82	31.97	17.51	32.50	42.46	24.88
2022 Purchased Power	25.76	27.94	28.19	26.27	28.88	36.23	36.56	48.30	52.06	28.94	29.94	45.94
2023 Purchased Power	68.02	30.86	24.59	13.71	5.10	9.46	24.47	23.42	22.61	24.81	26.53	26.14
2024 Purchased Power	44.12	29.67	10.16	2.24	20.38	12.98	-4.65	19.35	8.21	11.86	12.90	38.06
2025 Purchased Power	40.81	39.29	23.88	22.72	22.30	21.91	39.93	34.42	20.90	18.14	20.02	47.22

(2) Is not retail

**MISO Module E Data For Otter Tail Power Company
As of January 31, 2026**

AGGREGATE RESOURCES AS DEFINED BY MISO - Values reflect the Season Accredited Capacity (SAC)

No. Aggregate Resources	Designation	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26
1 Big Stone Plant	OTP.BIGSTON1	242.6	242.6	242.6	230.2	230.2	230.2	186.1	186.1	186.1	266.2	266.2	266.2
2 Coyote Station	OTP.COYOT1	134.7	134.7	134.7	110.6	110.6	110.6	142.0	142.0	142.0	120.2	120.2	120.2
3 FPL Energy ND Wind II	OTP.EDGLYEDGL	2.6	2.6	2.6	4.9	4.9	4.9	4.5	4.5	4.5	4.6	4.6	4.6
6 Jamestown 1	OTP.JAMSPK1	20.1	20.1	20.1	22.1	22.1	22.1	25.9	25.9	25.9	23.4	23.4	23.4
7 Jamestown 2	OTP.JAMSPK2	19.5	19.5	19.5	22.0	22.0	22.0	26.6	26.6	26.6	24.0	24.0	24.0
8 Lake Preston	OTP.HETLA	14.9	14.9	14.9	19.8	19.8	19.8	24.5	24.5	24.5	15.8	15.8	15.8
9 Solway	OTP.SLWAYO1	38.9	38.9	38.9	39.4	39.4	39.4	46.2	46.2	46.2	41.5	41.5	41.5
11 Hoot Lake Solar	OTP.HLSOLAR	30.6	30.6	30.6	18.9	18.9	18.9	-	-	-	27.1	27.1	27.1

LOCAL RESOURCES AS DEFINED BY MISO - Values reflect the Season Accredited Capacity (SAC)

No. Local Resource	Designation	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26
1 Ashtabula	OTP.ASHTUBULA	8.0	8.0	8.0	10.7	10.7	10.7	15.4	15.4	15.4	12.8	12.8	12.8
2 AshtabulaIII	OTP.ASHTAIII	10.9	10.9	10.9	16.4	16.4	16.4	18.3	18.3	18.3	15.6	15.6	15.6
3 Langdon	OTP.LANGDN1	6.5	6.5	6.5	13.0	13.0	13.0	11.5	11.5	11.5	9.7	9.7	9.7
4 Langdon	OTP.LANGDN2	3.4	3.4	3.4	6.8	6.8	6.8	6.7	6.7	6.7	5.3	5.3	5.3
5 Luverne	OTP.MPWR	8.4	8.4	8.4	13.0	13.0	13.0	19.0	19.0	19.0	13.4	13.4	13.4
6 Astoria Station	OTP.ASTORIA	227.6	227.6	227.6	213.5	213.5	213.5	240.9	240.9	240.9	263.7	263.7	263.7
7 Merricourt	MDU.MERRICOURT	38.3	38.3	38.3	58.3	58.3	58.3	69.9	69.9	69.9	47.0	47.0	47.0

BEHIND-THE-METER RESOURCES AS DEFINED BY MISO - Values reflect the Season Accredited Capacity (SAC)

No. BTM Resource	Designation	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26
1 Dayton Hollow Hydro #1	OTP.OTP	-	-	-	-	-	-	-	-	-	-	-	-
2 Dayton Hollow Hydro #2	OTP.OTP	0.5	0.5	0.5	0.3	0.3	0.3	0.5	0.5	0.5	0.4	0.4	0.4
3 Hoot Lake Hydro	OTP.OTP	0.5	0.5	0.5	-	-	-	-	-	-	0.4	0.4	0.4
4 Pisgah Hydro	OTP.OTP	0.4	0.4	0.4	-	-	-	0.3	0.3	0.3	0.4	0.4	0.4
5 Taplin Gorge Hydro	OTP.OTP	0.1	0.1	0.1	-	-	-	0.2	0.2	0.2	0.4	0.4	0.4

EXTERNAL RESOURCES AS DEFINED BY MISO - Values reflect the Season Accredited Capacity (SAC)

No. External Resources	Designation	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26
1	GARRISON HYDRO PLT	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
2	GARRISON HYDRO PLT	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-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26
1 None													
Total		817.2	817.2	817.2	808.6	808.6	808.6	847.2	847.2	847.2	900.6	900.6	900.6

OTTER TAIL POWER COMPANY
ESTIMATE OF MINNESOTA'S SHARE OF
MISO CHARGE TYPES
EXPENSE (REVENUE)

Charge Type Description		System - Retail January - December 2025	Minnesota - Retail January - December 2025
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss		
1	DA Asset Energy Amount	\$ 112,204,375	\$ 53,005,504
2	DA FBT Loss Amount	\$ -	\$ -
3	DA Non-asset Energy Amount	\$ (1,806,721)	\$ (853,497)
4	RT Asset Energy Amount	\$ 5,342,630	\$ 2,523,866
5	RT Distribution of Losses Amount	\$ (4,165,374)	\$ (1,967,729)
6	RT FBT Loss Amount	\$ -	\$ -
7	DA Loss Amount	\$ 3,232,728	\$ 1,527,145
8	RT Loss Amount	\$ 326,367	\$ 154,176
9	RT Non-Asset Energy Amount	\$ 418	\$ 197
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	\$ 832,145	\$ 393,107
14	RT Mkt Admin Amount	\$ 107,525	\$ 50,795
15	FTR Mkt Admin Amount	\$ 14,244	\$ 6,729
Congest & FTRs			
16	DA FBT Congestion Amount	\$ -	\$ -
17	DA Congestion	\$ 1,587,704	\$ 750,034
18	RT FBT Congestion Amount	\$ -	\$ -
19	RT Congestion	\$ 545,950	\$ 257,908
20	FTR Hourly Allocation Amount	\$ (56,473,416)	\$ (26,678,121)
21	FTR Monthly Allocation Amount	\$ (1,206,273)	\$ (569,845)
22	FTR Yearly Allocation Amount	\$ (241,774)	\$ (114,214)
23	FTR Monthly Transaction Amount	\$ -	\$ -
24	FTR Full Funding Guarantee Amount	\$ (675,770)	\$ (319,235)
25	FTR Guarantee Uplift Amount	\$ 811,806	\$ 383,498
26	FTR Auction Revenue Rights Transaction Amount	\$ (40,020,853)	\$ (18,905,907)
27	FTR Annual Transaction Amount	\$ 38,045,630	\$ 17,972,809
28	FTR Auction Revenue Rights Infeasible Uplift Amount	\$ 116,276	\$ 54,929
29	FTR Auction Revenue Rights Stage 2 Distribution Amount	\$ (2,760,311)	\$ (1,303,975)
30	DA Congestion Rebate on Option B GFA	\$ -	\$ -
RSG & Make Whole Payments			
31	DA Revenue Sufficiency Guarantee Distribution Amount	\$ 163,490	\$ 77,233
32	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ (86,534)	\$ (40,879)
33	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	\$ 134,738	\$ 63,650
34	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	\$ -	\$ -
35	RT Price Volatility Make Whole Payment	\$ (471,247)	\$ (222,618)
Revenue Neutrality Uplift			
36	RT Revenue Neutrality Uplift Amount	\$ 2,216,119	\$ 1,046,898
Other Charges			
37	RT Misc Amount	\$ 9,955	\$ 4,703
38	RT Net Inadvertent Amount	\$ 24,085	\$ 11,378
39	RT Uninstructed Deviation Amount	\$ -	\$ -
40	RT Demand Response Allocation Uplift Amount	\$ 100,872	\$ 47,652
41	DA Ramp Product	\$ (169,699)	\$ (80,166)
42	RT Ramp Product	\$ (12,419)	\$ (5,867)
43	RT Schedule 49 Cost Distribution Amount	\$ 268,162	\$ 126,680
ASM Charges			
44	RT ASM Non-Excessive Energy Amount	\$ 12,886,629	\$ 6,087,662
45	RT ASM Excessive Energy Amount	\$ 37,404	\$ 17,670
Grandfathered Charge Types			
46	DA Congestion Rebate on COGA	\$ -	\$ -
47	DA Losses Rebate on COGA	\$ -	\$ -
48	RT Congestion Rebate on COGA	\$ -	\$ -
49	RT Loss Rebate on COGA	\$ -	\$ -
50	TOTAL CHARGES	\$ 70,918,861	\$ 33,502,169
51	Less Schedule 16 & 17 (Lines 13, 14, 15)	\$ (953,914.39)	
52	Congestion and Losses Adjustment	\$ 2,650,561.18	
53	No DA generation sch., but still had output	\$ (281,872.46)	
54	Total 2025 MISO Charges	\$72,333,635.57	

Percent of Minnesota Sales to System $2,796,679,274 / 5,920,133,274 = 0.4724014$

Fuel Costs Allocated to Minnesota $\$127,206,362 \times 0.4724014 = \$60,092,463.49$

Otter Tail Power Company Detail of MISO Day 2 Charges - System January 2025 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													
1	DA Asset Energy Amount	555.02	(570,275)	\$ (22,691,020.29)	334,892	\$ 13,492,431.56	0	\$ -	4,634	\$ 351,484.47	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,780	\$ 171,015.53	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(13,724)	\$ (178,396.41)	23,953	\$ 636,653.48	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(583,999)	\$ (22,869,416.70)	363,626	\$ 14,300,100.57	0	\$ -	4,634	\$ 351,484.47	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (28,001.85)	0	\$ 806,268.65	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (1,324,174.88)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (149,926.70)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (1,502,103.43)	0	\$ 806,268.65	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (86,587.35)	0	\$ -	0	\$ (451.75)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (11,368.58)	0	\$ 411.62	0	\$ (1,572.94)	0	\$ 42.55	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (2,095.76)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (100,051.69)	0	\$ 411.62	0	\$ (2,024.69)	0	\$ 42.55	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (439,641.83)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (274,886.70)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (75,134.39)	0	\$ 920,057.50	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 52,369.09	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ 241,773.59	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (293,830.54)	0	\$ 60,874.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (60,874.03)	0	\$ 107,953.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (4,311.73)	0	\$ 3,201,118.36	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (3,178,257.98)	0	\$ 5,691.15	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (13,563.64)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 204,338.69	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (3,900,859.01)	0	\$ 4,354,533.93	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (17,029.15)	0	\$ -	0	\$ (568.48)	0	\$ -	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 47.11	0	\$ -	0	\$ -	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (9,448.41)	0	\$ 66.35	0	\$ (315.13)	0	\$ 2.10	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 3,326.47	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ (6.36)	0	\$ 24,605.22	0	\$ (0.21)	0	\$ 821.62	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (26,483.92)	0	\$ 24,718.68	0	\$ (883.82)	0	\$ 4,150.19	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ (42.10)	0	\$ 3,357.57	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (23,634.05)	0	\$ 92,796.73	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (255,287.57)	0	\$ 19,202.51	0	\$ (8,524.33)	0	\$ 640.99	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (7,693.14)	0	\$ 20.09	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 8,058.18	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (448.19)	0	\$ 1,711.34	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (21,159.30)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (308,264.35)	0	\$ 125,146.42	0	\$ (8,524.33)	0	\$ 640.99	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(57,541)	\$ (1,599,988.63)	25,307	\$ 623,391.06	(1,684)	\$ (58,499.83)	14,295	\$ 528,521.08	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	(148)	\$ -	0	\$ 124.35	0	\$ -	7	\$ 42.07	0	\$ -	0	\$ -
53	SUBTOTAL		(57,689)	\$ (1,599,988.63)	25,307	\$ 623,515.41	(1,684)	\$ (58,499.83)	14,301	\$ 528,563.15	0	\$ -	0	\$ -

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Charge Type Description	Acct	RETAIL	Cost	MWh	Revenue	ASSET BASED WHOLESALE		NON ASSET BASED WHOLESALE		ASSET BASED WHOLESALE			
			MWh				MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
54	DA Congestion Rebate on COGA	555.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
55	DA Losses Rebate on COGA	555.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
56	RT Congestion Rebate on COGA	555.22	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
57	RT Loss Rebate on COGA	555.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
58	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
59	TOTAL MISO DAY 2 CHARGES		(641,688)	\$ (30,307,167.73)	388,933	\$ 20,234,695.28	(1,684)	\$ (69,932.67)	18,935	\$ 884,881.35	0	\$ -	0	\$ -
60	Less Schedule 16 & 17 (Lines 16, 17, 18)			\$ (100,051.69)		\$ 411.62								
61	Congestion and Losses Adjustment			\$ (945,808.93)										
62	No DA generation sch., but still had output for current month			\$ (27,225.78)										
63														
64														
65	Total for MN Energy Adjustment Rider			\$ (29,234,081.33)		\$ 20,234,283.66								
66	Net Retail for MN Energy Adjustment Rider				\$ (8,999,797.67)									
67	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
68	NET MISO (Rev-Cost and MWh)									\$ 814,948.68			\$ -	
69	Less: Fuel Cost								17,025	\$ 562,462.69				
70	Less: Misc Cost Adjustment									(180.93)				
71	Plus: Capacity Revenue												\$ -	
72	Plus: Bilateral Sales												\$ -	
73	Less: Bilateral Purchases												\$ -	
74	Less: Schedule 24 for Asset Based Sales												\$ -	
75										\$ 258.48				
76	TOTAL ASSET or NON ASSET BASED WHOLESALE									\$ 252,408.44			\$ -	

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	Day Ahead & Real Time Energy													
1	DA Asset Energy Amount	555.02	(546,888)	\$ (20,372,131.10)	327,848	\$ 12,316,845.90	0	\$ -	6,805	\$ 433,546.79	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,898	\$ 162,772.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(15,279)	\$ (553,897.22)	12,323	\$ 537,889.19	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(562,168)	\$ (20,926,028.32)	345,069	\$ 13,017,507.14	0	\$ -	6,805	\$ 433,546.79	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (132,314.00)	0	\$ 489,681.09	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (1,183,090.88)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (121,519.52)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (1,436,924.40)	0	\$ 489,681.09	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (96,275.92)	0	\$ -	0	\$ (786.04)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (11,002.39)	0	\$ 229.45	0	\$ (1,708.41)	0	\$ 6.02	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (1,607.36)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (108,885.66)	0	\$ 229.45	0	\$ (2,494.45)	0	\$ 6.02	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (616,618.50)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (129,828.42)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (60,122.51)	0	\$ 1,030,031.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 44,466.38	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (44,213.22)	0	\$ 25,630.47	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (25,630.47)	0	\$ 49,681.43	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (4,311.73)	0	\$ 3,201,118.36	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (3,178,257.98)	0	\$ 5,691.15	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (13,560.79)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ (1.13)	0	\$ 204,328.19	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (3,455,926.25)	0	\$ 3,944,328.83	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (18,596.83)	0	\$ 0.05	0	\$ (547.34)	0	\$ -	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 1,507.45	0	\$ -	0	\$ -	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (10,104.93)	0	\$ 107.53	0	\$ (297.16)	0	\$ 3.08	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 178,817.66	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ -	0	\$ 27,801.19	0	\$ -	0	\$ 818.43	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (28,701.76)	0	\$ 29,416.22	0	\$ (844.50)	0	\$ 179,639.17	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ -	0	\$ 0.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (50,277.64)	0	\$ 46,729.14	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (103,435.17)	0	\$ 59,941.05	0	\$ (3,044.86)	0	\$ 1,764.34	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (16,548.18)	0	\$ 14.97	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 9,859.18	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (1,107.31)	0	\$ 1,289.10	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (39,588.44)	0	\$ 73.44	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (210,956.74)	0	\$ 117,906.93	0	\$ (3,044.86)	0	\$ 1,764.34	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(45,193)	\$ (1,034,192.79)	27,076	\$ 736,836.44	(1,906)	\$ (69,397.60)	12,799	\$ 546,363.23	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	(10)	\$ (297.07)	58	\$ 953.59	0	\$ -	34	\$ 819.01	0	\$ -	0	\$ -
53	SUBTOTAL		(45,203)	\$ (1,034,489.86)	27,133	\$ 737,790.03	(1,906)	\$ (69,397.60)	12,833	\$ 547,182.24	0	\$ -	0	\$ -

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
February 2025 includes any adjustments

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
Charge Type Description	Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE				
		MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	
Grandfathered Charge Types														
54	DA Congestion Rebate on COGA	555.05	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
55	DA Losses Rebate on COGA	555.06	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
56	RT Congestion Rebate on COGA	555.22	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
57	RT Loss Rebate on COGA	555.23	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
58	SUBTOTAL		0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
59	TOTAL MISO DAY 2 CHARGES		(607,371) \$	(27,201,912.99)	372,203 \$	18,336,859.69	(1,906) \$	(75,781.41)	19,637 \$	1,162,138.56	0 \$	-	0 \$	-
60	Less Schedule 16 & 17 (Lines 16, 17, 18)		\$	(108,885.66)	\$	229.45								
61	Congestion and Losses Adjustment		\$	(6,766.11)										
62	No DA generation sch., but still had output for current month		\$	(9,516.79)										
63														
64														
65	Total for MN Energy Adjustment Rider		\$	(27,076,744.43)	\$	18,336,630.24								
66	Net Retail for MN Energy Adjustment Rider				\$	(8,740,114.19)								
67	Retail MWh include losses of 2.8%													
ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS														
68	NET MISO (Rev-Cost and MWh)								\$	1,086,357.15			\$	-
69	Less: Fuel Cost							17,731	\$	733,659.71				
70	Less: Misc Cost Adjustment								\$	(87.33)			\$	-
71	Plus: Capacity Revenue												\$	-
72	Plus: Bilateral Sales												\$	-
73	Less: Bilateral Purchases												\$	-
74	Less: Schedule 24 for Asset Based Sales												\$	-
75									\$	307.42				
76	TOTAL ASSET or NON ASSET BASED WHOLESALE								\$	352,477.35			\$	-

Otter Tail Power Company Detail of MISO Day 2 Charges - System March 2025 includes any adjustments														
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	Day Ahead & Real Time Energy													
1	DA Asset Energy Amount	555.02	(512,369)	\$ (11,841,400.72)	270,107	\$ 6,538,725.75	0	\$ -	3,556	\$ 198,394.34	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,881	\$ 127,015.64	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(23,713)	\$ (609,116.65)	8,578	\$ 242,910.44	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(536,082)	\$ (12,450,517.37)	283,566	\$ 6,908,651.83	0	\$ -	3,556	\$ 198,394.34	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (242,845.56)	0	\$ 300,946.82	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (725,462.51)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (54,921.18)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (1,023,229.25)	0	\$ 300,946.82	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (78,213.81)	0	\$ -	0	\$ (344.16)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (9,771.08)	0	\$ 406.99	0	\$ (1,999.59)	0	\$ -	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (1,511.04)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (89,495.93)	0	\$ 406.99	0	\$ (2,343.75)	0	\$ -	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (531,443.64)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (141,234.82)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (54,774.30)	0	\$ 1,210,932.92	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 9,350.33	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (8,946.45)	0	\$ 28,445.22	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (28,445.22)	0	\$ 8,946.45	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (2,301.26)	0	\$ 3,770,617.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (3,747,095.83)	0	\$ 2,301.27	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (17,076.85)	0	\$ 0.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ (1.13)	0	\$ 152,445.80	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (3,999,875.86)	0	\$ 4,651,595.64	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (12,884.45)	0	\$ 0.24	0	\$ (440.31)	0	\$ -	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 8,434.84	0	\$ -	0	\$ 856.01	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (7,212.99)	0	\$ 346.84	0	\$ (246.25)	0	\$ 11.76	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 43,629.29	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ -	0	\$ 18,123.67	0	\$ -	0	\$ 619.64	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (20,097.44)	0	\$ 26,905.59	0	\$ (686.56)	0	\$ 45,116.70	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (77,357.61)	0	\$ 14,284.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (221,480.83)	0	\$ 103,889.19	0	\$ (7,571.90)	0	\$ 3,551.61	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (6,717.95)	0	\$ 135.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 17,637.29	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (637.87)	0	\$ 2,442.56	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (16,577.13)	0	\$ 5.50	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (322,771.39)	0	\$ 138,393.88	0	\$ (7,571.90)	0	\$ 3,551.61	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(39,044)	\$ (920,310.22)	17,680	\$ 251,668.82	(1,341)	\$ (42,658.44)	18,022	\$ 412,899.22	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	0	\$ (1,504.23)	217	\$ 9.15	0	\$ -	8	\$ 62.72	0	\$ -	0	\$ -
53	SUBTOTAL		(39,044)	\$ (921,814.45)	17,896	\$ 251,677.97	(1,341)	\$ (42,658.44)	18,029	\$ 412,961.94	0	\$ -	0	\$ -

Otter Tail Power Company														
Detail of MISO Day 2 Charges - System														
March 2025 includes any adjustments														
Charge Type Description	(A) Acct	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
		RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE				
		MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	
Grandfathered Charge Types														
54	DA Congestion Rebate on COGA	555.05	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
55	DA Losses Rebate on COGA	555.06	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
56	RT Congestion Rebate on COGA	555.22	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
57	RT Loss Rebate on COGA	555.23	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
58	SUBTOTAL		0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
59	TOTAL MISO DAY 2 CHARGES		(575,126) \$	(18,827,801.69)	301,462 \$	12,278,578.72	(1,341) \$	(53,260.65)	21,585 \$	660,024.59	0 \$	-	0 \$	-
60	Less Schedule 16 & 17 (Lines 16, 17, 18)		\$	(89,495.93)	\$	406.99								
61	Congestion and Losses Adjustment		\$	1,843.50										
62	No DA generation sch., but still had output for current month		\$	-										
63														
64														
65	Total for MN Energy Adjustment Rider		\$	(18,740,149.26)	\$	12,278,171.73								
66	Net Retail for MN Energy Adjustment Rider				\$	(6,461,977.53)								
67	Retail MWh include losses of 2.8%													
ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS														
68	NET MISO (Rev-Cost and MWh)							\$	606,763.94			\$	-	
69	Less: Fuel Cost							20,164 \$	601,566.24					
70	Less: Misc Cost Adjustment							\$	1.79					
71	Plus: Capacity Revenue													
72	Plus: Bilateral Sales													
73	Less: Bilateral Purchases													
74	Less: Schedule 24 for Asset Based Sales							\$	325.52					
75														
76	TOTAL ASSET or NON ASSET BASED WHOLESALE							\$	4,870.39			\$	-	

Otter Tail Power Company Detail of MISO Day 2 Charges - System April 2025 includes any adjustments														
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	MWh	Cost	RETAIL MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	Day Ahead & Real Time Energy													
1	DA Asset Energy Amount	555.02	(459,922)	\$ (12,675,765.91)	247,640	\$ 6,141,146.36	0	\$ -	3,326	\$ 207,205.12	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,412	\$ 115,637.14	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(16,944)	\$ (542,639.21)	15,482	\$ 424,031.38	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(476,866)	\$ (13,218,405.12)	267,534	\$ 6,680,814.88	0	\$ -	3,326	\$ 207,205.12	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (39,872.61)	0	\$ 229,608.11	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (618,340.37)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (30,692.96)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (688,905.94)	0	\$ 229,608.11	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (73,548.00)	0	\$ -	0	\$ (329.58)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (11,072.29)	0	\$ 289.53	0	\$ (1,516.89)	0	\$ 16.04	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (873.44)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (85,493.73)	0	\$ 289.53	0	\$ (1,846.47)	0	\$ 16.04	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (837,346.40)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ 97,401.62	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (141,175.17)	0	\$ 2,108,364.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 28,502.56	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (28,498.26)	0	\$ 33,855.11	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (33,855.11)	0	\$ 28,498.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (2,301.26)	0	\$ 3,770,617.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (3,747,095.83)	0	\$ 2,301.27	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (17,287.95)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ (400.45)	0	\$ 152,045.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (3,873,212.41)	0	\$ 5,286,837.10	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (10,863.23)	0	\$ -	0	\$ (313.43)	0	\$ -	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 16.79	0	\$ -	0	\$ 5,566.46	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (7,617.96)	0	\$ 399.37	0	\$ (219.64)	0	\$ 11.40	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 47,364.74	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ -	0	\$ 7,315.38	0	\$ -	0	\$ 211.20	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (18,481.19)	0	\$ 7,731.54	0	\$ (533.07)	0	\$ 53,153.80	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ (76.89)	0	\$ 479.92	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (16,855.34)	0	\$ 10,532.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (161,602.34)	0	\$ 9,023.10	0	\$ (4,665.06)	0	\$ 260.31	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (3,442.86)	0	\$ 19.73	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 27,463.18	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (2,271.14)	0	\$ 3,550.37	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (19,258.94)	0	\$ 3.49	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (203,507.51)	0	\$ 51,071.91	0	\$ (4,665.06)	0	\$ 260.31	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(49,122)	\$ (1,257,979.17)	19,737	\$ 342,228.68	(965)	\$ (43,603.03)	13,075	\$ 493,210.44	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	(1)	\$ (1.40)	39	\$ 84.23	(21)	\$ (69.28)	5	\$ 73.52	0	\$ -	0	\$ -
53	SUBTOTAL		(49,123)	\$ (1,257,980.57)	19,776	\$ 342,312.91	(986)	\$ (43,672.31)	13,079	\$ 493,283.96	0	\$ -	0	\$ -

Otter Tail Power Company Detail of MISO Day 2 Charges - System April 2025 includes any adjustments															
Charge Type Description	(A) Acct	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)		
		MWh	Cost	RETAIL MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue		
Grandfathered Charge Types															
54	DA Congestion Rebate on COGA	555.05	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	
55	DA Losses Rebate on COGA	555.06	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	
56	RT Congestion Rebate on COGA	555.22	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	
57	RT Loss Rebate on COGA	555.23	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	
58	SUBTOTAL		0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	
59	TOTAL MISO DAY 2 CHARGES		(525,989) \$	(19,345,986.47)	287,311	\$	12,598,665.98	(986) \$	(50,716.91)	16,405	\$	753,919.23	0 \$	-	
60	Less Schedule 16 & 17 (Lines 16, 17, 18)		\$	(85,493.73)		\$	289.53								
61	Congestion and Losses Adjustment		\$	30,960.54											
62	No DA generation sch., but still had output for current month		\$	-											
63															
64															
65	Total for MN Energy Adjustment Rider		\$	(19,291,453.28)		\$	12,598,376.45								
66	Net Retail for MN Energy Adjustment Rider				\$	(6,693,076.83)									
67	Retail MWh include losses of 2.8%														
ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS															
68	NET MISO (Rev-Cost and MWh)								\$	703,202.32			\$	-	
69	Less: Fuel Cost								15,393	\$	505,555.10				
70	Less: Misc Cost Adjustment									\$	(779.78)				
71	Plus: Capacity Revenue												\$	-	
72	Plus: Bilateral Sales												\$	-	
73	Less: Bilateral Purchases												\$	-	
74	Less: Schedule 24 for Asset Based Sales									\$	258.68			\$	-
75															
76	TOTAL ASSET or NON ASSET BASED WHOLESALE								\$	198,168.32			\$	-	

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	Day Ahead & Real Time Energy													
1	DA Asset Energy Amount	555.02	(425,318)	\$ (10,860,987.15)	214,975	\$ 5,377,016.87	0	\$ -	3,136	\$ 157,296.52	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	3,791	\$ 118,213.11	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(14,644)	\$ (306,515.35)	14,742	\$ 377,408.88	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(439,962)	\$ (11,167,502.50)	233,508	\$ 5,872,638.86	0	\$ -	3,136	\$ 157,296.52	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (44,529.99)	0	\$ 180,027.90	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (428,064.51)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (94,934.14)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (567,528.64)	0	\$ 180,027.90	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (49,046.60)	0	\$ -	0	\$ (215.37)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (7,062.84)	0	\$ 186.47	0	\$ (1,868.67)	0	\$ 0.06	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (870.88)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (56,980.32)	0	\$ 186.47	0	\$ (2,084.04)	0	\$ 0.06	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (1,031,418.36)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (92,399.67)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (101,176.98)	0	\$ 2,533,681.72	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 84,819.52	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (70,627.34)	0	\$ 88,619.01	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (88,619.01)	0	\$ 70,627.34	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (2,301.26)	0	\$ 3,770,617.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (3,747,095.83)	0	\$ 2,301.27	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (16,983.62)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 152,045.53	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (4,119,203.71)	0	\$ 5,671,293.24	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (8,884.18)	0	\$ 7.50	0	\$ (385.05)	0	\$ 0.31	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 13,506.32	0	\$ -	0	\$ 2,853.68	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (5,635.96)	0	\$ 117.07	0	\$ (244.01)	0	\$ 4.97	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 102,474.66	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ -	0	\$ 3,440.53	0	\$ -	0	\$ 149.18	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (14,520.14)	0	\$ 17,071.42	0	\$ (629.06)	0	\$ 105,482.80	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ (122.11)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (15,069.18)	0	\$ 16,327.98	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (234,683.13)	0	\$ 15,185.49	0	\$ (10,175.00)	0	\$ 658.31	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (3,124.08)	0	\$ 13.59	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 27,913.47	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (2,117.57)	0	\$ 2,382.68	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (20,232.36)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (275,348.43)	0	\$ 61,823.21	0	\$ (10,175.00)	0	\$ 658.31	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(26,851)	\$ (689,717.25)	25,894	\$ 463,391.69	(879)	\$ (23,631.53)	19,673	\$ 534,715.58	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	0	\$ -	0	\$ -	0	\$ -	9	\$ 101.98	0	\$ -	0	\$ -
53	SUBTOTAL		(26,851)	\$ (689,717.25)	25,894	\$ 463,391.69	(879)	\$ (23,631.53)	19,682	\$ 534,817.56	0	\$ -	0	\$ -

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Charge Type Description	Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
54	DA Congestion Rebate on COGA	555.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
55	DA Losses Rebate on COGA	555.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
56	RT Congestion Rebate on COGA	555.22	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
57	RT Loss Rebate on COGA	555.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
58	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
59	TOTAL MISO DAY 2 CHARGES		(466,813)	\$ (16,890,800.99)	259,402	\$ 12,266,432.79	(879)	\$ (36,519.63)	22,819	\$ 798,255.25	0	\$ -	0	\$ -
60	Less Schedule 16 & 17 (Lines 16, 17, 18)			\$ (56,980.32)		\$ 186.47								
61	Congestion and Losses Adjustment			\$ 41,026.20										
62	No DA generation sch., but still had output for current month			\$ -										
63														
64														
65	Total for MN Energy Adjustment Rider			\$ (16,874,846.87)		\$ 12,266,246.32								
66	Net Retail for MN Energy Adjustment Rider				\$ (4,608,600.55)									
67	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
68	NET MISO (Rev-Cost and MWh)									\$ 761,735.62			\$ -	
69	Less: Fuel Cost								21,940	\$ 677,936.44			\$ -	
70	Less: Misc Cost Adjustment									\$ -			\$ -	
71	Plus: Capacity Revenue												\$ -	
72	Plus: Bilateral Sales												\$ -	
73	Less: Bilateral Purchases												\$ -	
74	Less: Schedule 24 for Asset Based Sales									\$ 348.04			\$ -	
75														
76	TOTAL ASSET or NON ASSET BASED WHOLESALE									\$ 83,451.14			\$ -	

Otter Tail Power Company Detail of MISO Day 2 Charges - System June 2025 includes any adjustments														
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	Day Ahead & Real Time Energy													
1	DA Asset Energy Amount	555.02	(418,392)	\$ (14,286,089.24)	285,538	\$ 10,781,820.20	0	\$ -	22,979	\$ 1,099,859.06	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	3,817	\$ 120,904.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(37,381)	\$ (1,288,150.76)	10,953	\$ 831,967.82	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(455,773)	\$ (15,574,240.00)	300,308	\$ 11,734,692.25	0	\$ -	22,979	\$ 1,099,859.06	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (114,933.82)	0	\$ 211,772.45	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (559,070.08)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (43,328.74)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (717,332.64)	0	\$ 211,772.45	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (41,158.20)	0	\$ -	0	\$ (1,341.28)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (6,534.96)	0	\$ 276.82	0	\$ (1,167.94)	0	\$ -	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (871.28)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (48,564.44)	0	\$ 276.82	0	\$ (2,509.22)	0	\$ -	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (1,625,052.40)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (38,963.90)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (126,889.58)	0	\$ 2,111,885.64	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 52,945.69	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (52,906.99)	0	\$ 29,298.02	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (29,298.02)	0	\$ 52,906.99	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (967.31)	0	\$ 2,704,201.78	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (2,370,018.27)	0	\$ 971.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (530.18)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 254,778.24	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (2,619,574.25)	0	\$ 3,581,935.00	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (10,402.67)	0	\$ 0.01	0	\$ (791.21)	0	\$ -	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 17,625.24	0	\$ -	0	\$ 3,819.33	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (16,331.48)	0	\$ 31.40	0	\$ (1,241.99)	0	\$ 2.28	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 1,571.43	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ -	0	\$ 10,202.04	0	\$ -	0	\$ 776.11	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (26,734.15)	0	\$ 27,858.69	0	\$ (2,033.20)	0	\$ 6,169.15	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ (30.97)	0	\$ 969.82	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (8,958.70)	0	\$ 4,377.52	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (179,982.73)	0	\$ 111,162.10	0	\$ (13,692.06)	0	\$ 8,456.53	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (2,115.70)	0	\$ 73.15	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 17,399.84	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (1,484.00)	0	\$ 846.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (20,401.70)	0	\$ 25.45	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (212,973.80)	0	\$ 134,853.93	0	\$ (13,692.06)	0	\$ 8,456.53	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(50,604)	\$ (1,385,214.76)	7,937	\$ 381,953.20	(3,856)	\$ (102,726.99)	14,499	\$ 568,315.52	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	0	\$ (10,991.42)	370	\$ 103.89	0	\$ (456.81)	12	\$ 71.33	0	\$ -	0	\$ -
53	SUBTOTAL		(50,604)	\$ (1,396,206.18)	8,307	\$ 382,057.09	(3,856)	\$ (103,183.80)	14,512	\$ 568,386.85	0	\$ -	0	\$ -

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Charge Type Description	Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
54	DA Congestion Rebate on COGA	555.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
55	DA Losses Rebate on COGA	555.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
56	RT Congestion Rebate on COGA	555.22	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
57	RT Loss Rebate on COGA	555.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
58	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
59	TOTAL MISO DAY 2 CHARGES		(506,378)	\$ (20,595,625.46)	308,615	\$ 16,073,446.23	(3,856)	\$ (121,418.28)	37,491	\$ 1,682,871.59	0	\$ -	0	\$ -
60	Less Schedule 16 & 17 (Lines 16, 17, 18)			\$ (48,564.44)		\$ 276.82								
61	Congestion and Losses Adjustment			\$ 73,949.74										
62	No DA generation sch., but still had output for current month			\$ (3,344.71)										
63														
64														
65	Total for MN Energy Adjustment Rider			\$ (20,617,666.05)		\$ 16,073,169.41								
66	Net Retail for MN Energy Adjustment Rider				\$ (4,544,496.64)									
67	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
68	NET MISO (Rev-Cost and MWh)								\$ 1,561,453.31				\$ -	
69	Less: Fuel Cost							33,635	\$ 1,184,245.00					
70	Less: Misc Cost Adjustment								\$ 3.13					
71	Plus: Capacity Revenue												\$ -	
72	Plus: Bilateral Sales												\$ -	
73	Less: Bilateral Purchases												\$ -	
74	Less: Schedule 24 for Asset Based Sales									\$ 577.06			\$ -	
75														
76	TOTAL ASSET or NON ASSET BASED WHOLESALE								\$ 376,628.12				\$ -	

Otter Tail Power Company Detail of MISO Day 2 Charges - System July 2025 includes any adjustments																									
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)											
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE														
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue											
No.	Day Ahead & Real Time Energy																								
1	DA Asset Energy Amount	555.02	(451,808)	\$ (24,117,365.04)	399,174	\$ 22,106,603.20	0	\$ -	62,690	\$ 4,330,371.66	0	\$ -	0	\$ -											
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,075	\$ 189,927.88	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
3	RT Asset Energy Amount	555.19	(37,230)	\$ (1,861,905.68)	10,801	\$ 533,660.09	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
5	SUBTOTAL		(489,039)	\$ (25,979,270.72)	414,050	\$ 22,830,191.17	0	\$ -	62,690	\$ 4,330,371.66	0	\$ -	0	\$ -											
Day Ahead & Real Time Energy Loss																									
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
7	RT Distribution of Losses Amount	555.24	0	\$ (25,956.82)	0	\$ 682,237.82	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
9	DA Loss Amount		0	\$ (1,664,364.56)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
10	RT Loss Amount		0	\$ (70,517.58)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
12	SUBTOTAL		0	\$ (1,760,838.96)	0	\$ 682,237.82	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
Virtual Energy																									
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
Schedules 16 & 17																									
16	DA Mkt Admin Amount	555.01	0	\$ (59,724.84)	0	\$ -	0	\$ (4,335.37)	0	\$ -	0	\$ -	0	\$ -											
17	RT Mkt Admin Amount	555.18	0	\$ (8,112.96)	0	\$ 272.98	0	\$ (1,922.87)	0	\$ -	0	\$ -	0	\$ -											
18	FTR Mkt Admin Amount	555.13	0	\$ (1,122.16)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
19	SUBTOTAL		0	\$ (68,959.96)	0	\$ 272.98	0	\$ (6,258.24)	0	\$ -	0	\$ -	0	\$ -											
Congestion & FTRs																									
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
21	DA Congestion		0	\$ -	0	\$ (2,243,382.85)	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
23	RT Congestion		0	\$ (238,802.12)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
24	FTR Hourly Allocation Amount	555.14	0	\$ (147,887.44)	0	\$ 2,972,577.88	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 52,897.92	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (52,897.92)	0	\$ 68,927.84	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
29	FTR Guarantee Uplift Amount	555.37	0	\$ (68,927.84)	0	\$ 52,897.92	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (967.31)	0	\$ 2,704,201.78	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
31	FTR Annual Transaction Amount	555.38	0	\$ (2,370,018.27)	0	\$ 971.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (530.18)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 254,778.53	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
35	SUBTOTAL		0	\$ (2,880,031.08)	0	\$ 3,863,870.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
RSG & Make Whole Payments																									
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (10,262.65)	0	\$ 1.35	0	\$ (1,714.65)	0	\$ 0.19	0	\$ -	0	\$ -											
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 627.66	0	\$ -	0	\$ 56.74	0	\$ -	0	\$ -											
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (16,810.86)	0	\$ 309.67	0	\$ (2,808.55)	0	\$ 51.61	0	\$ -	0	\$ -											
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 22,556.93	0	\$ -	0	\$ -											
40	RT Price Volatility Make Whole Payment	555.42	0	\$ (4,398.85)	0	\$ 143,812.06	0	\$ (735.02)	0	\$ 24,030.14	0	\$ -	0	\$ -											
41	SUBTOTAL		0	\$ (31,472.36)	0	\$ 144,750.74	0	\$ (5,258.22)	0	\$ 46,695.61	0	\$ -	0	\$ -											
RNU & Misc Charges																									
42	RT Misc Amount	555.25	0	\$ (25,085.51)	0	\$ 6,006.30	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
43	RT Net Inadvertent Amount	555.27	0	\$ (14,157.37)	0	\$ 26,610.10	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (203,732.71)	0	\$ 11,144.55	0	\$ (34,042.00)	0	\$ 1,861.99	0	\$ -	0	\$ -											
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (44,475.35)	0	\$ 363.93	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
47	DA Ramp Product	555.63	0	\$ -	0	\$ 14,515.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
48	RT Ramp Product	555.64	0	\$ (1,707.94)	0	\$ 2,552.62	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (21,929.47)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -											
50	SUBTOTAL		0	\$ (311,088.35)	0	\$ 61,192.81	0	\$ (34,042.00)	0	\$ 1,861.99	0	\$ -	0	\$ -											
ASM Charges																									
51	RT ASM Non-Excessive Energy Amount	555.55	(47,757)	\$ (2,159,329.80)	12,313	\$ 690,733.72	(6,637)	\$ (297,562.27)	16,667	\$ 873,903.95	0	\$ -	0	\$ -											
52	RT ASM Excessive Energy Amount	555.56	(59)	\$ (602.01)	46	\$ 38.35	0	\$ -	2	\$ 19.52	0	\$ -	0	\$ -											
53	SUBTOTAL		(47,816)	\$ (2,159,931.81)	12,359	\$ 690,772.07	(6,637)	\$ (297,562.27)	16,669	\$ 873,923.47	0	\$ -	0	\$ -											

Otter Tail Power Company														
Detail of MISO Day 2 Charges - System														
July 2025 includes any adjustments														
Charge Type Description	(A) Acct	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
		RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE				
		MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	
Grandfathered Charge Types														
54	DA Congestion Rebate on COGA	555.05	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
55	DA Losses Rebate on COGA	555.06	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
56	RT Congestion Rebate on COGA	555.22	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
57	RT Loss Rebate on COGA	555.23	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
58	SUBTOTAL		0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
59	TOTAL MISO DAY 2 CHARGES		(536,855)	\$ (33,191,593.24)	426,409	\$ 28,273,287.65	(6,637)	\$ (343,120.73)	79,359	\$ 5,252,852.73	0	\$ -	0	\$ -
60	Less Schedule 16 & 17 (Lines 16, 17, 18)		\$	(68,959.96)	\$	272.98								
61	Congestion and Losses Adjustment		\$	(20,034.12)										
62	No DA generation sch., but still had output for current month		\$	(8,418.60)										
63														
64														
65	Total for MN Energy Adjustment Rider		\$	(33,094,180.56)	\$	28,273,014.67								
66	Net Retail for MN Energy Adjustment Rider				\$	(4,821,165.89)								
67	Retail MWh include losses of 2.8%													
ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS														
68	NET MISO (Rev-Cost and MWh)							\$	4,909,732.00			\$	-	
69	Less: Fuel Cost							72,722	\$	2,569,087.12			\$	-
70	Less: Misc Cost Adjustment								\$	-			\$	-
71	Plus: Capacity Revenue												\$	-
72	Plus: Bilateral Sales												\$	-
73	Less: Bilateral Purchases												\$	-
74	Less: Schedule 24 for Asset Based Sales								\$	1,188.75			\$	-
75														
76	TOTAL ASSET or NON ASSET BASED WHOLESALE							\$	2,339,456.13			\$	-	

Otter Tail Power Company Detail of MISO Day 2 Charges - System August 2025 includes any adjustments														
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	Day Ahead & Real Time Energy													
1	DA Asset Energy Amount	555.02	(445,823)	\$ (26,387,340.68)	384,951	\$ 24,304,598.16	(18)	\$ (2,727.86)	35,376	\$ 2,239,180.71	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,079	\$ 197,685.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(18,693)	\$ (870,908.86)	17,669	\$ 1,067,947.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(464,516)	\$ (27,258,249.54)	406,700	\$ 25,570,230.56	(18)	\$ (2,727.86)	35,376	\$ 2,239,180.71	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (62,235.18)	0	\$ 758,759.10	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (1,841,929.79)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (28,511.36)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (1,932,676.33)	0	\$ 758,759.10	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (65,554.44)	0	\$ -	0	\$ (2,841.56)	0	\$ 1.36	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (8,494.32)	0	\$ 205.17	0	\$ (1,874.20)	0	\$ -	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (1,145.52)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (75,194.28)	0	\$ 205.17	0	\$ (4,715.76)	0	\$ 1.36	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (3,727,454.27)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (349,643.41)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (53,616.26)	0	\$ 4,917,417.09	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 45,479.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (45,474.21)	0	\$ 299,202.78	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (299,202.78)	0	\$ 45,474.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (967.31)	0	\$ 2,704,201.78	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (2,370,018.27)	0	\$ 971.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (530.18)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 254,778.76	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (3,119,452.42)	0	\$ 4,540,070.70	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (9,037.48)	0	\$ 3.58	0	\$ (890.20)	0	\$ 0.14	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 3,986.89	0	\$ -	0	\$ 2,078.85	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (20,705.14)	0	\$ 86.50	0	\$ (2,039.41)	0	\$ 8.45	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 6,302.38	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ -	0	\$ 74,897.63	0	\$ -	0	\$ 7,378.80	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (29,742.62)	0	\$ 78,974.60	0	\$ (2,929.61)	0	\$ 15,768.62	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ (5.12)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (17,845.71)	0	\$ 17,479.42	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (226,936.80)	0	\$ 13,122.53	0	\$ (22,357.12)	0	\$ 1,292.48	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (16,305.51)	0	\$ 18,127.60	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 10,886.61	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (500.95)	0	\$ 4,664.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (18,463.66)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (280,057.75)	0	\$ 64,280.24	0	\$ (22,357.12)	0	\$ 1,292.48	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(52,886)	\$ (2,445,109.03)	7,872	\$ 404,510.13	(4,921)	\$ (179,535.74)	14,632	\$ 623,133.39	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	0	\$ (134.68)	3	\$ -	0	\$ -	137	\$ 2,324.99	0	\$ -	0	\$ -
53	SUBTOTAL		(52,886)	\$ (2,445,243.71)	7,875	\$ 404,510.13	(4,921)	\$ (179,535.74)	14,769	\$ 625,458.38	0	\$ -	0	\$ -

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Charge Type Description	Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
54	DA Congestion Rebate on COGA	555.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
55	DA Losses Rebate on COGA	555.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
56	RT Congestion Rebate on COGA	555.22	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
57	RT Loss Rebate on COGA	555.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
58	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
59	TOTAL MISO DAY 2 CHARGES		(517,402)	\$ (35,140,616.65)	414,575	\$ 31,417,030.50	(4,939)	\$ (212,266.09)	50,146	\$ 2,881,701.55	0	\$ -	0	\$ -
60	Less Schedule 16 & 17 (Lines 16, 17, 18)			\$ (75,194.28)		\$ 205.17								
61	Congestion and Losses Adjustment			\$ 48,655.89										
62	No DA generation sch., but still had output for current month			\$ -										
63														
64														
65	Total for MN Energy Adjustment Rider			\$ (35,114,078.26)		\$ 31,416,825.33								
66	Net Retail for MN Energy Adjustment Rider				\$ (3,697,252.93)									
67	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
68	NET MISO (Rev-Cost and MWh)									\$ 2,669,435.46			\$ -	
69	Less: Fuel Cost								45,224	\$ 1,704,532.24				
70	Less: Misc Cost Adjustment									\$ -			\$ -	
71	Plus: Capacity Revenue												\$ -	
72	Plus: Bilateral Sales												\$ -	
73	Less: Bilateral Purchases												\$ -	
74	Less: Schedule 24 for Asset Based Sales									\$ 948.71			\$ -	
75														
76	TOTAL ASSET or NON ASSET BASED WHOLESALE									\$ 963,954.51			\$ -	

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
September 2025 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
No.	Day Ahead & Real Time Energy		MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
1	DA Asset Energy Amount	555.02	(459,395)	\$ (18,214,784.04)	367,296	\$ 14,845,352.18	0	\$ -	36,409	\$ 1,899,020.17	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,305	\$ 129,933.39	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(18,110)	\$ (1,006,741.02)	11,264	\$ 555,666.02	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(477,505)	\$ (19,221,525.06)	382,865	\$ 15,530,951.59	0	\$ -	36,409	\$ 1,899,020.17	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (90,869.53)	0	\$ 309,823.67	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (844,654.54)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (40,220.93)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (975,745.00)	0	\$ 309,823.67	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (71,317.56)	0	\$ -	0	\$ (3,253.52)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (8,735.78)	0	\$ 563.86	0	\$ (2,024.38)	0	\$ 16.38	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (1,302.72)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (81,356.06)	0	\$ 563.86	0	\$ (5,277.90)	0	\$ 16.38	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (1,586,198.24)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ 115,257.49	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (182,658.90)	0	\$ 3,958,297.01	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 209,614.87	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (209,594.67)	0	\$ 104,004.90	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (104,004.90)	0	\$ 239,901.47	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (1,776.72)	0	\$ 3,996,089.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (3,737,427.47)	0	\$ 1,822.61	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (9,508.52)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 270,126.63	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (4,129,713.69)	0	\$ 7,193,658.60	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (7,767.27)	0	\$ 6.07	0	\$ (712.12)	0	\$ 0.32	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 1,597.63	0	\$ -	0	\$ 1,348.88	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (13,104.34)	0	\$ 34.85	0	\$ (1,201.31)	0	\$ 3.14	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 351.53	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ -	0	\$ 25,239.48	0	\$ -	0	\$ 2,314.65	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (20,871.61)	0	\$ 26,878.03	0	\$ (1,913.43)	0	\$ 4,018.52	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ -	0	\$ 0.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (20,503.70)	0	\$ 12,472.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (193,788.66)	0	\$ 11,978.60	0	\$ (17,771.73)	0	\$ 1,098.26	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (14,739.44)	0	\$ 84.19	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 6,412.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (104.87)	0	\$ 970.25	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (20,917.52)	0	\$ 65.75	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (250,054.19)	0	\$ 31,983.47	0	\$ (17,771.73)	0	\$ 1,098.26	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(61,947)	\$ (1,720,044.20)	7,904	\$ 467,842.00	(7,571)	\$ (308,079.68)	13,315	\$ 301,261.80	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	0	\$ (11,592.08)	312	\$ 59.79	0	\$ (1,352.59)	41	\$ -	0	\$ -	0	\$ -
53	SUBTOTAL		(61,947)	\$ (1,731,636.28)	8,216	\$ 467,901.79	(7,571)	\$ (309,432.27)	13,357	\$ 301,261.80	0	\$ -	0	\$ -

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Charge Type Description	Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
54	DA Congestion Rebate on COGA	555.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
55	DA Losses Rebate on COGA	555.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
56	RT Congestion Rebate on COGA	555.22	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
57	RT Loss Rebate on COGA	555.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
58	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
59	TOTAL MISO DAY 2 CHARGES		(539,452)	\$ (26,410,901.89)	391,081	\$ 23,561,761.01	(7,571)	\$ (334,395.33)	49,765	\$ 2,205,415.13	0	\$ -	0	\$ -
60	Less Schedule 16 & 17 (Lines 16, 17, 18)			\$ (81,356.06)		\$ 563.86								
61	Congestion and Losses Adjustment			\$ 765,719.95										
62	No DA generation sch., but still had output for current month			\$ (25,506.67)										
63														
64														
65	Total for MN Energy Adjustment Rider			\$ (27,069,759.11)		\$ 23,561,197.15								
66	Net Retail for MN Energy Adjustment Rider					\$ (3,508,561.96)								
67	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
68	NET MISO (Rev-Cost and MWh)								\$ 1,871,019.80				\$ -	
69	Less: Fuel Cost							42,194	\$ 1,296,584.24					
70	Less: Misc Cost Adjustment								\$ 8.33				\$ -	
71	Plus: Capacity Revenue												\$ -	
72	Plus: Bilateral Sales												\$ -	
73	Less: Bilateral Purchases												\$ -	
74	Less: Schedule 24 for Asset Based Sales												\$ -	
75									\$ 1,013.89					
76	TOTAL ASSET or NON ASSET BASED WHOLESALE								\$ 573,413.34				\$ -	

Otter Tail Power Company Detail of MISO Day 2 Charges - System October 2025 includes any adjustments														
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
No.	Day Ahead & Real Time Energy													
1	DA Asset Energy Amount	555.02	(449,352)	\$ (24,890,066.70)	276,429	\$ 15,628,753.08	0	\$ -	11,338	\$ 629,268.90	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,021	\$ 137,167.78	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(31,334)	\$ (1,862,432.83)	15,380	\$ 912,166.88	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(480,686)	\$ (26,752,499.53)	295,829	\$ 16,678,087.74	0	\$ -	11,338	\$ 629,268.90	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (41,346.49)	0	\$ 340,386.58	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (755,639.47)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (41,166.44)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (838,152.40)	0	\$ 340,386.58	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (64,636.76)	0	\$ -	0	\$ (1,031.71)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (10,322.59)	0	\$ 712.09	0	\$ (1,499.52)	0	\$ 2.69	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (970.40)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (75,929.75)	0	\$ 712.09	0	\$ (2,531.23)	0	\$ 2.69	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (3,730,861.27)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (109,881.96)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (392,691.64)	0	\$ 12,249,659.30	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 122,158.64	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (113,079.32)	0	\$ 413,190.15	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (413,190.15)	0	\$ 113,079.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (1,776.72)	0	\$ 3,996,089.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (3,737,427.47)	0	\$ 1,822.61	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (9,512.14)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 270,124.93	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (4,777,559.40)	0	\$ 13,435,263.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (12,672.46)	0	\$ 1.37	0	\$ (611.12)	0	\$ 0.02	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 39,184.52	0	\$ -	0	\$ 1,072.79	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (12,884.47)	0	\$ 3,630.18	0	\$ (621.12)	0	\$ 175.02	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 35,345.33	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ (22,758.62)	0	\$ 40,588.51	0	\$ (1,097.86)	0	\$ 1,957.99	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (48,315.55)	0	\$ 83,404.58	0	\$ (2,330.10)	0	\$ 38,551.15	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ -	0	\$ 2,516.15	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (8,805.03)	0	\$ 7,551.67	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (225,158.34)	0	\$ 12,082.69	0	\$ (10,861.40)	0	\$ 582.60	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (4,407.01)	0	\$ 2,792.57	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 4,424.59	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (853.03)	0	\$ 1,912.16	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (21,642.73)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (260,866.14)	0	\$ 31,279.83	0	\$ (10,861.40)	0	\$ 582.60	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(49,548)	\$ (2,128,331.93)	17,162	\$ 705,580.92	(2,638)	\$ (103,187.97)	13,650	\$ 939,520.79	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	0	\$ (10,984.96)	261	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
53	SUBTOTAL		(49,548)	\$ (2,139,316.89)	17,423	\$ 705,580.92	(2,638)	\$ (103,187.97)	13,650	\$ 939,520.79	0	\$ -	0	\$ -

Otter Tail Power Company Detail of MISO Day 2 Charges - System October 2025 includes any adjustments														
Charge Type Description	(A) Acct	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
		MWh	Cost	RETAIL MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	
Grandfathered Charge Types														
54	DA Congestion Rebate on COGA	555.05	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
55	DA Losses Rebate on COGA	555.06	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
56	RT Congestion Rebate on COGA	555.22	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
57	RT Loss Rebate on COGA	555.23	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
58	SUBTOTAL		0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
59	TOTAL MISO DAY 2 CHARGES		(530,234) \$	(34,892,639.66)	313,253	\$	31,274,714.77	(2,638) \$	(118,910.70)	24,988	\$	1,607,926.13	0 \$	-
60	Less Schedule 16 & 17 (Lines 16, 17, 18)		\$	(75,929.75)		\$	712.09						0 \$	-
61	Congestion and Losses Adjustment		\$	952,767.88										
62	No DA generation sch., but still had output for current month		\$	(164,106.96)										
63														
64														
65	Total for MN Energy Adjustment Rider		\$	(35,605,370.83)		\$	31,274,002.68							
66	Net Retail for MN Energy Adjustment Rider				\$	(4,331,368.15)								
67	Retail MWh include losses of 2.8%													
ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS														
68	NET MISO (Rev-Cost and MWh)								\$	1,489,015.43			\$	-
69	Less: Fuel Cost							22,382	\$	641,144.63			\$	-
70	Less: Misc Cost Adjustment								\$	(23,629.04)			\$	-
71	Plus: Capacity Revenue												\$	-
72	Plus: Bilateral Sales												\$	-
73	Less: Bilateral Purchases												\$	-
74	Less: Schedule 24 for Asset Based Sales								\$	476.48			\$	-
75														
76	TOTAL ASSET or NON ASSET BASED WHOLESALE								\$	871,023.36			\$	-

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
November 2025 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
No.	Day Ahead & Real Time Energy		MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
1	DA Asset Energy Amount	555.02	(440,216)	\$ (22,194,468.41)	335,504	\$ 17,248,615.14	0	\$ -	22,961	\$ 1,278,255.10	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	4,096	\$ 134,057.60	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(29,794)	\$ (1,065,089.03)	8,142	\$ 491,968.66	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(470,010)	\$ (23,259,557.44)	347,742	\$ 17,874,641.40	0	\$ -	22,961	\$ 1,278,255.10	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (44,955.69)	0	\$ 260,772.63	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (1,092,118.93)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (134,742.90)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (1,271,817.52)	0	\$ 260,772.63	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (64,835.36)	0	\$ -	0	\$ (1,955.15)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (9,069.79)	0	\$ 193.75	0	\$ (1,254.26)	0	\$ -	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (826.88)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (74,732.03)	0	\$ 193.75	0	\$ (3,209.41)	0	\$ -	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (4,698,525.82)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (232,574.00)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (191,537.01)	0	\$ 9,280,662.19	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 297,937.00	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (272,877.95)	0	\$ 325,523.48	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (325,523.48)	0	\$ 271,817.40	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (1,776.72)	0	\$ 3,996,089.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (3,737,427.47)	0	\$ 1,822.61	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (9,513.39)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 270,124.93	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (4,771,230.02)	0	\$ 9,745,451.14	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (11,763.69)	0	\$ -	0	\$ (701.80)	0	\$ -	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (3,895.87)	0	\$ 80.11	0	\$ (232.12)	0	\$ 4.67	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 578.90	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ -	0	\$ 55,425.12	0	\$ -	0	\$ 3,307.29	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (15,659.56)	0	\$ 55,505.23	0	\$ (933.92)	0	\$ 3,890.86	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ -	0	\$ 2,077.81	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (4,703.17)	0	\$ 5,585.26	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (208,291.43)	0	\$ 4,095.54	0	\$ (12,428.69)	0	\$ 244.22	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (2,014.45)	0	\$ 40.49	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 13,650.77	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (124.65)	0	\$ 1,484.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (22,085.50)	0	\$ 150.85	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (237,219.20)	0	\$ 27,085.07	0	\$ (12,428.69)	0	\$ 244.22	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(38,385)	\$ (1,416,955.85)	26,273	\$ 970,405.99	(5,112)	\$ (184,345.68)	7,697	\$ 197,810.59	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	0	\$ (651.01)	97	\$ 5.19	0	\$ (498.18)	41	\$ 5.19	0	\$ -	0	\$ -
53	SUBTOTAL		(38,385)	\$ (1,417,606.86)	26,369	\$ 970,405.99	(5,112)	\$ (184,843.86)	7,738	\$ 197,815.78	0	\$ -	0	\$ -

Otter Tail Power Company Detail of MISO Day 2 Charges - System November 2025 includes any adjustments														
Charge Type Description	(A) Acct	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
		RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE				
		MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	
Grandfathered Charge Types														
54	DA Congestion Rebate on COGA	555.05	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
55	DA Losses Rebate on COGA	555.06	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
56	RT Congestion Rebate on COGA	555.22	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
57	RT Loss Rebate on COGA	555.23	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
58	SUBTOTAL		0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-	0 \$	-
59	TOTAL MISO DAY 2 CHARGES		(508,395) \$	(31,047,822.63)	374,111 \$	28,934,055.21	(5,112) \$	(201,415.88)	30,698 \$	1,480,205.96	0 \$	-	0 \$	-
60	Less Schedule 16 & 17 (Lines 16, 17, 18)		\$	(74,732.03)	\$	193.75								
61	Congestion and Losses Adjustment		\$	845,986.86										
62	No DA generation sch., but still had output for current month		\$	(43,752.95)										
63														
64														
65	Total for MN Energy Adjustment Rider		\$	(31,775,324.51)	\$	28,933,861.46								
66	Net Retail for MN Energy Adjustment Rider				\$	(2,841,463.05)								
67	Retail MWh include losses of 2.8%													
ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS														
68	NET MISO (Rev-Cost and MWh)							\$	1,278,790.08			\$	-	
69	Less: Fuel Cost							25,586 \$	932,375.75					
70	Less: Misc Cost Adjustment							\$	-			\$	-	
71	Plus: Capacity Revenue											\$	-	
72	Plus: Bilateral Sales											\$	-	
73	Less: Bilateral Purchases											\$	-	
74	Less: Schedule 24 for Asset Based Sales							\$	674.07			\$	-	
75														
76	TOTAL ASSET or NON ASSET BASED WHOLESALE							\$	345,740.26			\$	-	

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
No.	Day Ahead & Real Time Energy		MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
1	DA Asset Energy Amount	555.02	(632,039)	\$ (45,875,761.73)	403,236	\$ 28,645,456.47	0	\$ -	8,634	\$ 559,058.32	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	\$ -	5,383	\$ 202,391.13	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(26,829)	\$ (1,154,702.84)	22,542	\$ 1,410,542.68	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	(9)	\$ (417.74)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(658,878)	\$ (47,030,882.31)	431,161	\$ 30,258,390.28	0	\$ -	8,634	\$ 559,058.32	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (83,907.75)	0	\$ 546,858.90	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (1,588,238.46)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (103,518.34)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (1,775,664.55)	0	\$ 546,858.90	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (81,246.28)	0	\$ -	0	\$ (702.06)	0	\$ -	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (10,635.96)	0	\$ 909.69	0	\$ (2,008.03)	0	\$ 14.24	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (1,046.72)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (92,928.96)	0	\$ 909.69	0	\$ (2,710.09)	0	\$ 14.24	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (7,807,585.79)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (560,998.34)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (38,946.49)	0	\$ 14,746,460.11	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 205,732.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (205,732.06)	0	\$ 596,878.18	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (596,878.18)	0	\$ 220,858.75	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (759.02)	0	\$ 2,230,409.99	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (2,152,915.59)	0	\$ 759.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (7,678.62)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ -	0	\$ 320,798.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (3,563,908.30)	0	\$ 10,514,310.53	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (33,518.65)	0	\$ 172.79	0	\$ (1,910.51)	0	\$ 9.84	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (16,279.57)	0	\$ 84.05	0	\$ (927.54)	0	\$ 4.70	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 29,484.58	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ (5.56)	0	\$ 66,965.62	0	\$ (0.31)	0	\$ 3,817.31	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (49,803.78)	0	\$ 67,222.46	0	\$ (2,838.36)	0	\$ 33,316.43	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ -	0	\$ 0.02	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (41,007.96)	0	\$ 20,344.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (395,598.13)	0	\$ 23,031.91	0	\$ (22,550.27)	0	\$ 1,312.65	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (980.26)	0	\$ 6.28	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 11,478.65	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (1,401.17)	0	\$ 1,371.75	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (26,235.12)	0	\$ 5.13	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (465,222.64)	0	\$ 56,237.97	0	\$ (22,550.27)	0	\$ 1,312.65	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(65,173)	\$ (3,341,780.95)	19,764	\$ 1,173,782.81	(2,873)	\$ (115,510.33)	21,226	\$ 977,171.21	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	(87)	\$ (2,873.89)	170	\$ 854.96	0	\$ -	25	\$ 742.95	0	\$ -	0	\$ -
53	SUBTOTAL		(65,260)	\$ (3,344,654.84)	19,934	\$ 1,174,637.77	(2,873)	\$ (115,510.33)	21,251	\$ 977,914.16	0	\$ -	0	\$ -

Otter Tail Power Company
Detail of MISO Day 2 Charges - System
December 2025 includes any adjustments

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Charge Type Description	Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
			MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
	Grandfathered Charge Types													
54	DA Congestion Rebate on COGA	555.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
55	DA Losses Rebate on COGA	555.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
56	RT Congestion Rebate on COGA	555.22	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
57	RT Loss Rebate on COGA	555.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
58	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
59	TOTAL MISO DAY 2 CHARGES		(724,138)	\$ (56,323,065.38)	451,095	\$ 42,618,567.60	(2,873)	\$ (143,609.05)	29,886	\$ 1,571,615.80	0	\$ -	0	\$ -
60	Less Schedule 16 & 17 (Lines 16, 17, 18)			\$ (92,928.96)		\$ 909.69								
61	Congestion and Losses Adjustment			\$ 862,259.78										
62	No DA generation sch., but still had output for current month			\$ -										
63														
64														
65	Total for MN Energy Adjustment Rider			\$ (57,092,396.20)		\$ 42,617,657.91								
66	Net Retail for MN Energy Adjustment Rider					\$ (14,474,738.29)								
67	Retail MWh include losses of 2.8%													
	ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
68	NET MISO (Rev-Cost and MWh)								\$ 1,428,006.75				\$ -	
69	Less: Fuel Cost							1,057	\$ 855,889.47				\$ -	
70	Less: Misc Cost Adjustment								\$ 33.53				\$ -	
71	Plus: Capacity Revenue												\$ -	
72	Plus: Bilateral Sales												\$ -	
73	Less: Bilateral Purchases												\$ -	
74	Less: Schedule 24 for Asset Based Sales												\$ -	
75									\$ 562.58				\$ -	
76	TOTAL ASSET or NON ASSET BASED WHOLESALE								\$ 571,521.17				\$ -	

Otter Tail Power Company Detail of MISO Day 2 Charges - System Year to Date 2025 includes any adjustments														
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description		Acct	MWh	Cost	RETAIL MWh	Revenue	MWh	ASSET BASED WHOLESALE Cost	MWh	Revenue	MWh	NON ASSET BASED WHOLESALE Cost	MWh	Revenue
No.	Day Ahead & Real Time Energy													
1	DA Asset Energy Amount	555.02	(5,811,799)	(254,407,181)	3,847,591	177,427,365	(18)	\$ (2,727.86)	221,844	\$ 13,382,941.16	0	\$ -	0	\$ -
2	DA Non-asset Energy Amount	555.09	0	0	52,538	1,806,721	0	\$ -	0	\$ -	0	\$ -	0	\$ -
3	RT Asset Energy Amount	555.19	(283,676)	(11,300,496)	171,830	8,022,813	0	\$ -	0	\$ -	0	\$ -	0	\$ -
4	RT Non-Asset Energy Amount	555.26	(9)	(418)	0	0	0	\$ -	0	\$ -	0	\$ -	0	\$ -
5	SUBTOTAL		(6,095,484)	(\$ 265,708,094.61)	4,071,958	\$ 187,256,898.27	(18)	\$ (2,727.86)	221,844	\$ 13,382,941.16	0	\$ -	0	\$ -
Day Ahead & Real Time Energy Loss														
6	DA FBT Loss Amount	555.04	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
7	RT Distribution of Losses Amount	555.24	0	\$ (951,769.29)	0	\$ 5,117,143.72	0	\$ -	0	\$ -	0	\$ -	0	\$ -
8	RT FBT Loss Amount	555.21	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
9	DA Loss Amount		0	\$ (12,625,148.98)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
10	RT Loss Amount		0	\$ (914,000.79)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
11	DA Losses Rebate on Option B GFA	555.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
12	SUBTOTAL		0	\$ (14,490,919.06)	0	\$ 5,117,143.72	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Virtual Energy														
13	DA Virtual Energy Amount	555.12	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
14	RT Virtual Energy Amount	555.32	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
15	SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
Schedules 16 & 17														
16	DA Mkt Admin Amount	555.01	0	\$ (832,145.12)	0	\$ -	0	\$ (17,587.55)	0	\$ 1.36	0	\$ -	0	\$ -
17	RT Mkt Admin Amount	555.18	0	\$ (112,183.53)	0	\$ 4,658.42	0	\$ (20,417.70)	0	\$ 97.98	0	\$ -	0	\$ -
18	FTR Mkt Admin Amount	555.13	0	\$ (14,244.16)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
19	SUBTOTAL		0	\$ (958,572.81)	0	\$ 4,658.42	0	\$ (38,005.25)	0	\$ 99.34	0	\$ -	0	\$ -
Congestion & FTRs														
20	DA FBT Congestion Amount	555.03	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
21	DA Congestion		0	\$ -	0	\$ (28,875,529.37)	0	\$ -	0	\$ -	0	\$ -	0	\$ -
22	RT FBT Congestion Amount	555.20	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
23	RT Congestion		0	\$ (1,956,554.23)	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
24	FTR Hourly Allocation Amount	555.14	0	\$ (1,566,610.67)	0	\$ 58,040,026.74	0	\$ -	0	\$ -	0	\$ -	0	\$ -
25	FTR Monthly Allocation Amount	555.15	0	\$ -	0	\$ 1,206,273.37	0	\$ -	0	\$ -	0	\$ -	0	\$ -
26	FTR Yearly Allocation Amount	555.17	0	\$ -	0	\$ 241,773.59	0	\$ -	0	\$ -	0	\$ -	0	\$ -
27	FTR Monthly Transaction Amount	555.35	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
28	FTR Full Funding Guarantee Amount	555.36	0	\$ (1,398,678.93)	0	\$ 2,074,449.19	0	\$ -	0	\$ -	0	\$ -	0	\$ -
29	FTR Guarantee Uplift Amount	555.37	0	\$ (2,074,449.19)	0	\$ 1,262,642.89	0	\$ -	0	\$ -	0	\$ -	0	\$ -
30	FTR Auction Revenue Rights Transaction Amount	555.39	0	\$ (24,518.35)	0	\$ 40,045,371.73	0	\$ -	0	\$ -	0	\$ -	0	\$ -
31	FTR Annual Transaction Amount	555.38	0	\$ (38,073,056.26)	0	\$ 27,426.09	0	\$ -	0	\$ -	0	\$ -	0	\$ -
32	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	0	\$ (116,276.06)	0	\$ 0.08	0	\$ -	0	\$ -	0	\$ -	0	\$ -
33	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	0	\$ (402.71)	0	\$ 2,760,713.49	0	\$ -	0	\$ -	0	\$ -	0	\$ -
34	DA Congestion Rebate on Option B GFA	555.07	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
35	SUBTOTAL		0	\$ (45,210,546.40)	0	\$ 76,783,147.80	0	\$ -	0	\$ -	0	\$ -	0	\$ -
RSG & Make Whole Payments														
36	DA Revenue Sufficiency Guarantee Distribution Amount	555.10	0	\$ (163,682.71)	0	\$ 192.96	0	\$ (9,586.22)	0	\$ 10.82	0	\$ -	0	\$ -
37	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	0	\$ -	0	\$ 86,534.45	0	\$ -	0	\$ 17,652.74	0	\$ -	0	\$ -
38	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	0	\$ (140,031.98)	0	\$ 5,293.92	0	\$ (10,394.23)	0	\$ 283.18	0	\$ -	0	\$ -
39	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.30	0	\$ -	0	\$ -	0	\$ -	0	\$ 471,803.90	0	\$ -	0	\$ -
40	RT Price Volatility Make Whole Payment	555.42	0	\$ (27,169.39)	0	\$ 498,416.45	0	\$ (1,833.40)	0	\$ 46,202.36	0	\$ -	0	\$ -
41	SUBTOTAL		0	\$ (330,884.08)	0	\$ 590,437.78	0	\$ (21,813.85)	0	\$ 535,953.00	0	\$ -	0	\$ -
RNU & Misc Charges														
42	RT Misc Amount	555.25	0	\$ (25,362.70)	0	\$ 15,407.68	0	\$ -	0	\$ -	0	\$ -	0	\$ -
43	RT Net Inadvertent Amount	555.27	0	\$ (299,175.46)	0	\$ 275,090.75	0	\$ -	0	\$ -	0	\$ -	0	\$ -
44	RT Revenue Neutrality Uplift Amount	555.28	0	\$ (2,609,977.84)	0	\$ 393,859.26	0	\$ (167,684.42)	0	\$ 21,724.29	0	\$ -	0	\$ -
45	RT Uninstructed Deviation Amount	555.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
46	RT Demand Response Allocation Uplift Amount	555.59	0	\$ (122,563.93)	0	\$ 21,691.67	0	\$ -	0	\$ -	0	\$ -	0	\$ -
47	DA Ramp Product	555.63	0	\$ -	0	\$ 169,699.39	0	\$ -	0	\$ -	0	\$ -	0	\$ -
48	RT Ramp Product	555.64	0	\$ (12,758.69)	0	\$ 25,177.31	0	\$ -	0	\$ -	0	\$ -	0	\$ -
49	RT Schedule 49 Cost Distribution Amount	555.65	0	\$ (268,491.87)	0	\$ 329.61	0	\$ -	0	\$ -	0	\$ -	0	\$ -
50	SUBTOTAL		0	\$ (3,338,330.49)	0	\$ 901,255.67	0	\$ (167,684.42)	0	\$ 21,724.29	0	\$ -	0	\$ -
ASM Charges														
51	RT ASM Non-Excessive Energy Amount	555.55	(584,052)	\$ (20,098,954.58)	214,919	\$ 7,212,325.46	(40,382)	\$ (1,528,739.09)	179,550	\$ 6,996,826.80	0	\$ -	0	\$ -
52	RT ASM Excessive Energy Amount	555.56	(306)	\$ (39,632.75)	1,572	\$ 2,228.31	(21)	\$ (2,376.86)	320	\$ 4,263.28	0	\$ -	0	\$ -
53	SUBTOTAL		(584,357)	\$ (20,138,587.33)	216,491	\$ 7,214,553.77	(40,403)	\$ (1,531,115.95)	179,871	\$ 7,001,090.08	0	\$ -	0	\$ -

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
Charge Type Description	Acct	RETAIL				ASSET BASED WHOLESALE				NON ASSET BASED WHOLESALE			
		MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue	MWh	Cost	MWh	Revenue
Grandfathered Charge Types													
54 DA Congestion Rebate on COGA	555.05	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
55 DA Losses Rebate on COGA	555.06	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
56 RT Congestion Rebate on COGA	555.22	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
57 RT Loss Rebate on COGA	555.23	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
58 SUBTOTAL		0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -	0	\$ -
59 TOTAL MISO DAY 2 CHARGES		(6,679,841)	\$ (350,175,934.78)	4,288,450	\$ 277,868,095.43	(40,421)	\$ (1,761,347.33)	401,715	\$ 20,941,807.87	0	\$ -	0	\$ -
60 Less Schedule 16 & 17 (Lines 16, 17, 18)			\$ (958,672.81)		\$ 4,658.42								
61 Congestion and Losses Adjustment			\$ 2,650,561.18		\$ -								
62 No DA generation sch., but still had output for current month			\$ (281,872.46)		\$ -								
63													
64													
65 Total for MN Energy Adjustment Rider			\$ (351,586,050.69)		\$ 277,863,437.01								
66 Net Retail for MN Energy Adjustment Rider				\$ (73,722,613.68)									
67 Retail MWh include losses of 2.8%													
ADDITIONAL REVENUE AND COSTS OF ASSET BASED AND NON ASSET BASED TRANSACTIONS													
68 NET MISO (Rev-Cost and MWh)								\$ 19,180,460.54				\$ -	
69 Less: Fuel Cost							335,054	\$ 12,265,038.63					
70 Less: Misc Cost Adjustment								\$ (24,630.30)					
71 Plus: Capacity Revenue												\$ -	
72 Plus: Bilateral Sales												\$ -	
73 Less: Bilateral Purchases												\$ -	
74 Less: Schedule 24 for Asset Based Sales								\$ 6,939.68				\$ -	
75													
76 TOTAL ASSET or NON ASSET BASED WHOLESALE								\$ 6,933,112.53				\$ -	

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System January 2025 includes any adjustments (Revenue) Expense									
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**		
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail		
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss								
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-	-
3	RT Asset Energy Amount	555.09	\$ -	\$ -	\$ -	\$ -	-	-	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-	-
5	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
RSG & Make Whole Payments									
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ -	\$ -	\$ -	\$ -	-	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-	-
9	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
Revenue Neutrality Uplift									
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ -	\$ -	\$ -	-	-	-
11	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
Other Charges									
12	DA Regulation-Down Distribution Amount	555.04	\$ -	\$ -	\$ -	\$ -	-	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ -	\$ -	\$ -	\$ -	-	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ -	\$ -	\$ -	\$ -	-	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ -	\$ -	\$ -	\$ -	-	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ 56.79	\$ (20,970.38)	\$ (13.57)	\$ (20,927.16)	-	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	-	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ -	\$ -	\$ -	-	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ -	\$ -	\$ -	-	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 66,563.16	\$ (308,796.75)	\$ -	\$ (242,233.59)	-	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 25,718.59	\$ (18,226.77)	\$ -	\$ 7,491.82	-	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ -	\$ -	\$ -	\$ -	-	-	-
28	RT Schedule 1A3 Amount	555.29	\$ -	\$ -	\$ -	\$ -	-	-	-
29	RT Schedule 1A4 Amount	555.30	\$ -	\$ -	\$ -	\$ -	-	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ -	\$ -	-	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	-	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ -	\$ -	\$ -	-	-	-
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ -	\$ -	-	-	-
38	TOTAL		\$ 92,338.54	\$ (347,993.90)	\$ (13.57)	\$ (255,668.93)	-	-	-
Grandfathered Charge Types									
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ -	\$ -	\$ -	\$ -	-	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	-	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-	-
42	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
43	TOTAL SPP CHARGES		\$ 92,338.54	\$ (347,993.90)	\$ (13.57)	\$ (255,668.93)	-	-	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ (255,668.93)					
45	Net KWH for retail = ((F) + (G)) * 1,000								-
46	January 2024 covers time period of 12/26/2023 -- 01/23/2024						** (F) and (G) increased for losses of 2.8%		
47	SPP Book Totals		\$ (255,655.36)	-					
48	Adjustments		\$ (13.57)	-					
49	Total SPP		\$ (255,668.93)	-					

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System February 2025 includes any adjustments (Revenue) Expense									
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**		
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail		
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss								
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-	-
3	RT Asset Energy Amount	555.09	\$ -	\$ -	\$ -	\$ -	-	-	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-	-
5	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
RSG & Make Whole Payments									
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ -	\$ -	\$ -	\$ -	-	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-	-
9	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
Revenue Neutrality Uplift									
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ -	\$ -	\$ -	-	-	-
11	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
Other Charges									
12	DA Regulation-Down Distribution Amount	555.04	\$ -	\$ -	\$ -	\$ -	-	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ -	\$ -	\$ -	\$ -	-	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ -	\$ -	\$ -	\$ -	-	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ -	\$ -	\$ -	\$ -	-	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ -	\$ (16,914.67)	\$ 237.35	\$ (16,677.32)	-	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	-	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ -	\$ -	\$ -	-	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ -	\$ -	\$ -	-	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 36,459.71	\$ (186,199.45)	\$ -	\$ (149,739.74)	-	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 24,856.50	\$ (12,205.22)	\$ -	\$ 12,651.28	-	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ -	\$ -	\$ -	\$ -	-	-	-
28	RT Schedule 1A3 Amount	555.29	\$ -	\$ -	\$ -	\$ -	-	-	-
29	RT Schedule 1A4 Amount	555.30	\$ -	\$ -	\$ -	\$ -	-	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ -	\$ -	-	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	-	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ -	\$ -	\$ -	-	-	-
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ -	\$ -	-	-	-
38	TOTAL		\$ 61,316.21	\$ (215,319.34)	\$ 237.35	\$ (153,765.78)	\$ -	\$ -	-
Grandfathered Charge Types									
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ -	\$ -	\$ -	\$ -	-	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	-	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-	-
42	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
43	TOTAL SPP CHARGES		\$ 61,316.21	\$ (215,319.34)	\$ 237.35	\$ (153,765.78)	-	-	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ (153,765.78)					-
45	Net KWH for retail = ((F) + (G)) * 1,000								-
46	February 2024 covers time period of 1/24/2024 - 2/21/2024						** (F) and (G) increased for losses of 2.8%		
47	SPP Book Totals		Net Retail	Net SPP KWH					
48	Adjustments		\$ (154,003.13)	-					
49	Total SPP		\$ 237.35	-					
			\$ (153,765.78)	-					

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System March 2025 includes any adjustments (Revenue) Expense									
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**		
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail		
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss								
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-	-
3	RT Asset Energy Amount	555.09	\$ -	\$ -	\$ 5.22	\$ 5.22	-	-	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-	-
5	TOTAL		\$ -	\$ -	\$ 5.22	\$ 5.22	-	-	-
RSG & Make Whole Payments									
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ -	\$ -	\$ 0.20	\$ 0.20	-	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-	-
9	TOTAL		\$ -	\$ -	\$ 0.20	\$ 0.20	-	-	-
Revenue Neutrality Uplift									
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ -	\$ 0.85	\$ 0.85	-	-	-
11	TOTAL		\$ -	\$ -	\$ 0.85	\$ 0.85	-	-	-
Other Charges									
12	DA Regulation-Down Distribution Amount	555.04	\$ -	\$ -	\$ 0.01	\$ 0.01	-	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ -	\$ -	\$ 0.05	\$ 0.05	-	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ -	\$ -	\$ -	\$ -	-	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ -	\$ -	\$ 0.01	\$ 0.01	-	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ -	\$ (9,590.11)	\$ 278.58	\$ (9,311.53)	-	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	-	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ -	\$ -	\$ -	-	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ -	\$ -	\$ -	-	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 4,810.92	\$ (166,686.24)	\$ -	\$ (161,875.32)	-	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 3,619.72	\$ (9,120.06)	\$ -	\$ (5,500.34)	-	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ -	\$ -	\$ -	\$ -	-	-	-
28	RT Schedule 1A3 Amount	555.29	\$ -	\$ -	\$ 0.01	\$ 0.01	-	-	-
29	RT Schedule 1A4 Amount	555.30	\$ -	\$ -	\$ 0.05	\$ 0.05	-	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ -	\$ -	-	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	-	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ -	\$ 0.01	\$ 0.01	-	-	-
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ -	\$ -	-	-	-
38	TOTAL		\$ 8,430.64	\$ (185,396.41)	\$ 278.72	\$ (176,687.05)	\$ -	\$ -	-
Grandfathered Charge Types									
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ -	\$ -	\$ 0.06	\$ 0.06	-	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	-	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-	-
42	TOTAL		\$ -	\$ -	\$ 0.06	\$ 0.06	-	-	-
43	TOTAL SPP CHARGES		\$ 8,430.64	\$ (185,396.41)	\$ 285.05	\$ (176,680.72)	-	-	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ (176,680.72)					
45	Net KWH for retail = ((F) + (G)) * 1,000								-
46	March 2024 covers time period of 2/22/2024 - 3/21/2024						** (F) and (G) increased for losses of 2.8%		
47	SPP Book Totals		\$ (176,965.77)	-					
48	Adjustments		\$ 285.05	-					
49	Total SPP		\$ (176,680.72)	-					

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System April 2025 includes any adjustments (Revenue) Expense									
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**		
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail		
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss								
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-	-
3	RT Asset Energy Amount	555.09	\$ -	\$ -	\$ -	\$ -	-	-	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-	-
5	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
RSG & Make Whole Payments									
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ -	\$ -	\$ -	\$ -	-	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-	-
9	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
Revenue Neutrality Uplift									
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ -	\$ -	\$ -	-	-	-
11	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
Other Charges									
12	DA Regulation-Down Distribution Amount	555.04	\$ -	\$ -	\$ -	\$ -	-	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ -	\$ -	\$ -	\$ -	-	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ -	\$ -	\$ -	\$ -	-	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ -	\$ -	\$ -	\$ -	-	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ 598.56	\$ (7,605.75)	\$ (109.26)	\$ (7,116.45)	-	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	-	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ -	\$ -	\$ -	-	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ -	\$ -	\$ -	-	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 35,290.09	\$ (128,743.52)	\$ -	\$ (93,453.43)	-	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 7,163.25	\$ (8,893.37)	\$ -	\$ (1,730.12)	-	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ -	\$ -	\$ -	\$ -	-	-	-
28	RT Schedule 1A3 Amount	555.29	\$ -	\$ -	\$ -	\$ -	-	-	-
29	RT Schedule 1A4 Amount	555.30	\$ -	\$ -	\$ -	\$ -	-	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ -	\$ -	-	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	-	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ -	\$ -	\$ -	-	-	-
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ -	\$ -	-	-	-
38	TOTAL		\$ 43,051.90	\$ (145,242.64)	\$ (109.26)	\$ (102,300.00)	\$ -	\$ -	-
Grandfathered Charge Types									
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ -	\$ -	\$ -	\$ -	-	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	-	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-	-
42	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
43	TOTAL SPP CHARGES		\$ 43,051.90	\$ (145,242.64)	\$ (109.26)	\$ (102,300.00)	-	-	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ (102,300.00)					-
45	Net KWH for retail = ((F) + (G)) * 1,000								-
46	March 2024 covers time period of 2/22/2024 - 3/21/2024						** (F) and (G) increased for losses of 2.8%		
47	SPP Book Totals		\$ (102,190.74)	-					
48	Adjustments		\$ (109.26)	-					
49	Total SPP		\$ (102,300.00)	-					

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System May 2025 includes any adjustments (Revenue) Expense									
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**		
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail		
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss								
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-	-
3	RT Asset Energy Amount	555.09	\$ -	\$ -	\$ -	\$ -	-	-	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-	-
5	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
RSG & Make Whole Payments									
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ -	\$ -	\$ -	\$ -	-	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-	-
9	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
Revenue Neutrality Uplift									
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ -	\$ -	\$ -	-	-	-
11	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
Other Charges									
12	DA Regulation-Down Distribution Amount	555.04	\$ -	\$ -	\$ -	\$ -	-	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ -	\$ -	\$ -	\$ -	-	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ -	\$ -	\$ -	\$ -	-	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ -	\$ -	\$ -	\$ -	-	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ -	\$ (4,866.32)	\$ (921.12)	\$ (5,787.44)	-	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	-	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ -	\$ -	\$ -	-	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ -	\$ -	\$ -	-	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 44,733.86	\$ (78,718.19)	\$ -	\$ (33,984.33)	-	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 4,108.74	\$ (8,572.34)	\$ -	\$ (4,463.60)	-	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ -	\$ -	\$ -	\$ -	-	-	-
28	RT Schedule 1A3 Amount	555.29	\$ -	\$ -	\$ -	\$ -	-	-	-
29	RT Schedule 1A4 Amount	555.30	\$ -	\$ -	\$ -	\$ -	-	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ -	\$ -	-	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	-	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ -	\$ -	\$ -	-	-	-
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ -	\$ -	-	-	-
38	TOTAL		\$ 48,842.60	\$ (92,156.85)	\$ (921.12)	\$ (44,235.37)	\$ -	\$ -	-
Grandfathered Charge Types									
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ -	\$ -	\$ -	\$ -	-	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	-	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-	-
42	TOTAL		\$ -	\$ -	\$ -	\$ -	-	-	-
43	TOTAL SPP CHARGES		\$ 48,842.60	\$ (92,156.85)	\$ (921.12)	\$ (44,235.37)	-	-	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ (44,235.37)					
45	Net KWH for retail = ((F) + (G)) * 1,000								-
46	May 2025 covers time period of 4/23/2025 - 5/22/2025						** (F) and (G) increased for losses of 2.8%		
47	SPP Book Totals		Net Retail	Net SPP KWH					
48	Adjustments		\$ (43,314.25)	-					
49	Total SPP		\$ (921.12)	-					
			\$ (44,235.37)	-					

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System June 2025 includes any adjustments (Revenue) Expense						
	(A)	(B)	(C)	(D)	(E)	(F) and (G)**
Charge Type Description	Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail
Day Ahead & Real Time Asset & Non Asset Energy & Loss						
1 DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-
2 DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-
3 RT Asset Energy Amount	555.09	\$ -	\$ -	\$ -	\$ -	-
4 RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-
5 TOTAL		\$ -	\$ -	\$ -	\$ -	-
RSG & Make Whole Payments						
6 DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-
7 RT Make-Whole-Payment Distribution Amount	555.10	\$ -	\$ -	\$ -	\$ -	-
8 RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-
9 TOTAL		\$ -	\$ -	\$ -	\$ -	-
Revenue Neutrality Uplift						
10 RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ -	\$ -	\$ -	-
11 TOTAL		\$ -	\$ -	\$ -	\$ -	-
Other Charges						
12 DA Regulation-Down Distribution Amount	555.04	\$ -	\$ -	\$ -	\$ -	-
13 DA Regulation-Up Distribution Amount	555.05	\$ -	\$ -	\$ -	\$ -	-
14 DA Spinning Reserve Distribution Amount	555.06	\$ -	\$ -	\$ -	\$ -	-
15 DA Supplemental Reserve Distribution Amount	555.07	\$ -	\$ -	\$ -	\$ -	-
16 RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-
17 RT Over-Collected Losses Distribution Amount	555.11	\$ -	(4,528.21)	\$ (3.99)	\$ (4,532.20)	-
18 RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	-
19 RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ -	\$ -	\$ -	-
20 RT Regulation-Up Distribution Amount	555.14	\$ -	\$ -	\$ -	\$ -	-
21 RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-
22 RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-
23 RT Pseudo Tie Congestion Amount	555.20	14,790.89	(80,694.42)	\$ -	\$ (65,903.53)	-
24 RT Pseudo Tie Loss Amount	555.21	6,333.29	(2,294.38)	\$ -	\$ 4,038.91	-
25 Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-
26 ARR Closeout Yearly Amount	555.26	\$ -	(418,641.46)	\$ -	\$ (418,641.46)	-
27 RT Demand Reduction Distribution Amount	555.28	\$ -	\$ -	\$ -	\$ -	-
28 RT Schedule 1A3 Amount	555.29	\$ -	\$ -	\$ -	\$ -	-
29 RT Schedule 1A4 Amount	555.30	\$ -	\$ -	\$ -	\$ -	-
30 DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ -	\$ -	-
31 DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-
32 RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	-
33 RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-
34 RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-
35 ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-
36 RtURDDistAoAmt	555.37	\$ -	\$ -	\$ -	\$ -	-
37 DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ -	\$ -	-
38 TOTAL		\$ 21,124.18	\$ (506,158.47)	\$ (3.99)	\$ (485,038.28)	\$ -
Grandfathered Charge Types						
39 DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ -	\$ -	\$ -	\$ -	-
40 DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	-
41 DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	(3.22)	\$ -	\$ (3.22)	-
42 TOTAL		\$ -	\$ (3.22)	\$ -	\$ (3.22)	-
43 TOTAL SPP CHARGES		\$ 21,124.18	\$ (506,161.69)	\$ (3.99)	\$ (485,041.50)	-
44 Net SPP Charges for Retail = (B) + (C) + (D)			\$ (485,041.50)			-
45 Net KWH for retail = ((F) + (G)) * 1,000						-
46 June 2024 covers time period of 5/24/2024 - 6/20/2024					** (F) and (G) increased for losses of 2.8%	
47 SPP Book Totals		Net Retail	Net SPP KWH			
48 Adjustments		\$ (485,037.51)	-			
49 Total SPP		\$ (3.99)	-			
		\$ (485,041.50)	-			

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System July 2025 includes any adjustments (Revenue) Expense									
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**		
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail		
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss								
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-	-
3	RT Asset Energy Amount	555.09	\$ 400.33	\$ -	\$ -	\$ 400.33	7	-	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-	-
5	TOTAL		\$ 400.33	\$ -	\$ -	\$ 400.33	7		
RSG & Make Whole Payments									
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ 13.50	\$ -	\$ -	\$ 13.50	-	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-	-
9	TOTAL		\$ 13.50	\$ -	\$ -	\$ 13.50			
Revenue Neutrality Uplift									
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ (0.48)	\$ -	\$ (0.48)	-	-	-
11	TOTAL		\$ -	\$ (0.48)	\$ -	\$ (0.48)			
Other Charges									
12	DA Regulation-Down Distribution Amount	555.04	\$ 0.13	\$ -	\$ -	\$ 0.13	-	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ 1.27	\$ -	\$ -	\$ 1.27	-	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ 1.12	\$ -	\$ -	\$ 1.12	-	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ 0.21	\$ -	\$ -	\$ 0.21	-	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ (0.05)	\$ -	\$ (0.05)	-	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ 138.55	\$ (4,629.96)	\$ (272.57)	\$ (4,763.98)	-	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	-	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ (0.03)	\$ -	\$ (0.03)	-	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ 0.04	\$ -	\$ -	\$ 0.04	-	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 10,493.20	\$ (69,555.73)	\$ -	\$ (59,062.53)	-	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 5,245.36	\$ (7,041.76)	\$ -	\$ (1,796.40)	-	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ 0.12	\$ -	\$ -	\$ 0.12	-	-	-
28	RT Schedule 1A3 Amount	555.29	\$ 0.26	\$ -	\$ -	\$ 0.26	-	-	-
29	RT Schedule 1A4 Amount	555.30	\$ 0.45	\$ -	\$ -	\$ 0.45	-	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ 1.32	\$ -	\$ -	\$ 1.32	-	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ (0.10)	\$ -	\$ (0.10)	-	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ (0.69)	\$ -	\$ (0.69)	-	-	-
37	DaUncertDistAoAmt	555.38	\$ 0.30	\$ -	\$ -	\$ 0.30	-	-	-
38	TOTAL		\$ 15,882.33	\$ (81,228.32)	\$ (272.57)	\$ (65,618.56)	\$ -	\$ -	
Grandfathered Charge Types									
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ 0.37	\$ -	\$ -	\$ 0.37	-	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	-	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-	-
42	TOTAL		\$ 0.37	\$ -	\$ -	\$ 0.37			
43	TOTAL SPP CHARGES		\$ 16,296.53	\$ (81,228.80)	\$ (272.57)	\$ (65,204.84)	7		
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ (65,204.84)					
45	Net KWH for retail = ((F) + (G)) * 1,000							6,785	
46	June 2024 covers time period of 5/24/2024 - 6/20/2024						** (F) and (G) increased for losses of 2.8%		
47	SPP Book Totals		\$ (64,932.27)	6,785					
48	Adjustments		\$ (272.57)						
49	Total SPP		\$ (65,204.84)	6,785					

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System August 2025 includes any adjustments (Revenue) Expense								
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**	
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail	
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss							
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-
3	RT Asset Energy Amount	555.09	\$ 5,102.85	\$ -	\$ -	\$ 5,102.85	217	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-
5	TOTAL		\$ 5,102.85	\$ -	\$ -	\$ 5,102.85	217	-
RSG & Make Whole Payments								
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ 340.45	\$ -	\$ -	\$ 340.45	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-
9	TOTAL		\$ 340.45	\$ -	\$ -	\$ 340.45	-	-
Revenue Neutrality Uplift								
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ 81.82	\$ (0.01)	\$ -	\$ 81.81	-	-
11	TOTAL		\$ 81.82	\$ (0.01)	\$ -	\$ 81.81	-	-
Other Charges								
12	DA Regulation-Down Distribution Amount	555.04	\$ 9.30	\$ -	\$ -	\$ 9.30	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ 30.49	\$ -	\$ -	\$ 30.49	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ 15.42	\$ -	\$ -	\$ 15.42	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ 3.25	\$ -	\$ -	\$ 3.25	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ -	\$ (4,922.44)	\$ (750.17)	\$ (5,672.61)	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ 0.18	\$ -	\$ -	\$ 0.18	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ (0.95)	\$ -	\$ (0.95)	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ (0.39)	\$ -	\$ (0.39)	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 48,744.70	\$ (37,820.22)	\$ -	\$ 10,924.48	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 8,302.92	\$ (1,587.41)	\$ -	\$ 6,715.51	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ 0.23	\$ (0.37)	\$ -	\$ (0.14)	-	-
28	RT Schedule 1A3 Amount	555.29	\$ 8.24	\$ -	\$ -	\$ 8.24	-	-
29	RT Schedule 1A4 Amount	555.30	\$ 14.56	\$ -	\$ -	\$ 14.56	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ 9.14	\$ -	\$ -	\$ 9.14	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ (0.06)	\$ -	\$ (0.06)	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ (0.11)	\$ -	\$ (0.11)	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ (13.62)	\$ -	\$ (13.62)	-	-
37	DaUncertDistAoAmt	555.38	\$ 3.16	\$ -	\$ -	\$ 3.16	-	-
38	TOTAL		\$ 57,141.59	\$ (44,345.57)	\$ (750.17)	\$ 12,045.85	-	-
Grandfathered Charge Types								
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ 5.66	\$ (1.05)	\$ -	\$ 4.61	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ (0.01)	\$ -	\$ (0.01)	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-
42	TOTAL		\$ 5.66	\$ (1.06)	\$ -	\$ 4.60	-	-
43	TOTAL SPP CHARGES		\$ 62,672.37	\$ (44,346.64)	\$ (750.17)	\$ 17,575.56	217	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ 17,575.56				
45	Net KWH for retail = ((F) + (G)) * 1,000						216,815	
46	August 2025 covers time period of 7/24/2025 - 8/21/2025						** (F) and (G) increased for losses of 2.8%	
47	SPP Book Totals		\$ 18,325.73	216,815				
48	Adjustments		\$ (750.17)					
49	Total SPP		\$ 17,575.56	216,815				

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System September 2025 includes any adjustments (Revenue) Expense									
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**		
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail		
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss								
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-	-
3	RT Asset Energy Amount	555.09	\$ -	\$ -	\$ (18.88)	\$ (18.88)	-	-	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-	-
5	TOTAL		\$ -	\$ -	\$ (18.88)	\$ (18.88)	-	-	-
RSG & Make Whole Payments									
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ -	\$ -	\$ (1.57)	\$ (1.57)	-	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-	-
9	TOTAL		\$ -	\$ -	\$ (1.57)	\$ (1.57)	-	-	-
Revenue Neutrality Uplift									
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ -	\$ (0.03)	\$ (0.03)	-	-	-
11	TOTAL		\$ -	\$ -	\$ (0.03)	\$ (0.03)	-	-	-
Other Charges									
12	DA Regulation-Down Distribution Amount	555.04	\$ -	\$ -	\$ (0.01)	\$ (0.01)	-	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ -	\$ -	\$ (0.06)	\$ (0.06)	-	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ -	\$ -	\$ (0.05)	\$ (0.05)	-	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ -	\$ -	\$ (0.01)	\$ (0.01)	-	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ 42.04	\$ (5,272.36)	\$ (274.42)	\$ (5,504.74)	-	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	-	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ -	\$ 0.01	\$ 0.01	-	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ -	\$ -	\$ -	-	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 144,440.15	\$ (16,277.28)	\$ -	\$ 128,162.87	-	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 10,568.86	\$ (2,586.88)	\$ -	\$ 7,981.98	-	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ -	\$ -	\$ (0.01)	\$ (0.01)	-	-	-
28	RT Schedule 1A3 Amount	555.29	\$ -	\$ -	\$ (0.01)	\$ (0.01)	-	-	-
29	RT Schedule 1A4 Amount	555.30	\$ -	\$ -	\$ (0.01)	\$ (0.01)	-	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ (0.06)	\$ (0.06)	-	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	-	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ -	\$ 0.36	\$ 0.36	-	-	-
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ (0.01)	\$ (0.01)	-	-	-
38	TOTAL		\$ 155,051.05	\$ (24,136.52)	\$ (274.28)	\$ 130,640.25	-	-	-
Grandfathered Charge Types									
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ -	\$ -	\$ (0.02)	\$ (0.02)	-	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ (0.03)	\$ -	\$ (0.03)	-	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-	-
42	TOTAL		\$ -	\$ (0.03)	\$ (0.02)	\$ (0.05)	-	-	-
43	TOTAL SPP CHARGES		\$ 155,051.05	\$ (24,136.55)	\$ (294.78)	\$ 130,619.72	-	-	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ 130,619.72					
45	Net KWH for retail = ((F) + (G)) * 1,000								-
46	August 2024 covers time period of 7/24/2024 - 8/22/2024						** (F) and (G) increased for losses of 2.8%		
47	SPP Book Totals		Net Retail	Net SPP KWH					
48	Adjustments		\$ 130,914.50	-					
49	Total SPP		\$ (294.78)	-					
			\$ 130,619.72	-					

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System October 2025 includes any adjustments (Revenue) Expense								
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**	
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail	
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss							
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-
3	RT Asset Energy Amount	555.09	\$ 4,340.81	\$ -	\$ (31.27)	\$ 4,309.54	114	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-
5	TOTAL		\$ 4,340.81	\$ -	\$ (31.27)	\$ 4,309.54	114	-
RSG & Make Whole Payments								
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ 81.58	\$ -	\$ (51.21)	\$ 30.37	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-
9	TOTAL		\$ 81.58	\$ -	\$ (51.21)	\$ 30.37	-	-
Revenue Neutrality Uplift								
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ 122.69	\$ -	\$ (1.17)	\$ 121.52	-	-
11	TOTAL		\$ 122.69	\$ -	\$ (1.17)	\$ 121.52	-	-
Other Charges								
12	DA Regulation-Down Distribution Amount	555.04	\$ 10.76	\$ -	\$ (0.06)	\$ 10.70	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ 40.69	\$ -	\$ (0.48)	\$ 40.21	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ 3.15	\$ -	\$ (0.24)	\$ 2.91	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ 0.99	\$ -	\$ (0.06)	\$ 0.93	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ -	\$ (7,010.25)	\$ (1,002.47)	\$ (8,012.72)	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ 0.43	\$ -	\$ -	\$ 0.43	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ (1.28)	\$ (0.53)	\$ (1.81)	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ (0.05)	\$ -	\$ (0.05)	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 77,091.67	\$ (56,397.22)	\$ -	\$ 20,694.45	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 14,550.20	\$ (1,340.25)	\$ -	\$ 13,209.95	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ -	\$ (0.25)	\$ 0.01	\$ (0.24)	-	-
28	RT Schedule 1A3 Amount	555.29	\$ 4.31	\$ -	\$ (0.09)	\$ 4.22	-	-
29	RT Schedule 1A4 Amount	555.30	\$ 7.61	\$ -	\$ (0.14)	\$ 7.47	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ (0.13)	\$ (0.13)	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ (0.04)	\$ (0.04)	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ (8.94)	\$ (0.36)	\$ (9.30)	-	-
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ (0.04)	\$ (0.04)	-	-
38	TOTAL		\$ 91,709.81	\$ (64,758.24)	\$ (1,004.63)	\$ 25,946.94	-	-
Grandfathered Charge Types								
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ 4.70	\$ -	\$ (0.58)	\$ 4.12	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-
42	TOTAL		\$ 4.70	\$ -	\$ (0.58)	\$ 4.12	-	-
43	TOTAL SPP CHARGES		\$ 96,259.59	\$ (64,758.24)	\$ (1,088.86)	\$ 30,412.49	114	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ 30,412.49				
45	Net KWH for retail = ((F) + (G)) * 1,000						113,594	
46	October 2024 covers time period of 9/23/2024 – 10/23/2024						** (F) and (G) increased for losses of 2.8%	
47	SPP Book Totals		Net Retail	Net SPP KWH				
48	Adjustments		\$ 31,501.35	113,594				
49	Total SPP		\$ (1,088.86)					
			\$ 30,412.49	113,594				

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System November 2025 includes any adjustments (Revenue) Expense								
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**	
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail	
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss							
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-
3	RT Asset Energy Amount	555.09	\$ 402.50	\$ -	\$ (4,340.19)	\$ (3,937.69)	87	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-
5	TOTAL		\$ 402.50	\$ -	\$ (4,340.19)	\$ (3,937.69)	87	-
RSG & Make Whole Payments								
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ 101.34	\$ -	\$ (81.63)	\$ 19.71	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-
9	TOTAL		\$ 101.34	\$ -	\$ (81.63)	\$ 19.71	-	-
Revenue Neutrality Uplift								
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ 37.98	\$ -	\$ (122.52)	\$ (84.54)	-	-
11	TOTAL		\$ 37.98	\$ -	\$ (122.52)	\$ (84.54)	-	-
Other Charges								
12	DA Regulation-Down Distribution Amount	555.04	\$ 11.40	\$ -	\$ (10.76)	\$ 0.64	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ 12.29	\$ -	\$ (40.67)	\$ (28.38)	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ 1.56	\$ -	\$ (3.14)	\$ (1.58)	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ 0.48	\$ -	\$ (0.99)	\$ (0.51)	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ -	\$ (8,441.94)	\$ (190.40)	\$ (8,632.34)	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ 0.41	\$ -	\$ (0.43)	\$ (0.02)	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ (0.59)	\$ 1.28	\$ 0.69	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ (0.05)	\$ 0.05	\$ -	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 81,442.30	\$ (37,617.69)	\$ 766.83	\$ 44,591.44	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 14,167.46	\$ (928.10)	\$ 8.15	\$ 13,247.51	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ 0.42	\$ -	\$ 0.24	\$ 0.66	-	-
28	RT Schedule 1A3 Amount	555.29	\$ 3.44	\$ -	\$ (4.31)	\$ (0.87)	-	-
29	RT Schedule 1A4 Amount	555.30	\$ 6.07	\$ -	\$ (7.61)	\$ (1.54)	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ -	\$ -	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ (8.20)	\$ 8.95	\$ 0.75	-	-
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ -	\$ -	-	-
38	TOTAL		\$ 95,645.83	\$ (46,996.57)	\$ 527.19	\$ 49,176.45	-	-
Grandfathered Charge Types								
39	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ 4.32	\$ -	\$ (4.73)	\$ (0.41)	-	-
40	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ (0.01)	\$ -	\$ (0.01)	-	-
41	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-
42	TOTAL		\$ 4.32	\$ (0.01)	\$ (4.73)	\$ (0.42)	-	-
43	TOTAL SPP CHARGES		\$ 96,191.97	\$ (46,996.58)	\$ (4,021.88)	\$ 45,173.51	87	-
44	Net SPP Charges for Retail = (B) + (C) + (D)			\$ 45,173.51				
45	Net KWH for retail = ((F) + (G)) * 1,000						87,493	
46	November 2024 covers time period of	0					** (F) and (G) increased for losses of 2.8%	
47	SPP Book Totals		Net Retail	Net SPP KWH				
48	Adjustments		\$ 49,195.39	87,493				
49	Total SPP		\$ (4,021.88)					
			\$ 45,173.51	87,493				

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group for Current Month - System December 2025 includes any adjustments (Revenue) Expense								
Charge Type Description		(A)	(B)	(C)	(D)	(E)	(F) and (G)**	
		Acct	Retail Debits	Retail Credits	Retail Adjustments	Net Retail	Charge types with MWH for Retail	
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss							
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	-	-
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	-	-
3	RT Asset Energy Amount	555.09	\$ 10,870.26	\$ -	\$ 6.41	\$ 10,876.67	181	-
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	-	-
5	TOTAL		\$ 10,870.26	\$ -	\$ 6.41	\$ 10,876.67	181	-
RSG & Make Whole Payments								
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	-	-
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ 367.53	\$ -	\$ (20.64)	\$ 346.89	-	-
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	-	-
9	TOTAL		\$ 367.53	\$ -	\$ (20.64)	\$ 346.89	-	-
Revenue Neutrality Uplift								
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ 161.52	\$ -	\$ 0.59	\$ 162.11	-	-
11	TOTAL		\$ 161.52	\$ -	\$ 0.59	\$ 162.11	-	-
Other Charges								
12	DA Regulation-Down Distribution Amount	555.04	\$ 4.72	\$ -	\$ 0.19	\$ 4.91	-	-
13	DA Regulation-Up Distribution Amount	555.05	\$ 25.32	\$ -	\$ 0.28	\$ 25.60	-	-
14	DA Spinning Reserve Distribution Amount	555.06	\$ 18.08	\$ -	\$ 0.01	\$ 18.09	-	-
15	DA Supplemental Reserve Distribution Amount	555.07	\$ 2.60	\$ -	\$ (0.01)	\$ 2.59	-	-
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	-	-
17	RT Over-Collected Losses Distribution Amount	555.11	\$ 386.85	\$ (13,665.50)	\$ (117.58)	\$ (13,396.23)	-	-
18	RT Regulation-Down Distribution Amount	555.12	\$ 0.49	\$ -	\$ -	\$ 0.49	-	-
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ (0.45)	\$ 0.29	\$ (0.16)	-	-
20	RT Regulation-Up Distribution Amount	555.14	\$ 0.11	\$ -	\$ -	\$ 0.11	-	-
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	-	-
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	-	-
23	RT Pseudo Tie Congestion Amount	555.20	\$ 187,104.09	\$ (115,089.87)	\$ -	\$ 72,014.22	-	-
24	RT Pseudo Tie Loss Amount	555.21	\$ 50,277.41	\$ (411.19)	\$ -	\$ 49,866.22	-	-
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	-	-
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	-	-
27	RT Demand Reduction Distribution Amount	555.28	\$ 0.08	\$ (9.40)	\$ 0.01	\$ (9.31)	-	-
28	RT Schedule 1A3 Amount	555.29	\$ 6.88	\$ -	\$ 0.11	\$ 6.99	-	-
29	RT Schedule 1A4 Amount	555.30	\$ 12.18	\$ -	\$ 0.18	\$ 12.36	-	-
30	DA Ramp Up Distribution Amount	555.31	\$ 7.97	\$ -	\$ (0.01)	\$ 7.96	-	-
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	-	-
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ (0.01)	\$ -	\$ (0.01)	-	-
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	-	-
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	-	-
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	-	-
36	RtURDDistAoAmt	555.37	\$ -	\$ (7.39)	\$ 5.76	\$ (1.63)	-	-
37	DaUncertDistAoAmt	555.38	\$ 1.08	\$ -	\$ (0.02)	\$ 1.06	-	-
38	RtLRsADistAoAmt	555.39	\$ -	\$ -	\$ 70.95	\$ 70.95	-	-
39	TOTAL		\$ 237,847.86	\$ (129,183.81)	\$ (39.84)	\$ 108,624.21	-	-
Grandfathered Charge Types								
40	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ 19.85	\$ -	\$ 0.09	\$ 19.94	-	-
41	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ (0.07)	\$ 0.01	\$ (0.06)	-	-
42	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	-	-
43	TOTAL		\$ 19.85	\$ (0.07)	\$ 0.10	\$ 19.88	-	-
44	TOTAL SPP CHARGES		\$ 249,267.02	\$ (129,183.88)	\$ (53.38)	\$ 120,029.76	181	-
45	Net SPP Charges for Retail = (B) + (C) + (D)			\$ 120,029.76				
46	Net KWH for retail = ((F) + (G)) * 1,000						181,493	
47		0					** (F) and (G) increased for losses of 2.8%	
48	Net KWH for retail = ((F) + (G)) * 1,000							
48	SPP Book Totals		Net Retail	Net SPP KWH (adjusted cumulatively)				
49	Adjustments		\$ 120,083.14	181,493				
50	Total SPP		\$ (53.38)	-				
			\$ 120,029.76	181,493				

Otter Tail Power Company Detail of Southwest Power Pool (SPP) Charges by Charge Group - Net Retail - System Year to Date 2025 includes any adjustments (Revenue) Expense																
Charge Type Description		Acct	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	YEAR TO DATE	
No.	Day Ahead & Real Time Asset & Non Asset Energy & Loss															
1	DA Asset Energy Amount	555.19	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
2	DA Non-asset Energy Amount	555.03	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3	RT Asset Energy Amount	555.09	\$ -	\$ -	\$ 5.22	\$ -	\$ -	\$ -	\$ 400.33	\$ 5,102.85	\$ (18.88)	\$ 4,309.54	\$ (3,937.69)	\$ 10,876.67	\$ 16,738.04	\$ -
4	RT Non-Asset Energy Amount	555.00	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	TOTAL		\$ -	\$ -	\$ 5.22	\$ -	\$ -	\$ -	\$ 400.33	\$ 5,102.85	\$ (18.88)	\$ 4,309.54	\$ (3,937.69)	\$ 10,876.67	\$ 16,738.04	\$ -
RSG & Make Whole Payments																
6	DA Make-Whole-Payment Distribution Amount	555.02	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
7	RT Make-Whole-Payment Distribution Amount	555.10	\$ -	\$ -	\$ 0.20	\$ -	\$ -	\$ -	\$ 13.50	\$ 340.45	\$ (1.57)	\$ 30.37	\$ 19.71	\$ 346.89	\$ 749.55	\$ -
8	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
9	TOTAL		\$ -	\$ -	\$ 0.20	\$ -	\$ -	\$ -	\$ 13.50	\$ 340.45	\$ (1.57)	\$ 30.37	\$ 19.71	\$ 346.89	\$ 749.55	\$ -
Revenue Neutrality Uplift																
10	RT Revenue Neutrality Uplift Distribution Amount	555.15	\$ -	\$ -	\$ 0.85	\$ -	\$ -	\$ -	\$ (0.48)	\$ 81.81	\$ (0.03)	\$ 121.52	\$ (84.54)	\$ 162.11	\$ 281.24	\$ -
11	TOTAL		\$ -	\$ -	\$ 0.85	\$ -	\$ -	\$ -	\$ (0.48)	\$ 81.81	\$ (0.03)	\$ 121.52	\$ (84.54)	\$ 162.11	\$ 281.24	\$ -
Other Charges																
12	DA Regulation-Down Distribution Amount	555.04	\$ -	\$ -	\$ 0.01	\$ -	\$ -	\$ -	\$ 0.13	\$ 9.30	\$ (0.01)	\$ 10.70	\$ 0.64	\$ 4.91	\$ 25.68	\$ -
13	DA Regulation-Up Distribution Amount	555.05	\$ -	\$ -	\$ 0.05	\$ -	\$ -	\$ -	\$ 1.27	\$ 30.49	\$ (0.06)	\$ 40.21	\$ (28.38)	\$ 25.60	\$ 69.18	\$ -
14	DA Spinning Reserve Distribution Amount	555.06	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1.12	\$ 15.42	\$ (0.05)	\$ 2.91	\$ (1.58)	\$ 18.09	\$ 35.91	\$ -
15	DA Supplemental Reserve Distribution Amount	555.07	\$ -	\$ -	\$ 0.01	\$ -	\$ -	\$ -	\$ 0.21	\$ 3.25	\$ (0.01)	\$ 0.93	\$ (0.51)	\$ 2.59	\$ 6.47	\$ -
16	RT Contingency Reserve Deployment Failure Amount	555.08	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.05)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.05)	\$ -
17	RT Over-Collected Losses Distribution Amount	555.11	\$ (20,927.16)	\$ (16,677.32)	\$ (9,311.53)	\$ (7,116.45)	\$ (5,787.44)	\$ (4,532.20)	\$ (4,763.98)	\$ (5,672.61)	\$ (5,504.74)	\$ (8,012.72)	\$ (8,632.34)	\$ (13,396.23)	\$ (110,334.72)	\$ -
18	RT Regulation-Down Distribution Amount	555.12	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.18	\$ -	\$ 0.43	\$ (0.02)	\$ 0.49	\$ 1.08	\$ -
19	RT Regulation Non-Performance Distribution Amount	555.13	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.03)	\$ (0.95)	\$ 0.01	\$ (1.81)	\$ 0.69	\$ (0.16)	\$ (2.25)	\$ -
20	RT Regulation-Up Distribution Amount	555.14	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.04	\$ (0.39)	\$ -	\$ (0.05)	\$ -	\$ 0.11	\$ (0.29)	\$ -
21	RT Spinning Reserve Distribution Amount	555.16	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
22	RT Supplemental Reserve Distribution Amount	555.17	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
23	RT Pseudo Tie Congestion Amount	555.20	\$ (242,233.59)	\$ (149,739.74)	\$ (161,875.32)	\$ (93,453.43)	\$ (33,984.33)	\$ (65,903.53)	\$ (59,062.53)	\$ 10,924.48	\$ 128,162.87	\$ 20,694.45	\$ 44,591.44	\$ 72,014.22	\$ (529,865.01)	\$ -
24	RT Pseudo Tie Loss Amount	555.21	\$ 7,491.82	\$ 12,651.28	\$ (5,500.34)	\$ (1,730.12)	\$ (4,463.60)	\$ 4,038.91	\$ (1,796.40)	\$ 6,715.51	\$ 7,981.98	\$ 13,209.95	\$ 13,247.51	\$ 49,866.22	\$ 101,712.72	\$ -
25	Miscellaneous Amount	555.23	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
26	ARR Closeout Yearly Amount	555.26	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (418,641.46)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (418,641.46)	\$ -
27	RT Demand Reduction Distribution Amount	555.28	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.12	\$ (0.14)	\$ (0.01)	\$ (0.24)	\$ 0.66	\$ (9.31)	\$ (8.92)	\$ -
28	RT Schedule 1A3 Amount	555.29	\$ -	\$ -	\$ 0.01	\$ -	\$ -	\$ -	\$ 0.26	\$ 8.24	\$ (0.01)	\$ 4.22	\$ (0.87)	\$ 6.99	\$ 18.84	\$ -
29	RT Schedule 1A4 Amount	555.30	\$ -	\$ -	\$ 0.05	\$ -	\$ -	\$ -	\$ 0.45	\$ 14.56	\$ (0.01)	\$ 7.47	\$ (1.54)	\$ 12.36	\$ 33.34	\$ -
30	DA Ramp Up Distribution Amount	555.31	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1.32	\$ 9.14	\$ (0.06)	\$ (0.13)	\$ -	\$ 7.96	\$ 18.23	\$ -
31	DA Ramp Down Distribution Amount	555.32	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
32	RT Ramp Non Performance Distribution Amount	555.33	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.10)	\$ (0.06)	\$ -	\$ (0.04)	\$ -	\$ (0.01)	\$ (0.21)	\$ -
33	RT Ramp Up Distribution Amount	555.34	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.11)	\$ -	\$ -	\$ -	\$ -	\$ (0.11)	\$ -
34	RT Ramp Down Distribution Amount	555.35	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
35	ArrAucTxnAoAmt	555.36	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
36	RtURDDistAoAmt	555.37	\$ -	\$ -	\$ 0.01	\$ -	\$ -	\$ -	\$ (0.69)	\$ (13.62)	\$ 0.36	\$ (9.30)	\$ 0.75	\$ (1.63)	\$ (24.12)	\$ -
37	DaUncertDistAoAmt	555.38	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 0.30	\$ 3.16	\$ (0.01)	\$ (0.04)	\$ -	\$ 1.06	\$ 4.47	\$ -
38	RtLrSaDistAoAmt	555.39	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 70.95	\$ 70.95	\$ -
39	TOTAL		\$ (255,668.93)	\$ (153,765.78)	\$ (176,687.05)	\$ (102,300.00)	\$ (44,235.37)	\$ (485,038.28)	\$ (65,618.56)	\$ 12,045.85	\$ 130,640.25	\$ 25,946.94	\$ 49,176.45	\$ 108,624.21	\$ (956,880.27)	\$ -
Grandfathered Charge Types																
40	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	\$ -	\$ -	\$ 0.06	\$ -	\$ -	\$ -	\$ 0.37	\$ 4.61	\$ (0.02)	\$ 4.12	\$ (0.41)	\$ 19.94	\$ 28.67	\$ -
41	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (0.01)	\$ -	\$ -	\$ (0.01)	\$ (0.06)	\$ (0.11)	\$ -
42	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (3.22)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (3.22)	\$ -
43	TOTAL		\$ -	\$ -	\$ 0.06	\$ -	\$ -	\$ (3.22)	\$ 0.37	\$ 4.60	\$ (0.05)	\$ 4.12	\$ (0.42)	\$ 19.88	\$ 25.34	\$ -
44	TOTAL SPP CHARGES - Energy Adjustment Rider		\$ (255,668.93)	\$ (153,765.78)	\$ (176,680.72)	\$ (102,300.00)	\$ (44,235.37)	\$ (485,041.50)	\$ (65,204.84)	\$ 17,575.56	\$ 130,619.72	\$ 30,412.49	\$ 45,173.51	\$ 120,029.76	\$ (939,086.10)	\$ -

OTTER TAIL POWER COMPANY
GENERATION MAINTENANCE EXPENSE

		Actual 2017	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Actual 2024	Actual 2025	2021 Test Year
STEAM POWER MAINTENANCE:											
SUPERVISION AND ENGINEERING	402 - 510	\$ 842,512	\$ 937,306	\$ 964,831	\$ 834,101	\$ 798,930	\$ 624,662	\$ 551,458	\$ 519,606	\$ 513,136	\$ 1,036,964
STRUCTURES	402 - 511	1,202,457	989,059	883,200	777,386	874,175	795,762	769,295	928,954	612,658	793,128
BOILER	402 - 512	7,207,999	9,023,720	8,465,029	5,026,948	6,229,229	6,980,241	5,798,533	5,707,751	7,468,950	8,205,372
ELECTRIC	402 - 513	797,052	2,241,699	2,869,209	1,080,670	2,714,136	2,866,936	1,460,691	506,162	2,213,663	2,044,118
MISCELLANEOUS	402 - 514	<u>1,063,183</u>	<u>1,010,467</u>	<u>1,394,309</u>	<u>874,095</u>	<u>921,925</u>	<u>941,350</u>	<u>1,103,508</u>	<u>1,158,550</u>	<u>1,345,660</u>	<u>1,484,118</u>
Total Steam Power Maintenance		11,113,203	14,202,252	14,576,578	8,593,200	11,538,395	12,208,951	9,683,485	8,821,023	12,154,067	13,563,700
HYDRO POWER MAINTENANCE:											
SUPERVISION & ENGINEERING	402 - 541	3,449	2,731	881	3,679	323	345	6,999	3	10,231	3,872
STRUCTURES	402 - 542	5,016	12,239	40	66	1,881	26,644	3,353	12,394	12,356	6,264
RESERVOIRS - DAMS	402 - 543	277,357	221,684	250,983	250,800	249,940	265,138	232,540	266,369	243,934	225,645
ELECTRIC	402 - 544	50,242	907	9,908	4,793	3,289	18,437	8,209	36,490	44,454	5,875
MISCELLANEOUS EXPENSE	402 - 545	-	38	-	-	3,512	718	23,304	9,966	130	626
Total Hydro Maintenance		336,064	237,599	261,812	259,338	258,945	311,282	274,404	325,222	311,105	242,282
IC POWER MAINTENANCE WITHOUT WIND:											
SUPERVISION AND ENGINEERING	402 - 551	85,285	67,972	39,346	22,886	15,715	25,714	18,287	38,449	26,028	93,428
STRUCTURES	402 - 552	124,923	37,358	25,836	30,910	30,733	77,501	49,766	67,804	62,984	211,316
GENERATING AND ELECTRIC	402 - 553	656,222	631,963	443,752	344,215	427,726	1,111,952	1,250,859	1,587,612	1,641,517	445,358
MISCELLANEOUS EXPENSE	402 - 554	<u>26,008</u>	<u>36,124</u>	<u>23,904</u>	<u>32,009</u>	<u>121,757</u>	<u>153,746</u>	<u>698,600</u>	<u>144,804</u>	<u>99,621</u>	<u>27,816</u>
Total IC Maintenance without wind		892,438	773,417	532,839	430,020	595,931	1,368,913	2,017,512	1,838,669	1,830,150	777,918
IC POWER MAINTENANCE WIND ONLY:											
SUPERVISION AND ENGINEERING	402 - 551	-	3,698	-	9,597	-	120	5,639	3,037	8,055	-
GENERATING AND ELECTRIC	402 - 553	12,986	42,680	6,919	-	3,488,759	3,624,610	4,001,874	4,063,089	4,522,910	55,073
MISCELLANEOUS EXPENSE	402 - 554	<u>6,338</u>	<u>8,408</u>	<u>87,649</u>	<u>315,907</u>	<u>434,679</u>	<u>239,117</u>	<u>112,941</u>	<u>129,037</u>	<u>56,556</u>	<u>139,210</u>
		19,324	54,787	94,568	325,504	3,923,438	3,863,847	4,120,453	4,195,163	4,587,521	194,283
Additional Contracted Wind Maintenance*		179,277	97,888	123,439	84,473	3,354,916	3,362,994	4,050,422	4,062,132	3,051,002	5,163,555
Total Maintenance		<u>\$ 12,540,306</u>	<u>\$ 15,365,943</u>	<u>\$ 15,589,236</u>	<u>\$ 9,692,535</u>	<u>\$ 19,671,625</u>	<u>\$ 21,115,986</u>	<u>\$ 20,146,276</u>	<u>\$ 19,242,209</u>	<u>\$ 21,933,845</u>	<u>\$ 19,941,738</u>

Note: 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.

Big Stone Plant Forced Outage Info

[PROTECTED
DATA BEGINS . . .

Outage Dates		Primary Reason for Outage	Duration (days)	Description of Equipment Failure		Steps Taken to Alleviate Reoccurrence
Start	End					
2/23/2025	2/26/2025	Furnace Wall Tube Leak Repair	2.65	Water wall leak into the boiler around a soot blower port.		The area was identified as sootblower erosion. Pad welding in common areas during the 2026 major outage.
4/27/2025	4/28/2025	Steam Leak on 101 LP Valve to BFP	1.03	Blown out gasket on 101 valve, causing steam to leak out.		review gasket material, and retorque after shutdowns.
9/12/2025	9/14/2025	Cyclone Tube Leak	1.51	tube leak in cyclone #10 due to coal erosion		Full cyclone wash, repair, and refractory in 2026 major outage.

. . . PROTECTED
DATA ENDS]

Coyote Station Forced Outage Info

[PROTECTED
DATA BEGINS . . .

Outage Dates		Primary Reason for Outage	Duration (days)	Description of Equipment Failure		Steps Taken to Alleviate Reoccurrence
Start	End					
2/22/2025	2/28/2025	Plant off line / Tube leak in #4 and #6 cyclones	5.31	Water makeup rate continued to increase until the plant had a hard time keeping up with water. Water could be see in cyclones #4 and #6, which was why the makeup rate was so high.		The leaks were repaired during the outage. During the major outage in 2025, significant repairs were done in the cyclones to reduce the likelihood of this occurring in the near future. A lot of welding was done to restore tube wall thickness and new refractory was added to protect the tubes.
6/18/2025	6/20/2025	Back Side Windbox Leak	2.01	A crack in the metal casing of the windbox was causing excessive heat to escape the boiler creating a hazardous environment for personnel and equipment.		Cracks typically grow over time and cannot always be seen due to location and insulation. Infrared cameras were used to find the specific location and size of this crack. The crack was repaired from one end to another. If hot areas are noticed, infrared cameras are used to find and watch these "hot spots". Repairs are typically completed during a planned outage unless they get worse.
6/20/2025	6/22/2025	Offline for 345kv line storm damage	1.89	Transmission line damage due to severe summer storm (strong winds)		This was an outside event that Coyote could not control. The transmission line was damaged in another part of the state, not by Coyote Station.
9/23/2025	10/1/2025	Wall Tube Leak	7.76	A corner water all tube ruptured and resulted in excessive water usage and moisture/water in the boiler. With this type/size of leak we are unable to run until the tube is repaired.		Corner tube was thin due to sootblower erosion. A section of the ruptured tube was replaced and other tubes near the ruptured tube we pad welded to restore wall thickness. The sootblower in that corner was also inspected to ensure it would not cause similar erosion going forward
12/18/2025	12/23/2025	Pendant Wash	4.4	Continued high loads and coal quality issues caused the boiler to get fouled (ash buildup on our tubes). An area in the mine was found to have high iron, which caused stubborn slag buildup in our pendants that our sootblowers and de-rates could not remove. We had been battling some fouling issues but had been able to shed the buildup with planned de-rates, but this was not possible with the iron deposits.		We are working with our mine to either go around this area or blend the coal to lower the concentration of iron in the coal supplied to Coyote. Engineering is also watching and trending our coal quality closer to try and predict future fouling.

. . . PROTECTED
DATA ENDS]

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

Month	(A)	(B)	* (C)		* (D)	* (E)		* (F)	* (G)	(H)
	Date Paid		Wind Production			Lost Production				
	Delivered MWh	Lost MWh	Delivered to OTP MWh	Amount OTP Paid		Lost MWh	Amount OTP Paid		Total OTP Paid	Reason Codes
			[PROTECTED DATA BEGINS . . .							
Jan-25										
Feb-25										
Mar-25										
Apr-25										
May-25										
Jun-25										
Jul-25										
Aug-25										
Sep-25										
Oct-25										
Nov-25										
Dec-25										
Total 2025										

. . . 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		* (C) Wind Production		* (E) Lost Production		* (G)	(H)
	Delivered MWh	Lost MWh	Delivered to OTP MWh	* (D) Amount OTP Paid	Lost MWh	* (F) Amount OTP Paid	Total OTP Paid	
			[PROTECTED DATA BEGINS . . .					
Jan-25	1/1: 9, 11, 21, 22, 26, 28	2/7/2025						4
Feb-25	2/1: 3, 6, 20, 21, 23, 26, 27, 28	3/14/2025						4
Mar-25	3/1: 6, 8, 10, 13, 14, 15, 16, 17, 19, 20, 21, 27, 28	4/21/2025						4
Apr-25	4/1: 2, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 20, 26, 28	5/21/2025						4
May-25	5/1: 4, 5, 9, 10, 11, 15, 16, 19, 20, 30	6/20/2025						4
Jun-25	6/1: 1, 2, 7, 8, 9, 10, 24	7/21/2025						4
Jul-25	7/1: 11, 13	8/20/2025						4
Aug-25	8/1: 14, 23	9/22/2025						4
Sep-25	9/4, 5, 7, 8, 10, 11, 12, 16, 21, 26, 27	10/20/2025						4
Oct-25	10/5, 8, 9, 11, 12, 17, 18, 21, 25, 26, 30, 31	11/20/2025						4
Nov-25	11/1, 6, 11, 21, 22	12/22/2025						4
Dec-25		1/20/2026						4
Total 2025								

. . . PROTECTED DATA ENDS]

Reason Code Explanation:

Curtailment was called for by Otter Tail Power due to negative LMP pricing. As specified in the Langdon Wind, LLC 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

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

Month	(A)	(B)	* (C) * (D) Wind Production		* (E) * (F) Lost Production		* (G)	(H)
	Date Paid		Delivered to OTP MWh	Amount OTP Paid	Lost MWh	Amount OTP Paid	Total OTP Paid	Reason Codes
	Delivered MWh	Lost MWh						
			[PROTECTED DATA BEGINS ...					
Jan-25								
Feb-25								
Mar-25								
Apr-25								
May-25								
Jun-25								
Aug-25								
Aug-25								
Sep-25								
Nov-25								
Nov-25								
Dec-25								
Total 2025								
... 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
ELECTRIC UTILITY - STATE OF MINNESOTA
ASM Charge Types
(Expense) Revenue

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Description	January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25	2025 Year End	Minnesota 47.24014%
1	Day Ahead Regulation Amount	\$ 110,524	\$ 87,328	\$ 92,428	\$ 87,032	\$ 88,048	\$ 119,532	\$ 132,678	\$ 139,085	\$ 131,062	\$ 110,399	\$ 128,471	\$ 118,769	\$ 1,345,355	\$ 635,548
2	Real Time Regulation Amount	\$ 57,866	\$ 58,418	\$ 25,111	\$ 33,675	\$ 32,337	\$ 213	\$ 1,222	\$ 70,603	\$ 65,459	\$ 126,844	\$ 141,477	\$ 48,740	\$ 661,964	\$ 312,713
3	Regulation Cost Distribution Amount	\$ (38,108)	\$ (36,159)	\$ (37,040)	\$ (37,055)	\$ (36,385)	\$ (39,631)	\$ (26,933)	\$ (24,690)	\$ (40,894)	\$ (51,870)	\$ (60,765)	\$ (68,828)	\$ (498,358)	\$ (235,425)
4	Regulation Subtotal	\$ 130,282	\$ 109,587	\$ 80,499	\$ 83,652	\$ 84,000	\$ 80,114	\$ 106,966	\$ 184,998	\$ 155,627	\$ 185,373	\$ 209,183	\$ 98,681	\$ 1,508,962	\$ 712,836
5															
6	Day Ahead Short-Term Reserve Amount	\$ 57,579	\$ 196,079	\$ 96,507	\$ 52,495	\$ 111,179	\$ 79,699	\$ 445,041	\$ 397,379	\$ 23,950	\$ 57,381	\$ 88,611	\$ 110,739	\$ 1,716,641	\$ 810,944
7	Real Time Short-Term Reserve Amount	\$ (12,795)	\$ (61,276)	\$ (370)	\$ 6,624	\$ (6,559)	\$ (24,661)	\$ 111,188	\$ 12,535	\$ 8,761	\$ 15,737	\$ (3,370)	\$ (10,201)	\$ 35,612	\$ 16,823
8	Short-Term Reserve Cost Distribution Amount	\$ (182,204)	\$ (78,008)	\$ (24,646)	\$ (38,207)	\$ (29,647)	\$ (20,582)	\$ (343,727)	\$ (270,500)	\$ (31,400)	\$ (66,503)	\$ (46,991)	\$ (44,819)	\$ (1,177,233)	\$ (556,127)
9	Short-Term Reserve Deployment Failure Charge Amount	\$ -	\$ (228)	\$ -	\$ (42,019)	\$ -	\$ -	\$ (28)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (42,275)	\$ (19,971)
10	Short-Term Reserve Subtotal	\$ (137,419)	\$ 56,795	\$ 71,491	\$ 20,912	\$ 74,973	\$ 34,457	\$ 212,502	\$ 139,414	\$ 1,312	\$ 6,615	\$ 38,249	\$ 55,719	\$ 575,020	\$ (559,274)
11															
12	Day Ahead Spinning Reserve Amount	\$ 16,760	\$ 23,499	\$ 34,249	\$ 58,568	\$ 81,549	\$ 43,665	\$ 28,713	\$ 41,391	\$ 18,494	\$ 28,804	\$ 36,299	\$ 39,092	\$ 451,082	\$ 213,092
13	Real Time Spinning Reserve Amount	\$ 2,191	\$ 2,721	\$ (1,715)	\$ (13,892)	\$ (15,933)	\$ (2,613)	\$ (6,747)	\$ (31,143)	\$ (3,516)	\$ 11,462	\$ (1,899)	\$ (9,826)	\$ (70,909)	\$ (33,498)
14	Spinning Reserve Cost Distribution Amount	\$ (20,665)	\$ (23,791)	\$ (26,298)	\$ (25,692)	\$ (26,699)	\$ (22,256)	\$ (20,638)	\$ (16,889)	\$ (15,791)	\$ (27,193)	\$ (25,760)	\$ (28,666)	\$ (280,338)	\$ (132,432)
15	Spinning Reserve Subtotal	\$ (1,714)	\$ 2,428	\$ 6,236	\$ 18,984	\$ 38,917	\$ 18,796	\$ 1,328	\$ (6,640)	\$ (812)	\$ 13,073	\$ 8,640	\$ 600	\$ 99,835	\$ 47,162
16															
17	Day Ahead Supplemental Reserve Amount	\$ 391,405	\$ 132,484	\$ 11,361	\$ 12,200	\$ 20,809	\$ 20,379	\$ 127,515	\$ 110,624	\$ 27,416	\$ 133,986	\$ 35,930	\$ 16,301	\$ 1,040,408	\$ 491,490
18	Real Time Supplemental Reserve Amount	\$ (12,663)	\$ (10,502)	\$ (7,781)	\$ (69,378)	\$ (66,226)	\$ (7,364)	\$ (60,434)	\$ 16,027	\$ (838)	\$ (39,468)	\$ (13,467)	\$ (8,306)	\$ (280,400)	\$ (132,461)
19	Supplemental Reserve Cost Distribution Amount	\$ (2,810)	\$ (4,317)	\$ (2,735)	\$ (4,616)	\$ (3,257)	\$ (1,327)	\$ (12,531)	\$ (10,967)	\$ (6,444)	\$ (14,388)	\$ (4,032)	\$ (2,196)	\$ (69,820)	\$ (32,983)
20	Supplemental Reserve Subtotal	\$ 375,932	\$ 117,665	\$ 845	\$ (61,794)	\$ (48,674)	\$ 11,688	\$ 54,549	\$ 115,684	\$ 19,934	\$ 80,130	\$ 18,431	\$ 5,799	\$ 690,188	\$ 326,046
21															
22	Contingency Reserve Deployment Failure Charge Amount	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
23	Real Time Excessive Deficient Energiz Deployment Charge Amount	\$ (15,819)	\$ (8,902)	\$ (12,098)	\$ (9,342)	\$ (27,545)	\$ (5,207)	\$ (7,792)	\$ (12,661)	\$ (22,849)	\$ (27,036)	\$ (39,340)	\$ (16,815)	\$ (205,405)	\$ (97,034)
24	Net Regulation Adjustment Amount	\$ (7,763)	\$ (11,203)	\$ (7,057)	\$ (13,179)	\$ (3,911)	\$ (520)	\$ (7,873)	\$ (2,088)	\$ 672	\$ 1,134	\$ (984)	\$ (1,234)	\$ (54,006)	\$ (25,512)
25	Real Time Miscellaneous	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
26	Summary of ASM	\$ (23,582)	\$ (20,105)	\$ (19,155)	\$ (22,521)	\$ (31,456)	\$ (5,727)	\$ (15,665)	\$ (14,749)	\$ (22,176)	\$ (25,903)	\$ (40,324)	\$ (18,048)	\$ (259,411)	\$ (122,546)
27															
28	Total	\$ 343,498	\$ 266,257	\$ 139,916	\$ 18,224	\$ 117,761	\$ 139,327	\$ 359,667	\$ 418,707	\$ 153,884	\$ 259,288	\$ 234,179	\$ 142,751	\$ 2,593,457	\$ 809,695

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
ASM Charge Types kWh

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	Description	January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25	2025 Year End	Minnesota 47.24014%
1	Day Ahead Regulation Amount	6,764,400	2,743,800	4,101,800	5,080	6,121	7,810	3,326	6,868	7,116	2,046	6,879	8,668	13,663,914	6,454,852
2	Real Time Regulation Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Regulation Cost Distribution Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Regulation Subtotal	6,764,400	2,743,800	4,101,800	5,080	6,121	7,810	3,326	6,868	7,116	2,046	6,879	8,668	13,663,914	6,454,852
5															
6	Day Ahead Short-Term Reserve Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Real Time Short-Term Reserve Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Short-Term Reserve Cost Distribution Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Short-Term Reserve Deployment Failure Charge Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Short-Term Reserve Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11															
12	Day Ahead Spinning Reserve Amount	2,768,200	1,258,600	3,512,900	4,902	7,696	4,296	2,292	2,967	1,537	650	2,605	4,857	7,571,501	3,576,788
13	Real Time Spinning Reserve Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Spinning Reserve Cost Distribution Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Spinning Reserve Subtotal	2,768,200	1,258,600	3,512,900	4,902	7,696	4,296	2,292	2,967	1,537	650	2,605	4,857	7,571,501	3,576,788
16															
17	Day Ahead Supplemental Reserve Amount	95,426,900	43,094,900	40,740,800	21,660	50,559	59,761	26,922	35,450	15,696	40,483	65,805	54,461	179,633,397	84,859,069
18	Real Time Supplemental Reserve Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Supplemental Reserve Cost Distribution Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Supplemental Reserve Subtotal	95,426,900	43,094,900	40,740,800	21,660	50,559	59,761	26,922	35,450	15,696	40,483	65,805	54,461	179,633,397	84,859,069
21															
22	Contingency Reserve Deployment Failure Charge Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Real Time Excessive Deficient Energy Deployment Charge Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Net Regulation Adjustment Amount	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Real Time Miscellaneous	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Summary of ASM	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27															
28	Total	104,959,500	47,097,300	48,355,500	31,642	64,376	71,867	32,541	45,284	24,348	43,179	75,289	67,986	200,868,812	94,890,709

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
Comparison of MISO Schedule 17 Rates and Amounts

	(A)	(B)	(C)
Line No.		Monthly Average Schedule 17 Amount	Monthly Average Schedule 17 Rate
1	April 2005 through December 2008	\$ 48,983	\$ 0.07220
2			
3	January 2009 through December 2009	\$ 68,439	\$ 0.09750
4			
5	January 2010 through December 2010	\$ 67,171	\$ 0.09380
6			
7	January 2011 through June 2011	\$ 67,418	\$ 0.09300
8			
9	July 2011 through July 2012	\$ 60,574	\$ 0.09040
10			
11	July 2012 through June 2013	\$ 62,583	\$ 0.08820
12			
13	July 2013 through June 2014	\$ 59,249	\$ 0.07656
14			
15	July 2014 through June 2015	\$ 52,207	\$ 0.07337
16			
17	July 2015 through June 2016	\$ 52,283	\$ 0.07479
18			
19	July 2016 through June 2017	\$ 54,561	\$ 0.07312
20			
21	July 2017 through June 2018	\$ 64,941	\$ 0.08239
22			
23	July 2018 through December 2019	\$ 65,680	\$ 0.08589
24			
25	January 2020 through December 2020	\$ 62,585	\$ 0.08917
26			
27	January 2021 through December 2021	\$ 64,618	\$ 0.08240
28			
29	January 2022 through December 2022	\$ 69,777	\$ 0.08002
30			
31	January 2023 through December 2023	\$ 75,607	\$ 0.08596
32			
33	January 2024 through December 2024	\$ 76,122	\$ 0.08843
34			
35	January 2025 through December 2025	\$ 78,306	\$ 0.08753
36			
37	Average monthly increase from prior period	\$ 2,184	\$ (0.00090)

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
Hoot Lake Solar Adjustment

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	Description	January-25	February-25	March-25	April-25	May-25	June-25	July-25	August-25	September-25	October-25	November-25	December-25	2025 Year End
1	Hoot Lake Solar Revenues	\$ 123,754	\$ 101,868	\$ 158,140	\$ 211,553	\$ 250,699	\$ 311,632	\$ 584,608	\$ 661,638	\$ 394,642	\$ 408,376	\$ 170,139	\$ 80,565	\$ 3,457,612
2														
3	Minnesota Sales	281,838,579	275,712,948	238,466,111	235,545,477	215,206,178	211,412,162	226,900,042	229,688,476	216,428,284	203,678,337	221,305,370	241,043,147	2,797,225,110
4	Total System Sales	602,284,529	589,770,866	533,208,522	506,015,599	442,130,258	435,216,071	459,046,318	460,094,059	463,456,819	428,629,031	473,057,393	527,223,809	5,920,133,274
5	MN Sales as Percent of Total Sales	46.7949%	46.7492%	44.7229%	46.5491%	48.6748%	48.5764%	49.4286%	49.9221%	46.6987%	47.5186%	46.7819%	45.7193%	47.2494%
6														
7	Minnesota's allocated share of Hoot Lake Solar Revenues	\$ 57,910	\$ 47,622	\$ 70,725	\$ 98,476	\$ 122,027	\$ 151,379	\$ 288,963	\$ 330,303	\$ 184,292	\$ 194,054	\$ 79,594	\$ 36,834	\$ 1,662,181
8	Hoot Lake Solar Revenues allocated to other jurisdictions	\$ 65,843	\$ 54,245	\$ 87,415	\$ 113,077	\$ 128,672	\$ 160,252	\$ 295,645	\$ 331,335	\$ 210,349	\$ 214,322	\$ 90,544	\$ 43,731	\$ 1,795,430
9														
10	Amount credited to MN EAR (grossed up to system total)	\$ 140,706	\$ 116,035	\$ 195,460	\$ 242,920	\$ 264,349	\$ 329,898	\$ 598,125	\$ 663,704	\$ 450,439	\$ 451,027	\$ 193,546	\$ 95,651	\$ 3,741,860

[PROTECTED DATA BEGINS...

Docket No. E017/AA-25-65
Attachment 19
is CONFIDENTIAL
in its Entirety

...PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS...

Docket No. E017/AA-25-65
Attachment 20
is CONFIDENTIAL
in its Entirety

...PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS...

Docket No. E017/AA-25-65
Attachment 21
is CONFIDENTIAL
in its Entirety

...PROTECTED DATA ENDS]

Appendix A – Section 2

The information provided in Appendix A addresses certain compliance obligations from annual reporting requirements pursuant to Minn. R. 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges and June 12, 2019, Orders in Docket No. E999/CI-03-802 and Docket No. E017/AA-24-65.

SECTION 2.1 | 7825.2810 Subpart 1.A. Commission Approved Base Cost of Fuel

No recovery of fuel costs is included in Otter Tail Power's base rates effective January 1, 2021.¹ All recovery is in the Energy Adjustment Rider – Electric Rate Schedule - Section 13.01. Attachment 4 - is now the most current Schedule approved in Docket No. E017/AA-24-65 in an Order dated November 12, 2024.

SECTION 2.2 | 7825.2810 Subpart 1.B. Billing Adjustment Amounts

Otter Tail Power provides the following Attachments with a breakdown by primary energy source:

1. Attachment 5 - kWh Sales by Primary Energy Source
2. Attachment 6 - Energy Cost by Primary Energy Source
3. Attachment 7 - Monthly Cost Components

SECTION 2.3 | 7825.2810 Subpart 1.D. The Total Cost of Fuel Delivered to Customers

Attachments 2 and 3 to this filing provide further details on forecasted and actual costs for 2025 as summarized in Table 1.

¹ In the Commission's November 5, 2019 Order in Docket No. E999/CI-03-802, OTP was ordered in its next rate case to "demonstrate that its proposed base rates exclude Fuel Clause Adjustment-related costs." This order requires OTP to remove base cost of energy from base rates and include all FCA eligible costs in the EAR. Otter Tail complied with that Order in its last rate case, Docket No. E017/GR-20-719.

Table 1

	Forecasted Costs - System	Actual Costs – System
January 2025	\$16,159,551	\$17,030,492
February	\$15,444,844	\$14,016,294
March	\$11,986,371	\$10,541,716
April	\$11,240,560	\$7,880,698
May	\$10,171,210	\$7,273,901
June	\$8,661,062	\$11,885,082
July	\$9,131,039	\$8,684,774
August	\$9,555,026	\$6,608,830
September	\$9,429,229	\$7,131,027
October	\$10,021,653	\$6,797,770
November	\$12,365,264	\$9,397,071
December	\$16,609,529	\$19,958,708
Total 2025	\$140,775,339	\$127,206,362

Table 2 reflects the Minnesota January through December 2025 reporting period.

Table 2

Item	Amount
Total 2025 kWh Sales (System)	5,920,133,274
Total 2025 kWh Sales Subject to COE – MN	2,796,679,274
Percent of MN Sales to System (Line 2 / Line 1)	0.4724014
Total 2025 System Fuel Costs	\$127,206,362
Percent of MN kWh Sales (Line 3 above)	0.4724014
2025 Fuel Costs Allocated to MN (Line 5 X Line 6)	\$60,092,464

SECTION 2.4 | 7825.2810 Subpart 1.E. Revenue Collected From Customers for Energy Delivered

Table 3 summarizes total recovery realized from approved rates from 2025 relative to costs incurred:

Table 3

Item	Amount
Recovery from FCA	\$65,602,211
MN Share of Fuel Costs	\$60,092,464
Total Over/(Under) Recovery (Line 1 – Line 2)	\$5,509,747

SECTION 2.5 | 7825.2810 Subpart 1.G. The Amount of Refunds Credited to Customers

Throughout 2025, Otter Tail Power's rates included adjustments to collect true-up balances associated from the January 2023 through December 2023 and the January 2024 through December 2024 recovery periods. This collection process will continue through August 2026.

Additionally, the rates in effect from September through December 2025 incorporated an initial refund to return the over-recovery that occurred between January and June 2025. This refunding adjustment concluded in December 2025. Table 4 provides detailed monthly amounts associated with each adjustment.

Otter Tail Power also began refunding the over-collection from the first four months of 2025 through its Energy Adjustment Rider.

Table 4

	Refund of Remaining Year 2023 True Up	Recovery of Calendar Year 2024 True Up	Refund of January to June 2024 Overcollection	Refund of January to June 2025 Overcollection
January 2025	(\$563,580)	\$0	(\$2,028,889)	\$0
February	(\$551,330)	\$0	(\$1,984,790)	\$0
March	(\$476,840)	\$0	(\$1,716,623)	\$0
April	(\$471,000)	\$0	(\$1,695,599)	\$0
May	(\$430,323)	\$0	(\$1,549,163)	\$0
June	(\$422,734)	\$0	(\$1,521,842)	\$0
July	(\$453,709)	\$0	\$0	\$0
August	(\$459,288)	\$0	\$0	\$0
September	\$0	\$64,915	\$0	(\$1,276,666)
October	\$0	\$61,090	\$0	(\$1,201,440)
November	\$0	\$66,378	\$0	(\$1,305,443)
December	\$0	\$72,299	\$0	(\$1,421,886)
Total 2025	(\$3,828,804)	\$264,683	(\$10,496,906)	(\$5,205,435)

Appendix B
Docket No. E017/AA-24-65
Rule 7825.2820 Independent Auditor's Report

INDEPENDENT ACCOUNTANT'S REPORT

Otter Tail Power Company:

We have performed the procedures enumerated below related to Otter Tail Power Company's (the "Company") forecasted Energy Adjustment Charges filed on Docket No. E017/AA-24-65 with the Minnesota Public Utilities Commission (the "Commission") for the period from January 1, 2025 to December 31, 2025, in accordance with the Commission Rules 7825.2500 to 7825.2820 governing automatic adjustment of energy charges, along with the Energy Adjustment Rider, as defined in Docket No. E-999/CI-03-802 by order of the Commission (the "subject matter"). The Company's management is responsible for the subject matter.

Otter Tail Power Company has agreed to and acknowledged that the procedures performed are appropriate to meet the intended purpose of assisting the specified parties in evaluating compliance with the subject matter. The procedures performed are specified in Docket No. E-999/AA-15-611 by order of the Commission.

We make no representation regarding the appropriateness of the procedures either for the purpose for which our report has been requested or for any other purpose. Accordingly, this report may not be suitable for either the purpose of which this report has been requested or for any other purpose. The procedures performed may not address all the items of interest to a user of this report and may not meet the needs of all users of this report and, as such, users are responsible for determining whether the procedures performed are appropriate for their purposes.

Our procedures and findings are as follows:

- a. We compared a random sample of twelve invoices received from energy suppliers to the amount recorded and paid by the Company and found them to be in agreement.
- b. As the Company no longer includes Energy Adjustment Charges within base costs, comparing the base costs of power to the bases used by the Company in calculating the billing adjustment each month is no longer applicable.
- c. We recalculated the billing adjustment charge (credit) per kWh charged to customers for purchased power on a monthly basis for the year ended December 31, 2025, by customer class. We identified no exceptions between our recalculation and the Company's reported adjustment.
- d. We compared the revenues billed to customers for energy delivered for the year ended December 31, 2025 as included in the Company's energy adjustment calculation filing, to the total sales of electric energy per the Company's general ledger and found them to be in agreement.
- e. We randomly selected twelve individual billings across customer classes and recalculated the energy adjustment charge (credit). We compared the recalculated charge (credit) per the customer bill to the energy adjustment charge (credit) as reported by the Company for that customer class in the energy adjustment calculation filing and found them to be in agreement.
- f. We inquired of the Company's management whether any corrections to energy adjustment charges or other billing errors occurred during the period. The Company's management stated that they did not identify any corrections to energy adjustment charges or other billing errors for the period January 1, 2025 through December 31, 2025.

- g. We reconciled total revenue and cost of power from the energy adjustment calculation filing to the Company's general ledger for the year ended December 31, 2025 and found them to be in agreement.
- h. We recalculated the true-up calculation for the year ended December 31, 2025 included within the energy adjustment calculation filing, and traced the related revenue and expense amounts to the Company's general ledger and found them to be in agreement.

We were engaged by the Company to perform this agreed-upon procedures engagement and conducted our engagement in accordance with attestation standards established by the American Institute of Certified Public Accountants. We were not engaged to and did not conduct an examination or review engagement, the objective of which would be the expression of an opinion or conclusion, respectively, on the subject matter. Accordingly, we do not express such an opinion or conclusion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you.

We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements related to our agreed-upon procedures engagement.

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

Deloitte & Touche LLP

February 27, 2026

Appendix C
Docket No. E017/AA-24-65
Rule 7825.2830 Notice of Report Availability



February 27, 2026

Notice of Availability of Reports

To: All Intervenors in Otter Tail Power Company
Retail Rate Proceedings
Docket No. E017/GR-15-1033
Docket No. E017/GR-20-719

The Minnesota Public Utilities Commission (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 and as amended by the Commission at its April 25, 2019 meeting. The subject matter of the reports filed includes the following:

- Minn. R. 7825.2810 Automatic Adjustment Charges
- Minn. R. 7825.2820 Annual Independent Auditors' Report
- Minn. R. 7825.2840 Notice of Reports Availability, Certificate of Service, and Service Lists

Also included in this Filing are the additional fuel clause related reporting requirements under various Commission Orders and as approved by the Commission at its April 25, 2019 agenda meeting.

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/ AMBER GRENIER

Amber Grenier

Manager, Regulatory Economics

Appendix D
Docket No. E017/AA-24-65
Decision Option Responses

Appendix D – Additional Reporting Requirements

Section 1 | DOCKET NO. E017/M-05-284

Otter Tail Power's 2 forecasted and actual non-energy Midcontinent Independent Transmission System Operator, Inc. (MISO) and Southwest Power Pool (SPP) market-related charges for 2025 are provided in summary form in Attachment 2 of this filing.

On April 7, 2005, the Commission issued its Order in Docket No. E017/M-05-284 granting recovery of "MISO Day 2" operation costs through the fuel clause adjustment subject to refund with interest. In accordance with the December 2006 Order in the same filing, Otter Tail Power submits the following additional reporting requirements.

Section 1.1 - Order Point 7.A.1.a | Plans for use of financial instruments or other mechanisms to hedge the costs of natural gas or other fuel **[PROTECTED DATA BEGINS . . .**

...PROTECTED DATA ENDS]

Section 1.2 - Order Point 7.A.1.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.

[PROTECTED DATA BEGINS . . .

. . . PROTECTED DATA ENDS]

Section 1.3 - Order Point 7.A.1.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.

No additional purchases or sales of FTRs for congestion hedging were made in 2025. The Company did not plant to acquire additional FTRs beyond those obtained through the standard MISO allocation process. In certain circumstances, the Company may elect to sell allocated FTRs back into the market, such as when a generating unit is expected to be off-line for an extended maintenance outage or when the unit is anticipated to be economically decommitted due to sustained low wholesale energy prices. Under these conditions, the allocated FTRs no longer correspond to actual system flows and, therefore, do not provide an effective hedge against congestion between generation and load.

The Company may also purchase additional FTRs to hedge bilateral energy purchase when analysis indicates that a monthly or seasonal FTR would provide a reasonable and cost-effective hedge against expected congestion costs. Historically, the purchase of FTRs for the purpose of hedging bilateral transactions has been infrequent.

Section 1.4 - Order Point 7.A.2 | Congestion Costs and Revenues

Otter Tail Power addresses congestion costs and revenues in Section VII this of this Appendix Section VII DOCKET NOS. E999/AA-09-961 and E999/AA-10-884 order point 25.

Section 1.5 - Order Point 7.A.3 | List of Network Resources Designated to Serve Native Load

See Attachment 8 - MISO Module E Data for Otter Tail Power.

Section 1.6 - Order Point 7.B | Annual FCA Forecast of the Cost per MWh of Fuel and Purchased Power Costs for the Next 12 months.

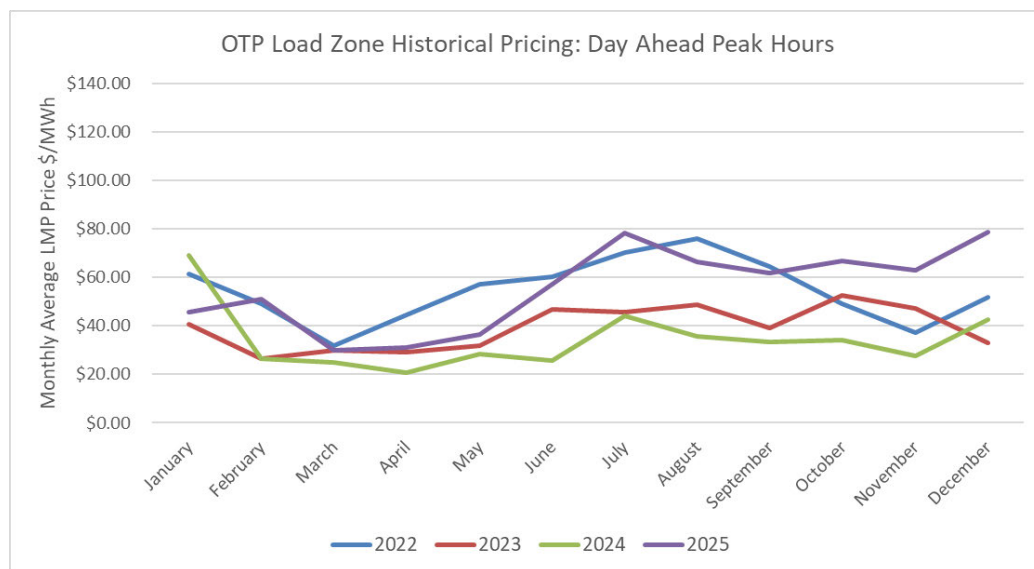
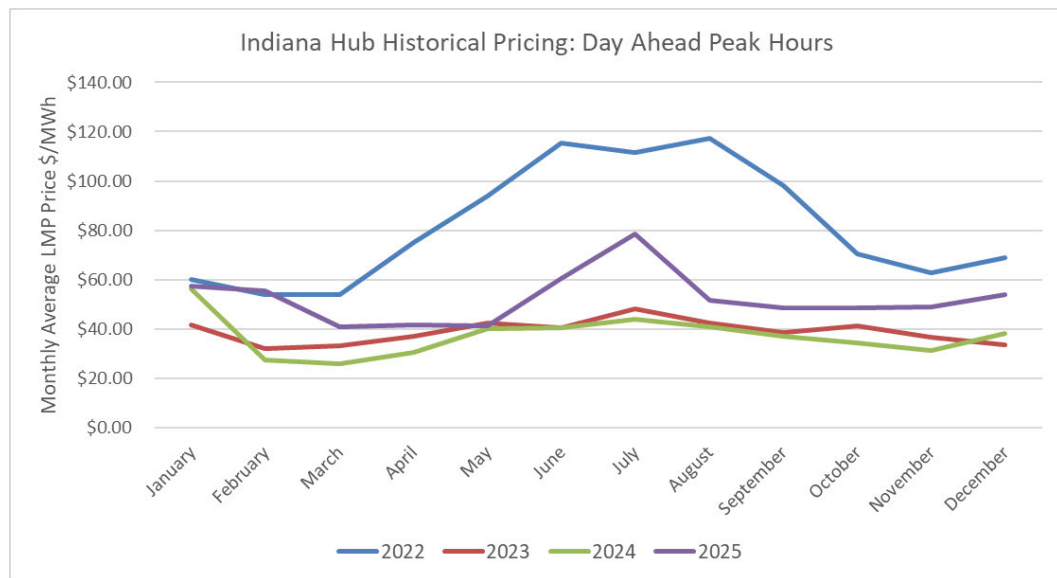
Forecasted costs for 2026 were filed and approved in Docket No. E017/AA-25-065 effective January 1, 2026.

Section 1.7 - Order Point 7.C | Key Factors Affecting Costs (including Revenue Sufficiency Guarantee Costs and Revenue Neutrality Uplift Costs)

Attachment 9 (System and Minnesota) and Attachment 10 (Monthly and Year-to-Date MISO Day 2 Charges) reflect total MISO costs for the reporting period of January through December 2025. Total net MISO charges for 2025 were \$72.3 million as found in Attachment 9.

The primary determinant of wholesale energy market credits and charges, as well as generation dispatch outcomes, is LMP. LMP levels in the Otter Tail Power load zone during 2025 were comparable to the elevated prices experienced in 2022 and were significantly higher than those observed in 2023 and 2024. In the latter half of 2025, the Otter Tail Power load zone experienced elevated congestion relative to the Indiana Hub, resulting in materially higher congestion-driven LMPs and driving load zone prices above 2022 levels.

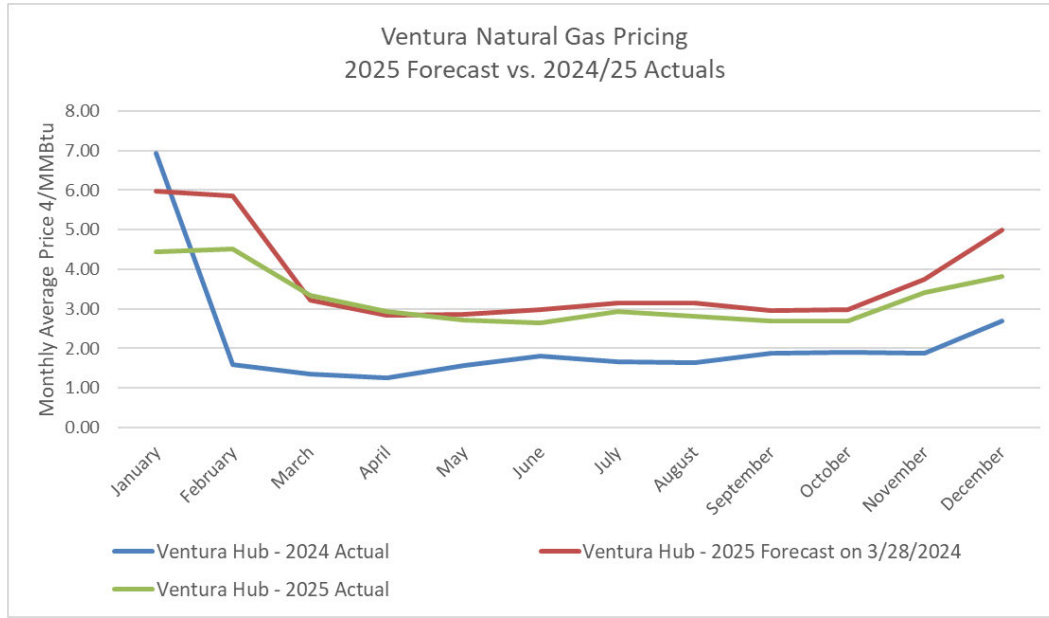
The following graphs present historical Day-Ahead (DA) peak LMPs for both the Indiana Hub – which is the most liquid and widely traded pricing point within the MISO market – and the Otter Tail Power load zone, illustrating these pricing trends and congestion impacts over time.



In 2025, DA peak LMP at the Indiana Hub were approximately 64 percent of the elevated 2022 levels, which represent the highest pricing year in recent history, and approximately 99 percent of the prior three-year average. By contrast, the Otter Tail Power load zone DA peak LMPs were approximately 102 percent of 2022 levels and 130 percent of the prior three-year average, reflecting elevated congestion conditions within the load zone.

Forecasts of generation production, economic market purchases, and wholesale energy charges are primarily driven by forecasted LMP values. In the MISO market, natural gas pricing is a key drive of LMP because natural gas-fired generation frequently

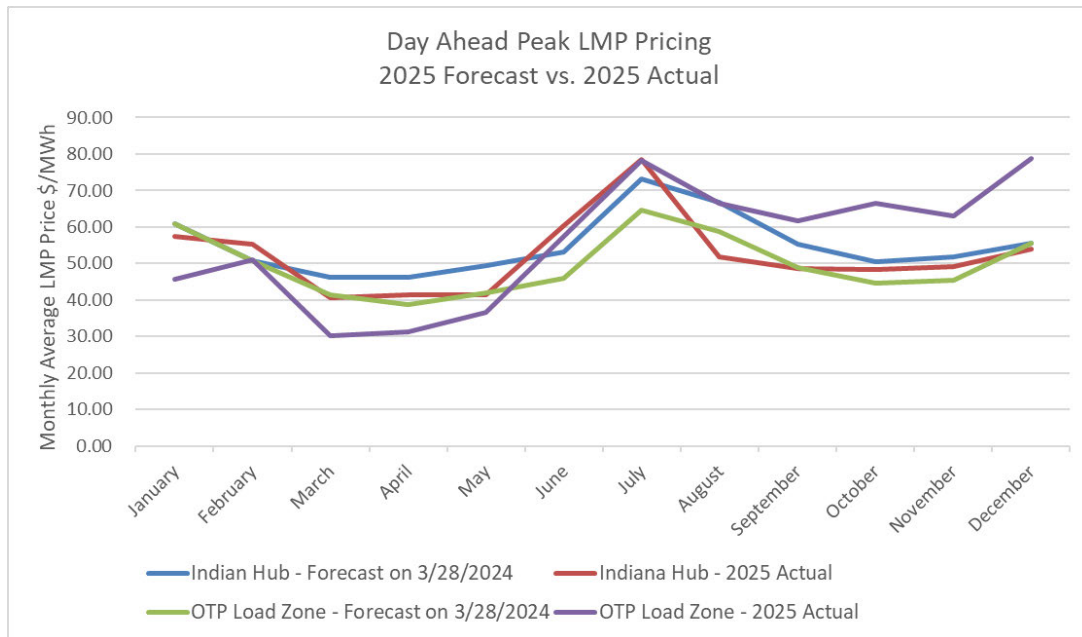
serves as the marginal, price-setting resource. The graph below demonstrates the natural gas March 28, 2024, forecast versus 2024 and 2025 actual Ventura Hub pricing. 2025 natural gas prices were over forecasted during the winter months.



Additional factors that influence LMP at the Otter Tail Power load zone include Manitoba Hydro (MHEB) and SPP import and export flows, weather conditions, transmission line outages, system constraints, and relevant contingencies.

To develop the Otter Tail Power load zone forecast, the Company relies on daily forward Indiana Hub price curves published by Intercontinental Exchange, Inc. (ICE). The Company evaluates historical basis differentials between the Indiana Hub and the load zone, reviews historical market conditions, and incorporates expectations regarding future markets to produce the load zone forecast. Deviations between actual and forecasted Indiana Hub prices typically result in corresponding deviations in the load zone forecast.

The 2025 load zone forecast was developed using the Indiana Hub forward price curve dated March 28, 2024. The following graph present the forecasted and actual Indiana Hub and Otter Tail Power load zone price curves.



Actual 2025 Indiana Hub prices were approximately 95 percent of the forward Indiana Hub price forecast dated March 28, 2024. In comparison, actual 2025 Otter Tail Power load zone prices were approximately 112 percent of the corresponding March 28, 2024, forward load zone price forecast. The increase in the Otter Tail load zone relative to forecasted levels appears to be driven primarily by elevated regional congestion, particularly in the latter half of 2025.

When comparing Otter Tail Power's 2025 generation to 2024, the Company's natural-gas-fired resources – Astoria Station and Solway Station – produced approximately 11 percent more MWhs. Solway Station experienced a turbine repair outage lasting over a month in 2024, which did not recur in 2025. Both units also benefited from elevated LMPs throughout 2025. The Company's coal-fired generation increased by approximately 15 percent relative to 2024. Big Stone Plant production increased by 31 percent year-over-year, while Coyote Station production decreased by approximately 3 percent; however, 2025 included a 65-day planned overhaul outage that did not occur in 2024. Hoot Lake Solar completed its second full year of operation in 2025 and experienced a modest 1 percent increase in output when compared to 2024. Otter Tail Power's wind resources and power purchase agreements (PPAs) produced approximately 8 percent more energy in 2025, though production continued to be affected by outages and derates associated with repowering upgrades. Overall, total Otter Tail Power generation increased by approximately 12 percent from 2024 to 2025.

Otter Tail Power also realized increased revenues from its strong Financial Transmission Rights (FTR) portfolio in 2025. The northwestern region of MISO continues to experience rising levels of renewable generation, combined with transmission line outages and upgrades necessary to support renewable expansion and interconnection. These conditions have contributed to persistent congestion between the Company's baseload resources and the Otter Tail Power's load zone. In addition, 2025 experienced a decline in MHEB imports into MISO, further contribution to congestion. This congestion is particularly pronounced at Big Stone Plant and Coyote Station, both of which are located within constrained transmission areas.

For the same reasons, the Company continues to experience significant congestions costs; however, revenues from the FTR portfolio more than offset these charges as shown in Attachment 3. In 2025, SPP congestion between the SPP/MISO border and Otter Tail Power's load within SPP (which is pseudo-tied back to MISO) resulted in a credit of approximately \$530,000. Energy injections at the MISO/SPP border produced congestion credits that exceeded the congestion charges associated with corresponding withdrawals at the load. Congestion charges and credits associated with SPP pseudo-tie are detailed in Attachment 3 of this filing.

Section 2 | DOCKET NO. E017/M-03-970

On February 2, 2006, Otter Tail Power filed in Docket No. E017/M-03-970 to remove the sunset provision for recovery of the purchase of wind generated energy 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 Power filed the Power Purchase 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 Power, 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 Power's request with the following reporting requirements:

Section 2.1 - Order Point 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 January to December 2025.

Section 2.2 - Order Point 3 | Track All Curtailments and Curtailment Payments and Report Them in Its FCA Filings.

Attachment 14 contains the curtailment costs incurred for the January through December 2025 time frame.

Section 3 | 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:

Section 3.1 | DOC Recommendation | Virtual Transactions

In the Minnesota Department of Commerce’s Review of the 2005-2006 Annual Automatic Adjustment Report dated April 16, 2007, the DOC recommended “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.”

Otter Tail Power did not utilize virtual transactions for retail customers in 2025. Historically, since the start of the Midcontinent Independent System Operator (MISO) Day 2 Market, the Company has only rarely used virtual transactions for retail load serving purposes.

On occasion, the Company may use virtual transactions to convert bilateral purchases between the day-ahead and real-time markets. For example, certain bilateral purchases are structured to settle in the real-time market, while the Company clears its load in the day-ahead market. In these instances, a virtual transaction may be used to convert a real-time purchase to the day-ahead market to more accurately hedge the Company’s load obligations.

Within Southwest Power Pool (SPP), where Otter Tail Power pseudo-ties its load back into MISO, the Company is required to pay real-time congestion and loss differences between its energy injection point at MISO/SPP boundary and its energy withdrawal point serving Otter Tail Power load within the SPP footprint.

Because Otter Tail Power holds Network Integrated Transmission Service (NITS) to serve its load, the Company is entitled to request and nominate Auction Revenue Rights (ARRs) and Transmission Congestion Rights (TCRs) between these two points. When nominated and awarded, ARRs and TCRs provide a hedge against day-ahead congestion between the Company’s injection and withdrawal points.

However, because pseudo-tie congestion charges are assessed based on real-time congestion, the use of virtual transactions could be employed to shift these real-time congestion charges into the day-ahead market. Doing so may better align congestion charges with any Otter Tail Power TCR positions, thereby improving the effectiveness of the associated hedge. To date, Otter Tail Power has not utilized virtual transactions on behalf of its SPP retail load.

Section 3.2 - Order Point 18 | Actual Expenses Pertaining to Maintenance of Generation Plant, with a Comparison to the Generation Maintenance Budget from the Utility's Most Recent Rate Case

Attachment 12 provides actual generation maintenance expenses for 2025, as well as the 2026 test year budget from the most recent rate case. Total 2025 maintenance expenses were \$21.9 million as compared to \$21.7 million for the 2026 rate case test year.

Section 3.3 - Order Point 21 | MISO Day 2 Charges Report for Every Month and Summary for the Entire Period

See Attachment 9 and Attachment 10.

Section 4 | DOCKET NO. E,G999/AA-07-1130 June 30, 2008

Recommendation

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

Section 4.1 - DOC Recommendation | Monthly and Year-to-Date Breakdown of MISO Day 2 Charges

Attachment 10 contains a monthly and year-to-date breakdown of MISO Day 2 Charges – System between Retail, Asset Based Wholesale, and Non-Asset Based Wholesale for 2025. Attachment 3 contains monthly comparisons of forecast to actual amounts for MISO Day 2 charge types for 2025.

Section 4.2 - DOC Recommendation | How the Auction Revenue Rights (ARR) Process will be Treated for Retail and Wholesale Purposes and Information Regarding ARR Purchases

Otter Tail Power has no activity to report for this item.

Section 5 | DOCKET NO. E001,015,002,017/M-08-528

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 Midcontinent 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 (see Attachment 17).

Section 5.1 - Order Point 5 | Costs and Revenues from Participation in the MISO Ancillary Service Market

Attachment 15 summarizes the 17 ancillary services market (ASM) charge types by month for the true up period of January through December 2025.

Section 5.2 - Order Point 8 | Summaries on the 12 MISO Ancillary Services Charge

See Attachment 15, Attachment 16, and Attachment 17.

Section 5.3 - Order Point 9 | Reporting Daily Ancillary Services Market Activity and Overall Net Savings Created by Participation

Otter Tail Power does not have the software to perform a daily activity and savings report. Otter Tail Power provides a monthly breakdown of charges in Attachment 15 and Attachment 16.

Section 5.4 - Order Point 10 | Benefits of Ancillary Services Market and the Market's Impact on System

Otter Tail Power has been participating in MISO Ancillary Service Market (ASM) since it started on January 6, 2009. The ASM has enabled Otter Tail Power to further optimize generation portfolio revenues by providing regulation and reserves without creating a negative impact on available energy necessary to meet customer needs. The ASM has added value for customers when generating units are below maximum

generation levels due to reduced energy prices. The generators can be backed down and still provide spinning reserves at the lower operating levels.

Section 5.5 - Order Point 11 | Explanations for all Contingency Reserve Deployment Failure and Excess/Deficient Energy Charges Incurred Spinning Reserves

MISO's Spinning Reserves process has provided a net benefit of \$47,162 for the January through December 2025 period (Attachment 15).

Supplemental Reserves

MISO Supplemental Reserves provided a net benefit of \$326,046 for the January through December 2025 period (Attachment 15).

Regulation

Prior to ASM, Otter Tail Power scheduled regulation on its system on an hourly basis to meet Balancing Authority control performance criteria requirements. Under the MISO ASM, Otter Tail Power units are only selected by MISO for regulation when it is cost effective. Most of the time Otter Tail Power units are cleared for energy instead of being held back to provide the MW used to reserve for regulation. Under ASM, due to regulation clearing and Otter Tail Power's ability to purchase affordable regulation service, the Company has more economic energy available from its low-cost generation facilities to serve customers. Including ASM charge type impact only, MISO's Regulation Reserves resulted in a net benefit of \$712,836 for the January through December 2025 period (Attachment 15).

Short-Term Reserve

Beginning December 7, 2021, MISO began clearing Short-Term Reserves (STR); a 30-minute rampable generation capacity product provided by on-line or off-line resources to be converted to energy within the STR deployment period (30 minutes). It is co-optimized with energy and ancillary services products. The product separately addresses market-wide, sub-regional and local short-term reserve needs. MISO's Short-Term Reserves resulted in a total of (\$559,274) for the January through December 2025 period (Attachment 15).

Real-Time Excessive/Deficient Energy Deployment 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 assesses a prorated share of the Day Ahead and Real Time Regulation Market cost. During the reporting period of January through December 2025 there was a total of (\$97,034) in penalties assessed to Otter Tail Power units (Attachment 15). These are normally mechanical failure situations where the unit fails to follow dispatch for a short time-period while small repairs are made.

Real-Time Contingency Deployment Failure Charge Amount

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 January through December 2025 period, there were no charges (Attachment 15, column O, line 22).

Net Regulation Adjustment Amount

The Real-Time Net Regulation Adjustment Amount represents a charge (or credit) to a generator to account for energy revenue lost (or gained) by going below (or above) their dispatch target to provide regulation services to the market. For the January through December 2025 period, there was a total of (\$25,512) in charges (Attachment 15).

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 Power. Otter Tail Power has been able to maximize the capabilities of its units to a greater extent, which ultimately has led to greater operational efficiencies for Otter Tail Power. Otter Tail Power will continue to develop strategies that will continue to allow the ASM to have a positive impact on customers. Otter Tail Power reviews all MISO charges and credits including ASM charge types on a daily basis.

Attachment 15 provides the summary of ASM hourly charges for the January through December 2025 period, which has provided (\$122,546) of net ASM revenue. Attachment 16 provides a summary of hourly MWh related to ASM products for the periods of January through December 2025.

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 Power through increased Schedule 17 charges. Attachment 17 provides a summary of the Schedule 17 rates before and after the start of ASM.

No Double Recovery of Costs

The Commission requested the utilities other than Otter Tail Power 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 Power's 2010 general rate case, Docket E017/GR-10-239 (2010 Rate Case), Otter Tail Power 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 Power (as a balancing authority) can 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.

Allow Continued ASM Charge Recovery

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 Power's customers. Otter Tail Power fully expects these benefits to continue due to its ability to offer generation into both markets which utilizes the full benefits of the Company's generation facilities relative to current market conditions.

Section 6 | DOCKET NO. E999/AA-08-995

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

Section 6.1 - Order Point 12 | 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.

While Otter Tail Power has not understood or construed Ordering Point 12 to create an annual reporting requirement within annual AAA dockets, Otter Tail Power 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 Power believes its current program serves Otter Tail Power's needs very well. A summary of Otter Tail Power'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 Power believes that the use of competition in the contractor selection process helps Otter Tail Power achieve reasonable pricing and contractual terms.

Otter Tail Power strives to have appropriate contractual assurances in place for each transaction by using Otter Tail Power standardized base contracts. A required step in Otter Tail Power'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 Power 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 Power'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 Power hold contractors accountable.

The contract approval process ensures the contract is reviewed at the appropriate levels within Otter Tail Power. 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 Power 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 Otter Tail Power identify vendors well suited for the project and to negotiate contracts with appropriate terms protecting Otter Tail Power. Otter Tail Power 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 Power uses a separate quality assurance SME and a quality assurance firm. For the smaller construction projects, Otter Tail Power 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 Power's engineering staff, outside quality assurance firms, and senior Otter Tail Power engineering management.

The scope of Project Management required depends on the size and complexity of the project / transaction. Otter Tail Power'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 Power also requires daily updates on work progress that are discussed in pre-scheduled meetings.

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

Use of Risk Management Provisions

During 2025 annual reporting period, Otter Tail Power successfully used contract provisions to clearly define the requirements for the work to be performed, such as scopes of work, specifications and performance criteria which allowed Otter Tail Power to reduce risk and help reduce mitigation/resolution of any potential issues at no cost to Otter Tail Power. Defined timelines in milestone schedules with liquidated damages tied to specific milestone dates. Otter Tail Power utilized partial and full lien waivers to ensure all subcontractors to the primary are being paid which prevents any liens that could potentially be placed on the project. Otter Tail Power utilized retainage on several large projects to ensure that security is held until such time final acceptance was achieved. No specific events occurred in 2025 that required any actions for remedy of performance, or deliverables.

Section 7 | 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:

Section 7.1 - Order Point 8 | Report Any Offsetting Revenues or Compensation Recovered by the Utility as a Result of Contracts, Investments, or Expenditures Paid for by Their Ratepayers.

Otter Tail Power does not have any offsetting revenues for contracts that are not passed back through the Energy Adjustment Rider.

Section 7.2 - Order Point 22 | Identification of Forced Outages and Planned Outages

The table below reflects the planned outages that were scheduled at Big Stone Plant and Coyote Station in 2025 and incorporated into Otter Tail Power’s 2025 forecast.

Forecast 2025 Planned Outages				
Line No.	Outage Start	Outage End	Plant	Duration & Type
1	09/25/2025	10/18/2025	Big Stone Plant	23-day minor outage
2	03/28/2025	05/16/2025	Coyote Station	7-Week Major Overhaul
3	09/15/2025	09/17/2025	Coyote Station	3-Day Boiler Wash
4	12/10/2025	12/14/2025	Coyote Station	3-Day Boiler Wash

Actual planned outages taken during 2025 were as follows:

Actual 2025 Planned Outages				
Line No.	Outage Start	Outage End	Plant	Duration & Type
1	09/25/2025	10/16/2025	Big Stone Plant	21-Day Minor Outage
2	03/27/2025	05/31/2025	Coyote Station	65-Day Major Overhaul

Forced Outages

Between January and December 2025, Otter Tail Power’s generators experienced a total of eight forced outages exceeding 24 hours in duration: three occurred at the Big Stone Plant and five at Coyote Station.

Attachment 13 presents a summary of the forced outages that occurred during this reporting period, including a brief overview of the following aspects for each event:

1. Dates of Outage
2. Primary Reason for Outage
3. Duration of Outage
4. Description of Equipment Failure
5. Change in Energy Costs
6. Steps Taken to Alleviate Reoccurrence

Of the eight forced outages that occurred during the reporting period, five were attributable to tube leaks, one resulted from a steam leak on a valve, one was caused by boiler plugging, and one was associated with a June 20, 2026 storm that led to a transmission outage. Otter Tail Power estimates that the aggregate cost of the replacement power for these forced outages resulted in an increase in energy costs of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

Section 7.3 - Order Point 25 | Report Congestion and Firm Transmission Rights Costs and Revenues in the Congestion and Firm Transmission Rights Sections of its Report

Otter Tail Power incurs congestion costs when delivering energy from its generation resources and purchased power agreements to load. For the January through December 2025 period, the combined Day-Ahead and Real-Time congestion costs within MISO totaled approximately \$30.8 million. To mitigate these costs, the Company receives Auction Revenue Rights (ARRs), which may be self-scheduled into Financial Transmission Rights (FTRs). For 2025, ARR and FTR revenues totaled approximately \$62.4 million, resulting in a net MISO congestion revenue of approximately \$31.6 million. Congestion within SPP resulted in a \$529,865 credit for the January through December 2025 period.

Attachment 10 provides monthly and annual details of all 2025 MISO Day 2 revenues and expenses, including the congestion components referenced above. Attachment 11 provides corresponding monthly and annual details for 2025 SPP revenues and expenses, inclusive of the congestion amounts noted.

Section 8 | 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 and other electric utilities:

Section 8.1 - Order Point 25 | Explain Why the Selected Option for Financial Transmission Rights and ARR is Better for Ratepayers Than the Alternative.

The Company's two largest generating stations (Big Stone Plant and Coyote Station) 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 Power's generating stations and Otter Tail Power'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 Power 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 Power's Big Stone Plant and Coyote Station generating units 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 Power preserves the right to change the grandfathered status on a yearly basis. This enables Otter Tail Power 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 Plant and Coyote Station generating units remain; Otter Tail Power continues to choose Option A treatment.

Section 9 | DOCKET NO. E017/AA-23-181

The information provided below addresses order points four and five in Docket No. E017/AA-23-181.

Section 9.1 - Order Point 4.A | List All Segments Eligible for Auction Revenue Rights (ARRs)

See Attachment 19

Section 9.2 - Order Point 4.B | List All Segments for which ARR were Awarded

See Attachment 20

Section 9.3 - Order Point 4.C | List ARR Segments Converted to Financial Transmission Rights (FTRs)

See Attachment 21

Section 9.4 - Order Point 4.D | Comprehensive Discussion of ARR Nomination and FTR Conversion Strategies

The two main drivers in Otter Tail Power's ARR nomination and FTR self-schedule strategy are: the hours of generation expected from a Source and the consistency of the congestion pattern from the entitlement. Typically, this results in the following strategy.

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Section 9.5 - Order Point 5.A | List All the Strategies Otter Tail Considered and Implemented to Address Congestion and Curtailment of Energy.

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Section 9.6 - Order Point 5.B | Comprehensive Discussion on the Merit of Each Strategy and How Otter Tail Decides Whether to Implement Each Strategy.

Each congestion-management and curtailment-mitigation strategy presents distinct advantages and limitations. The following sections summarize the merits, constraints, and implementation considerations associated with each approach.

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Appendix D

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Self-Scheduling and Self-Commitment Analysis

Not Public Attachments 2 and 3 to this analysis contain the required hourly information in Excel file format. *Due to the vast size of these files, paper copies are not provided.*

1. OVERVIEW OF ANALYSIS

Otter Tail Power conducted an analysis of its co-owned baseload coal units, Big Stone Plant (Big Stone) and Coyote Station (Coyote).¹ This analysis seeks to provide a reasonable quantification of the difference in the cost of running the plant versus the corresponding prevailing market energy revenues, including times of self-commitment.

For purposes of clarity, Otter Tail Power provides the following definitions of the terms Self-Commitment and Self-Schedule dispatch:

Definitions:

Self-Commitment dispatch: During a self-commitment, the utility requests the Midcontinent Independent System Operator (MISO) to commit the unit. The unit is committed to at least the unit's economic minimum output. MISO will commit the unit independent of market pricing assuming such a commitment does not result in a reliability concern. The unit is paid the prevailing Locational Marginal Price (LMP) market price for that unit and is not assured to be made whole to its costs. During self-commitment, MISO may dispatch the unit above minimums if market pricing is supportive of such dispatch.

Self-Schedule dispatch: Market Participants may submit self-schedules consisting of fixed quantities of energy, per hour, that may be dispatched from an online unit. If the self-schedule is less than the unit's economic maximum, the unit may be dispatched above the self-schedule on an economic basis. A self-schedule is a price taker up to the self-scheduled amount. Any cleared amount above the self-schedule is eligible to set price. A self-schedule is not a guaranteed dispatch unless the unit is designated as must-run or as a self-commitment. Otter Tail Power utilizes a self-schedule when units are undergoing testing and require specific generation output levels. It also uses a self-schedule when self-committing resources to ensure the economic minimum is dispatched

2. REASONS TO SELF-COMMIT OR SELF-SCHEDULE:

Capacity Accreditation Requirements

Seasonal dispatch is not currently viable for Otter Tail Power generating units. In order to meet MISO Module E seasonal capacity requirements, Otter Tail Power utilizes, and accredits,

¹ Big Stone Plant is a 474 MW plant, of which Otter Tail is a 53.9 percent owner. Coyote Station is a 427 MW plant, of which Otter Tail is a 35 percent owner.

its large baseload generation facilities for all four seasons² in a given planning year. Every generator that is a MISO accredited capacity resource and clears the Planning Resource Auction maintains a daily must offer requirement. This offer can be either a self-commit offer or an economic offer. This must offer requirement does not allow Otter Tail Power to de-commit, meaning make the unit unavailable to MISO for commitment and dispatch, on a seasonal basis, or otherwise, except for when the unit is on mechanical outage, overhaul, testing, etc. In the event Otter Tail Power were to forego capacity accreditation of the Big Stone or Coyote generators for a season, Otter Tail Power would potentially need to procure additional capacity resources to meet the MISO Module E capacity requirements for that season. Additional methods of procuring capacity would include construction of new generation facilities, bi-lateral capacity purchases from other capacity holders, or the purchase of capacity through the annual MISO capacity auction.

Otter Tail Power utilizes a full economic commitment offer for all company generating units except for Coyote and Big Stone. The current offer practices of Coyote and Big Stone are detailed below.

Coyote Station Joint Ownership

Prior to May 2021, Coyote was exclusively offered as a “must-run” unit, meaning Otter Tail Power and the other co-owners scheduled their shares of the unit as self-committed at minimum output. MISO could choose to dispatch the unit higher if market and/or reliability conditions merited additional output.

At the end of April 2021, Coyote co-owners implemented coordinated offer processes that allowed for joint economic offer capability. On May 1, 2021, Coyote was economically decommitted for the first time. Coyote is co-owned by Otter Tail Power (35 percent), Minnkota Power Cooperative (30 percent), Montana Dakota Utilities (25 percent), and Northwestern Energy (10 percent). Otter Tail Power, Minnkota Power Cooperative,³ and Montana Dakota Utilities operate within the MISO market, while Northwestern Energy operates within the Southwest Power Pool (SPP) market. The SPP and MISO markets do not coordinate the commitment nor the dispatch of jointly owned units. Both markets model the shares of a jointly owned unit as individual, separate, and distinct generators. As a result, partial commitment and dispatch of the unit, based on different co-owner shares and offers, can be a regular occurrence. Partial commitment and dispatch can result in under-recovery of startup and make whole payments to the partners whose shares are not committed or dispatched. From a practical standpoint, since the plant is one physical generator, commitment of a single owner’s share of the plant will result in the commitment of all owners’ shares of the plant. Per the co-owner contract, utilization of an economic offer requires unanimous agreement amongst the four co-owners. If any co-owner requests self-commitment, all other co-owners are required to self-commit their shares of the plant. Similarly, if MISO or SPP calls for a co-owner’s portion of the plant, all other co-owners are obligated to self-commit their share, at least to minimum output. For 2025, Coyote coal costs

² On August 31, 2022, FERC approved MISO Tariff revisions that include the adoption of a seasonal resource adequacy construct and capacity requirements. These changes allowed MISO to move forward with seasonal capacity auctions with each season having its own capacity requirement based on seasonal coincident peak loads and a seasonal reserve margin. Along with seasonal capacity requirements, MISO will also accredit resources on a seasonal basis. Similar to the annual auction, resources will have a must offer requirement for any season that they clear. (180 FERC ¶ 61,141 Order Accepting Proposed Tariff Revisions Subject to Condition, August 31, 2022. FERC Docket Nos. ER22-495-000, ER22-495-001).

³ Northern Municipal Power Agency owns a 30 percent share of the plant. Minnkota serves as operating agent for NMPA.

were approximately [PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS] percent fixed costs and [PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS] percent variable costs. Historically, as a result of the fixed costs, there have been relatively few hours throughout a typical year where it did not make economic sense to operate the plant.

Big Stone Plant Joint Ownership

At the end of April 2020, Big Stone co-owners implemented coordinated offer processes that allowed for joint economic offer capability (i.e., the plant can be offered into both MISO and SPP markets for economic dispatch). Big Stone is co-owned by Otter Tail Power (53.9 percent), Montana Dakota Utilities (22.7 percent), and Northwestern Energy (23.4 percent). Big Stone maintains similar market operating complexities as Coyote. Big Stone straddles both the MISO and SPP wholesale energy markets and can be committed and dispatched by either ISO. Big Stone contractual obligations require partners to take their minimum share of the plant whenever another owner calls for commitment. Big Stone differs from Coyote in that its coal contract is structured utilizing nearly 100 percent variable costs, which results in a higher percentage of hours where MISO/SPP LMP market pricing is lower than Big Stone variable operating costs. Per the co-owner contract, offering the unit for economic dispatch requires unanimous agreement amongst the three co-owners. If any co-owner requests self-commitment, all other co-owners are required to self-commit their share of the plant. Similarly, if MISO or SPP calls for a co-owner's portion of the plant, all other co-owners are obligated to self-commit their share, at least to minimum output.

Single Day Commitment by MISO

It should be noted that MISO utilizes a single day commitment and dispatch process. This means that market conditions for a given day, and that day only, would need to justify the economic commitment and dispatch of a unit. This often includes a large startup cost for baseload plants and may artificially increase cycling of the unit. The single day commitment and dispatch process does not consider the economics of running a baseload plant across multiple days. MISO has explored the possibility of a multi-day commitment process but does not currently have plans for development or implementation in the foreseeable future.

3. ANALYSIS APPROACH

The following reporting items in sections A-C were set forth in Attachment A of the Commission's January 11, 2021 Order. The Order, dated December 1, 2021, incorporated items D-H,⁴ and the Order dated November 17, 2022, incorporated sections I-L.⁴

- A. In the investigation docket, Minnesota Power, Otter Tail, and Xcel shall provide stakeholders with the underlying data (work papers) used to complete their analyses, in a live Excel spread sheet, including, at minimum, the data points listed below for each generating unit, with the understanding that this may include protected data.*

⁴ Docket No. E-999/CI-19-704.

Hourly data for all units:

- a) Date and hour
- b) Commit status (Null / Economic / Emergency / Must Run / Outage / Not Participating)
 - i. Any hours with unavoidable self-commitment should be labeled as such, with a cause listed for the self-commitment in that hour. (Testing, contract, dispatch of co-owned generation, etc.)
- c) Dispatch Status for Energy (Null / Economic / Self Schedule)
- d) Cleared MW
- e) Day ahead locational marginal price at unit node
- f) Real time MW adjustment
- g) Real time locational marginal price at unit node
- h) Day ahead dispatch minimum
- i) Real time dispatch minimum
- j) Fuel cost (\$/MWh)
 - i. If a utility excludes any fuel costs from its MISO offer curves, the utility should also provide an analysis that includes all fuel costs, including those currently treated as fixed costs due to contractual terms.
- k) Variable operations and maintenance costs (\$/MWh)
 - i. Utilities should provide Unit Fuel Costs and Unit Variable Cost as separate line items.
 - ii. Utilities should include all preventative maintenance in O&M costs for reporting purposes.
 - iii. Future analyses of self-commitment and self-scheduling should include all production costs including fuel, variable operations and maintenance, and other variable costs associated with the plant.
- l) Day ahead locational marginal price representative of utility load zone
- m) Real time locational marginal price representative of utility load zone
- n) Whether Day Ahead Cleared = Day Ahead Dispatch Minimum (0 or 1)
- o) Actual production in MWh (for all 8,760 hours of the year)
- p) Day ahead MISO payment
- q) Real time MISO payment
- r) Net MISO energy payment
 - i. Include ancillary services revenues and any other make-whole payments as a separate column in all reporting on revenue from generation.
- s) Production costs $((J+K) * O)$
- t) Net cost or benefit $(R-S)$

Monthly or annual data for all units:

- u) Revenue from ancillary services (monthly)
- v) Fixed operations and maintenance costs (preferably monthly) or reasonable estimates in approximation thereof
- w) Capital revenue requirements (annual) or reasonable estimates in approximation thereof

- x) Average heat rate at economic minimum
- y) Average heat rate at economic maximum
- z) To the extent not already provided, utilities should provide the following:
 - i. Length of minimum decommit time for each unit;
 - ii. Number of times in the analysis period that each unit incurred losses over a duration greater than or equal to its minimum decommit time;
 - iii. Of the periods identified in (ii), the number of periods when losses were greater than the relevant startup cost (warm or cold startup cost, depending on the length of the period); and
 - iv. Sum of losses in excess of startup cost that were incurred during periods identified in (iii).

Otter Tail Power Response

In addition to the above points a through z, Otter Tail Power incorporated additional columns to the Big Stone and Coyote hourly data spreadsheet templates, allowing for further analysis and insight into these units. As noted above, Otter Tail Power is one of multiple co-owners, and these units participate in both the MISO and SPP markets. As a result, there are numerous hours when Otter Tail Power is obligated to self-commit its share of these plants outside of Otter Tail Power's control. The additional columns, provided in AG-AL of Attachments 2 and 3, allow for analysis of hours when Otter Tail Power specifically endorsed self-commitment, excluding periods where the units must operate at least at minimum for building heat and plant testing, for both Big Stone and Coyote. These columns summarize MISO energy revenues, Ancillary Services Market (ASM) revenues, make whole payment revenues, variable production costs, and net benefits for Otter Tail Power endorsed hours of self-commitment (excluding required periods of building heat and plant testing). For this 2025 filing, for both Big Stone and Coyote, these values are zero as there were no hours in 2025 where Otter Tail Power endorsed self-commitment outside of required commitments for building heat and plant testing.

Furthermore, Otter Tail Power has included hourly day-ahead and real-time SPP LMP for both Big Stone and Coyote. This data is located in columns AN and AO of Attachments 2 and 3.

Filing Attachments:

Attachment 1 to this filing provides a summary of the monthly revenues and costs for Big Stone and Coyote for the current period.

Attachment 2 to this filing provides the requested hourly data for Big Stone for the current reporting period and an analysis of the minimum decommit time and startup costs. It also provides the data and calculations for the estimated "best-case and worst-case potential for economic commitment" for Big Stone.

Attachment 3 to this filing provides the requested hourly data for Coyote for the current reporting period and an analysis of the minimum decommit time and startup costs. It

also provides the data and calculations for the estimated “best-case and worst-case potential for economic commitment” for Coyote.

Attachment 4 to this filing provides the fixed monthly O&M costs for Big Stone and Coyote, per Attachment A of the Commission’s January 11, 2021 Order, part v.

Attachment 5 to this filing provides plant heat rate information as available from Big Stone and Coyote per Attachment A of the Commission’s January 11, 2021 Order, parts x and y.

Attachment 6 to this filing provides a summary of the minimum decommit time analysis for each plant per Attachment A of the Commission’s January 11, 2021 Order, part z.

Attachment 7 to this filing provides monthly energy MWh produced and curtailed from utility owned and contracted wind facilities.

Analysis Approach:

The following outlines Otter Tail Power’s analysis approach and assumptions included in the requested analysis, as well as other factors not included or considered:

1. This analysis compares the 2025 market energy revenues received versus both the variable costs included in determining the plant’s MISO offer curve and the variable costs included in determining the plant’s MISO offer curve plus fixed fuel costs. The market energy revenues are derived by the hourly Day Ahead (DA) and Real Time (RT) LMP per MWh of production.
2. Revenues associated with participation in the ASM are included in this analysis.
3. Revenues associated with unit make-whole payments are included in this analysis.
4. The costs of reagents are included in this analysis as they are included as part of Otter Tail Power’s offer curve submitted to MISO. Otter Tail Power began recovering reagent costs through its the FCA beginning July 1, 2022. Reagent costs were recovered in base rates prior to that date.
5. One factor that is not quantifiable is the potential impact on both market prices and the related commitment and dispatch of any other Otter Tail Power generating units when either Big Stone or Coyote switch between self-commitment and economic commitment offer status.
6. The large coal units require different time durations for hot, warm, and cold starts. Also, from an “on” condition, the unit must cool for different durations in order to qualify for a hot, warm, and cold start. The combined duration of cool down time and start up notification time for the coal plant starts are as follows:

Table 1
Startup Times by Plant

Startup Conditions	Big Stone	Coyote
	[PROTECTED DATA BEGINS ...	
Cold Start (including cool down time)		
Warm Start (including cool down time)		
Hot Start		
	... PROTECTED DATA ENDS]	

7. Otter Tail Power includes variable preventative maintenance costs in the Unit Variable O&M cost category and in Attachments 2 and 3.
 8. In a compliance filing dated December 29, 2025, in Docket No. E999/CI-19-704, the Commission suggested eliminating the “base-case” and “worst-case” naming convention and updating the case names to full economic and full self-commitment. Otter Tail Power chose to utilize the existing and reported data set for this analysis (included in Attachment 2 and Attachment 3). The Otter Tail Power analysis is discussed in Section 4 of this filing.
- B.** *Minnesota Power, Otter Tail, and Xcel Energy shall evaluate whether reducing minimum operating levels would benefit customers and to include that evaluation and discussion in the March 1, 2021 compliance report.*

Otter Tail Power Response

In March of 2016, Big Stone reduced its total plant economic minimums from **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. In December of 2021 and January of 2022, Big Stone conducted further testing to determine whether additional reductions to the economic minimum output could be achieved. It was determined the total plant economic minimum could be reduced from **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. This reduction was implemented on April 1, 2022. Except for testing and plant derates, and the air-quality control system (AQCS) scrubber train transition issue described below, when self-committed, the Otter Tail Power share of Big Stone is self-scheduled at the economic minimum.

In 2015, Big Stone completed construction and began operation of a new AQCS system that reduced nitrogen oxides and sulfur dioxide emissions by approximately 90 percent and mercury emissions by approximately 80 percent. The AQCS system requires operation of two scrubber trains when operating at high output levels and one scrubber train when operating at low output levels. The initial physical minimum limitation under two scrubber trains was **[PROTECTED DATA BEGINS...**

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current physical minimum limitation under one scrubber train is **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]**, which is the value listed in Columns L and M of Attachment 2 to this filing. Transitioning between one and two scrubber trains requires physical plant reconfigurations that can be labor intensive, cause additional wear and tear to the AQCS system, and require a minimum of 20 minutes to complete.

The decision to transition between one and two train operation is driven by MISO market pricing. Transitions between scrubber trains come with additional costs, complexity in timing, communication, and market pricing issues associated with updating physical plant operating limits. When market prices are high, Big Stone will move up to full output, requiring utilization of both scrubber trains and the two-train economic minimum limit. Ideally, due to physical conditions and mechanical costs associated with transitions between one and two scrubber trains, Big Stone would remain at two trains for a minimum of six hours. However, if market pricing is considerably negative, Big Stone will initiate a return to one train operation and the utilization of the one train economic minimum limit. The lower the prevailing LMP market, the quicker the plant will return to one train operations and a lower economic minimum. The process, economics, and timelines to transition from two scrubber trains to one scrubber train has been reviewed by the MISO Independent Market Monitor (IMM), who has determined the Big Stone train transition process to be reasonable.

Minimum load at Coyote changed from **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS] The reason for the varying minimum load level under colder ambient conditions is the temperature into the scrubber will be reduced and a higher temperature is needed to evaporate the slurry introduced to control sulfur emissions. Therefore, at lower loads and cold ambient temperatures, the plant would risk being out of compliance with regards to sulfur emissions with limited ability to increase scrubbing to control.

- C. *Utilities with co-ownership of baseload generating units shall discuss options of economically committing those units within the terms of their partnership in the March 1, 2021 compliance report.*

Otter Tail Power Response

Big Stone (April 2020) and Coyote (April 2021) co-owners have implemented the capability to offer these units into the MISO and SPP markets utilizing an economic offer. As previously mentioned, these units straddle both the MISO and SPP wholesale energy markets and can be committed and dispatched by either ISO. Big Stone and Coyote contractual obligations require partners to take their minimum share of the plant whenever another owner, or market, calls for commitment. Per the co-owner contract, utilization of an economic offer requires unanimous agreement amongst the co-owners. If any co-owner requests self-commitment, all other co-owners are required to self-commit their share of the plant.

Similarly, if MISO or SPP calls for a co-owner's portion of the plant, all other co-owners are obligated to self-commit their share, at least to minimum output. This results in economic decommitment occurring only when all co-owners agree to offer the unit economically and the MISO and SPP markets do not economically commit the unit.

As of April 2020 for Big Stone and as of April 2021 for Coyote, co-owners have been meeting regularly to discuss and coordinate unit offer practices. In these meetings, co-owner marketing teams meet with Big Stone and Coyote operations staff to discuss the health of the unit, operational considerations, historical, current, and projected market conditions (in both the SPP and MISO markets), weather forecasts, and potential adjustments to the economic offer curves. Co-owners will then indicate their offer preference, and duration of, for either an economic offer or self-commitment. In the event one co-owner calls for self-commitment, all other co-owners are required to self-commit their share at minimum output.

The Big Stone and Coyote co-owner marketing teams meet regularly to discuss market conditions and offer strategy. The periodicity of the meetings is adjusted, as appropriate, during times of low market pricing (extended decommitment) or high market pricing (extended commitment). Co-owner marketing teams maintain communication between regularly scheduled meetings in the event market conditions call for updated offer parameters.

- D.** *Minnesota Power, Otter Tail, and Xcel Energy shall file in their March 1, 2021 filing a complete analysis of the costs and benefits of economic or seasonal dispatch relative to self-scheduling at the following facilities:*
- a. Coyote Station*
 - b. Big Stone Plant*

Otter Tail Power Response

Otter Tail Power provides the updated analysis in Section 4 of this analysis.

- E.** *Otter Tail shall provide a discussion of the options of changing its current coal contract at Coyote Station and evaluation of how potential costs of changing the contract compare to Coyote Station's past and forecast operating losses in Docket No. E-999/CI-19-704.*

Otter Tail Power Response

Coyote is a mine mouth generating facility, meaning that it was conceived, sited, designed, and constructed to have a long-term, integrated relationship with an immediately adjacent mine serving the plant. The mine is typically intended to serve just the mine-mouth plant with which it contracts, and it is therefore typically much smaller than the large mines that serve numerous delivered-fuel plants, such as the mines in the Powder River Basin that serve Big Stone. As noted in prior filings in this docket Coyote is the only mine-mouth generation facility regulated by the Commission; all other coal generation facilities regulated by the Commission are delivered-fuel plants.

One of the primary benefits of a mine-mouth plant, in contrast to a delivered-fuel plant, is that it is not dependent on the rail systems or other transportation systems, over which the coal necessary to fuel the plant must be transported. Of course, without having a secure and consistent long-term relationship with the adjacent mine, a mine-mouth plant would be exposed to fuel shortages; conversely, without a long-term relationship, the supplying mine would typically not make investments necessary to ensure the extraction of a consistent supply of coal necessary to fuel the plant. Without consistent fuel, the plant would not be reliable and would not be accreditable for capacity.

Mine/plant contracts for mine-mouth plants have very different fixed/variable components when contrasted with delivered-fuel plants. These differences are due to the nature of the relationship and what each party requires from the relationship. The mine, in the case of a mine-mouth plant, must recoup its fixed costs (the costs of investments in opening the mine, the equipment, reclamation, etc.) and its variable costs (certain costs that vary with the volumes produced) generally from a single customer with which it has a long-term relationship. The larger fixed components of these contracts when compared to delivered fuel contracts are not because the transacting parties have different desires about the way the plant should operate, etc. Similarly, the plant requires a long-term relationship with its supplier, to ensure a consistent supply of fuel at a known cost (it cannot replace that fuel from the market if the supplier were to increase its prices or become unreliable in some other way). These are economic attributes applicable to mine-mouth plants, and they are the reasons for the differences in fuel contracts. These attributes have been the subject of significant academic study, often under the term “asset specificity,” (see, e.g., [Paul L. Joskow, "Contract Duration and Relationship-Specific Investments: Empirical Evidence from Coal Markets"](#), [American Economic Review](#), March 1987); and several works of Nobel Laureate, O.E. Williamson.

Consistent with the foregoing explanation of contracting for mine mouth plants, Coyote obtains its fuel through an all-requirements Lignite Sales Agreement (LSA) with Coyote Creek Mining Company, L.L.C (CCMC), a subsidiary of North American Coal. Under the LSA, CCMC is responsible for developing, constructing, operating, and eventually reclaiming the mining facility, the costs of which are reflected in the terms of the LSA. Coyote’s co-owners and CCMC entered into the LSA in 2012 with a term through the end of 2040.⁵ The long term of the LSA reflects the unique nature of mine mouth facilities as noted above.

Given the nature of mine-mouth agreements, there are few, if any, options for changing the terms of the LSA to address fluctuating market conditions. As one of several co-owners, Otter Tail Power lacks the ability, by itself, to seek changes to the terms of the LSA. Any effort to change the terms of the contract would require the co-owners to act in concert, and even then, the co-owners together lack the ability to make changes to the LSA without the agreement of the seller. Therefore,

⁵ In Docket No. E017/D-13-795, the Commission approved extending the remaining life of Coyote Station by 8.4 years to 27.4 years, with an AYFR of 2041 to correspond with the anticipated duration of the LSA.

any changes to the LSA would need to be secured through negotiations. In short, changes to the LSA would require at least two agreements: (1) an agreement among co-owners to pursue changes, to include an agreement on acceptable trade-offs and costs necessary to secure negotiated contract changes, and (2) an agreement between the co-owners and CCMC (and North American Coal) to change terms. In addition, any changes to the relationship would require approval of CCMC lenders. In sum, there are significant barriers to seeking changes to a mine-mouth supply agreement, especially in the context of joint-ownership of the generation facility.

A discussion concerning options for changing the LSA and an “evaluation of how potential costs of changing the contract compare to Coyote’s past and forecast operating losses” should also address the concept of operating losses. Otter Tail Power has previously noted in this docket and in Otter Tail Power’s most recent general rate case that an operating or production cost loss analysis has significant flaws.⁶ While comparisons of MISO revenue and production costs is a useful measure of a generation plant’s flexibility in responding to changing market conditions, it is not indicative of a generation plant’s cost effectiveness. Whether a generation facility is cost effective requires a broader analysis involving market price forecasts and other forecasts, capacity expansion modelling and other considerations generally considered in IRP proceedings. There are many cost-effective plants that have limited operational flexibility that would show production losses, including most non-dispatchable renewable resources and many base load generators. This issue is addressed more fully in the “Additional Discussion” section below.

F. *The Commission carries forward all the requirements from prior orders in Docket Nos. E-999/AA-18-373 and E-999/CI-19-704 and requires inclusion of the following in future reports:*

a. Information on annual carbon dioxide emissions

The following table provides 2025 carbon dioxide emissions and plant output for Big Stone and Coyote.

**Table 2
Plant CO₂ Emissions Data**

Year	Big Stone (Total Plant Data)			Coyote (Total Plant Data)		
	CO ₂ tons	Net MWh	CO ₂ Rate, lbMWh	CO ₂ tons	Net MWh	CO ₂ Rate, lbMWh
2025	2,656,747.2	2,031,367	2,615.7	2,636,217.7	2,131,059	2,474.1

Although the above data was used to calculate each plant’s annual average rate of CO₂ emitted per MWh, the rate produced for any given hour is dependent on

⁶ As used in this docket operation or production losses refers to a comparison of MISO revenues received for the plant and production costs. Among other problems this analysis does not account for Coyote Station’s significant capacity function. It also incorrectly assumes Otter Tail would rely on the spot market in the absence of Coyote Station, rather than securing replacement resources. See Docket No. E017/GR-20-719, Gerhardson Rebuttal at 16-21.

several variable operating conditions, such as load level and coal quality. Therefore, although a high-level estimate of avoided CO₂ emissions will be made by multiplying the annual average CO₂ rates by economic commitment hours, an exact number cannot be determined.

b. Reasons for unavoidable self-commit status designations

Attachments 2 and 3 contain hourly unavoidable self-commitment status designations.

The following list describes some of the reasons for unavoidable self-commitment at Coyote and Big Stone:

- Co-owner request
- Building heat requirements
- SPP market conditions
- Testing
- Maintenance and operational logistics
- Safety
- Emission requirements
- Third party obligation (i.e., steam contracts)

In the 2023 filing, Otter Tail Power added, or perhaps delineated, building heat requirements as a main reason for required self-commitment. While building heat has always been necessary for reliable operations during winter months, this reason for self-commitment had previously been included within the category of co-owner request. The understanding being that co-owners would almost always call for self-commitment during winter operating conditions. The addition of a building heating category, and the monitoring of necessary building heat conditions, will help to better pinpoint when building heating requirements are truly necessary.

During the winter season, building heat is required for Big Stone and Coyote to operate. Failure to provide building heat would result in freezing plant components and reduced reliability. Building heat is primarily provided through standard plant operations. While both Big Stone and Coyote maintain building heat that is independent of plant operations, called the auxiliary boiler, it is considered a back-up heating system and is not designed to be the primary source of heat for the plant. The auxiliary boiler was designed and sized to initiate unit startup after being offline. When the plant is online and committed, the auxiliary boiler functions as intended, as a back-up heating system for emergency situations.

In cold weather temperatures, if the plants are not operating, the risk to Big Stone and Coyote is twofold. First, if the auxiliary boiler fails, there is no redundant heating system. Second, and more importantly, if the auxiliary boiler fails, there would not be a means to initiate startup of the plant. If the auxiliary boiler trips for any reason, it must be immediately repaired. Based upon experience, Otter Tail Power knows it would take up to a week to bring in a

temporary boiler to heat the plant, and it would not be possible to avoid component freezing and damage in that scenario.

From a winter operations standpoint, the likelihood of Big Stone and Coyote being available to respond to a winter storm event is much higher if the plants are already online. If the plants have been offline for a period of time, the chance of a smooth startup and commitment is lower, reducing plant reliability.

Based on observation of internal and external temperatures, plant engineers determined that at an average daily temperature of 35 degrees the plant would retain enough residual heat to prevent any damage to its components. At this average daily temperature, the plant could be safely shut down and would not require the auxiliary boiler to run for plant heat.

Starting in October of 2023, Otter Tail Power began recording daily 7-day temperature forecasts at both Big Stone and Coyote. As noted above, if the 7-day average temperature forecast is less than 35 degrees (average of the daily high and daily low averaged across 7 days), self-commitment is determined to be required for building heat purposes.

Finally, it should also be noted that it is possible for multiple unavoidable self-commitment reasons to be present at any given time. For example, when self-commitment for building heat is required, non-Otter Tail Power co-owners may also request continued self-commitment due to expected SPP market conditions.

c. Plant startup conditions (e.g. cold, warm, or hot)

Attachments 2 and 3 identify designations for plant startup conditions for each startup occurrence.

d. Equivalent Forced Outage Rate information to be tracked over time

Tables 3 and 4 provide the Equivalent Forced Outage Rate (EFOR) for both Big Stone and Coyote for the past ten years and by month in 2025. The method and formula for calculating Equivalent Forced Outage Rate can be found on the NERC website.⁷

⁷ <https://www.nerc.com/pa/RAPA/gads/Pages/Data%20Reporting%20Instructions.aspx>.

Table 3
Equivalent Forced Outage Rates

Year	Big Stone	Coyote
	[PROTECTED DATA BEGINS...	
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		

...PROTECTED DATA ENDS]

Table 4
2025 Monthly Equivalent Forced Outage Rates

2025	Equivalent Forced Outage Rate	
Month	Big Stone	Coyote
	[PROTECTED DATA BEGINS...	
Jan		
Feb		
Mar		
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		
Total		

...PROTECTED DATA ENDS]

- e. Descriptions of changes to operating procedures and physical modifications to units to ensure plants are becoming more flexible to meet upcoming challenges as applicable.*

Otter Tail Power continually assesses operating procedures and physical modifications to both Big Stone and Coyote to increase flexibility. These types of changes often involve operating outside the original design parameters of the units or operating in conditions that have not been experienced previously. Every potential change is well thought out and designed and requires testing and validation under extended periods of operation. Therefore, small changes over long periods of time are required to ensure that negative impacts do not outweigh the positive results.

In April 2016, Big Stone lowered the minimum operating load from **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. Procedure changes required to accommodate this included shutting down one scrubber train and one boiler feed pump. These lower loads contributed to ash build up in the flue gas duct at the boiler exit. In October 2020, modifications were made to the duct to reduce the ash build up. After months of operation, it was determined that this modification was successful in reducing the ash accumulation.

To further increase flexibility, Big Stone performed more testing in late 2021 to reduce the minimum load from **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. Control logic and procedure changes were required, including reducing the boiler minimum air flow trip setting after consulting with Boiler OEM, modifying the boiler excess air curve, and valving in auxiliary steam from the main steam drum. The Big Stone co-owners approved operations at the new minimum load effective April 1, 2022.

Coyote also tested and successfully implemented the lowering of its minimum operating load from **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. Lowering the minimum operating load was made possible by the replacement of a bottom ash handling system that was completed in compliance with Coal Combustion Residual rules in 2019. Similar to Big Stone, Coyote tested a new minimum load of **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. This new minimum at Coyote is now in place at ambient temperatures greater than 32 degrees F.

Another change implemented to increase flexibility at Coyote is the installation of fuel analysis equipment in 2019. This equipment provides Coyote staff the ability to instantly analyze the quality of coal delivered to the plant from the adjacent mine. If coal quality is unacceptable, Coyote staff notifies the mine and higher quality coal is delivered. The result of installing the new equipment and

implementing procedures to work with the mine has significantly reduced fuel related limitations on boiler cleanliness across all load ranges.

In the spring of 2024, Coyote began a program feeding a magnesium oxide product into the furnace to aid in the operation of the unit. This product is blown into the gas stream and bonds to the ash particles as the heat is being transferred from the gas stream to the furnace wall and convection pass tubes. The product inhibits the bonding of the ash to the tubes making the ash much easier to clean with the conventional equipment that already exists in the boiler. The ability to keep the boiler and tubes cleaner increases the efficiency of the boiler and enables the unit to respond to market demands better. The program was a test during 2024 and the results were very successful. The program is planned to continue going forward.

- G.** *The Commission directs Xcel Energy, Minnesota Power, and Otter Tail to develop a methodology, that is consistent to the extent possible, for splitting fuel costs such that one part depends on the megawatt-hour (MWh) production (i.e. variable cost) and the other part is independent of the MWh generated (i.e. fixed cost) and update the reporting template accordingly.*

Otter Tail Power Response

Representatives from Minnesota Power, Otter Tail Power, and Xcel Energy met on January 24, 2022, to discuss a consistent methodology for reporting the required data. Column N in a plant's *Self-Commitment Hourly Template* tab will be used to provide variable portions of fuel costs and column O will be used to provide fixed portions of fuel costs if applicable. The Otter Tail Power fixed fuel costs, column O, have been converted into an hourly value (total monthly fixed costs divided by total monthly MWhs produced) for calculation purposes and to fit the hourly reporting format. It is Otter Tail Power's understanding, based on the conversations among the utilities, that Otter Tail Power is the only company that would have fixed fuel cost components factored into the analysis.

- H.** *The Commission requires the utilities to work together to develop a consistent method for estimating the best-case and worst-case potential for economic commitment for each plant.*

Otter Tail Power Response

During the meeting on January 24, 2022, the utilities discussed methods for estimating the best-case and worst-case potential for economic commitment. Otter Tail Power's analysis is included in Section 4 of this filing.

- I.** *The Commission requires the inclusion of MISO and SPP market conditions in determining its self-commitment endorsement and show net benefit results in addition to the analysis provided by otter tail in tables 6 and 8 of its 2021 filing.*

Otter Tail Power Response

MISO market conditions are included in Attachment 2 and Attachment 3. Net benefits for Otter Tail Power are based on MISO market pricing and are discussed in Section 4

and detailed in Attachment 2 and Attachment 3. Otter Tail Power has also included SPP hourly LMP pricing for Big Stone and Coyote in columns AN and AO of Attachment 2 and Attachment 3.

- J.** *The Commission requires the inclusion in its 2023 and 2024 annual reports an update on its progress toward implementing the Total Plant Offer Optimization Plan and Combined Modeling of MISO Co-Owner Generation Shares Plan at Big Stone Plant and Coyote Station.*

Otter Tail Power Response

The Total Plant Offer Optimization Plan and Combined Modeling of MISO Co-Owner Generation Shares Plan are potential initiatives, suggested by Otter Tail Power to the other co-owners, that may improve efficiencies and overall economic plant performance. All co-owners maintain historical awareness of these potential initiatives and have each considered the pros and cons of advancement. Moving forward with either of these initiatives would require unanimous consent from all co-owners (less Northwestern Energy on the Combined Modeling of MISO Co-Owner Generation Shares Plan). In January 2026, Otter Tail Power again inquired of each co-owner regarding their interest in pursuing one or both plans. In response to the Otter Tail Power January 2026 inquiry, none of the co-owners supported advancing either proposal.

- K.** *The Commission requires the inclusion of avoided carbon dioxide emissions due to economic commitment along with plant level carbon dioxide emissions in subsequent filings using the Department's recommended method.*

Otter Tail Power Response

Using the Department's recommended method, the calculated avoided carbon dioxide emissions due to economic commitment were 87,299 tons at Big Stone⁸ and zero tons at Coyote. Plant level carbon dioxide emissions are presented in Table 2.

- L.** *The Commission requires the inclusion of energy MWh produced and curtailed from utility owned and contracted wind facilities monthly for each facility*

Otter Tail Power Response

Attachment 7 provides energy MWh produced and curtailed from utility owned and contracted wind facilities. Monthly MWh production is provided for each facility, and monthly curtailment is provided for contracted wind facilities. The curtailment for Otter Tail Power owned facilities is provided as an annual total for each facility.

⁸ Calculated by multiplying the annual average carbon dioxide emission rate in Table 2 of 2,615.7 lb/MWh by the minimum Big Stone output by the number of hours on economic commitment at zero megawatts.

4. ANALYSIS RESULTS:

For the 2025 reporting period, the market revenues and plant costs for market operations at Big Stone and Coyote are detailed in the narrative and summary tables below.

General 2025 Market Conditions

The ten-year history of average, annual, day ahead, LMP pricing at Big Stone and Coyote pricing nodes are reflected in Table 5 below:

Table 5
DA LMP Average Hourly Price History

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Big Stone Plant	\$19.08	\$21.20	\$25.30	\$20.08	\$13.74	\$15.54	\$19.40	\$13.30	\$11.45	\$23.92
Coyote Station	\$17.44	\$20.34	\$24.82	\$20.39	\$13.30	\$25.76	\$38.27	\$25.37	\$24.22	\$37.05

The low 2020 LMP pricing levels were driven by several factors, including, but not limited to, low natural gas markets, continued renewable resource penetration, and impacts to load driven by the COVID-19 pandemic. System wide 2021 prices increased as compared to pricing in 2020, largely driven by natural gas price increases. The 2022 pricing increased substantially over 2021 due to further increases in the natural gas markets, reduced natural gas storage levels, and market uncertainty across the winter season due to historical winter storm events. The 2023 and 2024 market pricing experienced a reduction, once again driven by reduced natural gas pricing and increased levels of natural gas storage. In 2025, regional market pricing surged, approaching levels rarely seen in the last ten years. This surge was driven, in part, by once again increasing natural gas markets and a reduction in Manitoba Hydro imports into MISO. While Coyote tends to follow market wide pricing patterns more closely, elevated system congestion at Big Stone remained, keeping localized LMP pricing suppressed lower than the rest of the market. As mentioned in previous filings, as renewable resource penetration continues to grow, it is necessary to upgrade the transmission system. These upgrades often result in long-term, yet temporary, line outages, which act to exacerbate already constrained areas, increasing congestion within those transmission pockets. Big Stone is located within such a pocket. As Big Stone regional transmission system upgrades and outages are completed, congestion in this transmission constrained region should improve but only if the rate of transmission export expansion exceeds the rate of new generation siting.

Big Stone Plant

For the 2025 reporting period, the revenues, costs, and net benefits/costs of market operations for Big Stone are reflected in Table 6 below. This table compares the Big Stone market revenues against both variable costs and variable costs combined with fixed fuel costs.

Table 6
Big Stone Plant Net Benefit/Cost Summary 2025

Revenue	Variable Cost	Variable Cost Net Benefit / (Cost)	Variable Cost Plus Fixed Fuel Cost	Variable Cost Plus Fixed Fuel Cost Net Benefit/ (Cost)
[PROTECTED DATA BEGINS...				
...PROTECTED DATA ENDS]				

Revenues include MISO energy payments, ASM payments, and make whole payments. These revenues are reported on an hourly basis in columns T, U, and AA of the *Self-Commitment Hourly Template* tab in Attachment 2. Monthly summaries for Big Stone are included in Attachment 1 to this filing.

Variable costs include fuel for generation, reagents (i.e., lime, activated carbon, ammonia), emission allowances, and miscellaneous operation and maintenance costs (largely water treatment chemicals). Variable costs are reported on an hourly basis in column AC of the *Self-Commitment Hourly Template* tab in Attachment 2. Due to the co-ownership of Big Stone, and varying commitment and dispatch patterns of each co-owner, Otter Tail Power reports variable costs using an average per MWh cost by month which can be found in columns N, P, and Q of the *Self-Commitment Hourly Template* tab in Attachment 2.

Fixed fuel costs include train lease costs. Variable costs plus fixed fuel costs are reported on an hourly basis in column AD of the *Self-Commitment Hourly Template* tab in Attachment 2. Like variable costs, Otter Tail Power reports fixed fuel costs using an average per MWh cost by month (total fixed monthly fuel costs divided by MWhs generated in the month) which can be found in column O of the *Self-Commitment Hourly Template* tab in Attachment 2.

Figure 1 provides a year-over-year comparison for Big Stone revenues and total costs from 2017-2025. It shows that Big Stone's costs of operations have remained stable over the period, and that Markets have turned higher following lows in 2020. Otter Tail Power expects markets will be more volatile and uncertain in the future.

Figure 1
Big Stone Revenue and Fuel Cost

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Once again, it should be emphasized that Big Stone is a co-owned unit, operating in two markets, and that Otter Tail Power is obligated to self-commit its share of the plant if any other co-owner, MISO, or SPP commits a co-owner's share of the unit.

At the end of 2019, Otter Tail Power led the development of Big Stone economic offer capability for the co-owners. This capability was implemented near the end of April 2020. In 2024, Big Stone co-owners utilized economic offers in the months of March, April, May, October, and November.

Big Stone experienced one extended outage in 2025. This outage was the plant's scheduled fall maintenance outage occurring September 25, 2024 through October 16, 2024.

It should also be emphasized that for significant periods of 2025, Otter Tail Power was obligated to self-commit its share of the plant. The largest drivers in forced self-commitment were due to building heat requirements during cold winter months and co-owner requests to self-commit. Co-owner self-commitment requests were often driven by higher LMP pricing in the SPP market. At the Big Stone node, average SPP day ahead market pricing was approximately 7 percent higher than average day ahead MISO pricing. The 2025 day ahead Big Stone pricing in SPP averaged \$25.65 per MWh versus \$23.92 per MWh in MISO. This price difference can result in divergent commitment and dispatch patterns.

In past filings, Otter Tail Power provided additional analysis comparing Big Stone Actual performance against Otter Tail Power endorsed hours of self-commitment. In this 2025 filing, this analysis has been greatly simplified as there were no days in 2025 where Otter Tail Power called for Big Stone self-commitment outside of needs for building heat and plant testing. Table 7 reflects total hours, revenue, variable costs, and net benefit. Hourly calculations for this analysis can be found in columns AG through AL of the *Self-Commitment Hourly Template* tab in Attachment 2.

Table 7
Big Stone Plant Performance under OTP Endorsed Self-Commitment
Hours – Outside of Required Building Heat and Plant Testing Periods

2025

Scenario	Hours	Revenue	Variable Costs	Variable Cost Net Benefit / Cost
[PROTECTED DATA BEGINS...]				
2025 OTP Endorsed Hours of Self-Commitment Outside of Building Heat and Plant Testing Periods				
...PROTECTED DATA ENDS]				

Throughout 2025, outside of building heat and plant testing requirements, Otter Tail Power consistently called for utilization of an economic offer at Big Stone. The above analysis primarily demonstrates that Otter Tail Power is making prudent self-commitment decisions for Big Stone. However, it should be noted and emphasized that Otter Tail Power recommendations for economic commitment are often superseded by other co-owner requests for self-commitment.

In summary, significantly increased LMP pricing driven, in part, by rising natural gas markets, resulted in significant net benefits (market revenues, less production costs) throughout calendar year 2025. While periods of economic offers and economic decommitment were limited, the plant's ability to ramp between minimum and maximum output during market fluctuations worked to optimize economic performance. Otter Tail Power will continue to work with its co-owners to improve and enhance future plant performance.

Coyote Station

Table 8 below compares the Coyote market revenues against both variable costs, and variable costs combined with fixed fuel costs, for the 2025 reporting period.

Table 8
Coyote Station Net Benefit/Cost Summary 2025

Revenue	Variable Cost	Variable Cost Net Benefit / (Cost)	Variable Cost Plus Fixed Fuel Cost	Variable Cost Plus Fixed Fuel Cost Net Benefit/ (Cost)
[PROTECTED DATA BEGINS...]				
...PROTECTED DATA ENDS]				

Revenues include MISO energy payments, ASM payments, and make whole payments. These revenues are reported on an hourly basis in columns T, U, and AA of the *Self-Commitment Hourly Template* tab in Attachment 3.

Variable costs include the variable component of the mine fuel invoice for delivered lignite **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS], reagents costs (i.e., lime and activated carbon), coal conversion tax, and miscellaneous variable operation and maintenance costs (largely water treatment costs). Variable costs are reported on an hourly basis in column AC of the *Self-Commitment Hourly Template* tab in Attachment 3. Due to the co-ownership of Coyote, and varying commitment and dispatch patterns of each co-owner, Otter Tail Power reports variable cost using an average per MWh cost by month which can be found in columns N, P, and Q of the *Self-Commitment Hourly Template* tab in Attachment 3.

Fixed fuel costs include the fixed component of the mine fuel invoice for delivered lignite **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. Variable costs plus fixed fuel costs are reported on an hourly basis in column AD of the *Self-Commitment Hourly Template* tab in Attachment 3. Like variable costs, Otter Tail Power reports fixed fuel costs using an average per MWh cost by month (total fixed monthly fuel costs divided by MWhs generated in the month) which can be found in column O of the *Self-Commitment Hourly Template* tab in Attachment 3.

Figure 2 provides a year-over-year comparison for Coyote revenues and total costs (fixed and variable) from 2017-2025. Like Figure 1 did for Big Stone, Figure 2 shows that Coyote's costs of operations have remained stable over the period and that markets have turned higher following lows in 2020. Otter Tail Power expects markets will be more volatile and uncertain in the future. Taken together, Figures 1 and 2 demonstrate that the perceived "net benefit/costs" of Big Stone and Coyote in this docket have largely been driven by the prices available in the energy markets (which have been highly variable) not by the production costs of the plants (which have been very stable).

Figure 2
Coyote Revenue and Fuel Cost

[PROTECTED DATA BEGINS...

...PROTECTED DATA ENDS]

As reported in the above section describing the Coyote fuel contract, Coyote is fueled by the Coyote Creek mine. As a result of this fuel source, and the contract structure described above, much of the fuel costs for Coyote are fixed. This means Otter Tail Power is obligated to pay for these costs whether or not the fuel is consumed to generate electricity. These fixed costs equate to sunk costs and do not play a role in appropriately developing market offers on a day-to-day basis. As such, Otter Tail Power maintains it is appropriate to judge Coyote's commitment and dispatch decisions based on variable costs, not variable costs plus fixed fuel costs.

Throughout 2020 and early 2021, the co-owners worked toward the development of Coyote economic offer capability. At the end of April 2021, Coyote co-owners implemented coordinated offer processes that allowed for joint economic offer capability. On May 1, 2021, Coyote was economically decommitted for the first time.

Once again it should be emphasized that Coyote is a co-owned unit, operated in two markets, and that Otter Tail Power is obligated to self-commit its share of the plant if any other co-owner or either MISO or SPP commit a co-owner's share of the unit. In 2025, the largest drivers in forced self-commitment were due to building heat requirements during cold winter months and co-owner requests to self-commit. This resulted in significant periods where Otter Tail Power was obligated to self-commit its share of Coyote. In 2025, Coyote co-owners did not utilize economic offers.

Coyote experienced four notable outages in 2025. The largest was the Spring overhaul which ran from 3/27/2025 through 5/31/2026. Extended tube leak repairs ran from 2/22/2025 through 2/28/2025. An outage was required to repair a crack in the slag neck from 8/12/2025 through 8/18/2025. Finally, the unit tripped offline due to furnace pressure, lasting 9/23/2025 through 10/1/2025

At the Coyote node, the average day ahead SPP market pricing was approximately 84% percent of the average day ahead MISO pricing. The 2025 average day ahead Coyote pricing in SPP averaged \$31.09 per MWh versus \$37.05 per MWh in MISO.

In past filings, Otter Tail Power provided additional analysis comparing Coyote Station actual performance against Otter Tail Power endorsed hours of self-commitment. Like Big Stone in this 2025 filing, this analysis has been greatly simplified as there were no days in 2025 where Otter Tail Power called for Coyote Station self-commitment outside of needs for building heat and plant testing. Table 9 reflects total hours, revenue, variable costs, and net benefit. Hourly calculations for this analysis can be found in columns AG through AL of the *Self-Commitment Hourly Template* tab in Attachment 3.

Table 9
Coyote Station Performance under OTP Endorsed Self-Commitment
Hours – Outside of Required Building Heat and Plant Testing Periods
2025

Scenario	Hours	Revenue	Variable Costs	Variable Cost Net Benefit / Cost
	[PROTECTED DATA BEGINS...			
2025 OTP Endorsed Hours of Self-Commitment				
	...PROTECTED DATA ENDS]			

Throughout 2025, outside of building heat and plant testing requirements, Otter Tail Power has consistently called for utilization of an economic offer at Coyote Station. The above analysis primarily demonstrates that Otter Tail Power is making prudent self-commitment decisions for Coyote Station. However, it should be noted and emphasized that Otter Tail Power recommendations for economic commitment are often superseded by other co-owner requests for self-commitment.

In summary, significantly increased LMP pricing driven, in part, by rising natural gas markets, resulted in significant net benefits (market revenues, less production costs) throughout calendar year 2025. While periods of economic offers and economic decommitment were not utilized in 2025, driven by co-owner requests for self-commitment, the plant's ability to ramp between minimum and maximum output during market fluctuations worked to optimize economic performance. Otter Tail Power will continue to work with its co-owners to improve and enhance future plant performance.

Item Z

The following reporting item z, was set forth in Attachment A of the Commission's January 11, 2021 Order in Docket No. E-999/CI-19-704:

- z) To the extent not already provided, utilities should provide the following:*
- i. Length of minimum decommit time for each unit;*
 - ii. Number of times in the analysis period that each unit incurred losses over a duration greater than or equal to its minimum decommit time;*
 - iii. Of the periods identified in (ii), the number of periods when losses*

- were greater than the relevant startup cost (warm or cold startup cost, depending on the length of the period); and*
- iv. *Sum of losses in excess of startup cost that were incurred during periods identified in (iii).*

Item z, i, length of minimum decommit time for each unit, which Otter Tail Power interprets as the combined cool down time and startup notification time, were described earlier in this filing and are listed in Table 1.

In Otter Tail Power's review of the 2020 filing requirements, items z, ii through z, iv were ambiguous and difficult to answer. Otter Tail Power was uncertain about how to accurately develop the requested analysis. Prior to completion of the 2020 compliance filing, Otter Tail Power brought the issue to the other utilities, stakeholders, and the Department, as part of the required data template compliance filing meetings. Through these joint discussions, the utilities and stakeholders agreed that the language of item z was not specific enough to provide adequate direction to develop the requested analysis. Ultimately, Fresh Energy and The Sierra Club agreed to define and develop a calculation methodology for items z, ii through z, iv, which they then shared with the utilities and the Department. After a few relatively minor utility revisions, all parties came to agreement on the new item z calculation methodology. This new calculation directly utilizes the data provided within the agreed upon compliance filing template. For the 2025 compliance filing, Otter Tail Power continues to use the jointly developed, 2020 item z calculation methodology. Item z data and calculations can be found in Attachments 2 and 3 on the *Consecutive Hours* and *Item Z Summary* tabs.

The item z calculation essentially asks four questions relating to 2025 operations:

1. How many times throughout the 2025 operating year did the unit maintain consecutive hours of operating losses greater than the minimum downtime of the plant (cool down time plus startup notification time)?
2. What were the cumulative operating losses of the occurrences identified in item 1?
3. How many of the occurrences in item 1 had operating losses greater than the startup cost of the unit?
4. What were the cumulative operating losses of the occurrences identified in item 3?

Note that this analysis does not account for additional startup costs that would be incurred with cycling the plant on and off.

The item z analysis was applied to both a variable cost scenario and a variable cost-plus-fixed-fuel cost scenario. Otter Tail Power completed the requested item z calculation utilizing a cold minimum downtime (hot to cold cooldown and cold startup notification times). Table 10 summarizes the item z analysis for Big Stone and Coyote.

Table 10
Big Stone and Coyote Item Z Summary Table

		Big Stone		Coyote	
		Variable Costs	Variable Costs Plus Fixed Fuel	Variable Costs	Variable Costs Plus Fixed Fuel
Line		[PROTECTED DATA BEGINS...			
1	No. of Occurrences Consecutive Hours of Operating Loss Exceeds Min Downtime				
2	Cumulative Operating Losses of Hours Identified in Line 1				
3	No. of Occurrences in Line 1 Where Operating Losses Exceeded Startup Costs				
4	Cumulative Operating Losses of the Occurrences Identified in Line 3				
					...PROTECTED DATA ENDS]

While Otter Tail Power appreciates the intent of the above analysis, it is not representative of actual operational effectiveness or historical performance at Big Stone or Coyote. At both Big Stone and Coyote, the above occurrences are a result of the SPP market, building heat requirements, or co-owner requests, requiring the Otter Tail Power share of these jointly owned units to remain online and self-committed.

Full Economic Commitment and Full Self-Commitment Estimate

On January 24, 2022, Otter Tail Power, Minnesota Power, and Xcel Energy met to discuss the Commission requirement that “utilities are to work together to develop a consistent method for estimating the best-case and worst-case potential for economic commitment for each plant.” The utilities have commonly defined a “best-case” scenario to be 100 percent economic commitment and a “worst-case” to be 100 percent self-commitment. In a compliance filing dated December 29, 2025, in Docket No. E999/CI-19-704, the Commission suggested eliminating the “base-case” and “worst-case” naming convention and updating the case names to full economic and full self-commitment. Otter Tail Power chose to utilize the existing and reported data set for this analysis (included in Attachment 2 and Attachment 3), while the other two utilities chose other processes to complete their analysis. The Otter Tail Power analysis is discussed below.

It is important to note, and emphasize, the results of the analysis below are estimates. It is not possible for Otter Tail Power to precisely calculate how the MISO and SPP market might have been committed and dispatched differently under different offer assumptions.

Otter Tail Power developed three cases for both Big Stone and Coyote utilizing historical 2025 market data.

1. **Self-Commitment:** In this analysis, the Otter Tail Power share of the plant was self-committed, on a 24-hour calendar day basis, whenever the unit was not in an outage. Unit dispatch above minimum output was based on historical DA and RT LMP pricing,

utilizing the unit's heat input curve and cost of fuel and reagents. Market revenues were determined based on cleared DA and RT generation and historical 2025 DA and RT LMP pricing. The unit was not available for commitment and dispatch during historical 2025 outage periods. Whenever the unit returned from outage, cold startup costs were applied.

2. Economic – Otter Tail Power share is assumed to be independently committable and dispatchable: In this analysis, the Otter Tail Power share of the unit is assumed to be its own unique generator, independent of co-owner operational considerations. When the unit was online, future commitment and dispatch occur when market revenues exceed variable production costs. When the unit was offline, future commitment and dispatch occur when market revenues exceed variable production costs plus startup costs. Commitment decisions were based on a 24-hour calendar day basis. Commitment and dispatch decisions were based on historical DA and RT LMP pricing, utilizing the unit's heat input curve and cost of fuel and reagents. Market revenues were determined based on cleared DA and RT generation and historical 2025 DA and RT LMP pricing. The unit was not available for commitment and dispatch during historical 2025 outage periods. Whenever the unit returned from offline status, cold startup costs were applied. Forced self-commitment for building heat and testing needs were not enforced.
3. Economic – Otter Tail Power share constrained by unavoidable self-commitment: Case 3 is the same as case 2 except case 3 accounts for instances of unavoidable self-commitment. When 2025 historical instances of unavoidable self-commitment occur, the unit is required to come online regardless of prevailing market conditions. In this analysis, the unit can be committed by either favorable MISO market conditions or unavoidable self-commitment requirements.

Due to the complexities of commitment and dispatch analysis, several simplifying assumptions were required to model the above three case scenarios. Those assumptions are summarized below:

1. Unit commitment decisions were based on a calendar day basis, not an hour-by-hour basis.
2. The unit is only committable in the DA market, not the RT market (theoretically a baseload coal unit could be committed in the RT, but in practice this has very rarely occurred for Otter Tail Power units).
3. Co-optimization of ancillary services is not considered in this analysis. Commitment, dispatch, and market revenues are only based on energy.
4. Ramp rates are not accounted for in this analysis. Hour by hour dispatch was determined solely by market pricing, the unit's heat input curve, and cost of fuel and reagents.
5. Historical derates are not accounted for. It is assumed the unit maintains its full range of normal dispatch, econ min to econ max, for every hour the unit is not on outage. Economic minimum constraints associated with the Big Stone AQCS scrubber train transitions are not accounted for.
6. When an operating day contained one or more hours of outage, the unit's outage was assumed to be for the entire calendar day.

[illegible]

Figure 3
Big Stone Plant 2025 Actual, Full Economic, and
Full Self-Commitment Estimate
Variable Production Costs

[PROTECTED DATA BEGINS...

...PROTECTED DATA ENDS]

Figure 4
Big Stone Plant 2025 Actual, Full Economic, and
Full Self-Commitment Estimate
Variable Plus Fixed Production Cost

[PROTECTED DATA BEGINS...

...PROTECTED DATA ENDS]

Table 12 shows the tabular results of the actual Coyote 2025 historical analysis and modeled Coyote 2025 full economic and full self-commitment estimate analyses. Figures 5 and 6 show the same data in graphical format while also comparing the modeled data against 2025 actual results reported in Table 8.

[illegible]

...PROTECTED DATA ENDS]

Figure 6
Coyote Station 2025 Actual, Full Economic, and
Full Self-Commitment Estimate
Variable Plus Fixed Production Costs

[PROTECTED DATA BEGINS...

...PROTECTED DATA ENDS]

In some instances, the 2025 actual net benefits fall outside of the Full Economic scenario and Full Self-Commitment scenario. As previously noted, development of the above analysis required modeling assumptions and simplifications. The assumption and simplifications can drive divergence from actual net benefits. Furthermore, considering market net benefits are calculated as the difference between market revenues and production costs, where in 2025 production cost cases ranged from \$12 million to \$34 million, the deltas between the actual results and the modeled results do not seem to be excessive. Even though the actual net benefits do not always fall within the bandwidth of the modeled Full Economic and Full Self-Commitment scenarios, they do fall very close to those bandwidths, supporting the reasonableness of the modeling construct.

Hourly details for the Big Stone and Coyote 2025 Full Economic and Full Self-Commitment estimate analyses are included in Attachment 2 and Attachment 3, respectively, on the *Econ Commit BestWorst* tab.

Additional Discussion

Within the context of this docket, Otter Tail Power believes it is vital to highlight, and explain, the analytical value of comparing a plant's production costs against market revenues, and for what purposes that comparison is useful. Otter Tail Power believes there is potential for a misapplication of the production-cost-comparison-to market-price analysis in this docket. This comparison is useful in assessing the flexibility of a plant, but there are many cost-effective plants that have limited operational flexibility and would show "production cost losses", including most non-dispatchable renewable resources and many base load generators.

For illustration, Otter Tail Power performed the same production-cost-comparison-to-market-price for its wind PPA, Langdon II.⁹ The results are proportionally greater production cost losses for the Langdon II PPA than either Coyote or Big Stone:

Table 13 Langdon II PPA Revenues and Costs (OTP MN)			
Year	Total Revenues ¹⁰	PPA Cost	Net Gain / (Loss)
	[PROTECTED DATA BEGINS...		
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			

...PROTECTED DATA ENDS]

Otter Tail Power expects all its wind PPAs (and other utilities' wind PPAs) to show similar, if not larger, negative results under this analysis. This analysis demonstrates the Langdon II wind PPA's (or other PPA's) inability to respond flexibly to market prices and does not indicate the cost-effectiveness of the wind PPA to Otter Tail Power's resource portfolio. Wind generators frequently operate at low market price times and are frequently unavailable at high market price times. However, they produce energy at consistent prices over time and contribute cost-effectively to Otter Tail Power's resource portfolio.

The same has generally been true for Otter Tail Power's baseload resources: they are limited in their ability to respond to market prices. Like the wind generators, they have been able to produce energy at consistent prices over time and contribute cost effectively to Otter Tail Power's resource portfolio.

The questions in this docket aim to address whether baseload resources may operate more flexibly, given that increased flexibility might increase market opportunities in very low market conditions. While it is useful to consider these questions and how flexibility might be increased for the baseload units, baseload resources have limited flexibility in their ability to respond to market prices. If flexibility was the sole operational goal for generation resources, all generators would be natural gas peaking plants or other highly flexible alternatives. Neither renewable generators nor baseload generators fare well under these criteria.

⁹ The Langdon II PPA is intended to serve as a reasonable proof for the point made by this illustration.

¹⁰ Energy, ancillary services, congestion, capacity and other.

The point of the illustration in Table 13 for the Langdon II wind PPA is to critique the implication that “production losses” solely determine cost effectiveness. “Production losses” only demonstrate whether a generator highly responds to market prices: many generators have not been designed for that purpose. The cost effectiveness of a generator requires other analyses of the type generally considered in resource plan proceedings. It involves market price forecasts and other forecasts, capacity expansion modelling, and other considerations.

Applying the production-cost-comparison-to market-price analysis to non-dispatchable renewables, natural gas peaking generators, and baseload generators may provide perspective of the spectrum of flexibility in generation resources. The non-dispatchable renewables have no ability to respond to the market and would fare most poorly to the analysis. Wind generators would likely have a high degree of inverse correlation to market price. Natural gas peaking generators dispatch flexibly in response to changes in market prices and would fare most favorably. Baseload generators fall somewhere in the middle: they were not designed to be flexible but are somewhat dispatchable depending on their specific design characteristics and other considerations. It is certainly reasonable to consider whether it may be possible to increase their flexibility, but the lack of flexibility is not a fair indictment (when taken in isolation) of either renewable or baseload generation units.

The goal of a utility’s resource planning is to manage a portfolio of resources in a way that meets cost, risk, and other objectives. If Otter Tail Power were to focus on cost alone as a resource planning objective, it would focus on the performance of the portfolio of resources under a variety of circumstances over time. Table 14 below reflects the actual cost of energy paid by Otter Tail Power’s customers since 2014. It shows that Otter Tail Power’s customers have benefited from the Company’s consistent and cost-effective portfolio of resources over that period.

Table 14
Net Cost of Energy Paid by Otter Tail
Power Customers since 2014

Calendar Year	Net System Cost of Energy (\$/MWh)
2014	25.15
2015	24.73
2016	23.06
2017	23.78
2018	24.14
2019	23.93
2020	20.30
2021	21.68
2022	25.89
2023	20.75
2024	18.86
2025	21.00 ¹¹

¹¹ Calculation as proposed in Otter Tail’s FCA true-up filing being submitted March 1, 2026, in Docket No. E017/AA-24-65.

The production-cost-comparison-to-market-price used in this docket is useful in considering how greater responsiveness might improve the cost of energy. It should not suggest that renewables and baseload resources should be avoided because they are not adequately responsive to market prices.

Capital Requirements

Attachment A of the January 11, 2021 Order in Docket No. E-999/CI-19-704 requires the Company to provide the capital revenue requirements, or reasonable estimates in approximation thereof, for all generation units. Otter Tail Power operates its system as a whole unit, and while it is possible to approximate a single rate base item, in this case generating units, carving out a single item is a narrow view of the overall impact on the cost of service.

Otter Tail Power provides Table 15 in compliance with this Order Point utilizing December 2024 FERC Form 1 information, which provides the gross plant in service less asset retirement costs [Line 1] per steam plant.¹² The accumulated depreciation [Line 2] was taken from depreciation records as of December 31, 2024. Minnesota share allocation factor is calculated using the base / peak split between E1 and D1. The 2021 allocation factors and rate of return were approved in the 2020 MN Rate Review¹³ and are used for Table 15 calculations.

Table 15
Estimate of Capital Revenue Requirements
Rate Base 2024

	Big Stone	Coyote
Line [PROTECTED DATA BEGINS...		
1		
2		
3		
4		
5		
6		
7		
8		
9		
	...PROTECTED DATA ENDS]	

¹² FERC Form 1, page 402, Total Cost [Line 17] less Asset Retirement Costs [Line 16] by steam plant.

¹³ In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota MPUC Docket No. E017/GR-20-719.

5. CONCLUSION

The following conclusions can be drawn from the analysis conducted:

1. LMP pricing increased substantially in 2025 compared to 2024. The increased pricing was driven, in part, by rising natural gas markets, reduced Manitoba Hydro imports into MISO, and regional congestion. Both Coyote Station, and especially Big Stone Plant, remain in congestion-constrained transmission regions. Despite the ongoing congestion impacts, Coyote Station and Big Stone Plant experienced significant increases in LMP pricing in 2025 as compared to 2024.
2. Even before factoring all other benefits of reliable and dispatchable baseload resources, both Big Stone Plant and Coyote Station provided a significant net benefit to Otter Tail Power customers on a variable cost basis.
3. Otter Tail Power continues to work with its Big Stone and Coyote co-owners to further optimize plant performance.

Big Stone Plant and Coyote Station have both provided over four decades of reliable, dispatchable, and economical energy. Over this time, Otter Tail Power has utilized co-ownership to capture economies of scale, shared benefits, and reduced risk to the benefit of our customers

2025 Actual Big Stone Plant Performance - Variable Costs and Variable Plus Fixed Costs

Row Labels	Net MISO Energy Payment [PROTECTED DATA BEGINS...	ASM Payments	Make Whole Payments	Sum of Variable Production Costs	Sum of Net Variable (Cost) or Benefit	Sum of Variable and Fixed Production Costs	Sum of Net Variable and Fixed (Cost) or Benefit
<1/1/2025							
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Grand Total							

...PROTECTED DATA ENDS]

2025 Big Stone OTP Endorsed Self Commitment Performance
(Outside of Required Building Heat and Plant Testing Periods): Utilization of
Variable Costs

Row Labels	Net MISO Energy Payments [PROTECTED DATA BEGINS...	ASM Payments	Make Whole Payments	Variable Production Costs - OTP Endorsed Self- Commit Hours	Net Variable (Cost) or Benefit - OTP Endorsed Self- Commit Hours
<1/1/2025					
Jan					
Feb					
Mar					
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Grand Total					

...PROTECTED DATA ENDS]

2025 Actual Coyote Station Performance - Variable Costs and Variable Plus Fixed Costs

Row Labels	Net MISO Energy Payments [PROTECTED DATA BEGINS...	ASM Payments	Make Whole Payments	Variable Production Costs	Net Variable (Cost) or Benefit	Variable & Fixed Production Costs	Net Variable & Fixed (Cost) or Benefit
<1/1/2025							
Jan							
Feb							
Mar							
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Grand Total							

...PROTECTED DATA ENDS]

**2025 Coyote Station OTP Endorsed Self Commitment Performance
(Outside of Required Building Heat and Plant Testing Periods): Utilization of
Variable Costs**

Row Labels	Net MISO Energy Payments [PROTECTED DATA BEGINS...	ASM Payments	Make Whole Payments	Variable Production Costs - OTP Endorsed Self- Commit Hours	Net Variable (Cost) or Benefit - OTP Endorsed Self- Commit Hours
<1/1/2025					
Jan					
Feb					
Mar					
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Grand Total					

...PROTECTED DATA ENDS]

Annual Non-Fuel Variable Expenses
(Reagents, Water, Emissions Allowances)

Plant	FYE 2025
Big Stone	Protected Data Begins...
Coyote	...PROTECTED DATA ENDS]

Annual Fixed O&M Expenses

Plant	FYE 2025
Big Stone	Protected Data Begins...
Coyote	...PROTECTED DATA ENDS]

**Otter Tail Power Company
Plant Heat Rates**

Big Stone Plant	2025
	[PROTECTED DATA BEGINS...
Average Heat Rate at economic minimum	
Average Heat Rate at economic maximum	
Coyote Station	2025
Average Heat Rate at economic minimum	
Average Heat Rate at economic maximum	...PROTECTED DATA ENDS]

Only Variable Costs

...PROTECTED DATA ENDS]

...PROTECTED DATA ENDS]

...PROTECTED DATA ENDS]

Only Variable Costs

...PROTECTED DATA ENDS]

...PROTECTED DATA ENDS]

...PROTECTED DATA ENDS]

2025 PURCHASED POWER AGREEMENTS - WIND PURCHASES (MWh)

COMPANY	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
[PROTECTED DATA BEGINS...													
...PROTECTED DATA ENDS]													

2025 PURCHASED POWER AGREEMENTS - CURTAILMENTS (MWh)

[illegible]

...PROTECTED DATA ENDS]

2025 NET GENERATION - OTTER TAIL OWNED (MWh)													
	January	February	March	April	May	June	July	August	September	October	November	December	Total
Langdon Wind	[PROTECTED DATA BEGINS...												
Ashtabula Wind													
Luverne													
Merricourt													
Ashtabula III Wind													

2025 WIND CURTAILMENT - OTTER TAIL OWNED (MWh)													...PROTECTED DATA ENDS]
Langdon Wind	[PROTECTED DATA BEGINS...												
Ashtabula Wind													
Luverne													
Merricourt													
Ashtabula III Wind*													

...PROTECTED DATA ENDS]

*When Ashtabula III was purchased the curtailment tag was not included in the Purchase Agreement. Because of this OTP does not have access to the wind curtailment data. OTP requested the data from Nextera, but there are issues with SCADA and Nextera was unable to provide it at the time of filing. The repower of Ashtabula III should correct this with the issue with the curtailment tag.

CERTIFICATE OF SERVICE

**RE: In the Matter of Otter Tail Power Company's Petition for Approval
of the Annual True-Up for its Energy Adjustment Rider, Rate
Schedule 13.01
Docket No. E017/AA-24-65**

I, Valerie Moxness, hereby certify that I have this day served a copy of the following, or a summary thereof, on Sasha Bergman 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
Compliance Filing**

Dated this 27th day of February 2026.

/s/ VALERIE MOXNESS

Valerie Moxness
Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
Fergus Falls MN 56537
(218) 739-8346

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	24-65AA-24-65
2	Mariah	Bevins	maria.bevins@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	24-65AA-24-65
3	Tom	Boyko	tboyko@eastriver.coop	East River Electric Power Coop.		211 S. Harth Ave Madison SD, 57042 United States	Electronic Service		No	24-65AA-24-65
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6	Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.		12700 West Dodge Road PO Box 2047 Omaha NE, 68103-2047 United States	Electronic Service		No	24-65AA-24-65
7	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	24-65AA-24-65
8	Jason	Decker	jason.decker@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	24-65AA-24-65
9	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	24-65AA-24-65
10	Charles	Drayton	charles.drayton@enbridge.com	Enbridge Energy Company, Inc.		7701 France Ave S Ste 600 Edina MN, 55435 United States	Electronic Service		No	24-65AA-24-65
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12	Michael	Fairbanks	michael.fairbanks@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	24-65AA-24-65
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28	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	24-65AA-24-65
29	Tim	Miller	tim.miller@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	24-65AA-24-65
30	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-65AA-24-65
31	Matthew	Olsen	molsen@otpc.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	24-65AA-24-65
32	Marcia	Podratz	mpodratz@mnpower.com	Minnesota Power		30 W Superior S Duluth MN, 55802 United States	Electronic Service		No	24-65AA-24-65
33	David G.	Prazak	dprazak@otpc.com	Otter Tail Power Company		P.O. Box 496 215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	24-65AA-24-65
34	Rate Case Inbox	Rate Case Inbox	mnratescase@otpc.com	Otter Tail		null null, null United States	Electronic Service		No	24-65AA-24-65
35	Generic Notice	Regulatory	regulatory_filing_coordinators@otpc.com	Otter Tail Power Company		215 S. Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		Yes	24-65AA-24-65
36	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	24-65AA-24-65
37	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	24-65AA-24-65
38	Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC		1742 Patriot Rd Northfield MN, 55057 United States	Electronic Service		No	24-65AA-24-65
39	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN,	Electronic Service		No	24-65AA-24-65

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