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May 1, 2025

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission

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

121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01
Docket No. E017/AA-25-65
Initial Filing

Dear Mr. Seuffert:

Otter Tail Power Company (Otter Tail Power) hereby submits to the Minnesota Public Utilities Commission (Commission) its 2026 Forecasted Energy Adjustment Rider 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 considers trade secret. Otter Tail believes this filing comports with the Commission's Notice relating to Revised Procedures for Handling Trade Secret and Privileged Data, pursuant to Minn. R. 7829.0500. As required by the revised procedures, a statement providing the justification for excising the trade secret data follows this letter.

If you have any questions regarding this filing, please contact me at 218-739-8282 or at cbyrnes@otpco.com.

Sincerely,

/s/ CHRISTOPHER BYRNES
Christopher Byrnes
Supervisor, Regulatory Analysis
Regulatory Economics

vjm
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.

- Portions of Operational Parameters information in Petition;
- Portions of Planned and Forced Outage information in Petition;
- Table 5 of Petition, Otter Tail Plant 2026 Planned Outages;
- Portions of Internal Combustion information in Petition;
- Portions of Wind Generation information in Petition;
- Table 6 of Petition, 2026 Winter Energy Purchase;
- Portions of Wind Curtailment information in Petition;
- Portions of Annual Compliance/Reporting Requirements information in Petition;
- Portions of Attachment 3.1 – Generation and Fuel Forecast details;
- Portions of Attachment 3.2 – Steam and Water Sales forecast details;
- Portions of Attachment 6 – Municipal Sales details;
- Attachment 11 in its entirety – Rule 7825.2830 Annual Five-year Projection 2026-2030;
- Appendix A Section 1.3, Page 5 - Portions of Procurement of Transportation Services;
- Appendix A Section 3, Page 7 - Portions of Forecast discussion;
- Appendix A Section 3, Pages 8-10 – Hedging discussion
- Portions of Attachment 12 – 2022-2024 Actuals Compared to 2026 Forecast
- Portions of Attachment 13 – Unplanned Outages Actuals to Forecast
- Portions of Attachment 14 – 2022- 2024 Bilateral Purchase Actual to Forecast

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: May 01, 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 Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01	**Docket No. E017/AA-25-65**

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 forecasted rates for its Energy Adjustment Rider (EAR) under Otter Tail Power's Rate Schedule Section 13.01 for the calendar year 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 Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01

Docket No. E017/AA-25-65

PETITION

I. INTRODUCTION

Otter Tail Power Company (Otter Tail Power or Company) submits this Petition to the Minnesota Public Utilities Commission (Commission) for approval of its annual forecasted rates for its Energy Adjustment Rider (EAR) under Otter Tail Power's Rate Schedule Section 13.01 for calendar year 2026. This filing is made in compliance with the December 2018 Order to seek approval of Otter Tail Power's proposed EAR rates for 2026.

Otter Tail Power's requested, forecasted average cost of fuel and purchased power for the calendar year 2026 is $0.02794 per kWh. Table 1 below provides the summary of the monthly cost per kWh Otter Tail Power forecasts for 2026.

Table 1
Monthly Forecasted Fuel Cost per kWh For Calendar Year 2026 ($/kWh)[1]

Jan	Feb	Mar	April	May	June
$ 0.03115	$ 0.02780	$ 0.02486	$ 0.02243	$ 0.02218	$ 0.02487
July	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
$ 0.03374	$ 0.03024	$ 0.02575	$ 0.02365	$ 0.03003	$ 0.03576

(1) Monthly values based on calculated fuel cost per kWh rates Attachment 2, Line 17

These forecasted rates are computed on a Minnesota (OTP MN) jurisdictional basis. This method differs from past EAR rates that the Company developed to accommodate Coyote Station (Coyote) conversion to Available Maximum Emergency (AME) status beginning in June of 2026.[1] The updated methodology used in this forecast is further discussed in Section IV.B. of this filing. The Company derives customer-class-specific EAR rates from these amounts by applying class-specific Energy Adjustment Factor ratios to the average monthly rates.

[1] Order Dated July 22nd, 2024 in Docket No. E017/RP-21-339.

In this filing, Otter Tail Power describes the process and associated assumptions used to develop the forecasted costs reflected above in Table 1. Specifically, Otter Tail Power provides: (1) the overall sales forecast and associated assumptions; (2) forecasted costs of fuel, reagents, and associated operations of Otter Tail Power's owned generation; (3) forecasted purchased power costs and associated assumptions; (4) forecasted non-energy wholesale market charges and associated assumptions; (5) forecasted wind curtailment expenses and associated assumptions; (6) forecasted Minnesota direct assigned solar projects and associated assumptions; (7) forecasted asset-based sales; and (8) forecasted costs and revenue from steam and water sales.

Otter Tail Power bases its forecast on reasonable assumptions and information known at the time it develops its forecast, which the Company completed in April of 2025. It is also reasonable to expect that actual results will differ from forecast assumptions. This is especially likely if Otter Tail Power experiences periods of energy market price volatility (as experienced in recent years) and economic uncertainty due to (or exacerbated by) inflation, continued geo-political unrest, and evolving energy markets (changing demand for energy and the sources from which those demands are met). In many cases, those variances are out of the control of Otter Tail Power. In this filing, the Company provides an overview of various risks inherent in the forecasted rates and summarizes potential impacts to the EAR rates should actual results differ from the forecast. Otter Tail Power may submit a refreshed Fuel EAR forecast with its July 31, 2025, Reply Comments if forecasted sales, market conditions, or owned-generation assumptions have changed substantially from this Initial Filing.

Appendix A to this forecast provides further compliance reporting stemming from prior Commission Rules and Orders as they apply to the forecast information provided in this filing.

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
Senior Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
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(218) 739-8774
ldonofrio@otpco.com

C. Date of Filing and Proposed Effective Date of Rates

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

The date of this filing is May 1, 2025. Otter Tail Power proposes the forecasted EAR rates become effective beginning January 1, 2026 as recommended in this Petition following Commission approval. At its April 25, 2019 meeting, the Commission approved a variance to the filing requirement in Minn. R. 7825.2840, allowing Automatic Adjustment of Charges information to be included in this May 1, 2025 filing. The information contained in this filing is submitted in compliance with the aforementioned Rules concerning Automatic Adjustment of Charges, the Commission's June 12, 2019 Order[2] (June 2019 Order) in Docket No. E-999/CI-03-802, and the December 2019 Order.

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. The procedural schedule for this EAR process was adopted by the June 2019 Order.

E. Title of Utility Employee Responsible for Filing

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

Chris Byrnes
Supervisor, Regulatory Analysis
Regulatory Economics
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[2] Order Approving Additional Details of New Fuel Clause Adjustment Process, MN Public Utilities Commission Docket No. E-999/CI-03-802, (June 12, 2019).

F. Impact on Rates

(Minn. Rules 7829.1300, subp 4(F))

The EAR Rates have no effect on Otter Tail Power's current 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 people 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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Regulatory Economics
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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 Minnesota Department of Commerce and the Minnesota Office of the Attorney General, Residential Utilities Division. 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. Otter Tail Power also provides notice of availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in Otter Tail Power's previous two general rate cases as required by the December 2019 Order.[3]

[3] Compliance with the Order Point 6 in the Commission's December 18, 2019, Order in Docket No. E-017/AA-19-297.

IV. DESCRIPTION OF FILING

In *Section A* below, Otter Tail Power provides a summary of the overall forecasted Minnesota jurisdictional sales and forecasted fuel and purchased power costs for January 2026 through December 2026. In *Section B,* Otter Tail Power provides a general overview of Otter Tail Power's EAR forecast process. In *Section C*, Otter Tail Power provides a description of the sales forecast process, and in *Section D*, a description of the EnCompass forecasting modelling software, as well as detail on forecasted fuel, purchased power, and other costs recoverable through the EAR. These descriptions of sales and costs fully support the resulting forecasted rates and fulfill certain Annual Automatic Adjustment (AAA) filing requirements as described in the narrative. *Section E* provides a non-exhaustive list of risks Otter Tail Power, and its customers are exposed to, along with their related impacts. Finally, additional annual compliance and reporting requirements are described and addressed in *Section F* in Appendix A.

A. Summary of Overall Sales, Fuel and Purchased Power Costs

Table 2 provides the forecasted 2026 summary of Minnesota sales in Megawatt-hours (MWhs), Minnesota costs, and the annual average cost per MWh. Attachment 2, Lines 13, 15, and 17 show these costs, sales, and average rates on a monthly and annual basis.

Table 2
2026 Minnesota Sales and Cost

Minnesota Sales (MWh)	Minnesota Cost ($)	Average ($/MWh)
2,758,657	$ 77,084,271	27.94

Table 3 below summarizes the forecasted annual generation by generation type and proportion by generation type (Column C) Otter Tail Power used to meet 2026 load needs. The Company calculates this proportion by dividing the volume supplied per generation type by the Total Generation & Purchases volume (Column B, Line 6).

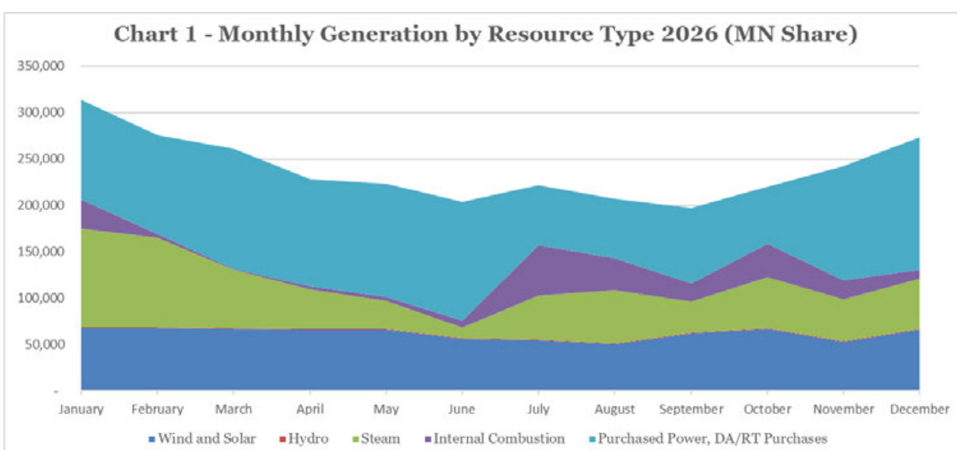
Table 3
Generation Type and Proportion - Minnesota Share

	(A)	(B)	(C)
Line No.	**Generation Type**	**Volume (MWh)**	**Proportion**
1	OTP Steam Generation	643,929	22.4%
2	OTP Internal Combustion (Peaking and Natural Gas) Generation	222,853	7.8%
3	OTP Wind & Solar Generation - Owned	744,938	25.9%
4	OTP Hydro Generation	9,474	0.3%
5	Purchased Power, DA/RT Purchases & Other Market Charges, Wind Curtailment, less Asset-Based Sales	1,252,392	43.6%
6	**Total Generation and Purchases**	**2,873,586**	**100.0%**

(1) Attachment 3.1: Line 26
(2) Attachment 3.1: Line 50 plus Line 55
(3) Attachment 3.1: Line 35 plus Line 42
(4) Attachment 3.1: Line 44
(5) Attachment 3.1: Lines 68 minus Line 70 plus Attachment 5: Line 7

The forecasted Total Generation & Purchases MWhs in Table 3 is greater than the forecasted System Sales in Table 2 due to transmission line losses. Otter Tail Power assumes approximately 6.36 percent for transmission line losses in this forecast. This value is derived from Otter Tail Power's 2021 Line Loss Study.[4]

Chart 1 below is an area graph, which reflects how Otter Tail Power forecasts that each of its generation and energy supply resources will meet customer monthly load needs for 2026.



[4] Order Point 5, Ordered December 18, 2019, in Docket No. E017/AA-19-297.

B. Overview of Forecast Process

Otter Tail Power begins its EAR forecasting process by developing the system sales forecast, which includes the sales forecasts of four municipal communities to which Otter Tail Power delivers energy. The Company then uses sales forecast data, along with forward energy and fuel pricing forecasts, to develop the generation and fuel costs forecast. The generation and fuel costs forecast includes baseload steam generation and associated reagents, internal combustion generation, wind generation, solar generation, hydro generation, purchased power, and asset-based sales. After developing the generation and fuel costs forecast, Otter Tail Power develops the non-energy wholesale market charges, wind curtailment, steam and water sales, and Hoot Lake Solar generation credit forecasts. The Company then uses data from the above listed forecasts to calculate the monthly cost per kilowatt-hour (kWh) forecast. Calculations of the monthly cost per kWh are shown in Attachment 2.

Once Otter Tail Power completes the system forecast, the Company removes non-Minnesota costs and revenues from the system forecast. Non-Minnesota costs and revenues refer to certain system costs that the Commission has determined will not be borne by Minnesota customers, such as Coyote variable costs beginning in June of 2026. The Company then allocates the remaining system costs based on Minnesota's proportion of monthly forecast kWh sales for each month, as shown in Attachment 6. After calculating the Minnesota allocation of shared costs and revenues, the Company then adds Minnesota-specific costs and revenues to the allocated shared costs and revenues. Minnesota-specific costs and revenues are those costs and revenues that the Commission has determined will be borne by Minnesota customers alone, and not shared system-wide, such as Hoot Lake Solar. Finally, Otter Tail Power applies the Minnesota total costs and revenues to the respective monthly Minnesota sales forecast to calculate the monthly EAR rate for Minnesota.

C. Description of Sales Forecast

Attachment 6 provides a summary of the sales forecast Otter Tail Power used in calculating 2026 EAR rates. The sales forecast includes forecasted system retail kWh sales of 5,846,235,663 kWh and forecasted sales to four municipalities of 2,785,473 kWh. The total of these two amounts equals 2026 forecasted sales, 5,849,021,136 kWh. The Minnesota annual jurisdictional sales for 2026 is 2,758,656,715 (provided as MWh in Table 2 above). Otter Tail Power provides a description of Attachment 6 in subparts *1* and *2* of this section below.

1. System Sales Forecast

Otter Tail Power develops its sales forecast using econometric models. The Company uses standard ordinary least squares (OLS) regression models. The purpose of these models is to estimate the relationship between a dependent variable and independent variables (e.g., heating degree days, or Gross Regional Product). These econometric models forecast the average use-per-meter and the number of meters for each customer class using historical sales data and historical number of meters, economic activity, and weather conditions as primary independent variables. The models forecast the Large Commercial class slightly differently, using kWh sales instead of use-per-meter and number of meters. The models also use Month-specific variables to capture any seasonal patterns that are not related to the other independent variables. For all classes except Large Commercial, the models develop monthly sales forecasts by multiplying use-per-meter forecasts by number of meter forecasts for each customer class and jurisdiction. Combining the various jurisdictional class forecasts yields the total system sales forecast.

The econometric techniques utilize 20 years of historical data (2005 through 2024) to produce estimated effects of weather, economic factors, and demographic factors on class usage. The Company then inserts forecast values for the independent values (derived from Woods and Poole economic forecasts or based on weather normal conditions) into the equations to produce forecast values of class-level sales. Attachment 6.a (Sales Forecast Description) provides further detail on the forecasting methodology the Company used in the 2026 sales forecast. Otter Tail Power continues to use a 55 degree threshold for heating degree days (HDD) in this forecast as Otter Tail Power believes it is a more appropriate metric than a 65 degree HDD threshold for Otter Tail Power's load.

2. Municipal Sales Forecast

As noted above, Otter Tail Power delivers energy on a wholesale basis to four small municipalities. The four municipalities are Newfolden, MN; Shelly, MN; Nielsville, MN; and Badger, SD. The Company develops the municipality forecasts, which do not vary much, based on historical information using the average kWh sales of the prior two years. This forecast is provided in Attachment 6.

D. Description of Forecast Modeling Software, Fuel, Purchased Power Costs, and Other Costs Recoverable Through the EAR

In subparts 1. through 6. below, Otter Tail Power provides a description of the modeling software, EnCompass, and reviews the various fuel and purchased power costs applicable to the EAR. Subparts 7.–9. reviews reagent expenses, revenues, and costs associated with steam sales, and credits resulting from Hoot Lake Solar generation, respectively.

1. Overview of EnCompass Modeling Software

Otter Tail Power uses EnCompass (a resource planning modeling software) to perform the majority of its generation fuel, purchased power, and asset-based sales forecasting. EnCompass performs full year, 8,760[5] hourly modeling using the operating parameters for our generating units and using the sales forecast (described in *Section C* above) as the basis to determine the energy requirements for Otter Tail Power's system.

The EnCompass model performs an economic dispatch of available resources to meet energy requirements, considering operational specifications and performance parameters of existing thermal resources (heat rates, maintenance schedules, forced outage rates, and minimum/maximum capabilities), hydro units, owned wind and solar, and power purchase agreements. Price forecasts for oil, coal, and natural gas, as well as forecasted locational marginal prices (LMPs) for the Otter Tail Power load zone (OTP.OTP) are key inputs into EnCompass. The model also uses 'shapes' or 'profiles' for retail sales, energy prices, and renewable generation that help determine retail sales and economic dispatch.

The results of the EnCompass economic dispatch forecast is included in Attachment 3.1 to this filing. Attachment 3.1 includes the MWh and fuel costs associated with generating electricity at our steam and internal combustion (peaking & natural gas) generation plants based on the forecasted dispatch of those plants, as well as wind, solar, and hydro generation, purchased power costs, and asset-based sales.

2. Overview of Generation Types and Associated Costs

a. Steam Generation

i. Operational Parameters

In April of 2020, the owners of Big Stone Plant agreed to a methodology to allow the operation of Big Stone Plant to be offered into the Midcontinent Independent System Operator (MISO)/ Southwest Power Pool (SPP) markets on an economic dispatch basis. This methodology includes weekly, bi-weekly, or as-needed meetings with all Co-Owners (Otter Tail Power Company, Montana-Dakota Utilities Co., and NorthWestern Energy) to review the economic

[5] 24 hours per day by 365 days per year.

dispatch or self-commitment status of Big Stone Plant. In this 2026 forecast for Big Stone Plant, the EnCompass modeling reflects self-commitment at minimum output, while allowing for market driven dispatch above minimums, for **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. Please note, all Big Stone Plant Co-Owners maintain the contractual right to request the plant to be self-committed for any reason, at any time.

Otter Tail Power is a Co-Owner of Coyote Station with Minnkota Power Cooperative, Montana-Dakota Utilities Co., and Northwestern Energy. In April of 2021, the Co-Owners of Coyote Station developed and implemented capability to offer the plant under an economic offer. As with Big Stone Plant, each Coyote Co-Owner maintains the contractual right to request self-commitment. For Coyote Station, the EnCompass modeling reflects self-commitment at minimum output, while allowing for market driven dispatch above minimums for **[PROTECTED DATA BEGINS...**

...PROTECTED DATA ENDS]. Otter Tail Power will continue to monitor the commitment of the plant and adjust appropriately to reflect plant operations in future forecasts. In Otter Tail Power's last IRP, Otter Tail Power was ordered to place Minnesota's portion of Coyote on Available Maximum Emergency (AME) by June 1, 2026. This was implemented in this year's EAR model by creating a timeseries for the net dispatch limit of Coyote to equal the sum of North Dakota, and South Dakota's allocations, effectively removing Minnesota's allocation from the model, of the plant starting June 1, 2026. Allocations for each jurisdiction were determined by using E2 allocations which are billed kWh sales with no adjustments for load control but does include line losses.

ii. Fuel Supply

Steam plant costs are related to coal and fuel oil costs for our Big Stone Plant and Coyote Station. A large factor in determining the economic dispatch of the steam generation plants is the forecasted Locational

Marginal Price (LMP) for the OTP.OTP load zone. Otter Tail Power calculates forward day ahead OTP.OTP load zone pricing using forward, day ahead Indiana Hub pricing (both monthly peak and monthly off peak) and including a basis adjustment from Indiana Hub to the OTP.OTP load zone. Based on historical deltas between the OTP.OTP load zone and the Indiana hub, Otter Tail Power forecasts a future basis to predict forward pricing at OTP.OTP. Otter Tail Power acquires forward day ahead Indiana Hub pricing from the Intercontinental Exchange (ICE) website.[6] ICE is a subscription-based trading platform that offers historical, current, and forward pricing information for numerous commodities including energy, natural gas, and oil. The Company based the 2026 forecast on the forward, day ahead Indiana Hub price curve dated March 13, 2025. Otter Tail Power provides this information in Attachment 7.

Otter Tail Power has several coal contracts in place to maintain low coal costs for its coal burning generating facilities. The primary coal supply agreements are listed in Table 4 below.

Table 4 – Primary Coal Supply Agreements

	(A)	(B)	(C)	(D)
Line No.	**Plant**	**Coal Supplier**	**Type of Coal**	**Expiration Date**
1	Big Stone Plant	Navajo Transitional Energy Company, LLC	Wyoming subbituminous	December 31, 2026
2	Coyote Station	Coyote Creek Mining Company, L.L.C.	North Dakota lignite	December 31, 2040

Otter Tail Power entered into the current coal purchase agreement with Navajo Transitional Energy Company, LLC in November 2024 for the purchase of subbituminous coal for Big Stone Plant's coal requirements through December 31, 2026. Otter Tail Power has no fixed minimum purchase requirements under this agreement but Big Stone Plant's coal requirements for the period covered must be wholly purchased under this agreement.

[6] ICE website: https://www.theice.com/index.

In October 2012, the Coyote Station owners, including Otter Tail Power, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of North American Coal Corporation, for the purchase of coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040. The price per ton being paid by the Coyote Station owners under the LSA reflects the cost of production, along with an agreed profit and capital charge. The LSA requires the Coyote Station owners to purchase the membership interests in CCMC in the event of certain early termination events and at the end of the term of the LSA.

Beginning in May 2024, Coyote Station began using a fuel additive in 2024 that improves boiler efficiency by reducing the buildup of slag in the boiler and therefore reducing the frequency and associated cost of boiler washes. The fuel additive is added at an equivalent rate of about $1.95/ton of fuel, and therefore the usage rate cost is $106,000 /month OTP total. The Company will no longer recover the cost of this additive and the other Coyote reagents from Minnesota ratepayers after June of 2026 unless Coyote is called upon under AME events.

iii. Planned and Forced Outages

Another set of key factors that affect the Company's forecast is planned and forced outages of Otter Tail Power's coal generation plants. Otter Tail Power determines the timing of planned outages and overhauls by the length of service required between them. Based on operating history, plant personnel have a good understanding of the length of time between operational periods before the boiler or other systems will need to be cleaned or maintained while off-line. Larger scheduled outages, referred to at times as overhauls, are scheduled in approximately three-year intervals or when significant outages are needed for certain projects. Table 5 below summarizes Otter Tail Power's planned plant outages for Big Stone Plant and Coyote Station in 2026.

Table 5 – Otter Tail Plant 2026 Planned Outages

	(A)	(B)	(C)	(D)
Line No.	**Outage Start**	**Outage End**	**Plant**	**Duration & Type**
[PROTECTED DATA BEGINS…				

…PROTECTED DATA ENDS]

Plant outages, whether planned or unplanned, have an impact on Otter Tail Power's expected EAR-related costs. These impacts are generally the difference between the costs of generation at one of Otter Tail Power's owned facilities and the costs of purchasing energy supply in some way in the market. The Company determined its estimated planned outage cost in the forecast by using a modeling run removing the planned outage variables from the EnCompass base case model scenario. The resulting difference between the base case EnCompass run and the run without the planned outage variables was **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**. This signifies that the cost of purchasing in the market is higher than generating at the plant. Otter Tail Power schedules planned outages to minimize added costs of energy and typically schedules these outages in the spring or fall when energy usage is generally lowest.

The forecast also includes forced outage rates for each plant based on six years of historical data. Otter Tail Power used a six-year average (2019 to 2024) Equivalent Demand Forced Outage Rate for each plant as the forced outage input in the forecast. The Company includes forced outage rates in the forecast to reasonably account for costs associated with potential unplanned outages, and to plan for the effect unplanned outages have on rates. Otter Tail Power estimated forced outage costs in the forecast similarly to how it estimated planned outage costs. The Company removed forced outage rates for each of the thermal plants from the base case and ran the EnCompass model. The difference between the base case EnCompass run and the run without forced outage rates of all thermal plants was **[PROTECTED DATA BEGINS… …PROTECTED DATA ENDS]**.

b. Internal Combustion

Internal combustion plant costs are related to fuel oil costs (for Otter Tail Power's Jamestown #1 and #2 and Lake Preston peaking plants) and natural gas fuel costs (for Otter Tail Power's Solway and Astoria Station natural gas-fired peaking plants).

The Company forecasts fuel oil costs based on a Wood-Mackenzie fuel oil forecast. The forecasted fuel oil cost used in the 2026 forecast is **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** per gallon.

Fuel cost and forecasted output from Astoria Station is a major variable and assumption in this forecast. Astoria's operational timing, and ability to provide economical and dispatchable energy, will have a large impact on the Company's natural gas fuel costs. Natural gas prices play a vital role in the economic dispatch and costs associated with Astoria Station and Solway. At the same time, due to uncertainty with regard to the amount of dispatch of these plants, Otter Tail Power generally procures gas for its Solway and Astoria plants on a day-ahead or intra-day basis.

Like forward energy pricing described earlier, Otter Tail Power acquires forward natural gas pricing curves from the ICE website. Ventura hub, located in northern Iowa, is the most liquid natural gas trading hub in our region. Daily, ICE posts forward natural gas price curves for Ventura hub. For forecasting purposes, Otter Tail Power uses the forward Ventura curve for both Solway and Astoria. For this forecast, Otter Tail Power used the forward natural gas price curve dated March 13, 2025. This information is provided in Attachment 8 to this filing.

Astoria Station is located on the Northern Border Pipeline. Unlike the Great Lakes Pipeline, where Otter Tail Power's existing Solway plant is located, the Northern Border Pipeline has higher requirements and tighter tolerances for balancing daily nominations and withdrawals of gas. Due to the highly variable and intermittent nature of a simple cycle gas turbine, differences between the gas and electric trading days, and changes between the MISO day ahead forecast and actual real time operations, Otter Tail Power continues to use Park and Loan (PAL) service for its natural gas supply. PAL is the Northern Border Pipeline balancing service. This service allows an entity to "park" excess gas in the pipe to be consumed later, or to be "loaned" gas from the pipe to be replaced later. The PAL service Otter Tail Power procures allows for additional supply availability, enhanced operational flexibility, and enables Astoria to better operate within required Northern Border operating tolerances.

2025 Astoria PAL service levels allow for a **[PROTECTED DATA BEGINS…**

…PROTECTED DATA ENDS] As with prior forecasts, the PAL service costs are included in the forecast.

c. Wind Generation

Otter Tail Power has a significant portfolio of wind generation, both from an owned-wind perspective and from wind purchase power agreements. Otter Tail Power's owned wind generation contributes to the energy output for the Company's generation system with no associated fuel costs. Otter Tail Power's existing owned wind generation fleet consists of the Merricourt (150 MWs), Langdon (40.5 MWs), Ashtabula (48 MWs), Ashtabula III (62.4 MWs), and Luverne (49.5 MWs) wind energy facilities. The Company forecasted generation output from the Langdon, Ashtabula, Ashtabula III, and Luverne wind farms based on an hourly generation profile that reflects the average historical performance of each facility and adjusted this forecast based on the Re-Power upgrades. The Company forecasted Merricourt based on a forward-looking hourly generation profile that reflects expected facility performance.

d. Hydro Generation

Like wind generation, hydro generation also contributes to the energy output for Otter Tail Power's generation system without associated fuel costs. The Company's Hydro generation is sourced from the following facilities: Dayton Hollow, Hoot Lake, Pisgah, Taplin Gorge (Friberg), and Wright (Central). Otter Tail Power forecasts generation for our hydro plants using historical averages. Hydro generation is included in Attachment 3.1, Line 44.

e. Solar Generation

Otter Tail Power completed the construction of our 49.9 MW Hoot Lake Solar project in August of 2023, near Fergus Falls, Minnesota. This project provides zero fuel cost energy output. At the Commission's March 25, 2021 meeting in Docket No. E017/M-20-844,[7] the Commission approved Otter

[7] In the Matter of Otter Tail power Company's Petition for Approval of the Hoot Lake Solar Project.

Tail Power's request to fully allocate to Minnesota the output and costs of the Hoot Lake Solar project. Subpart *9.*, below, describes Otter Tail Power's previously approved methodology (from a forecast perspective) to fully allocate the zero-fuel cost output from Hoot Lake Solar to Minnesota customers.

Otter Tail Power also completed two smaller solar projects in 2020: Blue Jay Solar in Jamestown, North Dakota, and Blue Heron Solar near the city of Ottertail, Minnesota. Each of these facilities is approximately 40-kilowatts (kW) in capacity. Otter Tail Power includes these in the small co-generation line on Attachment 3.1 for forecasting purposes. Small co-generation is described further below.

Otter Tail Power completed the construction of fifteen small scale solar projects in 2024 in compliance with the Commission's January 26, 2024 Order in Docket No. E017/M-23-338. These projects provide zero fuel cost energy output and progresses Otter Tail Power's compliance toward the Small-Scale Solar Energy Standard (SES). Otter Tail Power includes the forecasted generation for these projects in the Minnesota Solar Generation Credit line in Attachment 2.

3. Purchased Power

As a member of MISO, each day Otter Tail Power offers all its available generation into the MISO market and acquires all its energy from the MISO market. From a cost of energy perspective, the proceeds from the sale of the Company's generation into the market offsets costs associated with energy withdrawals for load. In instances where the Company's load is greater than its combined dispatched generation and existing purchased power amounts, Otter Tail Power procures the remaining energy from the market. The Company determines forecasted market purchases using the EnCompass model. The model projects hourly economic dispatch of generation where the forecasted hourly market prices are compared to the marginal cost of Otter Tail Power's thermal units. If the hourly market price is less than the marginal cost of Otter Tail Power's units, the model reflects an hourly market purchase (subject to self-commitment and minimum run restrictions on the thermal units).

In addition to purchases from the MISO market, purchased power costs also include energy purchases from our Edgeley (21 MWs) and Langdon (19.5 MWs) Wind Purchased Power Agreements (PPAs). Otter Tail Power also acquires energy from shared loads, small co-generation,[8] and bilateral purchases. These are provided in detail in Attachment 3.1, Lines 99-105, excluding Line 101.[9] The costs for these PPAs are set forth in the PPAs as a price per MWh for all output. The Company forecasts the generation output of the PPA facilities using an hourly generation profile that reflects the average historical performance of each facility.

For the 2026 operating year, Otter Tail Power also procured winter energy delivered to MINN.HUB. The Company procured the energy at a package price of [**PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]** across all MWhs of the purchase period. For Encompass modeling purposes, the model equivalized this purchase to the OTP.OTP load zone utilizing the historical basis between OTP.OTP and MINN.HUB and MINN.HUB forward pricing as of March 13, 2025. This purchase is detailed in Table 6 below and is embedded in Attachment 3.1, Line 97, Bilateral Purchases.

Table 6
2026 Winter Energy Purchase

Time Frame	MWs	MINN.HUB Purchase Price ($/MWh)	Equivalent OTP.OTP Valuation ($/MWh)
[PROTECTED DATA BEGINS...			
		...PROTECTED DATA ENDS]	

Otter Tail Power procured this energy as a hedge to protect customers against the historic volatility of energy markets primarily driven by natural gas pricing during the winter months (December, January, February) and the corresponding impacts natural gas prices have on energy prices. Under existing market conditions, the price of natural gas is a large driver in energy market pricing. The

[8] Due to small size, these Small Co-Generation purchase agreements are modeled as a group for forecasting. These agreements are less than 20MW, generally under 2MW,. Otter Tail Power will provide details for actuals in the True-Up filing in this Docket.
[9] Attachment 3, Line 101 is for Tribal (WAPA)-related energy purchases, which are not subject to the EAR.

volume hedged for December 2026 reflects the change in operations at Coyote Station under AME for Minnesota's share of the plant.

Customers benefited from a competitive energy market where multiple parties provided competitive offers at both the OTP.OTP load zone and MINN.HUB. Ultimately, the MISO market will fulfill this purchase, and the counterparty will make Otter Tail Power financially whole to the above stated contract price under a contract for differences (CFD) arrangement.

4. Fuel Costs of Asset-Based Sales and MN Asset-Based Margins

In certain situations, Otter Tail Power may sell more energy into the market from its generation fleet than what the Company needs to serve its own load. In these situations, Otter Tail Power credits any asset-based margins that it realizes to the EAR rate calculation. Asset-based margins are the net difference between asset-based sales and the fuel cost of sales associated with asset-based sales. Similar to market purchases, forecasted asset-based sales are derived from the hourly economic dispatch where the hourly market prices are compared to the marginal cost of Otter Tail Power's thermal units (that are running to meet customer load). If the hourly market price is more than the marginal cost of Otter Tail Power's generating units (and the unit generation is not needed to meet customer need), the Company assumes its generation unit will be dispatched and registers an hourly asset-based sale. Forecasted fuel costs of asset-based sales and asset-based margins are included on Attachment 3.1, Lines 108 and 110, respectively.

5. Wind Curtailment

On occasion, when there is an abundance of energy available to the market relative to demand for energy, hourly LMP prices at generators can become negative. In those situations, the generator pays for (as opposed to being paid for) the generation it sells into the market. To avoid having to pay the negative LMP price, wind generating facilities are sometimes taken offline. Some of Otter Tail Power's wind PPAs have curtailment payment provisions included in the agreement. These payments offset a portion of the lost production the generator realizes when the units are taken offline.

Otter Tail Power developed its 2026 monthly forecasted wind curtailment MWhs using the monthly average of the available actual wind curtailment MWhs for the wind PPAs subject to wind curtailment. The Company then determined forecasted wind curtailment costs by multiplying the forecasted monthly MWhs by the 2026 blended forecasted annual average cost per MWh of Otter Tail Power's wind PPAs subject to wind curtailment.

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS] The forecasted wind curtailment cost calculation is included in Attachment 5.

6. Wholesale Market Charges

Forecasted wholesale market charges consist of numerous charges and credits Otter Tail Power is subjected to as a participant in the MISO and the SPP energy markets. This subset of wholesale market charges/credits does not include the primary charges/credits associated with the injection of energy (generation) and the withdrawal of energy (load), as these charges are captured in other sections of this forecast.

This forecast includes approximately 70 MISO and SPP wholesale market charge types. The Company forecasts each charge type individually. The primary methods Otter Tail Power uses to forecast the different charge types vary according to the charge type and include averaging, application of calculated historical rates, and scaling to meet forecasted loads. The Company based all forecasting methods on historical data and future projections. For historical data, Otter Tail Power used the most recent 24 months of available data, which included April of 2023 through March of 2025.

In some cases, Otter Tail Power has chosen to customize certain charge type forecasts to account for known, and unique, historical events and market conditions.

The Company categorized the individual charge types into three base tables/categories: MISO Wholesale Market Charges (Non-Energy); MISO Ancillary Services Market (ASM) Charges; and SPP Wholesale Market Charges (Non-Energy). A description of each category is provided below.

- <u>MISO Wholesale Market Charges (Non-Energy)</u>: This category forecasts numerous, miscellaneous MISO wholesale charges and credits including uplift charges, make whole payments, financial transmission rights charges and credits, real time miscellaneous charges, etc. This summary also includes forecasting for net congestion and net loss charges and credits. These are charges and credits associated with moving energy from Otter Tail Power generation resources to Otter Tail Power load. The charge types and associated forecasted charges/credits for this category are provided as Attachment 4.1 to this filing.

For completeness, the Company provided forecasted amounts for the Day Ahead Market Admin, Real Time Market Admin, and FTR Market Admin (Schedules 16 and 17) charge types (Attachment 4.1, Line 18). However, these amounts are not included in the 2026 EAR calculation, as they are currently recovered in Otter Tail Power's base rates. Total Forecasted MISO Wholesale Charges (Attachment 4.1, Line 61) does not include these amounts. They are provided as informational only.

Otter Tail Power adjusted six of the wholesale market charges to account for the transfer of Coyote to AME status beginning in June of 2026. The six charges adjusted are Real Time Congestion, Real Time Losses, Day Ahead Congestion, Day Ahead Losses, Hourly FTR Allocation, and Monthly FTR Allocation Amounts. In the previous three years the Coyote Share of these charge types was approximately 13.42 percent. The Company removed this amount from the system total for the charges and then allocated the charges to Minnesota's share. Otter Tail Power will adjust any difference between the forecast amount and actual amount in the True-Up Compliance filing in this docket.

- <u>SPP Wholesale Market Charges (Non-Energy)</u>: The primary drivers of the SPP wholesale market charges forecast are the Real-Time Over Collected Losses Distribution Amount, the Real-Time Pseudo-Tie Congestion Amount, the Real-Time Pseudo-Tie Loss Amount, the Auction Revenue Rights Daily Amount, and the Auction Revenue Rights Annual Closeout Amount. These charge types are the result of Otter Tail Power's required SPP transmission service necessary to serve Otter Tail Power's pseudo tied load within the SPP footprint. This category also forecasts other numerous, miscellaneous SPP wholesale charges and credits. The charge types and associated forecasted charges/credits for this category are provided as Attachment 4.2 to this filing.

- <u>MISO ASM Market Charges</u>: This category forecasts MISO ASM charges and credits, including regulation reserves, spinning reserves, supplemental reserves, and short-term reserves, both withdrawn by Otter Tail Power load and produced by Otter Tail Power generation. It also includes other miscellaneous charges associated with the ASM market. The charge types and associated forecasted charges/credits for this category are provided as Attachment 4.3 to this filing.

7. Reagents

Otter Tail Power's coal-fired generation facilities, Big Stone Plant and Coyote Station, use substances called reagents to process emissions and are necessary for compliance with federal regulations enforced by the Environmental Protection Agency. These reagents include anhydrous ammonia, pebble lime, powder activated carbon, and magnesium oxide. Forecasted reagent expenses are included in Attachment 3.1, Line 135. The Company determined the forecasted reagent expenses using a forecasted cost per MWh for each applicable reagent and multiplying that by the forecasted output (MWh) of the applicable facility, including Coyote Station being dispatched as an AME resource beginning June 1, 2026.

8. Costs and Revenues Associated with Steam/Water Sales

Otter Tail Power sells steam and water from its Big Stone Plant to a geographically adjacent, non-affiliated company. The 2026 forecasted steam/water sale expenses and revenues are included on Attachment 3.2, Line 13. Steam/water sale expenses and revenues were forecasted by Big Stone Plant employees, who have the best knowledge and experience with the facility's steam sales. The revenue forecasts consider many factors, including: the customer's needs and forecasts provided by the customer, contractual agreements between Big Stone Plant and the customer, and Big Stone Plant's forecasted operational output and ability to provide steam/water. The expense forecast is derived from the revenue forecast. The Company forecasts the amount of coal burned based on the measured energy and boiler efficiency. Reagent amounts attributable to steam sales are determined in proportion to the amount of forecasted coal burned. The amount of coal and reagents forecasted to be used, tons and/or lbs., is then multiplied by a forecasted $/ton or $/lb. to arrive at the system forecasted costs. The system forecasted costs are applied to the Minnesota allocator on Attachment 3.1, Line 11 to calculate Minnesota's share of steam and water sales.

9. Minnesota Solar Generation Credit

In Docket No. E017/M-20-844, the Commission approved Otter Tail Power's request to fully allocate to Minnesota the output and costs of the Hoot Lake Solar project. In this filing, Otter Tail Power calculated the Minnesota EAR rate on a jurisdictional basis. Due to this change, the methodology for calculating the Hoot Lake Solar as well as the addition of the Small Scale Solar projects, the Company used the Encompass model to perform the 2026 forecast fully included in for Minnesota. The credit for Minnesota specific solar generation is included in Attachment 2 Line 9.

10. MISO Planning Resource Auction Results

The Commission's Order dated December 29, 2022, in Docket No. E017/AA-22-214 required Otter Tail Power to include actual known MISO Planning Resource Auction (PRA) costs and revenues in the EAR. The 2024/2025 planning year results were only $555,000, of which the January to May 2025 revenues will be included in the 2025 recovery year True-up Filing. Results for the MISO June 2025/ May 2026 planning year auction will be known sometime in late April or early May 2025. Should the June to December 2025 results be materially different, Otter Tail Power will update its 2025 rates to include known (anticipated) revenues in the following month after the results are known. If the results are not immaterially different, Otter Tail Power will include the 2025 portion of those revenues in the 2025 annual True-up Filing. The Commission waived the 30-day notice of a significant event filing for the inclusion of these costs and/or revenues.

No estimated PRA costs or revenues for the 2026 portion of the June 2025/May 2026 MISO planning year are included in this EAR forecast due to uncertainty in the ability to forecast those results. Once the Planning Year 2025/2026 results are known, if they are materially different, Otter Tail Power will include the 2026 portion of those results in the forecast and provide updated rates with our July 31, 2025 Reply Comments in this Docket.

E. Risks (Mitigation)

Otter Tail Power manages its supply resource portfolio to cost-effectively meet energy needs while maintaining flexibility and reasonably limiting the risk of exposure to variability in the availability and cost of resources. Some risk mitigation strategies include forward procurement of energy or fuel supplies, having a diverse owned generation supply (thermal, wind, solar, hydro), and having the ability to procure the energy needed from the broader MISO market when necessary or when economically beneficial. Despite these strategies, there remains inherent risk of separation between forecasted costs and actual costs that is either difficult or outside of the Company's control to manage.

Table 7 below identifies key variables or assumptions that could impact actual costs relative to forecasted costs that may have a five percent or greater impact on the fuel cost per kWh. Within the table, Otter Tail Power identifies the risk [Column A], a description of the risk [Column B], and potential impact on the fuel cost per kWh [Column C].

Table 7
Risk Matrix

Line No.	(A) **Variable**	(B) **Risk**	(C) **Potential Impact on cost/kWh**
1	Sales	Actual sales differ from forecasted sales.	Increases in sales may result in more reliance on market purchases – potentially at higher-than-average cost. Lower sales may reduce market purchases and lower average cost.
2	Weather	Weather drives usage higher or lower than forecasted	Colder or hotter weather than normal can increase demand for energy- may result in more purchases from the market.
3	Natural Gas Prices	Actual gas prices differ from forecasted prices. Generally, gas is procured on a short-term (day ahead) basis due to uncertainly of dispatch of Otter Tail Power's gas generation and limiting the ability to hedge price.	Otter Tail Power is exposed to price variances, which could increase or decrease costs relative to forecast.
4	Locational Marginal Prices (Market Prices)	Actual prices differ from forecasted prices, which impact both dispatch of generation and cost of purchases from the market.	Cost of market purchases could be higher or lower than forecasted.
5	Wind	The forecast includes a certain amount of wind generation for both Otter Tail Power's owned wind resources and for certain PPAs. Variance from the forecast will impact the cost of energy.	If our owned wind resource generation is less than forecasted, we will replace it with a resource that has a higher cost. If our owned wind generation is greater than forecasted, energy will be supplied at lower average cost. If our Wind PPAs do not produce as much energy as forecasted, the EAR-related cost per kWh could be higher or lower depending on the market purchase price comparison needed to replace the Wind PPA price.
6	Solar	The forecast includes a certain amount of solar generation. Variance from the forecast will impact the cost of energy.	If our owned solar resource generation is less than forecasted, we will replace it with a resource that has a higher cost. If our owned solar generation is greater than forecasted, energy will be supplied at lower average cost.

7	Market Purchases	Market prices may either be higher or lower than forecasted which will impact the overall fuel cost per kWh.	Entering into PPAs creates price certainty and reduces rate volatility. Certainty of pricing comes at a premium cost. Otter Tail Power's supply portfolio is described throughout this Petition and includes an all-of-the-above strategy. Otter Tail Power relies on the market to supply a certain amount of energy for its customers. This approach exposes Otter Tail Power to potential volatility in the market but also helps us mitigate EAR-related costs.
8	Unplanned Outages at Otter Tail Power Generating Facilities	More outages than forecasted could potentially increase exposure to market purchases.	Cost of additional market purchases could be higher or lower than the cost of generation.
9	Freight Prices	Railroad tariffed rates can change, which can impact the cost of fuel.	The coal freight prices used for Big Stone Plant are based on current tariffed rates. These rates can be adjusted by the railroad, affecting actual fuel cost per kwh.
10	Asset-Based Sales and Margins	The relation of market prices to the cost of Otter Tail Power's owned generation resources is different than forecasted and results in lower Asset-Based Sales and Margins than forecasted.	Creates less of a credit to the EAR calculation, increasing overall cost per kWh.

F. Annual Compliance/Reporting Requirements

In Appendix A to this filing, Otter Tail Power provides certain annual reporting requirements specified in the Rule sections described below to satisfy compliance obligations stemming from either these Rules or prior Commission Orders. The Commission granted rule variances for these rules[10] to align with the new forecasting and true-up mechanisms, filing timings, and reporting requirements. Otter Tail Power's compliance with requirements ordered[11] in Docket No. E017/AA-19-297 is also discussed below.

Minn. R. 7825.2800 Annual Report: Policies and Actions

Appendix A Section 1 includes the following and a summary of the topics listed in the rule:

Section 1.1 Fuel Procurement Practices

Section 1.2 Fuel Utilization

Section 1.3 Procurement of Transportation Services

[10] Order dated June 12, 2019, in Docket No. E-999/CI-03-802.

[11] Order Approving 2020 Fuel Forecasts dated December 18, 2019.

Minn. R. 7825.2810 Annual Report: Automatic Adjustment of Charges

Appendix A Section 2 contains a summary of the annual reporting (by month) of all forecasted electric automatic adjustment charges for the forecast period January 1, 2026, to December 31, 2026. It includes the following:

Appendix A Section 2 Subpt. 1.A. Commission Approved Base Cost of Fuel
Appendix A Section 2.1 Subpt. 1.D. Total Cost of Fuel Delivered to Customers

Additional Reporting Requirements

Additional Reporting Requirements as Ordered by the Commission are also provided in Appendix A in the following sections:

Appendix A Section 3	Passing MISO Day 2 Costs Through Fuel Clause Order in Docket No. E017/M-05-284
Appendix A Section 4	Southwest Power Pool (SPP) Energy Market Related Costs – Order in Docket No. E017/GR-15-1033
Appendix A Section 5	MN DOC'S Review of 2005/2006 AAA Report Docket No. E,G999/AA-06-1208
Appendix A Section 6	MN PUC ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS DOCKET NOS. E999/AA-09-961 and E999/AA-10-884
Appendix A Section 7	MN OES'S Review of 2006/2007 AAA Report Docket No. E,G999/AA-07-1130

Minn. R. 7825.2830 Annual Five-Year Projection

Attachment 11 contains a monthly five-year projection of fuel cost by energy source marked as Not Public.

Minn. R. 7825.2840 Notice of Reports Availability

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

Additional Requirements Ordered December 18, 2019, in Docket No. E017/AA-19-297

Order Point 2 – Otter Tail Power shall identify any and all variables for which Otter Tail Power's Strategist run outcome would be inconsistent with the historical data of the variable and describe and justify any and all steps used to address the inconsistency issue(s).

Otter Tail Power no longer uses Strategist and has switched to EnCompass. Most variables/inputs in Otter Tail Power's EnCompass modeling are consistent with historical data of the variable. The inputs that vary from historic data are provided below. All the variances are the result of known and measurable changes or reasonably anticipated changes provided from reliable resources Otter Tail Power uses in its forecasting (i.e., Wood-Mackenzie forecasts, Intercontinental Exchange (ICE) trading platform forecasts, Woods and Poole economic forecasts, etc...).

- <u>Otter Tail Power's forecasted owned-solar generation:</u> Hoot Lake Solar was deemed commercially operational in August of 2023.
- <u>Forecasted LMP and Natural Gas Energy Pricing:</u> 2026 forecasted LMP and Natural Gas prices are significantly higher than historical 2023 and 2024 prices, and more in alignment with the higher prices experienced in 2022. Otter Tail Power has used the most recent forecasts available for this forecast. This has resulted in a twelve percent decrease in the forecasted Otter Tail Power Internal Combustion generation.
- <u>Asset-based sales:</u> The 2026 forecasted asset-based sales are higher than historical asset-based sales due to the interdependent relationship of all the 2026 EnCompass model inputs and was the result of the EnCompass model determining there were more instances where an asset-based sale would be made in this 2026 forecast compared to recent history. The 2026 forecasted asset-based sales amount is $9.1 million.
- <u>Steam Plant Reagents and Steam/Water Sales:</u> As mentioned previously, Otter Tail Power includes forecasted steam plant reagent expenses and steam/water sales in this forecast reflective of the Commission's approval in the 2020 Rate Case.

The items listed above, along with all other EnCompass inputs/variables identified earlier in this Petition, result in an overall decrease in Otter Tail Power-owned Steam generation output, increased Purchased Power, increased Wind/Solar generation output, and decreased Internal Combustion MWh for 2026, compared to recent history. The 2026 EnCompass forecast modeling results are consistent with what Otter Tail Power expects to occur as its served load and generation resource fleet continues to evolve.

Order Point 3 – Otter Tail Power shall provide as public data the historical system sales and their breakdown by customer class, except for classes for which private customer usage could be derived.

The sales forecast data included in Attachment 6 to this filing is public data. Otter Tail Power has aggregated individual large customer data into the appropriate customer classes to prevent private, customer usage from being derived. Total forecasted sales of the four municipalities are provided as public data in Attachment 6; however, sales specific to each municipality is protected.

Order Point 4 – Otter Tail Power shall provide as public data the total historical net system FCA costs, including their breakdown by major components.

Total forecasted net system FCA (EAR) costs and their breakdown by major component are included as public data in Attachment 2. Otter Tail Power has two coal-fired generation facilities, Big Stone Plant and Coyote Station. To prevent disclosure of individual, private, plant data, especially when one of those generating facilities has a forecasted planned outage, the highest level of monthly data granularity Otter Tail Power can provide as public data in Attachment 3.1 is to the Total OTP-Owned level. Annual totals for the major components are provided as public data.

Order Point 5 – Otter Tail Power shall update its 2010 internal line losses study and incorporate that information into the 2021 Forecast.

This compliance obligation was satisfied in the 2021 MN EAR Forecast Filing, which was approved by the December 2020 Order. Otter Tail Power updated its line losses study and incorporated the results into the 2021 MN EAR Forecast. These updated parameters have been included in subsequent EAR forecasts.

Order Point 6 - The variance to Minn. Rules 7825.2840 is revised as follows: By September 1 of each year, gas utilities and by March 1 and May 1 of each year, electric utilities shall provide notice of availability of the reports defined in parts 7825.2800 to 7825.2830 to all intervenors in the previous two general rate cases.

Otter Tail Power has included all intervenors from its previous two Minnesota general rate cases (Docket No. E017/GR-15-1033 and E017/GR-20-719) in the notice of availability of reports.

Additional Requirements Ordered March 12, 2024 in Docket No. E-999/CI-03-802

Order Point 2 – In their future Fuel Clause Adjustment filings, the three utilities shall incorporate –

A. Answers to recurring information requests, including the most recent three-year average of actual annual data compared to the forecast for the FCA calculation components, generation costs, purchase costs, inter-system sales and outages; and

B. A comparison of the actual winter energy purchase amounts to the forecast amounts, with an explanation of a variance of five percent or greater.

Attachment 12 contains the most recent three-year average of actual annual data compared to the forecast for the FCA (EAR) calculation components, generation costs, purchase costs, and inter-system sales to comply with Order Point 2.A. and is marked as Not Public. In previous EAR filings this analysis was done at the system level. In this filing Attachment 12 contains the Minnesota allocation, achieved by multiplying the system level by the approved EAR True-Up percent of Minnesota kWh sales subject to the EAR.

Attachment 13 provides the most recent three-year average of actual annual data compared to the forecast for the EAR calculation of outages in compliance with Order Point 2.A. The 2026 forecast Forced Outage Rate inputs for Big Stone Plant and Coyote Station (8.7 percent and 10.9 percent, respectively) are different than the previous three years, 2022-2024 EFORd rates and corresponding outage MWh, as shown in the table below.

Table 8
Historic and Forecasted EFORD Rates

EFORd (Force Outage Rate)	Big Stone Plant	Coyote Station
2019	0.9	19.4
2020	1.7	8.2
2021	13.0	10.7
2022	18.7	11.2
2023	15.5	6.9
2024	2.3	8.9
2026F (2019-2024 Average)	**8.7**	**10.9**

The greater than 5 percent variance when comparing the 2026 forecasted MWh of forced outages to the 2022-2024 three-year average and the 2024 actual outages is due to the large range of outage MWh for each plant in 2020-2022, which influences the three-year average. Beginning November 2022, Big Stone Plant experienced a 56.3-day unplanned outage due to bearing #7 vibration/exciter causing a higher EFORd rate for Big Stone Plant in 2022. The 2026 forecast forced outage rate inputs the Company used in this filing for Big Stone Plant fall between the lowest and second highest EFORd rate among years 2022-2024 while Coyote is higher than that same time frame. The 2026 forecasted outage MWh also exhibit the effect of the long 2022 Big Stone Plant outage and mirror the EFORd for each plant for outage MWh among years 2022-2024. Given this similar correlation, the 2026 forecasted outage MWh are reasonable based on the inputs used and previous years actuals.

Attachment 14 provides a comparison of the actual winter energy purchase amounts to the forecast amounts to comply with Order Point 2.B. and is marked as Not Public. Total forecasted MWhs of forward purchases in 2025 and 2026 increased from the 2022-2024 average levels as these purchases are based on forecasts that assume normal plant availability and average weather assumptions. The historical purchase in the winter of 2022/23, which accounted for Winter Storm Elliot, combined with the extended Big Stone exciter forced outage,[12] does not have an equivalent purchase in the 2025 and 2026 forecasts. The average cost per MWh in 2026 has decreased relative to the 2022- 2024 average. This cost decrease is tied directly to forward energy market pricing at the time of the forward purchases.

The 2025 and 2026 forecasts consist of already completed and confirmed forward energy purchases. Assuming Otter Tail Power does not make additional forward energy purchases for these time periods, the existing forecasted values will become future actual values. Otter Tail Power provides Attachments 14.1-14.6, which are protected in their entirety. Attachments 14.1-14.6 contain the trade confirmations from the 2025 energy purchases.

V. ALLOCATIONS AND RATE DESIGN

Attachment 2 summarizes the forecasted costs and sales applicable to the MN EAR that are detailed in Attachments 3.1 through 6. Lines 1 through 11 of Attachment 2 provide the costs/credits applicable to the MN EAR and Line 15 provides the sales applicable to the MN EAR rate calculation. Line 17 provides the forecast Cost per kWh (Line 13/ Line 15).

Otter Tail Power assess each customer class a class-specific Energy Adjustment Factor (EAF) monthly rate, which is calculated by multiplying the forecasted monthly EAR rate by the applicable EAF ratio listed on page 2 of Otter Tail Power's Electric Rate Schedule Section 13.01. Class-specific EAF rates are calculated in Attachment 1.

Proposed Rates by Service Category

In this filing, Otter Tail Power requests the Commission approve its total cost of energy upon which to develop rates, detailed in Attachment 2. Otter Tail Power also provides Attachment 1, which reflects the current approved 13.01 tariff mechanism. Attachment 1 calculates the class-specific EAF rates and contains the following components: Service Category [Column A], Section [Column B], EAF Ratio [Column C], and the forecasted monthly EAF rates for each service category with the appropriate E8760 EAF ratio applied [Columns D through O].

VI. ENERGY ADJUSTMENT RIDER RATE SCHEDULE

Redline and non-redline versions of pages 1 and 2 of Otter Tail Power's current EAR Rate Schedule, Section 13.01, are included as Attachment 9.a to this Petition. Otter Tail Power requests changes to this Rate Schedule in this Docket based on the change in

[12] As discussed, in May 1, 2024 filing in Docket No. E017/AA-24-65.

methodology previously discussed in this filing. In addition, we are taking this opportunity to replace Bruce G. Gerhardson with our Manager of Regulation & Retail Energy Solutions, Stuart D. Tommerdahl, in the footer. The currently approved EAR Rate Schedule, Section 13.01 is also included as Attachment 9 for reference.

VII. CUSTOMER NOTIFICATION

Attachment 10 is the proposed notice to customers that will be included with customer bills the month after the new EAR rates are approved. Otter Tail Power will work with the Consumer Affairs Office regarding this proposed notice. Once approved, these rates will be posted on Otter Tail Power's website.[13]

VIII. CONCLUSION

Otter Tail Power respectfully requests that the Commission approve the following:

1) The 2026 Minnesota Cost of Energy Forecast of $27.94 per MWh.
2) Implementation of the forecasted 2026 EAR rates as listed in Attachment 1.
3) Energy Adjustment Rider Rate Schedule, Section 13.01.

Dated: May 1, 2025

Respectfully submitted,

OTTER TAIL POWER COMPANY

By: */s/ CHRIS BYRNES*
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[13] https://www.otpco.com/pricing/minnesota/energy-adjustment-and-riders-mn/

OTTER TAIL POWER COMPANY
FUEL CLAUSE ADJUSTMENT FORECAST PETITION ATTACHMENTS

Attachment 1	Proposed Monthly EAR Rates by Service Category
Attachment 2	Minnesota EAR Rate Calculation
Attachment 3.1	Generation and Fuel Forecast (Not Public)
Attachment 3.2	Steam and Water Sales (Not Public)
Attachment 4.1	MISO Wholesale Market Charges Forecast
Attachment 4.2	SPP Wholesale Market Charges Forecast
Attachment 4.3	MISO ASM Market Charges Forecast
Attachment 5	Wind Curtailment Forecast
Attachment 6	System Sales and Municipal Forecast (Not Public)
Attachment 6.a	System Sales Forecast Description
Attachment 7	Intercontinental Exchange Local Marginal Price Forecast
Attachment 8	Intercontinental Exchange Natural Gas Price Forecast
Attachment 9	Energy Adjustment Rider Rate Schedule 13.01
Attachment 9.a	Energy Adjustment Rider Rate Schedule 13.01, Proposed Redline and Clean
Attachment 10	Customer Notification
Attachment 11	Rule 7825.2830 Annual Five-year Projection 2024-2028 (Not Public)
Attachment 12	2022-2024 Actuals Compared to 2026 Forecast (Not Public)
Attachment 13	Unplanned Outages Actuals to Forecast (Not Public)
Attachment 14	2022-2024 Bilateral Purchase Actual to Forecast (Not Public)
Appendix A	Compliance Items (Not Public)
Appendix B	Notice of Report Availability

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2026 PROPOSED FORECASTED EAR RATES

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(M)
Line No.	Description	Section (2)	EAF Ratio (2)	January-26	February-26	March-26	April-26	May-26	June-26	July-26	August-26	September-26	October-26	November-26	December-26
1	Proposed Cost per kWh - Attachment 2 (Line 17)			$ 0.031146	$ 0.027799	$ 0.024859	$ 0.022434	$ 0.022176	$ 0.024870	$ 0.033737	$ 0.030235	$ 0.025753	$ 0.023650	$ 0.030031	$ 0.035763
2	2024 True-up Factor (1)			$ 0.000300	$ 0.000300	$ 0.000300	$ 0.000300	$ 0.000300	$ 0.000300	$ 0.000300	$ 0.000300	$ -	$ -	$ -	$ -
3	EAR Rates with True-up			**$ 0.031446**	**$ 0.028099**	**$ 0.025159**	**$ 0.022734**	**$ 0.022476**	**$ 0.025170**	**$ 0.034037**	**$ 0.030535**	**$ 0.025753**	**$ 0.023650**	**$ 0.030031**	**$ 0.035763**
4															
5															
6															
7	Residential	9.01, 9.02	1.0555	$ 0.033191	$ 0.029658	$ 0.026555	$ 0.023996	$ 0.023723	$ 0.026567	$ 0.035926	$ 0.032230	$ 0.027182	$ 0.024963	$ 0.031698	$ 0.037748
8	Farms	9.03	1.0281	$ 0.032330	$ 0.028889	$ 0.025866	$ 0.023373	$ 0.023108	$ 0.025877	$ 0.034993	$ 0.031393	$ 0.026477	$ 0.024315	$ 0.030875	$ 0.036768
9	General Service	10.01, 10.02, 10.03, 10.07	1.0461	$ 0.032896	$ 0.029394	$ 0.026319	$ 0.023782	$ 0.023512	$ 0.026330	$ 0.035606	$ 0.031943	$ 0.026940	$ 0.024740	$ 0.031415	$ 0.037412
10	Large General Service	10.04, 10.06, 11.01, 14.03	1.0207	$ 0.032097	$ 0.028681	$ 0.025680	$ 0.023205	$ 0.022941	$ 0.025691	$ 0.034742	$ 0.031167	$ 0.026286	$ 0.024140	$ 0.030653	$ 0.036503
11	Large General Service - TOD - Winter On-Peak	10.05, 10.06	1.2673	$ 0.039852	$ 0.035610	$ 0.031884	$ 0.028811	$ 0.028484					$ 0.029972	$ 0.038058	$ 0.045322
12	Large General Service - TOD - Winter Mid-Peak	10.05, 10.06	1.1106	$ 0.034924	$ 0.031207	$ 0.027942	$ 0.025248	$ 0.024962					$ 0.026266	$ 0.033352	$ 0.039718
13	Large General Service - TOD - Winter Off-Peak	10.05, 10.06	0.8499	$ 0.026726	$ 0.023881	$ 0.021383	$ 0.019322	$ 0.019102					$ 0.020100	$ 0.025523	$ 0.030395
14	Large General Service - TOD - Summer On-Peak	10.05, 10.06	1.2664						$ 0.031875	$ 0.043104	$ 0.038670	$ 0.032614			
15	Large General Service - TOD - Summer Mid-Peak	10.05, 10.06	0.9956						$ 0.025059	$ 0.033887	$ 0.030401	$ 0.025640			
16	Large General Service - TOD - Summer Off-Peak	10.05, 10.06	0.6896						$ 0.017357	$ 0.023472	$ 0.021057	$ 0.017759			
17	Irrigation Service	11.02	0.9250	$ 0.029088	$ 0.025992	$ 0.023272	$ 0.021029	$ 0.020790	$ 0.023282	$ 0.031484	$ 0.028245	$ 0.023822	$ 0.021876	$ 0.027779	$ 0.033081
18	Outdoor Lighting	11.03, 11.04, 11.07	0.8645	$ 0.027185	$ 0.024292	$ 0.021750	$ 0.019654	$ 0.019431	$ 0.021759	$ 0.029425	$ 0.026398	$ 0.022263	$ 0.020445	$ 0.025962	$ 0.030917
19	OPA	11.05	1.0210	$ 0.032106	$ 0.028689	$ 0.025687	$ 0.023211	$ 0.022948	$ 0.025699	$ 0.034752	$ 0.031176	$ 0.026294	$ 0.024147	$ 0.030662	$ 0.036514
20	Controlled Service Deferred Load	14.01, 14.06	0.9513	$ 0.029915	$ 0.026731	$ 0.023934	$ 0.021627	$ 0.021381	$ 0.023944	$ 0.032379	$ 0.029048	$ 0.024499	$ 0.022498	$ 0.028568	$ 0.034021
21	Controlled Service Interruptible	14.04	0.9883	$ 0.031078	$ 0.027770	$ 0.024865	$ 0.022468	$ 0.022213	$ 0.024876	$ 0.033639	$ 0.030178	$ 0.025452	$ 0.023373	$ 0.029680	$ 0.035345
22	Controlled Service Off-Peak	14.07, 14.12	0.9164	$ 0.028817	$ 0.025750	$ 0.023056	$ 0.020833	$ 0.020597	$ 0.023066	$ 0.031192	$ 0.027982	$ 0.023600	$ 0.021673	$ 0.027520	$ 0.032773

(1) As of the date of this filing, there is no Commission-approved true-up factor to be included in 2024 rates.
(2) Minnesota Class EAF Ratios in 13.01 Tariff as filed by Otter Tail on March 8, 2022, in Docket No. E017/GR-20-719.

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

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
Line No.	**Description**	**Source Attachment**	**January-26**	**February-26**	**March-26**	**April-26**	**May-26**	**June-26**	**July-26**	**August-26**	**September-26**	**October-26**	**November-26**	**December-26**	**2026 Year End**
1	Plant Generation		$ 3,948,829	$ 2,712,925	$ 1,772,066	$ 1,235,583	$ 1,090,815	$ 975,809	$ 3,491,431	$ 3,137,777	$ 1,925,644	$ 2,979,217	$ 2,314,558	$ 2,208,178	$ 27,792,834
2	Steam Plant Reagents		$ 202,487	$ 183,478	$ 119,203	$ 81,058	$ 57,675	$ 22,205	$ 91,575	$ 109,336	$ 64,126	$ 103,973	$ 86,039	$ 103,421	$ 1,224,575
3	Purchased Power		$ 7,286,056	$ 6,059,699	$ 5,147,871	$ 4,325,026	$ 4,410,618	$ 5,442,393	$ 5,471,635	$ 4,334,398	$ 4,108,621	$ 3,434,519	$ 5,708,340	$ 8,328,856	$ 64,058,034
4	Wind Curtailment		$ (2,812)	$ (538)	$ 8,916	$ 587	$ 12,270	$ 19,091	$ 7,730	$ (7,813)	$ 1,719	$ 17,701	$ 2,951	$ 8,767	$ 68,571
5	Intersystem Sales (Fuel Cost of Asset-Based Sales)		$ (561,777)	$ (117,744)	$ (21)	$ (50)	$ -	$ (64,721)	$ (323,765)	$ (193,555)	$ (272,283)	$ (455,020)	$ (30,055)	$ (72,141)	$ (2,091,132)
6	MISO Resource Book Charge (excluding Schedule 16 & 17)		$ (722,539)	$ (542,763)	$ (512,632)	$ (450,077)	$ (453,953)	$ (456,057)	$ (483,201)	$ (458,282)	$ (403,167)	$ (430,330)	$ (489,216)	$ (531,841)	$ (5,934,059)
7	SPP Resource Book Charge		$ (57,135)	$ (69,311)	$ (11,803)	$ 8,197	$ 7,999	$ (124,059)	$ 8,462	$ 8,214	$ 7,551	$ 8,474	$ 9,648	$ 10,731	$ (193,031)
8	MISO Ancillary Services Market		$ (130,077)	$ (70,360)	$ (42,986)	$ (38,139)	$ (53,785)	$ (51,269)	$ (41,873)	$ (29,834)	$ (85,084)	$ (7,461)	$ (38,549)	$ (49,127)	$ (638,545)
9	Minnesota Solar Generation Credit		$ (228,052)	$ (251,851)	$ (299,607)	$ (340,480)	$ (388,273)	$ (450,943)	$ (936,874)	$ (594,750)	$ (385,864)	$ (229,464)	$ (137,177)	$ (248,971)	$ (4,492,305)
10	Steam and Water Sales - Net Margin		$ (54,808)	$ (56,679)	$ (42,869)	$ (19,206)	$ (23,768)	$ (35,522)	$ (46,682)	$ (44,662)	$ (39,734)	$ (37,804)	$ (37,564)	$ (50,061)	$ (489,359)
11	Asset-Based Margins - 100%		$ (903,583)	$ (183,632)	$ 1	$ (55)	$ -	$ (18,560)	$ (335,607)	$ (211,450)	$ (156,343)	$ (320,575)	$ (17,393)	$ (74,113)	$ (2,221,311)
12															
13	**Fuel Costs & Purcahse Power for System Use - Minnesota**		$ 8,776,591	$ 7,663,224	$ 6,138,139	$ 4,802,445	$ 4,659,597	$ 5,258,368	$ 6,902,831	$ 6,049,378	$ 4,765,187	$ 5,063,230	$ 7,371,582	$ 9,633,699	$ 77,084,271
14															
15	**Energy for Minnesota Use (kWh)**		281,790,149	275,665,229	246,921,473	214,068,196	210,119,755	211,431,598	204,608,272	200,078,401	185,036,619	214,092,312	245,466,959	269,377,752	2,758,656,715
16															
17	**Cost per kWh**	**Line 13 / Line 15**	**$ 0.03115**	**$ 0.02780**	**$ 0.02486**	**$ 0.02243**	**$ 0.02218**	**$ 0.02487**	**$ 0.03374**	**$ 0.03024**	**$ 0.02575**	**$ 0.02365**	**$ 0.03003**	**$ 0.03576**	**$ 0.02794**

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2026 SALES FORECAST KWH

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	Description	January-26	February-26	March-26	April-26	May-26	June-26	July-26	August-26	September-26	October-26	November-26	December-26	2026 Year-End
1	**Coal (tons)**	**[PROTECTED DATA BEGINS...**												
2	Big Stone													
3	Coyote													
4	**Total Coal**													
5														
6	**Oil - Coal Units (Gallons)**													
7	Big Stone													
8	Coyote													
9	**Total Oil - Coal Units**													
10														
11	**Oil - Peaking Units (Gallons)**													
12	Jamestown 1													
13	Jamestown 2													
14	Lake Preston													
15	**Total Oil - Peaking units**													
16														
17	**Natural Gas (MMBTU)**													
18	Solway													
19	Astoria													
20	**Total Natural Gas**													
21														
22														
23	**Energy (MWh)**													
24	Big Stone													
25	Coyote													
26	**Total Coal**													
27														
28	**Wind**													
29	Langdon													
30	Ashtabula													
31	Ashtabula III													
32	Luverne													
33	Merricourt													
34	200 MW Wind Gen													
35	**Total Wind**													
36														
37	**Solar**													
38	Flickertail Solar													
39	Solway Solar													
40	<40 kW Solar													
41	Hoot Lake Solar													
42	**Total Solar**													
43														
44	**Hydro**													
45														
46	**Peaking Units**													
47	Jamestown 1													
48	Jamestown 2													
49	Lake Preston													
50	**Total Peaking units**													
51														
52	**Natural Gas**													
53	Solway													
54	Astoria													
55	**Total Natural Gas**													
56													**...PROTECTED DATA ENDS]**	
57	**OTP-Owned Total**	205,930	169,015	131,600	112,512	101,517	75,784	157,483	142,797	116,226	158,521	119,098	130,711	1,621,194
58														
59	**Purchases**	**[PROTECTED DATA BEGINS...**												
60	Edgeley PPA													
61	Langdon PPA													
62	Tribal (WAPA)													
63	Shared Load													
64	Small Co-gen													
65	Bilateral purchases													
66	Market Purchases													
67													**...PROTECTED DATA ENDS]**	
68	**Total Purchases excluding Tribal (WAPA)**	107,809	107,186	129,997	116,382	122,047	127,728	64,368	64,379	80,787	61,914	123,098	143,010	1,248,704
69														
70	Less: Asset Based Sales	19,457	4,433	1	2	-	1,250	9,577	5,644	7,648	13,918	857	2,097	64,882
71														
72	**System Use**	**294,283**	**271,769**	**261,596**	**228,893**	**223,563**	**202,263**	**212,273**	**201,532**	**189,366**	**206,516**	**241,338**	**271,624**	**2,805,015**
73														

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2026 SALES FORECAST KWH

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	Description	January-26	February-26	March-26	April-26	May-26	June-26	July-26	August-26	September-26	October-26	November-26	December-26	2026 Year-End
74														
75	**Fuel Costs - Coal**	**[PROTECTED DATA BEGINS...**												
76	Big Stone -Variable													
	Big Stone - Fixed													
77	Coyote - Variable													
	Coyote - Fixed													
78	**Total Fuel Costs - Coal**													
79														
80	**Fuel Oil Costs - Coal Units**													
81	Big Stone													
82	Coyote													
83	**Total Fuel Oil Costs - Coal Units**													
84														
85	**Fuel Oil Costs - Peaking Units**													
86	Jamestown 1													
87	Jamestown 2													
88	Lake Preston													
89	**Total Fuel Oil Costs - Peaking Units**													
90														
91	**Fuel Costs - Natural Gas ($)**													
92	Solway													
93	Astoria - Variable													
94	**Total Fuel Costs - Natural Gas Units**													
95														
96	**Total OTP-Owned Fuel Costs**													
97														
98	**Purchases ($)**													
99	Edgeley PPA													
100	Langdon PPA													
101	Tribal (WAPA) excluded from Total*													
102	Shared Load													
103	Small Co-gen													
104	Bilateral Purchases													
105	Market Purchases													
													...PROTECTED DATA ENDS]	
106	**Total Purchases excluding Tribal (WAPA)***	$ 7,286,056	$ 6,059,699	$ 5,147,871	$ 4,325,026	$ 4,410,618	$ 5,442,393	$ 5,471,635	$ 4,334,398	$ 4,108,621	$ 3,434,519	$ 5,708,340	$ 8,328,856	$ 64,058,034
107														
108	Asset Based Sales	$ (1,465,360)	$ (301,376)	$ (20)	$ (105)	$ -	$ (83,281)	$ (659,372)	$ (405,005)	$ (428,625)	$ (775,596)	$ (47,447)	$ (146,254)	$ (4,312,442)
109	Avg thermal Cost ($/MWh)	$ 28.87	$ 26.56	$ 27.32	$ 26.58	$ 31.02	$ 51.79	$ 33.81	$ 34.30	$ 35.60	$ 32.69	$ 35.06	$ 34.41	$ 31.75
110	Fuel Cost of Sales	$ 561,777	$ 117,744	$ 21	$ 50	$ -	$ 64,721	$ 323,765	$ 193,555	$ 272,283	$ 455,020	$ 30,055	$ 72,141	$ 2,091,132
111	Margin	$ (903,583)	$ (183,632)	$ 1	$ (55)	$ -	$ (18,560)	$ (335,607)	$ (211,450)	$ (156,343)	$ (320,575)	$ (17,393)	$ (74,113)	$ (2,221,311)
112														
113	**Fuel Cost + Purchased Power for System Use**	**$ 9,769,526**	**$ 8,471,248**	**$ 6,919,917**	**$ 5,560,504**	**$ 5,501,434**	**$ 6,334,922**	**$ 8,303,694**	**$ 7,067,170**	**$ 5,605,639**	**$ 5,638,141**	**$ 7,975,451**	**$ 10,390,781**	**$ 87,538,425**
114														
115														
116	**Reagents**	**[PROTECTED DATA BEGINS...**												
117	BSP Pebble Lime ($/MWH)													
118	BSP Pebble Lime ($)													
119														
120	BSP Act. Carbon ($/MWH)													
121	BSP Act. Carbon ($)													
122														
123	BSP Anh. Ammonia ($/MWH)													
124	BSP Anh. Ammonia ($)													
125														
126	COY Lime ($/MWH)													
127	COY Lime ($)													
128														
129	COY Act. TIFI ($/MWH)													
130	COY Act. TIFI ($)													
131														
132	COY Act. Carbon ($/MWH)													
133	COY Act. Carbon ($)													
134													**...PROTECTED DATA ENDS]**	
135	**Total Reagents**	**$ 202,487**	**$ 183,478**	**$ 119,203**	**$ 81,058**	**$ 57,675**	**$ 22,205**	**$ 91,575**	**$ 109,336**	**$ 64,126**	**$ 103,973**	**$ 86,039**	**$ 103,421**	**$ 1,224,575**

*Tribal (WAPA) is not FCA applicable and therefore excluded fro

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2026 STEAM SALES FORECAST

[PROTECTED DATA BEGINS...

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	Description	January-26	February-26	March-26	April-26	May-26	June-26	July-26	August-26	September-26	October-26	November-26	December-26	2026 Year End
1	Coal Burned for Steam and Water Sales ($)													
2	Pebble Lime for Steam and Water Sales ($)													
3	Activated Carbon for Steam and Water Sales ($)													
4	Anhydrous Ammonia for Steam and Water Sales ($)													
5	Total Costs for Steam and Water Sales ($)													
6														
7	Revenue from Steam and Water Sales													
8														
9	**Net Margin - Total Company**													
10														
11	**MN Allocator**													
12														
13	**Net Margin - MN Share**	$ (54,808)	$ (56,679)	$ (42,869)	$ (19,206)	$ (23,768)	$ (35,522)	$ (46,682)	$ (44,662)	$ (39,734)	$ (37,804)	$ (37,564)	$ (50,061)	$ (489,359)

...PROTECTED DATA ENDS]

Otter Tail Power Company
MISO Wholesale Market Charges (Non-Energy)
2026 FORECAST - Minnesota Share

Line No.	Charge Type Description	Acct	January	February	March	April	May	June	July	August	September	October	November	December	Total Annual Forecast
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
	Day Ahead & Real Time Asset & Non Asset Energy & Loss														
1	DA Asset Energy Amount***	555.02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	DA FBT Loss Amount	555.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	DA Non-asset Energy Amount***	555.09	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	RT Asset Energy Amount***	555.19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	RT Distribution of Losses Amount	555.24	$ (132,899)	$ (122,366)	$ (116,995)	$ (101,710)	$ (99,233)	$ (98,909)	$ (104,997)	$ (101,915)	$ (93,662)	$ (105,139)	$ (119,754)	$ (133,240)	$ (1,330,819)
6	RT FBT Loss Amount	555.21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	DA Loss Amount		$ 245,951	$ 226,458	$ 216,520	$ 188,231	$ 183,647	$ 158,483	$ 168,237	$ 163,299	$ 150,076	$ 168,465	$ 191,883	$ 213,492	$ 2,274,742
8	RT Loss Amount		$ 23,200	$ 21,361	$ 20,424	$ 17,755	$ 17,323	$ 14,949	$ 15,869	$ 15,404	$ 14,156	$ 15,891	$ 18,100	$ 20,138	$ 214,571
9	RT Non-Asset Energy Amount***	555.26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	DA Losses Rebate on Option B GFA	555.08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	**TOTAL**		**$ 136,253**	**$ 125,454**	**$ 119,948**	**$ 104,277**	**$ 101,737**	**$ 74,523**	**$ 79,110**	**$ 76,788**	**$ 70,570**	**$ 79,217**	**$ 90,229**	**$ 100,390**	**$ 1,158,495**
	Virtual Energy														
12	DA Virtual Energy Amount	555.12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	RT Virtual Energy Amount	555.32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Schedules 16 & 17														
15	DA Mkt Admin Amount	555.01	$ 42,447	$ 46,550	$ 36,543	$ 31,615	$ 30,098	$ 27,449	$ 33,212	$ 31,150	$ 27,848	$ 40,401	$ 36,547	$ 41,179	$ 425,038
16	RT Mkt Admin Amount	555.18	$ 5,241	$ 5,945	$ 5,167	$ 5,284	$ 5,884	$ 4,732	$ 4,898	$ 4,160	$ 3,925	$ 5,669	$ 5,287	$ 6,148	$ 62,340
17	FTR Mkt Admin Amount	555.13	$ 744	$ 737	$ 654	$ 649	$ 714	$ 767	$ 920	$ 799	$ 722	$ 727	$ 611	$ 520	$ 8,565
18	**TOTAL**		**$ 48,433**	**$ 53,232**	**$ 42,363**	**$ 37,548**	**$ 36,696**	**$ 32,948**	**$ 39,030**	**$ 36,109**	**$ 32,494**	**$ 46,797**	**$ 42,445**	**$ 47,847**	**$ 495,942**
	Congest & FTRs														
19	DA FBT Congestion Amount	555.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DA Congestion		$ 979,257	$ 901,645	$ 862,074	$ 749,443	$ 731,190	$ 631,002	$ 669,836	$ 650,174	$ 597,528	$ 670,746	$ 763,983	$ 850,020	$ 9,056,898
21	RT FBT Congestion Amount	555.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	RT Congestion		$ 112,981	$ 104,027	$ 99,461	$ 86,466	$ 84,361	$ 72,801	$ 77,282	$ 75,013	$ 68,939	$ 77,387	$ 88,144	$ 98,070	$ 1,044,933
23	FTR Hourly Allocation Amount	555.14	$ (1,634,083)	$ (1,504,573)	$ (1,438,541)	$ (1,250,593)	$ (1,220,135)	$ (1,052,952)	$ (1,117,753)	$ (1,084,944)	$ (997,093)	$ (1,119,272)	$ (1,274,856)	$ (1,418,426)	$ (15,113,221)
24	FTR Monthly Allocation Amount	555.15	$ (43,008)	$ (39,599)	$ (37,861)	$ (32,915)	$ (32,113)	$ (27,713)	$ (29,418)	$ (28,555)	$ (26,243)	$ (29,458)	$ (33,553)	$ (37,332)	$ (397,769)
25	FTR Yearly Allocation Amount	555.17	$ (187,701)	$ 0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (187,701)
26	FTR Monthly Transaction Amount	555.35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	FTR Full Funding Guarantee Amount	555.36	$ 140,574	$ 16,901	$ (46,481)	$ (164,415)	$ (56,996)	$ (31,952)	$ 9,661	$ (25,381)	$ (49,248)	$ (65,620)	$ (118,448)	$ (36,238)	$ (427,643)
28	FTR Guarantee Uplift Amount	555.37	$ (109,711)	$ (26,895)	$ 46,482	$ 159,607	$ 48,955	$ 34,103	$ (14,161)	$ 25,381	$ 49,248	$ 69,161	$ 120,353	$ 29,307	$ 431,831
29	FTR Auction Revenue Rights Transaction Amount	555.39	$ (1,590,586)	$ (1,593,328)	$ (1,781,108)	$ (2,334,665)	$ (2,395,602)	$ (1,909,404)	$ (1,900,744)	$ (1,880,481)	$ (2,368,243)	$ (2,441,207)	$ (2,460,730)	$ (1,633,662)	$ (24,289,760)
30	FTR Annual Transaction Amount	555.38	$ 1,515,561	$ 1,518,173	$ 1,704,509	$ 2,260,915	$ 2,319,927	$ 1,815,453	$ 1,807,220	$ 1,787,954	$ 2,287,852	$ 2,358,339	$ 2,377,200	$ 1,556,605	$ 23,309,705
31	FTR Auction Revenue Rights Infeasible Uplift Amount	555.40	$ 5,045	$ 5,053	$ 6,824	$ 10,077	$ 10,339	$ 1,005	$ 1,001	$ 990	$ 6,262	$ 6,455	$ 6,507	$ 5,181	$ 64,739
32	FTR Auction Revenue Rights Stage 2 Distribution Amount	555.41	$ (96,198)	$ (96,362)	$ (88,105)	$ (78,651)	$ (80,704)	$ (99,401)	$ (98,950)	$ (97,895)	$ (77,690)	$ (80,083)	$ (80,724)	$ (98,802)	$ (1,073,564)
33	DA Congestion Rebate on Option B GFA	555.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	**TOTAL**		**$ (907,868)**	**$ (714,957)**	**$ (672,747)**	**$ (594,732)**	**$ (590,778)**	**$ (567,056)**	**$ (596,027)**	**$ (577,744)**	**$ (508,687)**	**$ (553,553)**	**$ (612,125)**	**$ (685,277)**	**$ (7,581,551)**
	RSG & Make Whole Payments														
35	DA Revenue Sufficiency Guarantee Distribution Amount	555.1	$ 8,597	$ 6,886	$ 5,490	$ 4,225	$ 3,965	$ 2,600	$ 4,254	$ 4,280	$ 3,970	$ 3,992	$ 3,573	$ 7,108	$ 58,941
36	DA Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.11	$ (11)	$ (1,731)	$ (2,397)	$ (1,474)	$ (5,948)	$ (3,147)	$ (8,466)	$ (1,421)	$ (6,138)	$ (886)	$ (5,863)	$ (778)	$ (38,258)
37	RT Revenue Sufficiency Guarantee First Pass Distribution Amount	555.29	$ 4,286	$ 4,294	$ 4,309	$ 4,265	$ 4,376	$ 4,429	$ 4,409	$ 4,362	$ 4,258	$ 4,389	$ 4,425	$ 4,402	$ 52,204
38	RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	555.3	$ (13,843)	$ (13,867)	$ (13,916)	$ (13,774)	$ (14,133)	$ (14,305)	$ (14,240)	$ (14,088)	$ (13,753)	$ (14,177)	$ (14,290)	$ (14,218)	$ (168,605)
39	RT Price Volatility Make Whole Payment	555.42	$ (17,426)	$ (17,456)	$ (17,517)	$ (17,338)	$ (17,791)	$ (18,007)	$ (17,925)	$ (17,734)	$ (17,312)	$ (17,845)	$ (17,988)	$ (17,898)	$ (212,239)
40	**TOTAL**		**$ (18,397)**	**$ (21,874)**	**$ (24,031)**	**$ (24,096)**	**$ (29,531)**	**$ (28,430)**	**$ (31,968)**	**$ (24,601)**	**$ (28,975)**	**$ (24,526)**	**$ (30,144)**	**$ (21,384)**	**$ (307,957)**
	Revenue Neutrality Uplift														
41	RT Revenue Neutrality Uplift Amount	555.28	$ 69,725	$ 69,845	$ 70,090	$ 69,375	$ 71,185	$ 72,049	$ 71,723	$ 70,958	$ 69,269	$ 71,403	$ 71,974	$ 71,613	$ 849,208
42	**TOTAL**		**$ 69,725**	**$ 69,845**	**$ 70,090**	**$ 69,375**	**$ 71,185**	**$ 72,049**	**$ 71,723**	**$ 70,958**	**$ 69,269**	**$ 71,403**	**$ 71,974**	**$ 71,613**	**$ 849,208**
	Other Charges														
43	RT Misc Amount	555.25	$ (11,590)	$ (11,610)	$ (11,650)	$ (11,532)	$ (11,833)	$ (11,976)	$ (11,922)	$ (11,795)	$ (11,514)	$ (11,869)	$ (11,964)	$ (11,904)	$ (141,157)
44	RT Net Inadvertent Amount	555.27	$ (951)	$ (952)	$ (956)	$ (946)	$ (970)	$ (982)	$ (978)	$ (967)	$ (944)	$ (973)	$ (981)	$ (976)	$ (11,577)
45	RT Uninstructed Deviation Amount	555.31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	RT Demand Response Allocation Uplift Amount	555.59	$ 1,925	$ 3,933	$ 3,040	$ 732	$ 7	$ 17	$ 1,037	$ 993	$ 3,247	$ 1,833	$ 112	$ 8,203	$ 25,077
47	DA Ramp Product	555.63	$ (2,008)	$ (2,953)	$ (6,420)	$ (3,478)	$ (4,023)	$ (4,868)	$ (4,062)	$ (2,761)	$ (6,427)	$ (2,718)	$ (6,808)	$ (3,438)	$ (49,965)
48	RT Ramp Product	555.64	$ (280)	$ (319)	$ (613)	$ (274)	$ (622)	$ (341)	$ (1,070)	$ 7	$ (287)	$ (53)	$ (505)	$ (9)	$ (4,366)
49	RT Schedule 49 Cost Distribution Amount	555.65	$ 10,652	$ 10,670	$ 10,708	$ 10,598	$ 10,875	$ 11,007	$ 10,957	$ 10,840	$ 10,582	$ 10,908	$ 10,996	$ 10,940	$ 129,734
50	**TOTAL**		**$ (2,251)**	**$ (1,231)**	**$ (5,892)**	**$ (4,900)**	**$ (6,566)**	**$ (7,143)**	**$ (6,038)**	**$ (3,683)**	**$ (5,343)**	**$ (2,872)**	**$ (9,151)**	**$ 2,816**	**$ (52,254)**
	ASM Charges														
51	RT ASM Non-Excessive Energy Amount***	555.55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	RT ASM Excessive Energy Amount***	555.56	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Grandfathered Charge Types														
54	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	**TOTAL**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
59	**TOTAL MISO Day 2 Wholesale CHARGES**		$ (674,107)	$ (489,531)	$ (470,269)	$ (412,529)	$ (417,257)	$ (423,109)	$ (444,171)	$ (422,173)	$ (370,672)	$ (383,533)	$ (446,771)	$ (483,994)	$ (5,438,117)
60	**Less: Schedule 16 & 17 (Lines 15, 16, 17)**		$ (48,433)	$ (53,232)	$ (42,363)	$ (37,548)	$ (36,696)	$ (32,948)	$ (39,030)	$ (36,109)	$ (32,494)	$ (46,797)	$ (42,445)	$ (47,847)	$ (495,942)
61	**Total Forecasted MISO Day 2 Wholesale Energy Market Charges**		**$ (722,539)**	**$ (542,763)**	**$ (512,632)**	**$ (450,077)**	**$ (453,953)**	**$ (456,057)**	**$ (483,201)**	**$ (458,282)**	**$ (403,167)**	**$ (430,330)**	**$ (489,216)**	**$ (531,841)**	**$ (5,934,059)**

*** These energy related charge types are forecasted in aggregate within Otter Tail's EnCompass forecast found on line 104, Market Purchases of Attachment 3.1

Otter Tail Power Company
SPP Wholesale Market Charges (Non-Energy)
2026 FORECAST - Minnesota Share

Line No.	Charge Type Description	Acct	January	February	March	April	May	June	July	August	September	October	November	December	Total Forecast
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
	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**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
6	**RSG & Make Whole Payments**														
7	DA Make-Whole-Payment Distribution Amount	555.02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	RT Make-Whole-Payment Distribution Amount	555.10	$ 13	$ 14	$ 14	$ 13	$ 14	$ 14	$ 14	$ 14	$ 13	$ 14	$ 14	$ 14	$ 164
9	RT Revenue Sufficiency Guarantee Distribution Amount	555.18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**TOTAL**		**$ 13**	**$ 14**	**$ 14**	**$ 13**	**$ 14**	**$ 14**	**$ 14**	**$ 14**	**$ 13**	**$ 14**	**$ 14**	**$ 14**	**$ 164**
11	**Revenue Neutrality Uplift**														
12	RT Revenue Neutrality Uplift Distribution Amount	555.15	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 84
13	**TOTAL**		**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 7**	**$ 84**
14	**Other Charges**														
15	DA Regulation-Down Distribution Amount	555.04	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 14
16	DA Regulation-Up Distribution Amount	555.05	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 28
17	DA Spinning Reserve Distribution Amount	555.06	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 16
18	DA Supplemental Reserve Distribution Amount	555.07	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4
19	RT Contingency Reserve Deployment Failure Amount	555.08	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
20	RT Over-Collected Losses Distribution Amount	555.11	$ (6,237)	$ (5,743)	$ (5,491)	$ (4,774)	$ (4,657)	$ (4,642)	$ (4,928)	$ (4,783)	$ (4,396)	$ (4,934)	$ (5,620)	$ (6,253)	$ (62,459)
21	RT Regulation-Down Distribution Amount	555.12	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2
22	RT Regulation Non-Performance Distribution Amount	555.13	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (2)
23	RT Regulation-Up Distribution Amount	555.14	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (3)
24	RT Spinning Reserve Distribution Amount	555.16	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
25	RT Supplemental Reserve Distribution Amount	555.17	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
26	RT Pseudo Tie Congestion Amount	555.20	$ 14,209	$ 13,083	$ 12,509	$ 10,874	$ 10,609	$ 10,575	$ 11,226	$ 10,896	$ 10,014	$ 11,241	$ 12,804	$ 14,245	$ 142,285
27	RT Pseudo Tie Loss Amount	555.21	$ 2,703	$ 2,489	$ 2,380	$ 2,069	$ 2,018	$ 2,012	$ 2,136	$ 2,073	$ 1,905	$ 2,139	$ 2,436	$ 2,710	$ 27,070
28	Miscellaneous Amount	555.23	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 13
29	ARR Closeout Yearly Amount	555.26	$ -	$ -	$ -	$ -	$ -	$ (131,973)	$ -	$ -	$ -	$ -	$ -	$ -	$ (131,973)
30	RT Demand Reduction Distribution Amount	555.28	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
31	RT Schedule 1A3 Amount	555.29	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5
32	RT Schedule 1A4 Amount	555.30	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 16
33	DA Ramp Up Distribution Amount	555.31	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2
34	DA Ramp Down Distribution Amount	555.32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
35	RT Ramp Non Performance Distribution Amount	555.33	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)
36	RT Ramp Up Distribution Amount	555.34	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (0)	$ (1)
37	RT Ramp Down Distribution Amount	555.35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
38	ArrAucTxnAoAmt	555.36	$ (67,838)	$ (79,168)	$ (21,229)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (168,234)
39	RT Uninstructed Resource Deviation Distribution Amount	555.37	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (1)	$ (7)
40	**TOTAL**		**$ (57,156)**	**$ (69,332)**	**$ (11,824)**	**$ 8,177**	**$ 7,978**	**$ (124,021)**	**$ 8,441**	**$ 8,193**	**$ 7,530**	**$ 8,452**	**$ 9,626**	**$ 10,710**	**$ (193,225)**
41	**Grandfathered Charge Types**														
42	DA GFA Carve Out Distribution Deployment Daily Amount	555.01	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 6
43	DA GFA Carve Out Distribution Deployment Monthly Amount	555.22	$ -	$ -	$ -	$ -	$ (0)	$ -	$ -	$ -	$ -	$ -	$ (0)	$ (0)	$ (0)
44	DA GFA Carve Out Distribution Deployment Yearly Amount	555.27	$ -	$ -	$ -	$ -	$ -	$ (60)	$ 0	$ -	$ (0)	$ -	$ -	$ -	$ (60)
45	**TOTAL**		**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ (60)**	**$ 1**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ 0**	**$ (55)**
46	**TOTAL FORECASTED SPP ENERGY MARKET CHARGES**		**$ (57,135)**	**$ (69,311)**	**$ (11,803)**	**$ 8,197**	**$ 7,999**	**$ (124,059)**	**$ 8,462**	**$ 8,214**	**$ 7,551**	**$ 8,474**	**$ 9,648**	**$ 10,731**	**$ (193,031)**
47															

*** These energy related charge types are forecasted in aggregate within Otter Tail's EnCompass forecast found on line 104, Market Purchases of Attachment 3.1

Otter Tail Power Company
MISO ASM Market Charges
2026 FORECAST - Minnesota Share

Line No.	(A)	(B) January	(C) February	(D) March	(E) April	(F) May	(G) June	(H) July	(I) August	(J) September	(K) October	(L) November	(M) December	(N) 12-Month Total
1	Day Ahead Regulation Amount	$ (31,309)	$ (27,053)	$ (30,418)	$ (17,541)	$ (40,001)	$ (29,622)	$ (38,904)	$ (31,166)	$ (32,764)	$ (13,310)	$ (24,845)	$ (33,031)	$ (349,966)
2	Real Time Regulation Amount	$ (19,040)	$ (19,794)	$ (7,867)	$ (15,530)	$ (8,331)	$ 2,176	$ 4,265	$ (8,362)	$ 2,425	$ (12,721)	$ (13,709)	$ (22,725)	$ (119,215)
3	Regulation Cost Distribution Amount	$ 11,568	$ 12,267	$ 12,808	$ 8,012	$ 9,129	$ 6,980	$ 10,177	$ 8,213	$ 8,353	$ 13,866	$ 14,593	$ 15,803	$ 131,770
4														
5	**Regulation Subtotal**	**$ (38,781)**	**$ (34,581)**	**$ (25,477)**	**$ (25,060)**	**$ (39,203)**	**$ (20,467)**	**$ (24,462)**	**$ (31,315)**	**$ (21,986)**	**$ (12,165)**	**$ (23,962)**	**$ (39,953)**	**$ (337,411)**
6														
7	Day Ahead Short-Term Reserve Amount	$ (147,026)	$ (47,077)	$ (25,347)	$ (11,899)	$ (19,094)	$ (22,569)	$ (19,681)	$ (31,832)	$ (62,538)	$ (7,614)	$ (10,733)	$ (10,837)	$ (416,246)
8	Real Time Short-Term Reserve Amount	$ 3,425	$ 14,094	$ 94	$ 935	$ 660	$ (250)	$ (4,295)	$ 2,741	$ (3,422)	$ (6)	$ (149)	$ 153	$ 13,979
9	Real Time Short-Term Reserve Cost Distribution Amount	$ 59,540	$ 19,262	$ 6,980	$ 5,268	$ 11,415	$ 6,318	$ 18,674	$ 21,900	$ 26,181	$ 8,669	$ 4,362	$ 5,340	$ 193,911
10	Short-Term Reserve Deployment Failure Charge	$ 42	$ 42	$ 42	$ 42	$ 43	$ 43	$ 43	$ 43	$ 42	$ 43	$ 43	$ 43	$ 510
11														
12	**Short-Term Reserve Subtotal**	**$ (84,018)**	**$ (13,679)**	**$ (18,231)**	**$ (5,654)**	**$ (6,977)**	**$ (16,458)**	**$ (5,260)**	**$ (7,148)**	**$ (39,736)**	**$ 1,092**	**$ (6,477)**	**$ (5,300)**	**$ (207,846)**
13														
14	Day Ahead Spinning Reserve Amount	$ (4,839)	$ (7,996)	$ (15,210)	$ (11,156)	$ (20,051)	$ (19,127)	$ (13,793)	$ (8,745)	$ (18,031)	$ (10,407)	$ (22,557)	$ (14,285)	$ (166,195)
15	Real Time Spinning Reserve Amount	$ (1,626)	$ (1,187)	$ 592	$ 1,978	$ 202	$ (2,141)	$ (3,126)	$ (200)	$ 1,348	$ 989	$ 309	$ (2,467)	$ (5,330)
16	Spinning Reserve Cost Distribution Amount	$ 8,196	$ 8,638	$ 9,801	$ 7,085	$ 9,991	$ 6,317	$ 7,970	$ 5,279	$ 5,809	$ 10,533	$ 10,836	$ 10,470	$ 100,928
17														
18	**Spinning Reserve Subtotal**	**$ 1,732**	**$ (546)**	**$ (4,817)**	**$ (2,093)**	**$ (9,858)**	**$ (14,950)**	**$ (8,949)**	**$ (3,666)**	**$ (10,874)**	**$ 1,115**	**$ (11,411)**	**$ (6,281)**	**$ (70,598)**
19														
20														
21	Day Ahead Supplemental Reserve Amount	$ (20,069)	$ (31,309)	$ (3,424)	$ (2,936)	$ (7,573)	$ (8,870)	$ (15,246)	$ (13,942)	$ (10,458)	$ (7,930)	$ (7,031)	$ (3,376)	$ (132,162)
22	Real Time Supplemental Reserve Amount	$ 4,129	$ 2,609	$ 2,244	$ (9,148)	$ 2,896	$ 2,496	$ 4,216	$ 18,666	$ (9,050)	$ 2,737	$ 3,470	$ (1,306)	$ 23,959
23	Supplemental Reserve Cost Distribution Amount	$ 1,224	$ 1,429	$ 983	$ 1,074	$ 1,104	$ 1,083	$ 1,958	$ 1,764	$ 1,351	$ 1,846	$ 972	$ 1,228	$ 16,017
24														
25	**Supplemental Reserve Subtotal**	**$ (14,715)**	**$ (27,271)**	**$ (197)**	**$ (11,010)**	**$ (3,572)**	**$ (5,291)**	**$ (9,071)**	**$ 6,488**	**$ (18,157)**	**$ (3,347)**	**$ (2,589)**	**$ (3,453)**	**$ (92,186)**
26														
27														
28	Contingency Reserve Deployment Failure Charge Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Real Time Excessive Deficient Energy Deployment Charge Amount	$ 3,767	$ 3,774	$ 3,787	$ 3,748	$ 3,846	$ 3,893	$ 3,875	$ 3,834	$ 3,742	$ 3,858	$ 3,889	$ 3,869	$ 45,880
30	Net Regulation Adjustment Amount	$ 1,939	$ 1,942	$ 1,949	$ 1,929	$ 1,980	$ 2,004	$ 1,995	$ 1,973	$ 1,926	$ 1,986	$ 2,002	$ 1,991	$ 23,615
31														
32	**Other Charge Subtotal**	**$ 5,706**	**$ 5,716**	**$ 5,736**	**$ 5,677**	**$ 5,826**	**$ 5,896**	**$ 5,869**	**$ 5,807**	**$ 5,669**	**$ 5,843**	**$ 5,890**	**$ 5,861**	**$ 69,496**
33														
34	**TOTAL**	**$ (130,077)**	**$ (70,360)**	**$ (42,986)**	**$ (38,139)**	**$ (53,785)**	**$ (51,269)**	**$ (41,873)**	**$ (29,834)**	**$ (85,084)**	**$ (7,461)**	**$ (38,549)**	**$ (49,127)**	**$ (638,545)**

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
2026 WIND CURTAILMENT FORECAST

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	**Description**	**January-26**	**February-26**	**March-26**	**April-26**	**May-26**	**June-26**	**July-26**	**August-26**	**September-26**	**October-26**	**November-26**	**December-26**	**2026 Year End**
1	Forecasted Curtailment MWhs	(153.62)	(29.37)	484.63	32.25	656.61	1,009.47	410.61	(419.47)	94.56	944.42	156.21	466.38	3,652.68
2														-
3														
4	**Forecasted Wind Curtailment Cost - MN Share**	$ (2,812)	$ (538)	$ 8,916	$ 587	$ 12,270	$ 19,091	$ 7,730	$ (7,813)	$ 1,719	$ 17,701	$ 2,951	$ 8,767	$ 68,571

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOT
2026 SALES FORECAST KWH & ALLOCATI(

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Line No.	Description	January-26	February-26	March-26	April-26	May-26	June-26	July-26	August-26	September-26	October-26	November-26	December-26	2026 Year End
1	**Minnesota**													
2	Residential	66,657,227	58,629,015	50,076,490	38,484,943	32,731,654	34,404,236	40,370,418	37,798,395	32,692,218	36,791,997	46,532,173	60,695,090	535,863,856
3	Farm	4,753,685	4,362,937	3,947,986	3,353,768	3,153,450	3,475,775	4,543,590	4,791,530	4,082,836	3,940,756	5,426,615	4,993,316	50,826,244
4	Small Commercial	37,276,809	33,580,804	31,059,923	25,063,337	22,647,989	22,955,810	25,664,452	25,331,948	23,768,404	26,885,463	32,108,313	36,708,173	343,051,425
5	Large Commercial	165,404,583	155,639,414	156,084,363	142,690,897	145,931,547	143,042,400	145,897,439	142,231,026	132,524,665	149,214,660	163,132,956	172,628,991	1,814,422,940
6	OPA	1,865,923	1,751,351	1,742,143	1,670,387	1,748,769	1,724,560	1,748,722	1,723,078	1,669,958	1,699,072	1,697,784	1,783,496	20,825,243
7	Streetlighting	363,539	364,602	389,704	383,213	423,676	414,661	466,879	404,583	389,985	474,955	368,845	354,493	4,799,135
8	**Total - Minnesota kWh**	276,321,766	254,328,123	243,300,609	211,646,545	206,637,085	206,017,442	218,691,500	212,280,560	195,128,066	219,006,903	249,266,686	277,163,559	2,769,788,843
9														
10	**North Dakota**													
11	Residential	77,371,179	68,686,953	59,743,971	45,505,081	36,343,453	35,084,395	40,405,453	38,070,169	33,489,689	39,254,244	51,623,929	68,541,995	594,120,511
12	Farm	4,542,418	3,619,660	3,387,222	2,828,632	2,657,842	2,123,211	2,091,342	2,288,888	3,014,850	3,650,935	5,858,096	5,704,194	41,767,290
13	Small Commercial	56,794,821	50,952,759	45,828,955	35,239,237	28,806,295	25,683,927	28,236,126	28,628,705	29,094,896	35,613,171	45,929,099	55,635,118	466,443,109
14	Large Commercial	120,887,283	114,701,627	117,089,442	116,320,343	115,422,909	115,608,156	120,083,472	119,824,444	117,120,251	117,123,301	117,829,576	120,188,765	1,412,199,569
15	OPA	1,612,621	1,517,583	1,524,151	1,441,892	1,403,799	1,496,065	1,643,593	1,615,230	1,393,691	1,314,448	1,327,425	1,536,528	17,827,026
16	Streetlighting	545,696	502,047	527,440	488,205	482,761	450,044	531,310	464,672	469,536	465,627	447,983	439,601	5,814,922
17	**Total - North Dakota kWh**	261,754,018	239,980,629	228,101,181	201,823,390	185,117,059	180,445,798	192,991,296	190,892,108	184,582,913	197,421,726	223,016,108	252,046,201	2,538,172,427
18														
19	**South Dakota**													
20	Residential	14,946,367	13,235,568	11,664,260	9,155,125	7,768,531	7,717,400	8,783,110	8,437,535	7,238,966	7,763,205	9,821,949	12,816,916	119,348,932
21	Farm	1,105,799	997,485	854,818	687,753	581,583	583,015	639,978	683,957	602,576	655,294	1,088,563	1,095,802	9,576,623
22	Small Commercial	9,092,909	8,205,685	7,784,734	6,218,692	5,603,610	5,391,411	6,044,153	6,002,891	5,583,889	5,972,523	7,535,727	8,750,389	82,186,613
23	Large Commercial	27,962,728	26,520,040	26,177,060	25,652,831	27,415,470	26,500,929	27,821,244	28,094,457	27,137,469	26,771,470	25,985,846	25,526,291	321,565,835
24	OPA	417,863	382,709	403,012	372,391	366,778	356,549	364,954	364,517	337,758	344,741	348,992	390,735	4,450,999
25	Streetlighting	109,434	100,418	103,717	90,966	94,773	88,084	99,358	80,938	90,162	91,051	101,029	95,461	1,145,391
26	**Total - South Dakota kWh**	53,635,100	49,441,905	46,987,601	42,177,758	41,830,745	40,637,388	43,752,797	43,664,295	40,990,820	41,598,284	44,882,106	48,675,594	538,274,393
27														
28	**Municipals**	**[PROTECTED DATA BEGINS...**												
29	Newfolden, MN													
30	Nielsville, MN													
31	Shelly, MN													
29	Badger, SD													
32													**...PROTECTED DATA ENDS]**	
33	**Total - Municipals kWh**	409,734	302,726	258,926	173,552	127,182	125,081	138,896	147,449	185,537	247,501	290,156	378,733	2,785,473
34														
35	**Energy for System Use (kWh)**	592,120,617	544,053,383	518,648,317	455,821,245	433,712,071	427,225,709	455,574,489	446,984,411	420,887,336	458,274,415	517,455,056	578,264,087	5,849,021,136

36	**Total System Allocation**													
37	Minnesota Allocation	46.6665%	46.7469%	46.9105%	46.4319%	47.6438%	48.2222%	48.0035%	47.4917%	46.3611%	47.7895%	48.1717%	47.9303%	47.3547%
38	North Dakota Allocation	44.2062%	44.1098%	43.9799%	44.2769%	42.6820%	42.2366%	42.3622%	42.7067%	43.8557%	43.0794%	43.0986%	43.5867%	43.3948%
39	South Dakota Allocation	9.0581%	9.0877%	9.0596%	9.2531%	9.6448%	9.5119%	9.6039%	9.7686%	9.7391%	9.0772%	8.6736%	8.4175%	9.2028%
40	Municipal Allocation	0.0692%	0.0556%	0.0499%	0.0381%	0.0293%	0.0293%	0.0305%	0.0330%	0.0441%	0.0540%	0.0561%	0.0655%	0.0476%
41	**Total**	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Sales Forecast Description

Otter Tail Power Company (Otter Tail) developed its 2026 calendar year sales forecast in February 2025. The 2026 sales forecast statistical models use actual sales data through December 2024.

Otter Tail's sales estimate was developed by creating sales forecasts for the following classes:

- Residential
- Farm
- Small Commercial
- Large Commercial/Pipelines[1]
- Other Public Authority (OPA)
- Streetlighting
- Unclassified[2]

To develop the 2026 Sales Forecast, Otter Tail used the forecasting software MetrixND (developed by Itron - https://www.itron.com/na/pages/default.aspx). Econometric models were developed by state and by class. For most classes, Otter Tail used MetrixND to forecast both the Use-Per-Meter (UPM) and the Number of Meters for each state and class by month using historical sales, meter counts, economic data and weather data. For all classes, except Streetlighting, 20 years of historical data was used. With projects underway or recently completed to update streetlights to LED, shorter timeframes were used to develop those forecasts. The total sales forecast for each class was calculated by multiplying the forecasted UPM by the forecasted number of meters. These sales class models were summed at the state level to yield a state sales forecast, then all state forecasts were summed to produce a sales forecast at the system level.

Otter Tail does not model the pipeline customer's forecast. Pipeline pumping load is very significant, and it is best forecasted with direct input from the customers themselves. This load is also significantly impacted by world and national economic trends as well as federal and state energy and environmental policy. Otter Tail employs individuals that specialize in working with large commercial customers. They work very

[1] Sales for the Large Commercial and Pipeline classes have been combined to protect individual customer usage information (pertains to MN and ND only).
[2] Unclassified sales include company use and are not applicable to the Energy Adjustment Rider calculation. Otter Tail must forecast Unclassified sales to determine its overall load but forecasted kWh sales for the Unclassified class are not included in the Energy Adjustment Rider calculation.

closely with the pipeline companies to acquire updated projections on demand (kW) and energy (kWh). For the purposes of this sales forecast, pipeline sales were developed based on the projections from the pipeline companies with input from Otter Tail's specialists.

In addition to the pipelines, a few Large Commercial customers are known to be starting service or making modifications to their existing service. These additions or modifications are also being accounted for in this forecast.

Class Forecasts

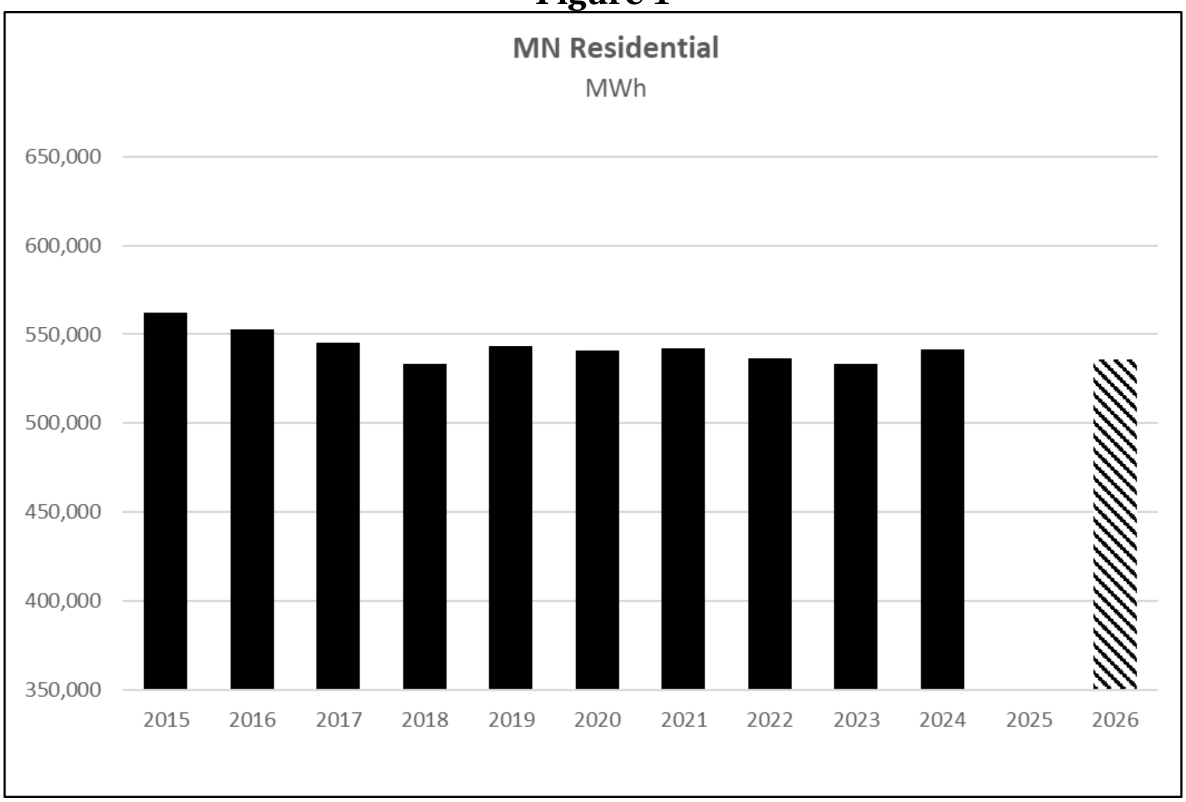
As noted earlier, Otter Tail developed its sales forecast at a class level for each state. Below is a discussion of each of the classes forecasted. In each of the bar graphs below, the solid bars represent weather normalized actual sales and the lined bars represent the 2026 weather normalized forecasted sales.

Minnesota

a) Residential

For the Minnesota Residential class, Otter Tail used weather and the Number of Households to forecast 2026 kWh sales. This class is extremely weather-sensitive, so weather is an important predictor of sales. Figure 1 shows the historic weather normalized sales and 2026 forecasted sales for the Minnesota Residential Class.

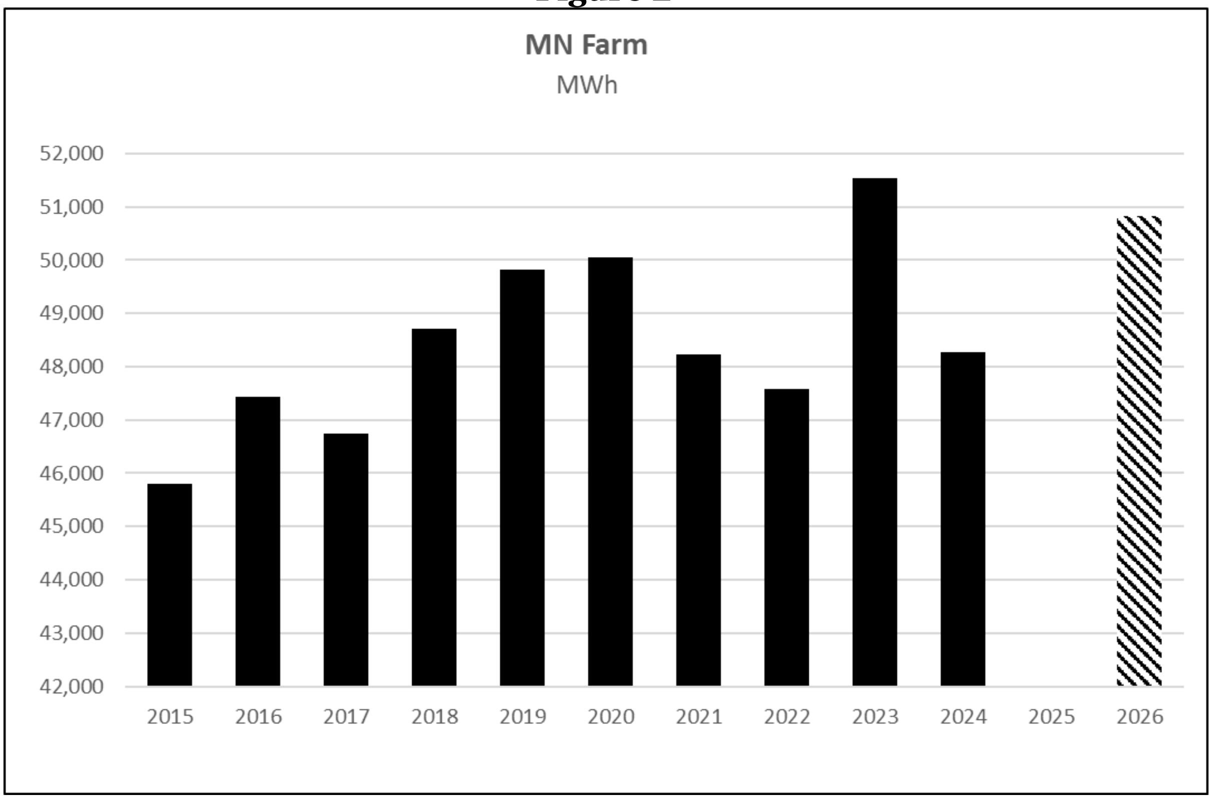
Figure 1



b) Farms

A historical sales trend was used as a predictor of farm UPM. Farm Employment was used as a predictor of farm meter counts. Weather also plays a part in predicting sales for this class. See Figure 2 for the historic weather normalized sales and 2026 forecasted sales for the Minnesota Farm Class.

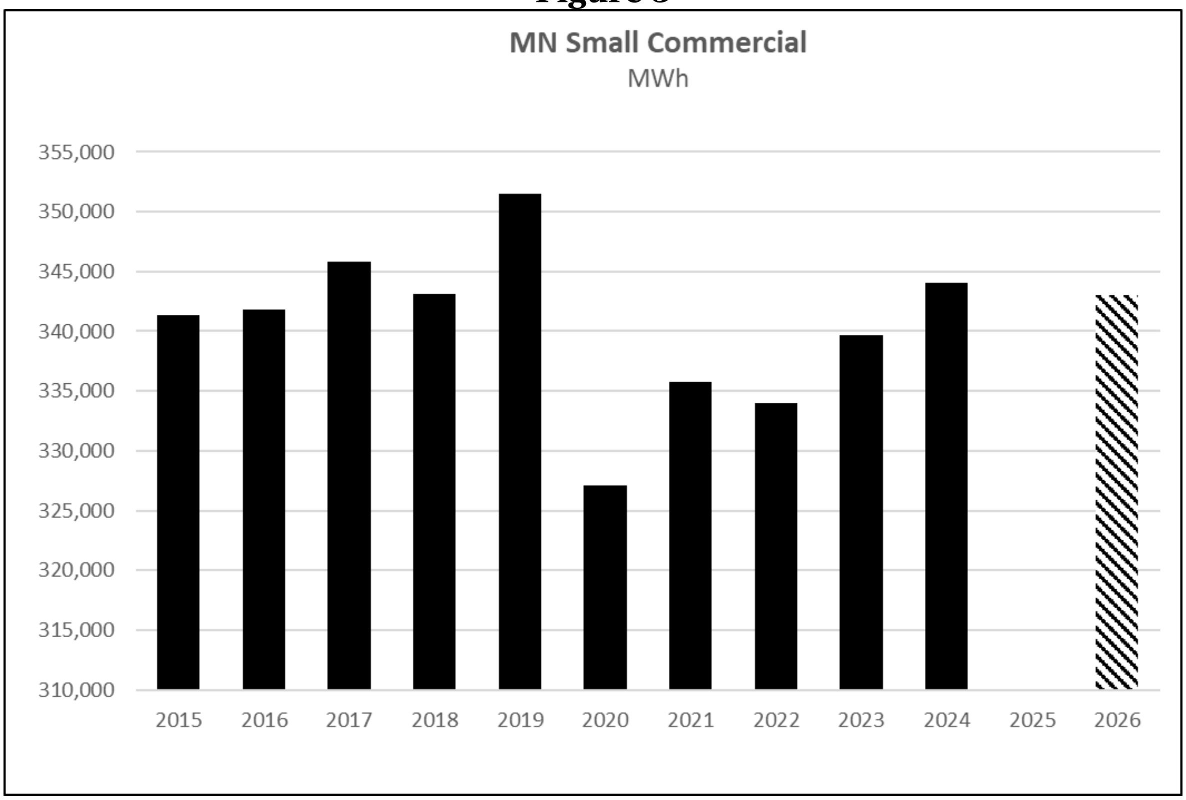
Figure 2



c) Small Commercial

The primary forecasting variables used for the Small Commercial class were weather and the Gross Regional Product economic variable. This class saw a large decrease in sales in 2020, most likely due to COVID; however, sales has continued to rebound from the 2020 level. Figure 3 shows the historic weather normalized sales and 2026 forecasted sales for the Small Commercial class.

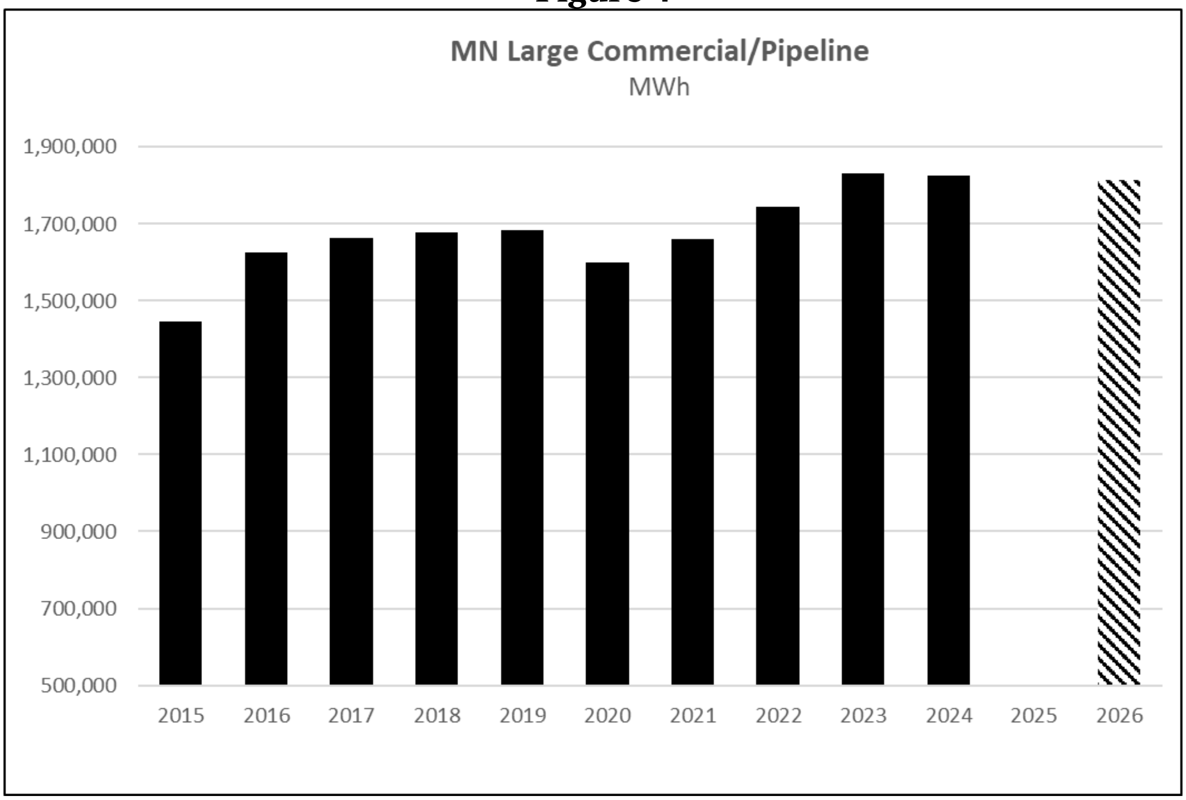
Figure 3



d) MN Large Commercial/Pipeline

Gross Regional Product was a key variable in the Large Commercial forecast. Pipelines are forecasted separately from the Large Commercial customers, as described above. Figure 4 details the historic weather normalized sales and 2026 forecasted sales for the combined Large Commercial and Pipeline classes.

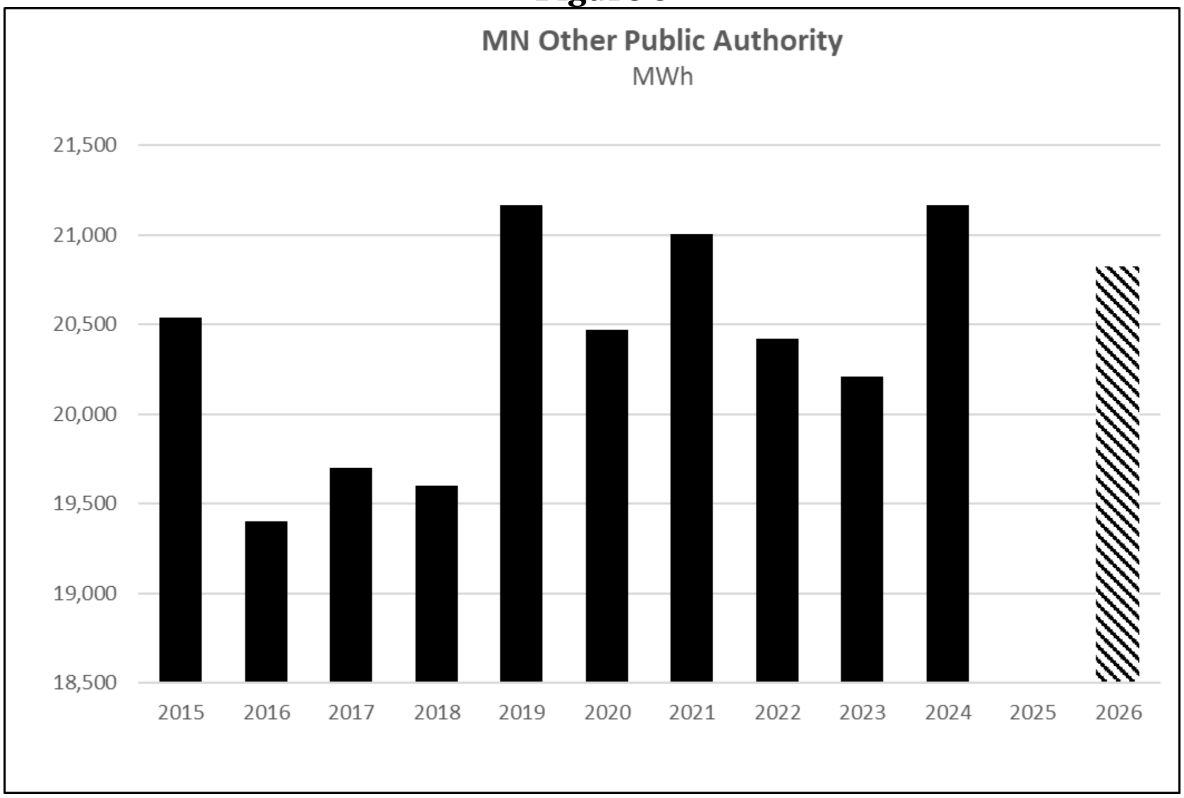
Figure 4



e) Other Public Authority (OPA)

Weather, along with historical sales, was used as a variable to forecast sales for this class. Refer to Figure 5 below for historic weather normalized sales and 2026 forecasted sales for the OPA Class.

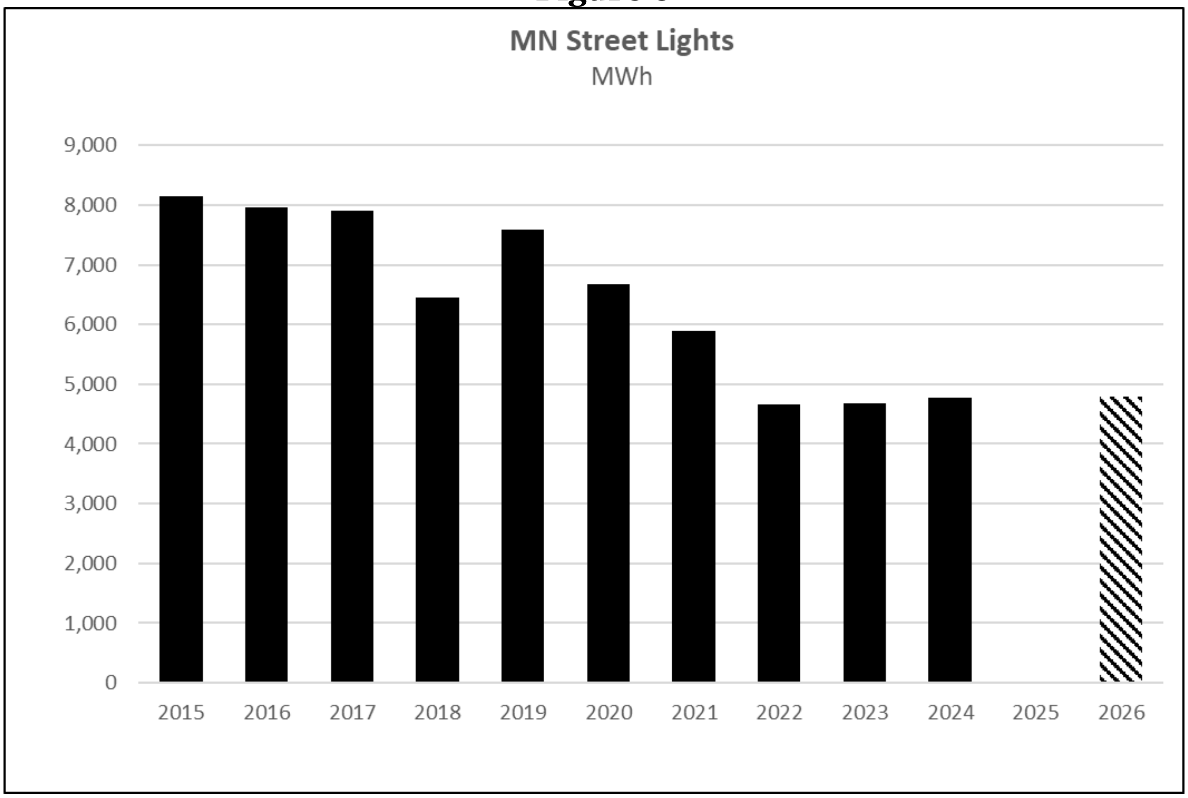
Figure 5



f) Street Lighting

Otter Tail's Street Lighting forecast shows a downward trend due to the deployment of more efficient LED bulbs. Figure 6 details the historic sales and 2026 forecasted sales for this class.

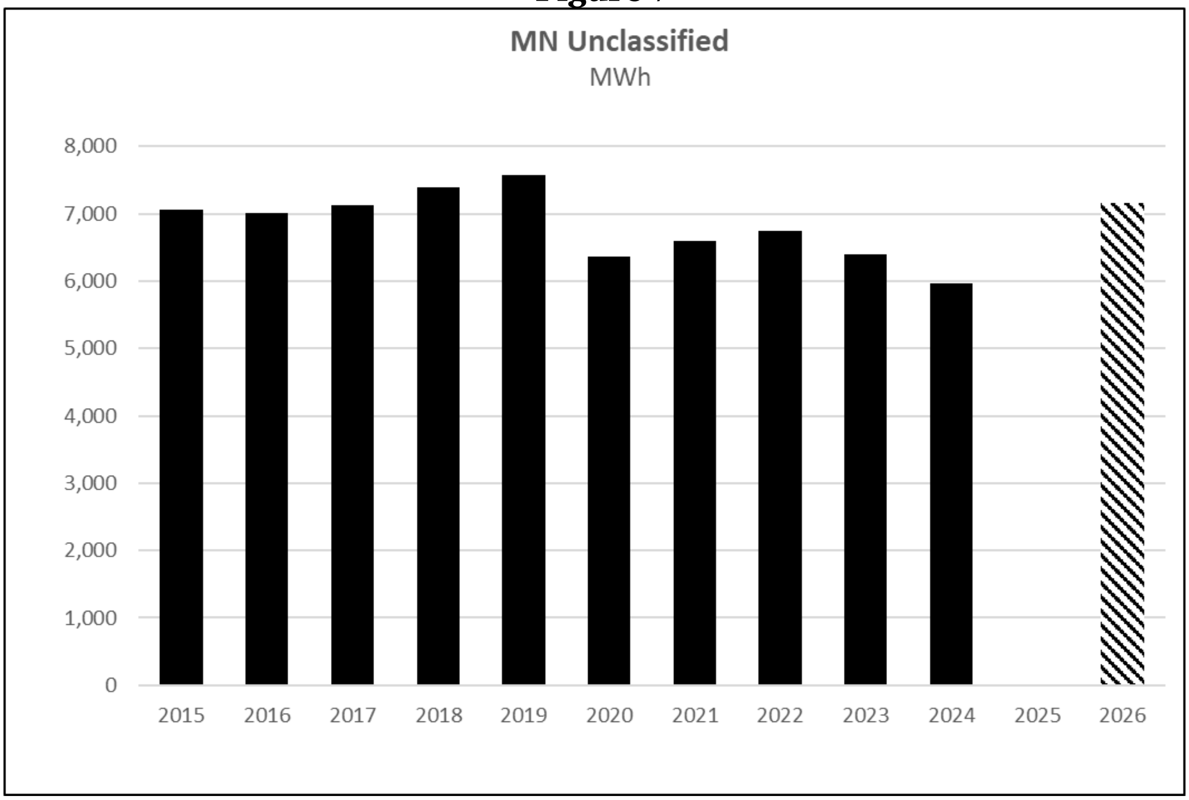
Figure 6



g) Unclassified

This class is made up of Company Use accounts. It is mainly Otter Tail's own use of electricity. It makes up less than 0.3 percent of Otter Tail's total Minnesota kWh sales. See Figure 7 for the historic weather normalized sales and 2026 forecasted sales for this class.

Figure 7

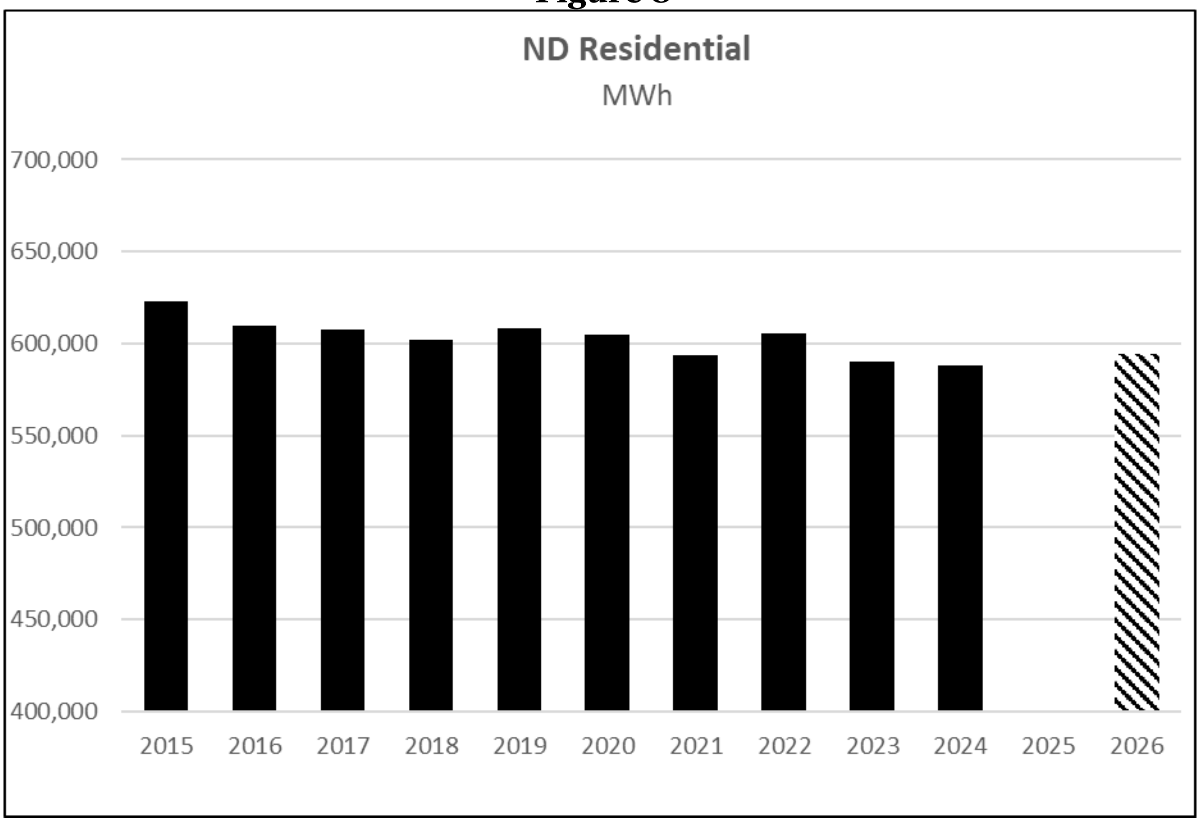


North Dakota

a) Residential

For the North Dakota Residential class, Otter Tail used weather and historical sales to forecast 2026 kWh. This class is extremely weather-sensitive, so weather is an important predictor of sales. Sales within this class have modestly declined since 2015. Figure 8 shows the historic weather normalized sales and 2026 forecasted sales for the North Dakota Residential class.

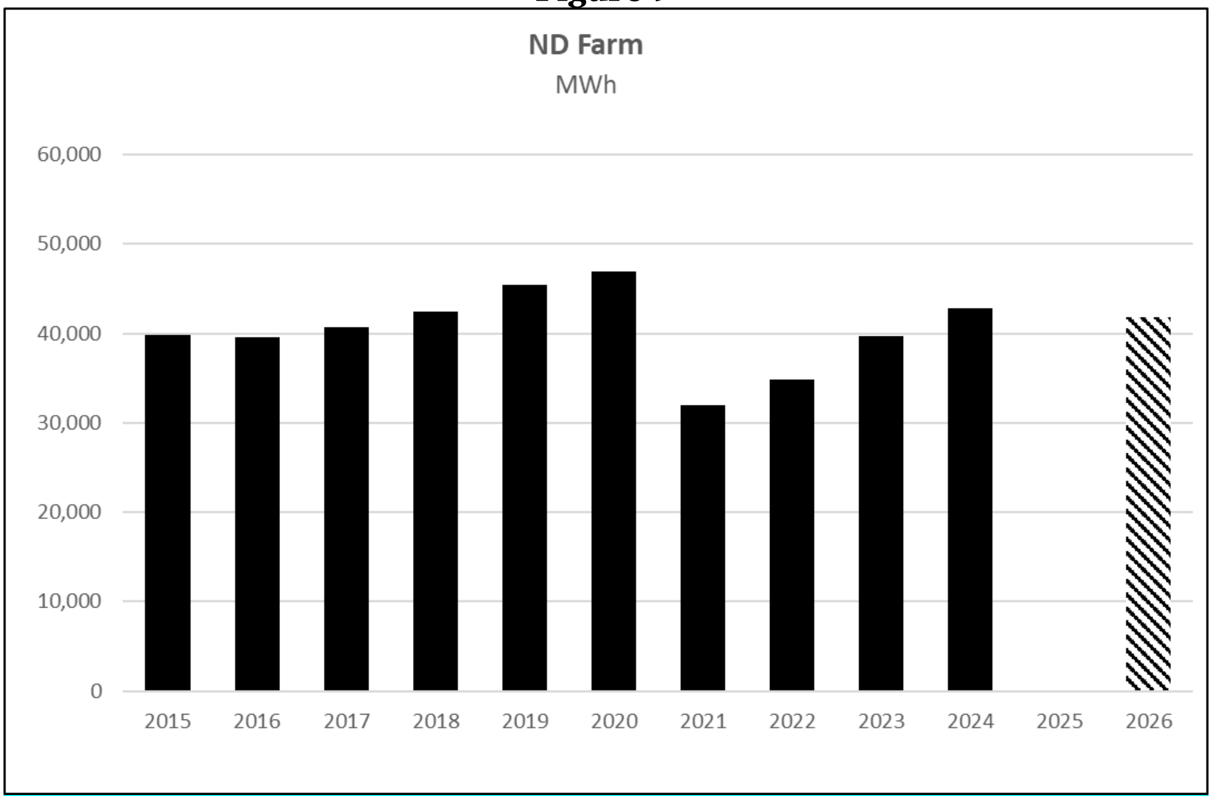
Figure 8



b) Farms

In the North Dakota Farm class, weather and the Farm Employment economic variable were selected to predict sales for this class. See Figure 9 for the historic weather normalized sales and 2026 forecasted sales for the Farm class.

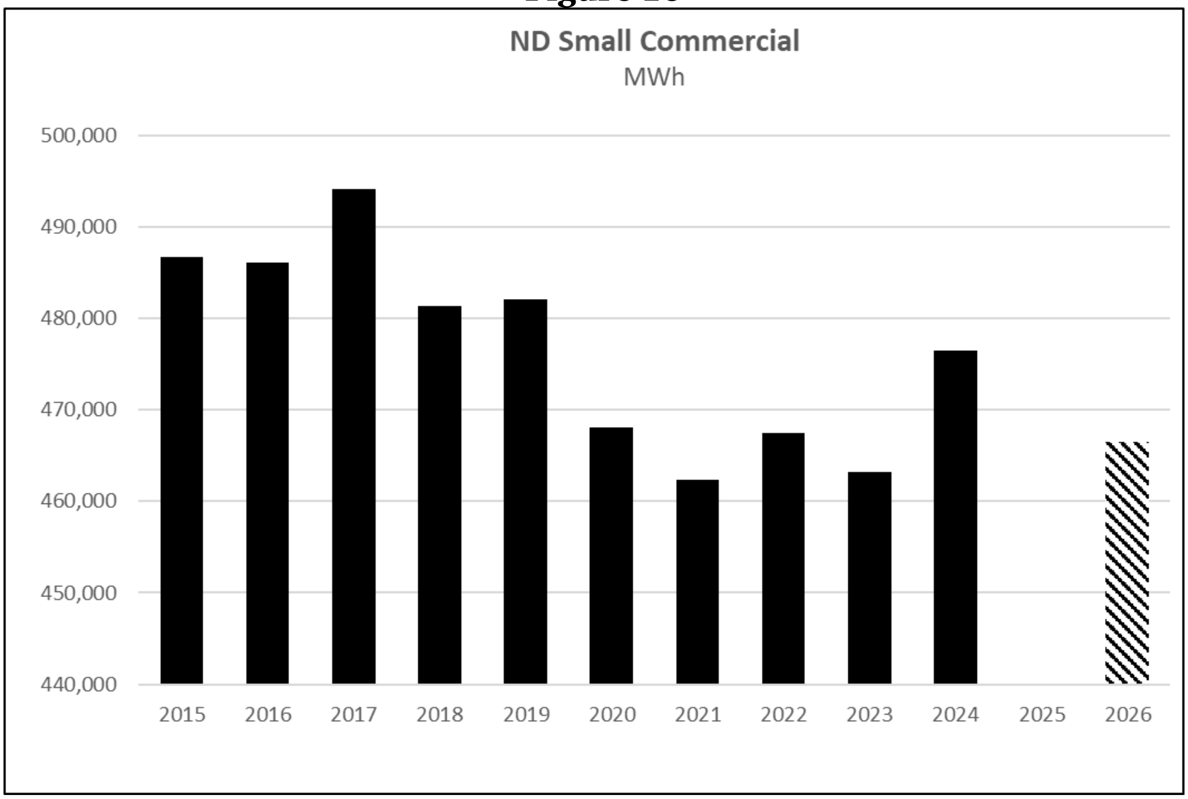
Figure 9



c) Small Commercial

The main forecasting variables used for the North Dakota Small Commercial class were weather and Gross Regional Product. Though we have seen some recovery in recent years, the decline in UPM from efficiency improvements is evident in the predicted lower sales. Figure 10 shows the historic weather normalized sales and 2026 forecasted sales for the Small Commercial class.

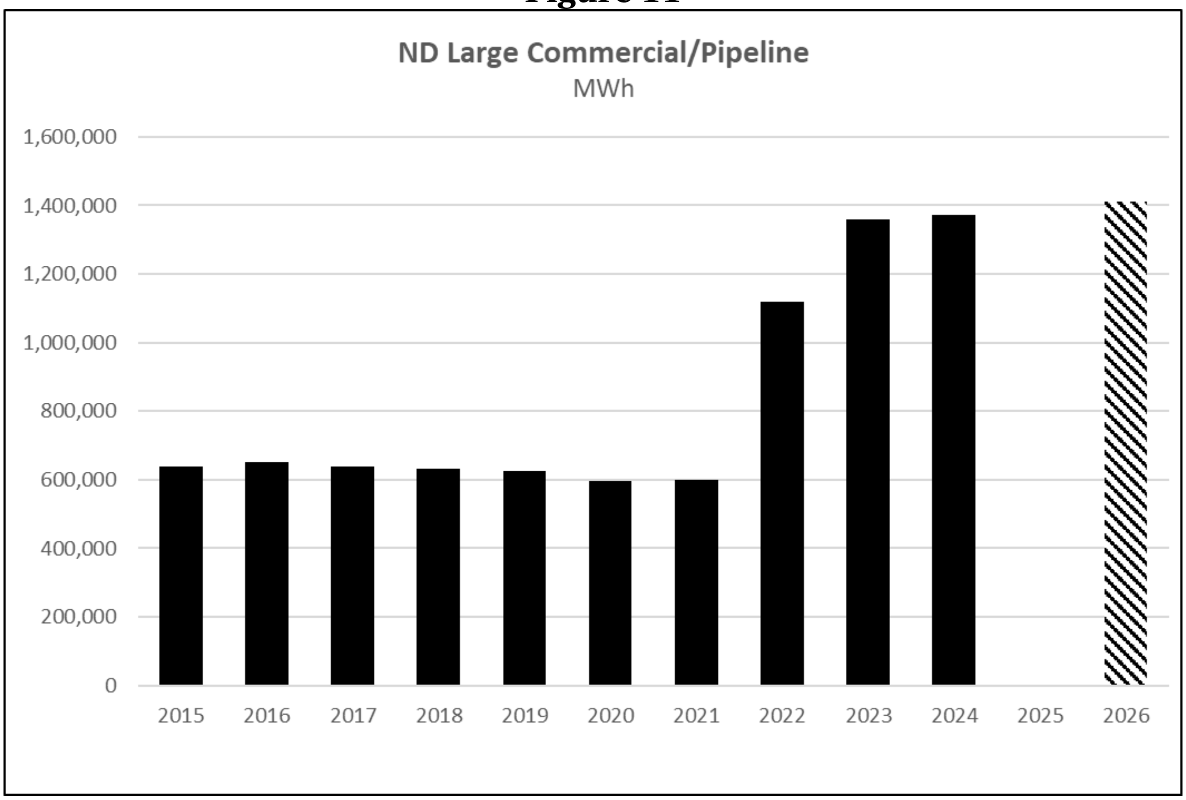
Figure 10



d) Large Commercial/Pipeline

Historical sales were used as a key predictor for the Large Commercial forecast. Pipelines are forecasted separately from the other Large Commercial customers, as described above. There was a significant increase in sales for this class in 2022 with the addition of new Large Commercial load and additional new load is expected through 2025. Figure 11 details the historic weather normalized sales and 2026 forecasted sales for the ND Large Commercial/Pipeline classes.

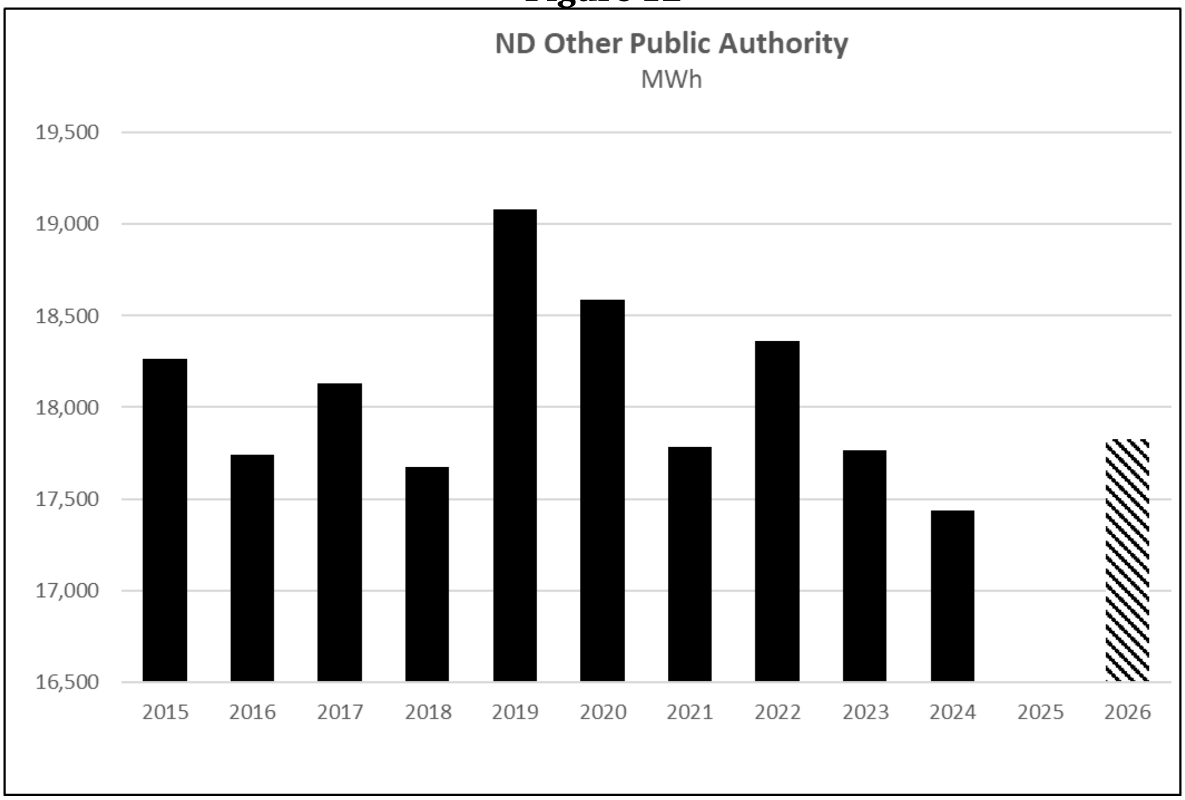
Figure 11



e) Other Public Authority (OPA)

Weather and a historical sales trend were the significant forecasting variables used for this class. Sales are forecast to be slightly higher, after a decrease in 2024. Refer to Figure 12 below for historic weather normalized sales and 2026 forecasted sales for the North Dakota OPA class.

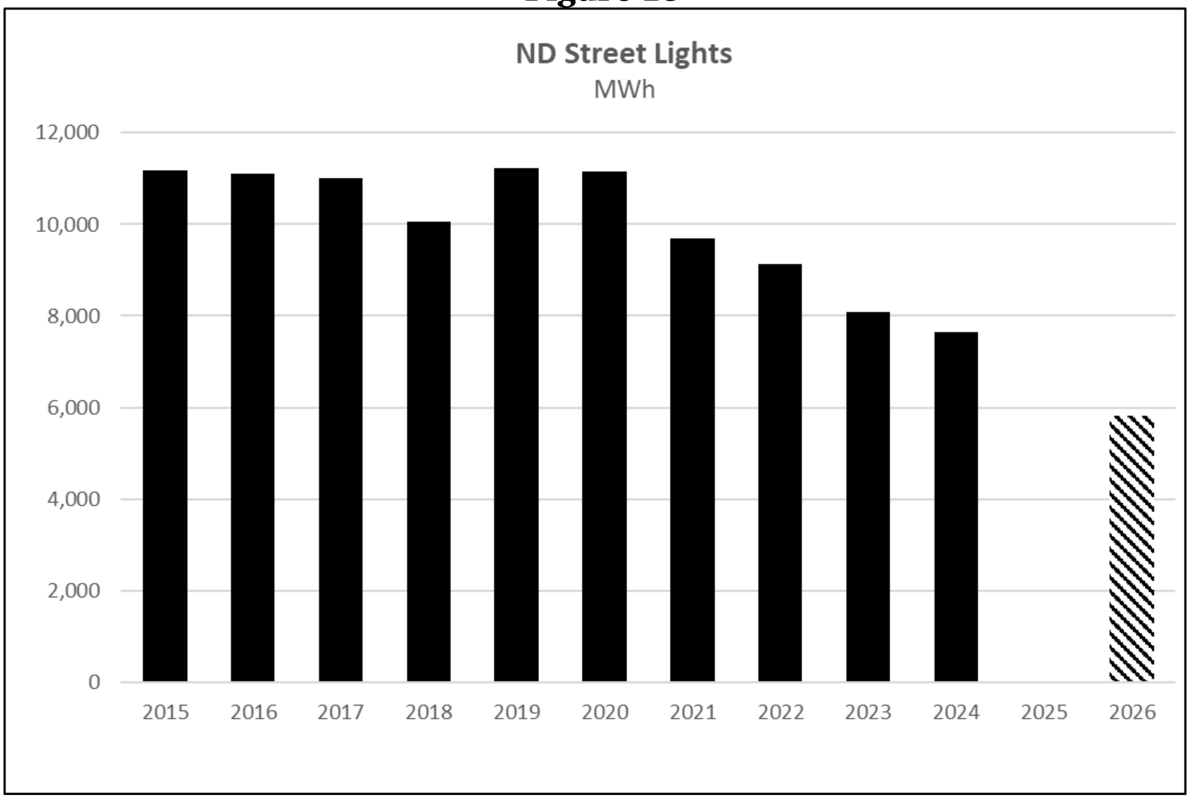
Figure 12



f) Street Lighting

Historically, Otter Tail's North Dakota Street Lighting forecast showed very little change over the past 20 years until recent year. There is currently an effort to switch street lighting to LED bulbs, which decreased kWh sales in 2021 and 2022 and is expected to continue that decrease into 2026. Figure 13 details the historic sales and 2026 sales forecast for this class.

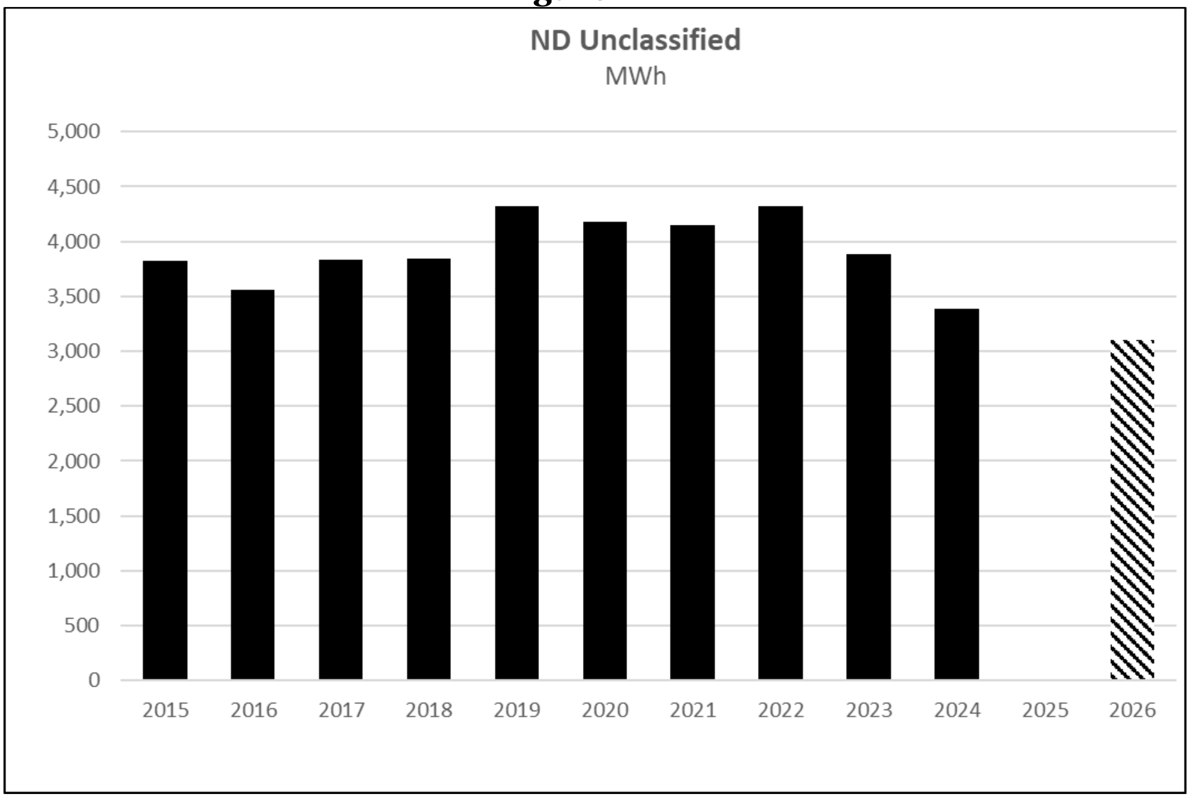
Figure 13



g) Unclassified

This class is made up of Company Use accounts. It is mainly Otter Tail's own use of electricity. It makes up approximately 0.1 percent of Otter Tail's total North Dakota kWh sales. See Figure 14 for the historic weather normalized sales and 2026 forecasted sales for this class.

Figure 14

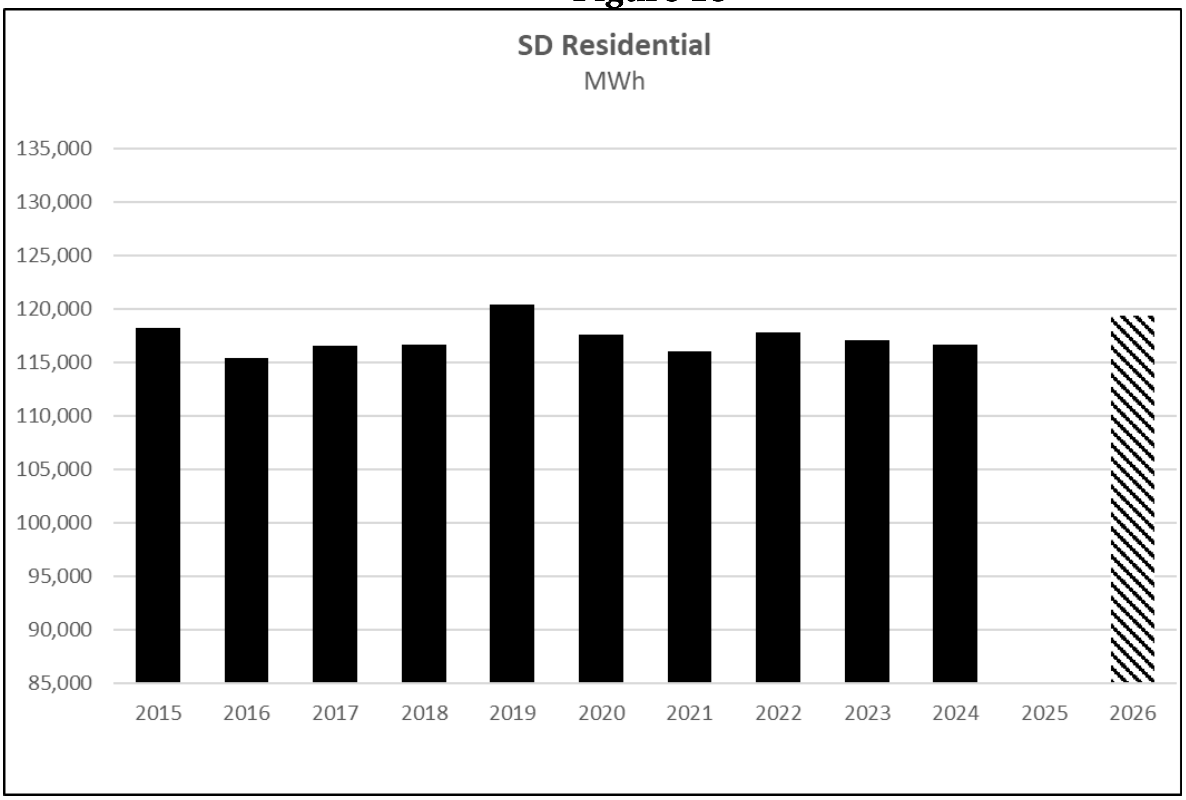


South Dakota

a) Residential

Otter Tail used weather and a historical sales trend variable to forecast the 2026 South Dakota Residential sales. This class is extremely weather-sensitive, so weather is an important predictor of sales. Figure 15 shows the historic weather normalized sales and 2026 forecasted sales for the South Dakota Residential class.

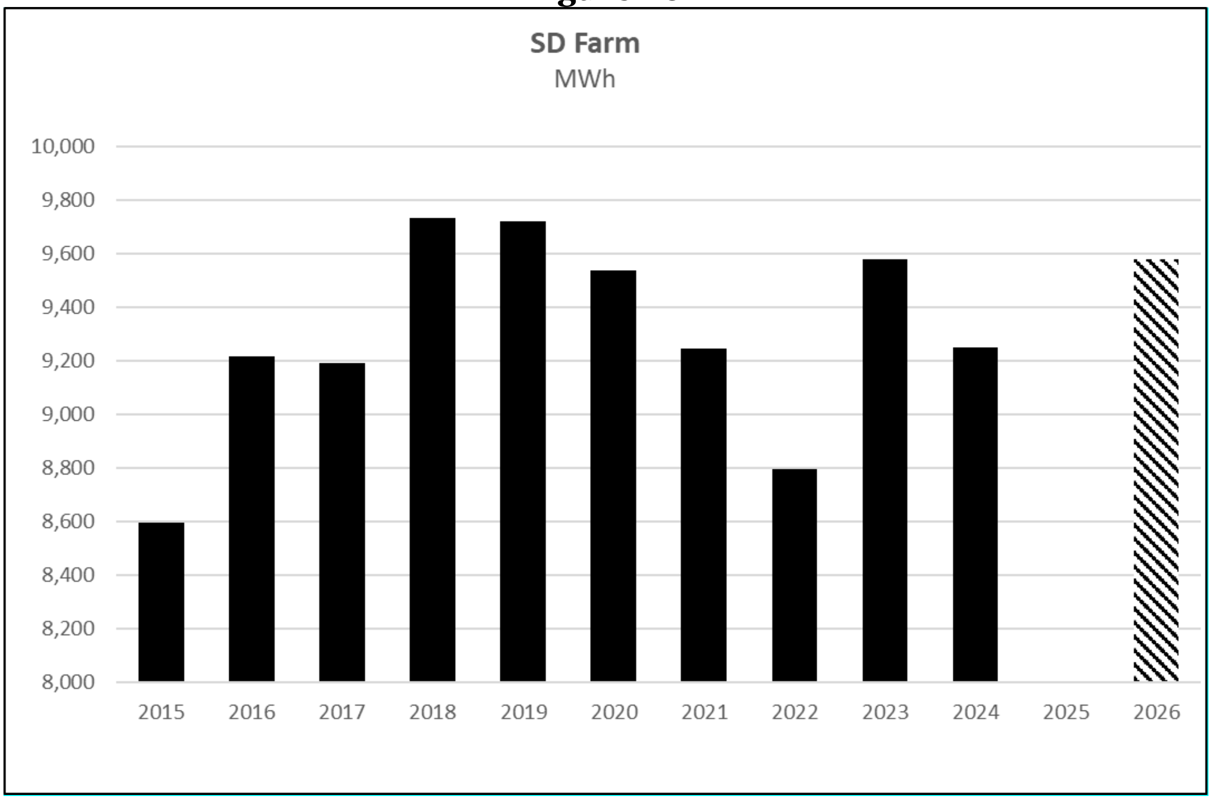
Figure 15



b) Farms

A historical sales trend and weather were the main predictors in the SD Farm class model. See Figure 16 for the historic weather normalized sales and 2026 forecasted sales for this class.

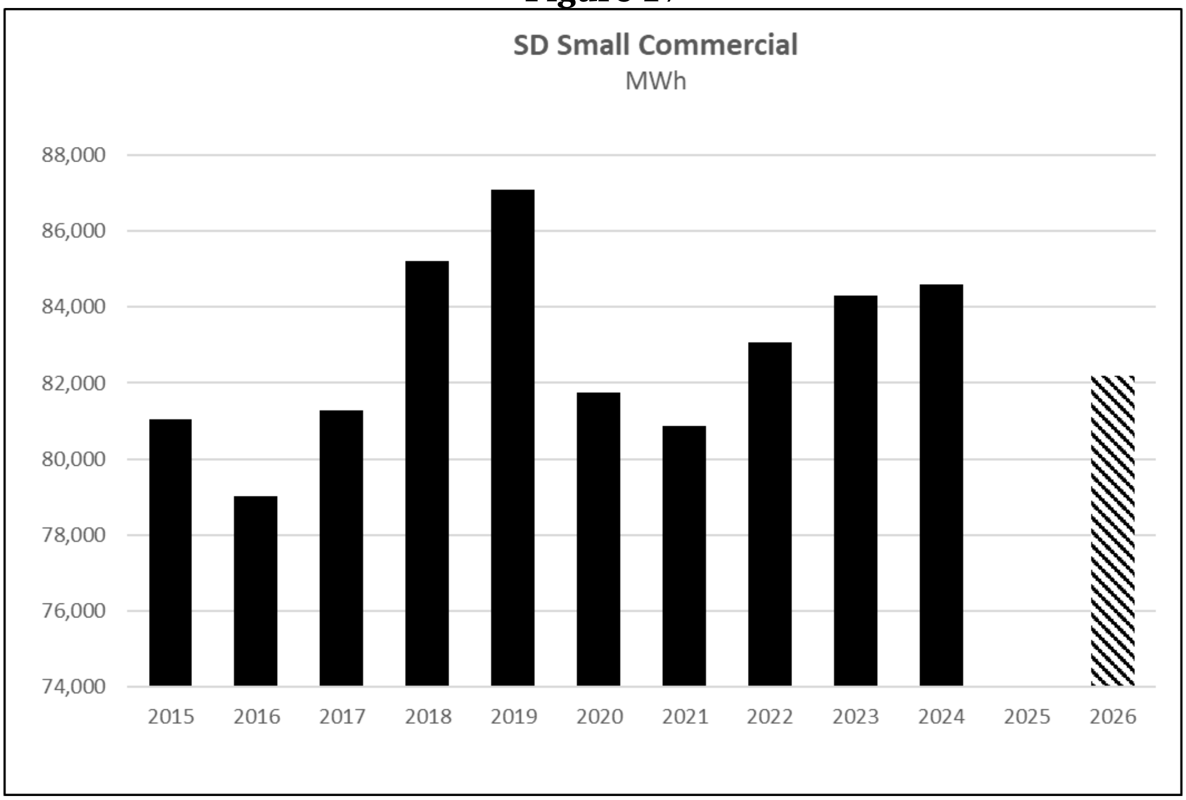
Figure 16



c) Small Commercial

In the South Dakota Small Commercial class, a historical sales trend and weather were used to predict sales. Though we have seen some rebound in this class since 2021, with the declining UPM due to efficiencies, the sales in this class are predicted to be lower in 2026. Figure 17 shows the historic weather normalized sales and 2026 forecasted sales for the Small Commercial class.

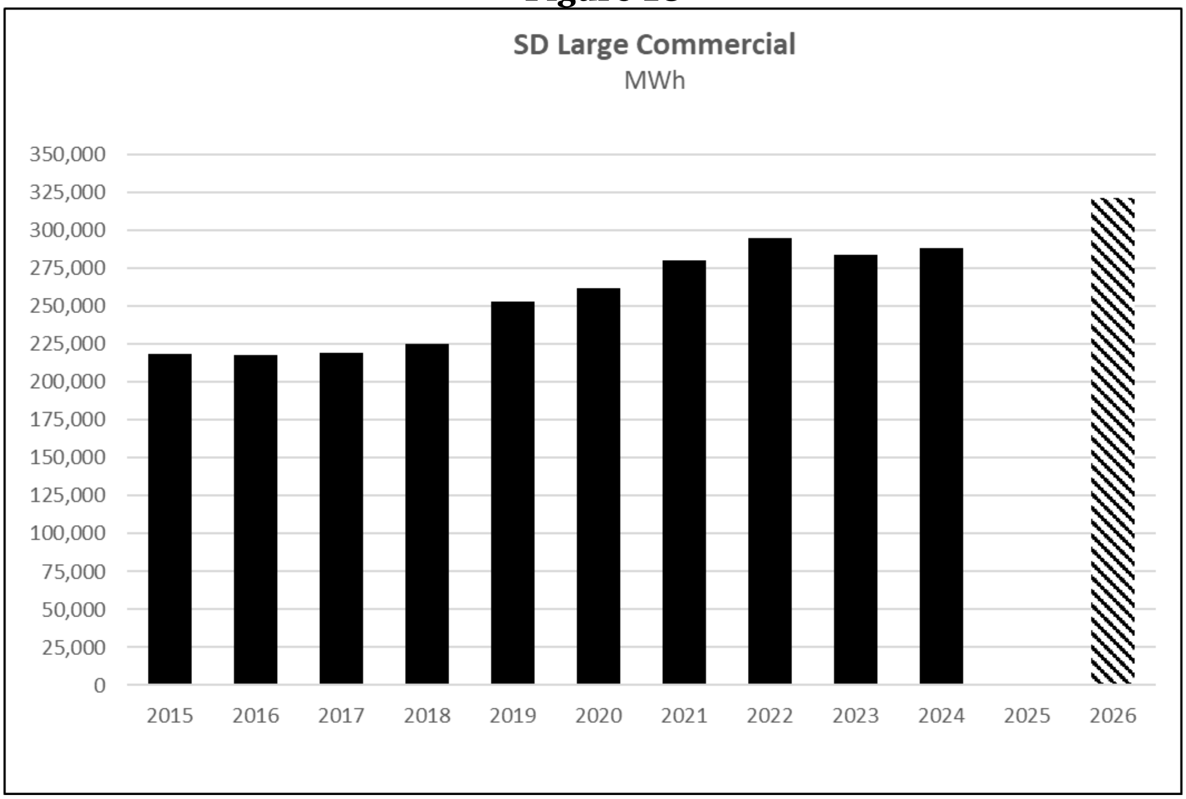
Figure 17



d) Large Commercial

The South Dakota Large Commercial class has been relatively consistent in recent years. Along with known growth at one customer's location, the Gross Regional Product economic variable represents growth in this class. Figure 18 details the historic weather normalized sales and 2026 forecasted sales for the Large Commercial class.

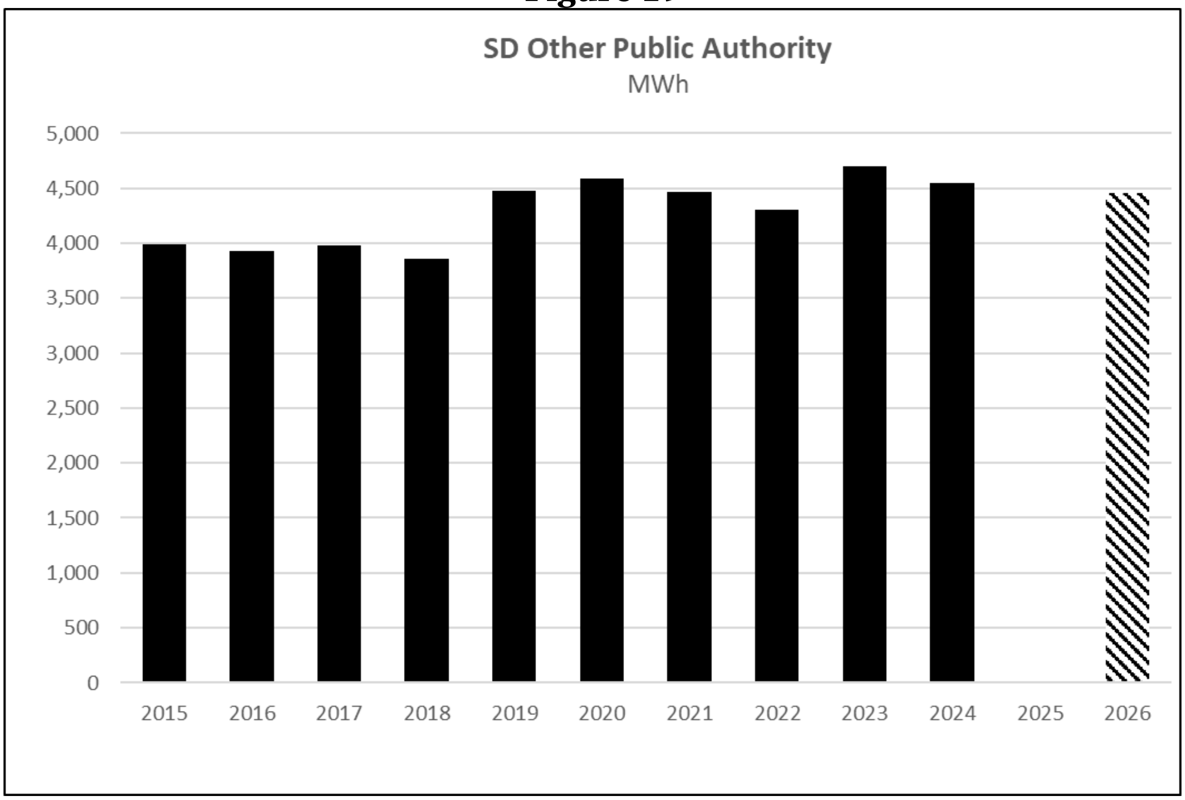
Figure 18



e) Other Public Authority (OPA)

Using a historical sales trend, the South Dakota OPA class is predicted to remain relatively the same in 2026. Refer to Figure 19 below for historic weather normalized sales and the 2026 forecasted sales for the OPA class.

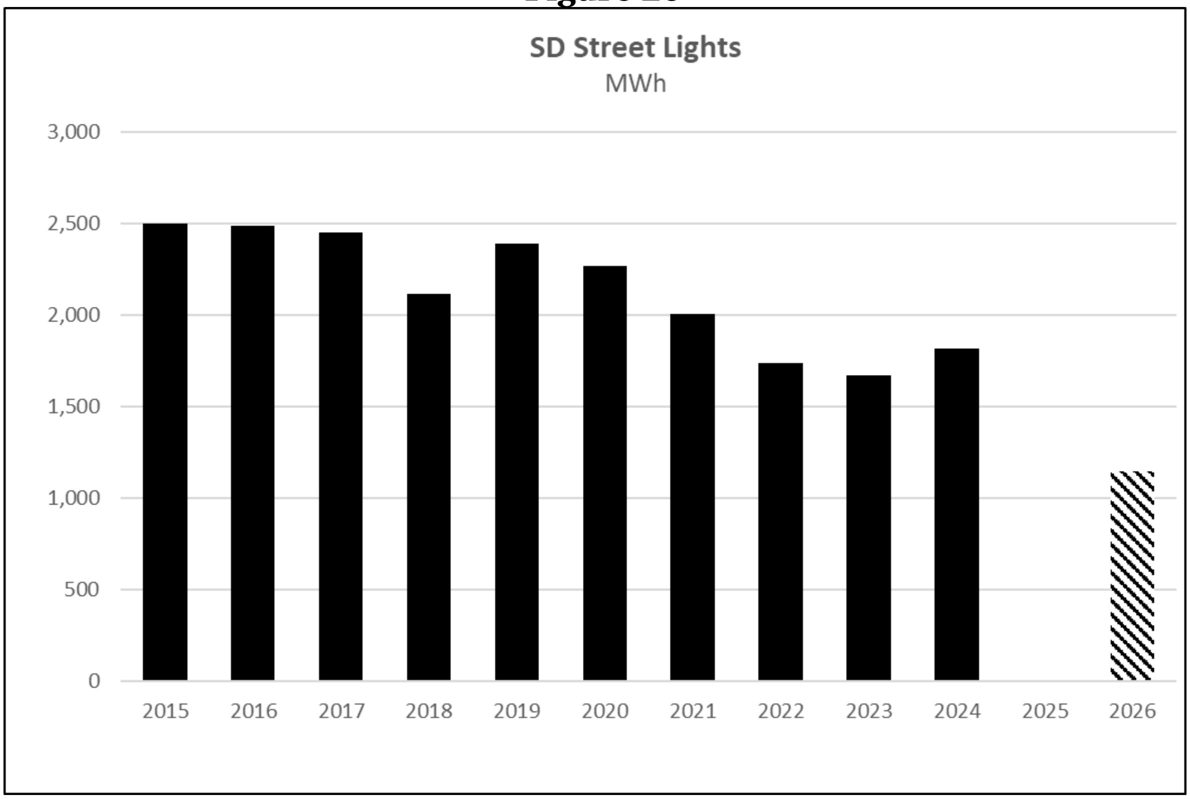
Figure 19



f) Street Lighting

Otter Tail's South Dakota Street Lighting sales have declined in recent years and is expected to continue into 2026 with the replacement of fixtures to LED bulbs. Figure 20 details the historic sales and 2026 forecasted sales for this class.

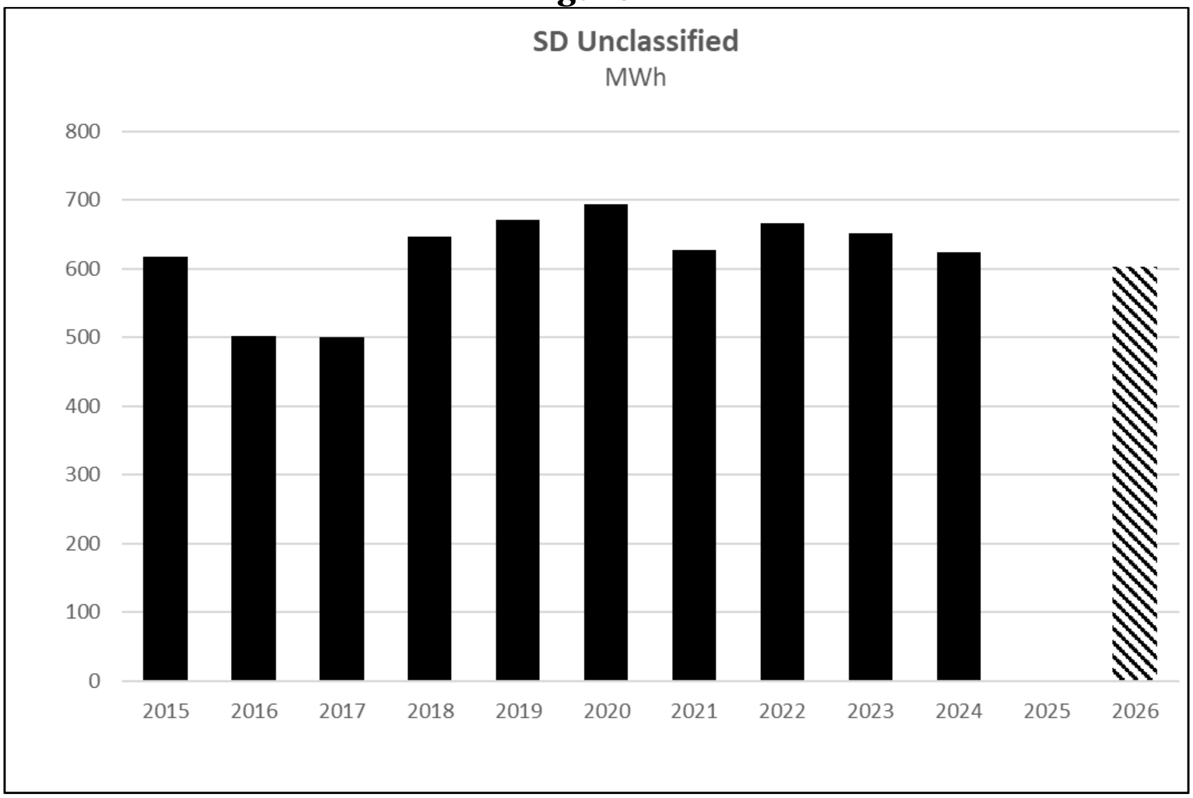
Figure 20



g) Unclassified

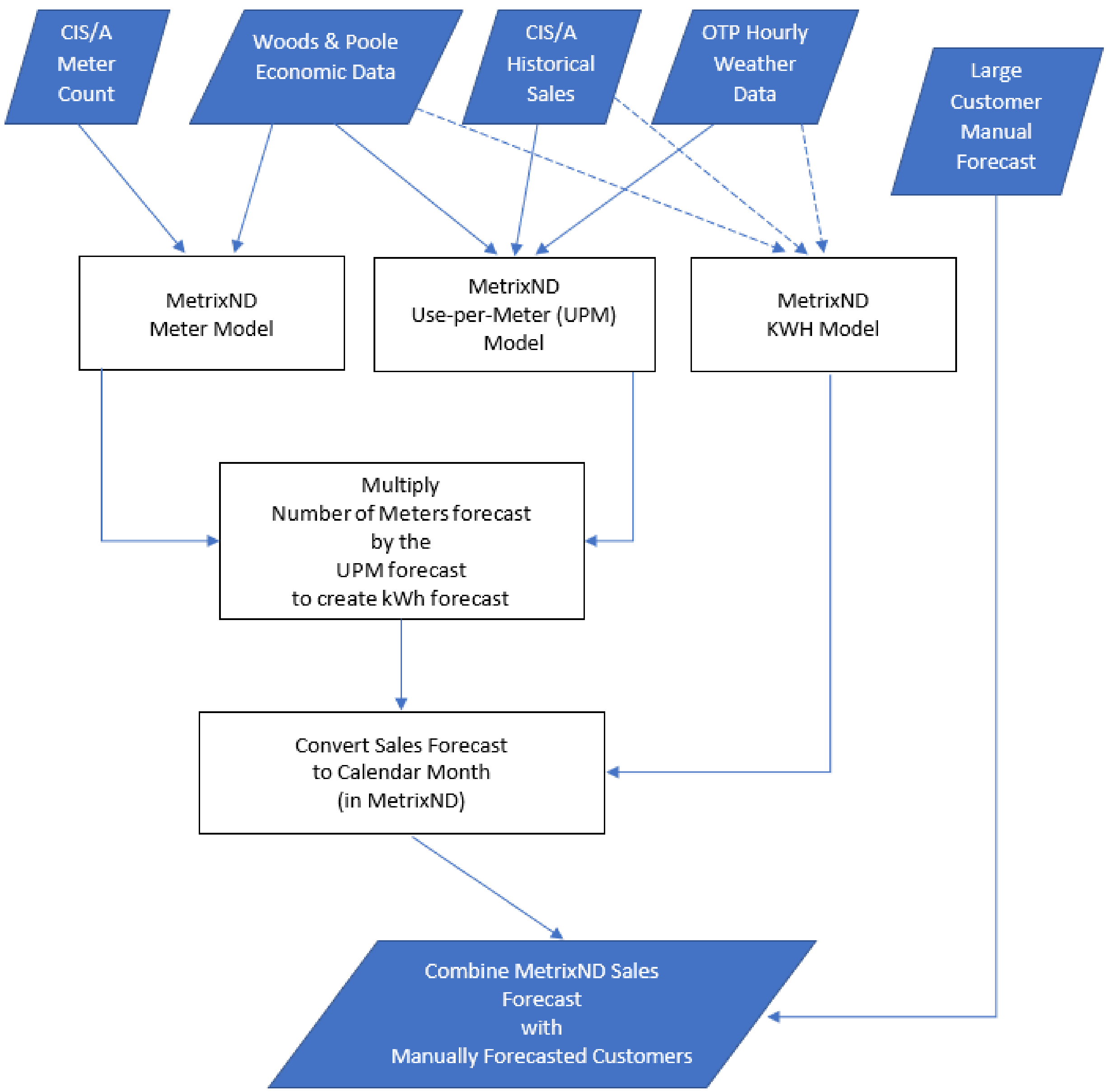
This class is made up of Company Use accounts. It is mainly Otter Tail's own use of electricity. It makes up 0.1 percent of Otter Tail's total South Dakota kWh sales. See Figure 21 for the historic weather normalized sales and 2026 forecasted sales for this class.

Figure 21



Sales Model Description

The following flowchart is the process Otter Tail follows to create its sales forecast.



Meter Count Model

The meter count models, designed in MextrixND, forecast monthly meter counts by state and by class, based on historical meter counts, economic indicators and various binary variables. 2024 Woods and Poole (developed by Woods & Poole Economics, Inc. - http://www.woodsandpoole.com) data was used for all economic data variables. The variables most often used are Number of Households and Gross Regional Product.

Use-Per-Meter (UPM) Model

The UPM Models, also designed in Metrix ND, forecast estimated monthly UPM as a function of historical usage, econometric indicators, weather conditions and binary variables. Weather conditions are represented using monthly heating degree days and cooling degree days (definitions to follow), with a base of 65 degrees for cooling and 55 degrees for heating. In some cases, binary variables are included in the equation to account for unique events in the historical period.

1. MODEL INPUTS

a) Sales and Meter Count Historical Data

<u>Adjustments Made</u>

Monthly kWh data was graphed, and values were checked for errors due to meters not being billed, being billed twice in one month, etc. As described in detail below, any bill adjustments are applied to the month in which the error occurred. In most cases corrections are found and downloaded during the following month's billing updates.

<u>Detailed Information</u>

Historical kWh data and the number of meters are read from Otter Tail's SAS CIS/A data sets. These SAS data sets are created from extracts of Otter Tail's Customer Information System (CIS), which are downloaded the first day of each month containing the prior month's billing data. The datasets include billing adjustments of prior bills to appropriately reflect actual usage and billing in the month of the original bill. Any changes made in Otter Tail's CIS are included in the CIS/A extract files, and the corrections are made to the month the error occurred (as opposed to the month the adjustment was made). For example, if a customer has a bill adjustment to their July bill, but the need for the adjustment was not determined or made in the CIS until December, the adjustment in the

CIS/A data set would adjust the July bill, not the December bill. Meter count and UPM are derived from this dataset.

b) Otter Tail Power Company's Weather Data

Adjustments Made

Otter Tail graphs hourly monitoring station temperatures each month after downloading the data. Any missing or obviously bad temperatures are corrected based on temperatures from other nearby monitoring points or by judgment when necessary.

Detailed Information

Otter Tail used 20 years of historical weather in its 2026 Sales Forecast. This weather was collected from 2005 through 2024, from 12 monitoring stations throughout Minnesota, North Dakota, and South Dakota. Otter Tail's service territory is broken up into 12 geographic divisions. There is one weather station in each of Otter Tail's 12 divisions so that the weather across Otter Tail's entire service territory is well represented.

The UPM forecast uses heating degree days (HDD) and cooling degree days (CDD) as inputs – values calculated from dry bulb temperatures in the weather data referenced above. For each weather station, an average dry bulb temperature is calculated for each day. The HDD are then calculated by subtracting the average daily temperature from 55 degrees (the base). For example, if the average temperature for the day is 30 degrees, the HDD for that day is 25 (55-30). CDD are calculated by subtracting 65 (the base) from the average daily temperature. For example, if the average daily temperature is 70 degrees, the CDD for that day is 5 (70-65).

To determine the HDD and CDD for Minnesota, the weather stations in Minnesota are weighted by sales and summed.

MN Daily Heating Degree Days=
[(Station 1 Sales/Total MN Sales)*Station 1 HDD]+
[(Station 2 Sales/Total MN Sales)*Station 2 HDD]+ …
[(Station 6 Sales/Total MN Sales)*Station 6 HDD]

MN Daily Cooling Degree Days=
[(Station 1 Sales/Total MN Sales)*Station 1 CDD]+
[(Station 2 Sales/Total MN Sales)*Station 2 CDD]+ …
[(Station 6 Sales/Total MN Sales)*Station 6 CDD]

This process is repeated for North Dakota and South Dakota.

Otter Tail creates HDD and CDD based on billing month weather and calendar month weather. The process is as follows:

1. *Billing Month HDD and CDD:*
   Daily HDD and CDD are added by billing cycle to determine the HDD and CDD for each cycle per month. Once a HDD and CDD value for each cycle and month is obtained, all the cycles are combined into one billing month, averaging the cycle HDD and the cycle CDD. An HDD value and a CDD value for each billing month have now been created.

   Next, Normal Billing HDD and CDD is calculated by averaging 20 years of monthly billing HDD and CDD. These values are used in the sales forecast.

2. *Calendar Month HDD and CDD:*
   Daily HDD and CDD are added by calendar month.

   Normal Calendar HDD and CDD are calculated by averaging 20 years of monthly Calendar HDD and CDD. These values are used in the sales forecast.

Otter Tail's sales forecast uses weather normalization principally to compare the sales forecast to weather normalized historical data. HDD and CDD may be used in all models with the exception of street lighting as that usage is not considered temperature sensitive. Most of Otter Tail's other customer classes have some level of weather sensitivity.

c) Woods & Poole Economics, Inc.

<u>Adjustments Made</u>

None

<u>Detailed Information</u>

In its 2026 sales forecast, Otter Tail used economic data from Woods & Poole Economics, Inc. Their database contains historical economic and demographic data through 2022 and forecast economic and demographic data through the year 2060. Otter Tail subscribes to this information by county to use primarily in its meter models.

The sales forecast used the following variables from Woods & Poole:

•*Number of Households*

•*Farm Employment*

•*Gross Regional Product*

Otter Tail does not serve the entire load in the counties within its service territory. This is especially problematic when Otter Tail does not serve a large city that has a significant impact on the economy of the county. Some examples are Fargo, North Dakota; Moorhead, Minnesota; Grand Forks, North Dakota and Minot, North Dakota. Otter Tail does not serve these larger cities, but it does serve small communities surrounding these larger ones. To reflect this, Otter Tail used econometric data only from counties where Otter Tail served at least 10 percent of the population of the county. County and City population data is downloaded from www.census.gov. The percentage of the population served in each county was determined by dividing the sum of population of the towns served by Otter Tail in each county by the population of the county. Towns to be used in the calculation were obtained from an internal database of towns served by Otter Tail Power Company. The data is then summed to the state level and graphed as a reasonability check. Annual Woods & Poole data is converted from annual data to monthly data by interpolating between annual values with a flat line.

As Otter Tail serves three states with economic differences, using econometric models makes it possible to utilize the different economic data pertinent for each state and determine whether particular variables are drivers for each state.

2. CALENDAR MONTH CALCULATION

Because historical usage data, in its purest form, is in billing month format, Otter Tail creates all models using billing month data. After creating billing month sales models, these models are adapted to calendar month. As weather generally only affects UPM, not the number of meters, the calendar month conversion is only applied to the UPM model. To create the calendar month UPM forecast, the calendar month HDD and CDD are substituted for the billing month HDD and CDD, resulting in a calendar month UPM forecast.

3. BINARY VARIABLES

All models that make up the sales forecast utilize binary variables. Monthly binary variables that account for seasonal differences are the most commonly used variables. Annual binary variables are used to account for the deviations in growth or consumption that are not expected in the calendar year. For example, the Large Commercial model uses binary variables starting in January 2011 to account for the change in meters from Small Commercial to Large Commercial. Other binary variables are utilized as necessary to improve the fit of the model and statistical significance of the economic and weather variables.

Locational Marginal Price Forecast ($/MWh)
Indiana Hub pricing provided by Intercontinental Exchange*
March 14, 2025

	(A)	(B)	(C)	(D)	(E)
Line No.	**Month**	**Indiana Hub Peak Forecast**	**OTP.OTP Loadzone Peak Forecast**	**Indiana Hub Off Peak Forecast**	**OTP.OTP Loadzone Off Peak Forecast**
1	**Jan-26**	72.50	77.15	56.15	59.85
2	**Feb-26**	57.65	63.35	45.60	50.35
3	**Mar-26**	42.65	41.20	32.20	33.45
4	**Apr-26**	42.50	37.15	30.85	28.50
5	**May-26**	43.20	38.73	29.70	27.48
6	**Jun-26**	47.45	41.85	30.10	27.53
7	**Jul-26**	73.40	77.63	40.40	43.58
8	**Aug-26**	61.40	66.30	33.15	36.63
9	**Sep-26**	48.65	48.78	29.35	31.55
10	**Oct-26**	46.25	50.95	30.20	31.78
11	**Nov-26**	44.15	48.23	34.35	34.70
12	**Dec-26**	53.25	56.55	42.00	45.70

*Source: ICE https://www.theice.com

Natural Gas Forecast provided by Intercontinental Exchange*

	(A)	(B)
Line No.	**Month**	**Ventura Hub ($/MMBtu)**
1	Jan-26	6.9770
2	Feb-26	6.7030
3	Mar-26	4.2670
4	Apr-26	3.5915
5	May-26	3.5640
6	Jun-26	3.6030
7	Jul-26	3.7205
8	Aug-26	3.7430
9	Sep-26	3.6150
10	Oct-26	3.6580
11	Nov-26	4.1020
12	Dec-26	5.3500

*Source: ICE https://www.theice.com

Attachment 9
Clean Versions of
Electric Rate Schedule Section 13.01 – Energy Adjustment Rider

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 cost of energy for the current month, divided by all forecasted Kilowatt-Hour sales exclusive of intersystem sales for the current month. 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: **C**

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 Midwest 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 Tail*Winds* program is not included in the cost of energy adjustment calculation.

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 to provide Minnesota customers the full amount of avoided purchased power costs associated with 100 percent of the Hoot Lake Solar plant output. **N**
N

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. **N**
N

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	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	**C**
Large General Service TOD – Winter On-Peak	10.05, 10.06, 11.01	1.2673	**C**
Large General Service TOD – Winter Shoulder	10.05, 10.06, 11.01	1.1106	**C**
Large General Service TOD – Winter Off-Peak	10.05, 10.06, 11.01	0.8499	**C**
Large General Service TOD – Summer On-Peak	10.05, 10.06, 11.01	1.2664	**C**
Large General Service TOD – Summer Shoulder	10.05, 10.06, 11.01	0.9956	**C**
Large General Service TOD – Summer Off-Peak	10.05, 10.06, 11.01	0.6896	**C**
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	

Forecasted Class EAF’s are published on OTP’s website at https://www.otpco.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.

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.

Attachment 9a
Redline and Clean Versions of
Electric Rate Schedule Section 13.01 – Energy Adjustment Rider

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~~all~~ forecasted Minnesota retail Kilowatt-Hour sales. ~~exclusive of intersystem sales for the current month.~~ 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 ~~Midwest~~ Midcontinenent 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 Tail*Winds* program is not included in the cost of energy adjustment calculation.

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 ~~to provide Minnesota customers the full amount of avoided purchased power costs associated with 100 percent of the Hoot Lake Solar plant output~~ 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.

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 **C**
by forecasted Minnesota retail Kilowatt-Hour sales. The applicable adjustment will be applied to **C**
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 Midcontinenent ISO (MISO) and Southwest Power Pool (SPP) costs and **C** 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 Tail*Winds* program is not included in the cost of energy adjustment calculation.

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. **C**

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.

The Minnesota Public Utilities Commission approved monthly rates for our Energy Adjustment Rider. A rider is a charge for a specific feature, such as the cost of fuel. This rider pays for the cost of fuel we use to generate electricity to serve our customers, transportation costs for that fuel, and costs we incur to buy energy to supplement our own power plants. We established this rider in 1977 and currently apply it to customer bills monthly per kilowatt-hour of energy used.

We've included 2026 monthly rates on this insert. Each customer class receives a separate Energy Adjustment Factor Rate to better reflect their cost of energy use.[1]

Approved 2026 Energy Adjustment Rider Rates ($/kWh)						
Service category	**JAN.**	**FEB.**	**MAR.**	**APRIL**	**MAY**	**JUNE**
Residential	$0.033191	$0.029658	$0.026555	$0.023996	$0.023723	$0.026567
Farm	$0.032330	$0.028889	$0.025866	$0.023373	$0.023108	$0.025877
General Service	$0.032896	$0.029394	$0.026319	$0.023782	$0.023512	$0.026330
Large General Service non TOD	$0.032097	$0.028681	$0.025680	$0.023205	$0.022941	$0.025691
Large General Service TOD – Winter On-Peak	$0.039852	$0.035610	$0.031884	$0.028811	$0.028484	
Large General Service TOD – Winter Shoulder	$0.034924	$0.031207	$0.027942	$0.025248	$0.024962	
Large General Service TOD – Winter Off-Peak	$0.026726	$0.023881	$0.021383	$0.019322	$0.019102	
Large General Service TOD – Summer On-Peak						$0.031875
Large General Service TOD – Summer Shoulder						$0.025059
Large General Service TOD – Summer Off-Peak						$0.017357
Irrigation Service	$0.029088	$0.025992	$0.023272	$0.021029	$0.020790	$0.023282
Outdoor Lighting	$0.027185	$0.024292	$0.021750	$0.019654	$0.019431	$0.021759
OPA	$0.032106	$0.028689	$0.025687	$0.023211	$0.022948	$0.025699
Controlled Service Deferred Load	$0.029915	$0.026731	$0.023934	$0.021627	$0.021381	$0.023944
Controlled Service Interruptible	$0.031078	$0.027770	$0.024865	$0.022468	$0.022213	$0.024876
Controlled Service Off-Peak	$0.028817	$0.025750	$0.023056	$0.020833	$0.020597	$0.023066

[1] *We calculated these rates by multiplying the approved Energy Adjustment Rider Rate by the Class Energy Adjustment Factor Ratio.*

Service category	JULY	AUG.	SEPT.	OCT.	NOV.	DEC.
Residential	$0.035926	$0.032230	$0.027182	$0.024963	$0.031698	$0.037748
Farm	$0.034993	$0.031393	$0.026477	$0.024315	$0.030875	$0.036768
General Service	$0.035606	$0.031943	$0.026940	$0.024740	$0.031415	$0.037412
Large General Service non TOD	$0.034742	$0.031167	$0.026286	$0.024140	$0.030653	$0.036503
Large General Service TOD – Winter On-Peak				$0.029972	$0.038058	$0.045322
Large General Service TOD – Winter Shoulder				$0.026266	$0.033352	$0.039718
Large General Service TOD – Winter Off-Peak				$0.020100	$0.025523	$0.030395
Large General Service TOD – Summer On-Peak	$0.043104	$0.038670	$0.032614			
Large General Service TOD – Summer Shoulder	$0.033887	$0.030401	$0.025640			
Large General Service TOD – Summer Off-Peak	$0.023472	$0.021057	$0.017759			
Irrigation Service	$0.031484	$0.028245	$0.023822	$0.021876	$0.027779	$0.033081
Outdoor Lighting	$0.029425	$0.026398	$0.022263	$0.020445	$0.025962	$0.030917
OPA	$0.034752	$0.031176	$0.026294	$0.024147	$0.030662	$0.036514
Controlled Service Deferred Load	$0.032379	$0.029048	$0.024499	$0.022498	$0.028568	$0.034021
Controlled Service Interruptible	$0.033639	$0.030178	$0.025452	$0.023373	$0.029680	$0.035345
Controlled Service Off-Peak	$0.031192	$0.027982	$0.023600	$0.021673	$0.027520	$0.032773

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

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA
MINN. R. 7825.2830 - ANNUAL FIVE-YEAR PROJECTION
JANUARY 2026- DECEMBER 2030

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(N)	(N)	(N)
Line No.	Description	January-26	February-26	March-26	April-26	May-26	June-26	July-26	August-26	September-26	October-26	November-26	December-26	2026 Year-End	January-27	February-27	March-27	April-27	May-27	June-27	July-27	August-27	September-27	October-27	November-27	December-27	2027 Year-End	2028 Year-End	2029 Year-End	2030 Year-End
	[PROTECTED DATA BEGINS...																													
1	**Energy (MWh)**																													
2	Steam																													
3	Hydro																													
4	Wind																													
5	Solar																													
6	Other																													
7																														
8	**OTP-Owned Total**																													
9																														
10	Purchases																													
11																														
12	**System Use**																													
13																														
14																														
15	**Fuel Costs**																													
16	Steam																													
17	Other																													
18																														
19	**OTP-Owned Total**																													
20																														
21	Purchases																													
31																														
32	**System Use**																													
33																														
34																														
35	**$/MWh**																													
36	Steam																													
37	Other																													
38	Purchases																													
39																														
40	**OTP-Owned Total**																													
																														...PROTECTED DATA ENDS]

*Tribal (WAPA) is not FCA applicable and therefore excluded from the FCA calculation.

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
					Expense (Revenue)			
Line No.		2026 Forecast	2024 Actual	2023 Actual	2022 Actual	3-Year Average	Variance	Variance Percentage
	Percent of MN Sales Subject to FCA*		48.0642%	48.1142%	45.8406%			
1	**Plant Generation**							
2	***Coal***	[PROTECTED DATA BEGINS...						
3	Big Stone							
4	Coyote							
5	Hoot Lake							
6					...PROTECTED DATA ENDS]			
7	**Total Coal**	$ 19,510,048	$ 22,092,172	$ 20,868,842	$ 20,336,382	$ 21,099,132		
8								
9	***Wind***	[PROTECTED DATA BEGINS...						
10	Langdon Wind							
11	Ashtabula Wind							
12	Ashtabula III							
13	Luverne Wind							
14	Merricourt							
15					...PROTECTED DATA ENDS]			
16	**Total Wind**	$ -	$ -	$ -	$ -	$ -		
17								
18	**Total Hydro**	$ -	$ -	$ -	$ -	$ -		
19								
20	***Oil - Peaking Units***	[PROTECTED DATA BEGINS...						
21	Jamestown 1							
22	Jamestown 2							
23	Lake Preston							
24					...PROTECTED DATA ENDS]			
25	**Total Oil - Peaking Units**	$ 203,664	$ 93,211	$ 213,254	$ 219,739	$ 175,402		
26								
27	***Natural Gas***	[PROTECTED DATA BEGINS...						
28	Solway							
29	Astoria							
30					...PROTECTED DATA ENDS]			
31	**Total Natural Gas**	$ 8,079,121	$ 7,107,399	$ 7,770,321	$ 9,213,548	$ 8,030,423		
32								
33	***Solar***	[PROTECTED DATA BEGINS...						
34	Flickertail Solar							
35	Solway Solar							
36	<40 kW Solar							
37	Hoot Lake Solar							
38					...PROTECTED DATA ENDS]			
39	**Total Solar**	$ -	$ -	$ -	$ -	$ -		
40								
41	**Total OTP-Owned**	$ 27,792,834	$ 29,292,783	$ 28,852,417	$ 29,769,669	$ 29,304,956	$ (1,512,123)	-5.16%
42								

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

Line No.	(A)	(B) 2026 Forecast	(C) 2024 Actual	(D) 2023 Actual	(E) 2022 Actual	(F) 3-Year Average	(G) Variance	(H) Variance Percentage
		Expense (Revenue)						
43	**Wholesale Market Charges**							
44	**MISO Wholesale Market Charges**							
45	555.02 DA Asset Energy Amount**	-	-	-	-	-		
46	555.04 DA FBT Loss Amount	-	-	-	-	-		
47	555.09 DA Non-asset Energy Amount**	-	-	-	-	-		
48	555.19 RT Asset Energy Amount**	-	-	-	-	-		
49	555.24 RT Distribution of Losses Amount	(1,330,819)	(1,182,898)	(1,339,296)	(2,426,782)	(1,649,658)		
50	555.21 RT FBT Loss Amount	-	-	-	-	-		
51	DA Loss Amount	2,274,742	3,213,712	3,417,484	6,113,276	4,248,157		
52	RT Loss Amount	214,571	241,928	278,903	278,550	266,460		
53	555.26 RT Non-Asset Energy Amount**	-	-	189	2,790	993		
54	555.08 DA Losses Rebate on Option B GFA	-	-	-	-	-		
55	555.12 DA Virtual Energy Amount	-	-	-	-	-		
56	555.32 RT Virtual Energy Amount	-	-	-	-	-		
57	555.01 DA Mkt Admin Amount	425,038	387,022	385,247	337,222	369,830		
58	555.18 RT Mkt Admin Amount	62,340	52,026	51,285	46,612	49,975		
59	555.13 FTR Mkt Admin Amount	8,565	7,738	9,461	11,836	9,678		
60	555.03 DA FBT Congestion Amount	-	-	-	-	-		
61	DA Congestion	9,056,898	9,393,749	12,459,720	15,287,250	12,380,240		
62	555.20 RT FBT Congestion Amount	-	-	-	-	-		
63	RT Congestion	1,044,933	683,830	1,751,917	1,265,466	1,233,738		
64	555.14 FTR Hourly Allocation Amount	(15,113,221)	(19,682,195)	(22,389,107)	(26,794,250)	(22,955,184)		
65	555.15 FTR Monthly Allocation Amount	(397,769)	(513,419)	(631,742)	(597,924)	(581,028)		
66	555.17 FTR Yearly Allocation Amount	(187,701)	(270,438)	(29,699)	(243,515)	(181,217)		
67	555.35 FTR Monthly Transaction Amount	-	-	-	-	-		
68	555.36 FTR Full Funding Guarantee Amount	(427,643)	(210,879)	(840,808)	308,589	(247,699)		
69	555.37 FTR Guarantee Uplift Amount	431,831	168,535	804,628	(328,304)	214,953		
70	555.38 FTR Annual Transaction Amount	23,309,705	(7,720,689)	28,677,031	26,362,839	15,773,060		
71	555.39 FTR Auction Revenue Rights Transaction Amount	(24,289,760)	6,721,849	(29,641,926)	(26,378,596)	(16,432,891)		
72	555.40 FTR Auction Revenue Rights Infeas ble Uplift Amount	64,739	68,065	66,540	79,847	71,484		
73	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount	(1,073,564)	(1,144,396)	(925,055)	(453,207)	(840,886)		
74	555.07 DA Congestion Rebate on Opt on B GFA	-	-	-	-	-		
75	555.10 DA Revenue Sufficiency Guarantee Distribution Amount	58,941	53,198	56,598	101,758	70,518		
76	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amoun	(38,258)	(30,038)	(30,929)	(54,455)	(38,474)		
77	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Am	52,204	37,711	64,870	261,932	121,504		
78	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount	(168,605)	-	-	-	-		
79	555.42 RT Price Volatility Make Whole Payment	(212,239)	(177,190)	(227,122)	(337,137)	(247,150)		
80	555.28 RT Revenue Neutrality Uplift Amount	849,208	817,318	851,272	456,713	708,434		
81	555.25 RT Misc Amount	(141,157)	(302,693)	(57,738)	56,478	(101,318)		
82	555.27 RT Net Inadvertent Amount	(11,577)	(11,274)	(22,578)	32,172	(560)		
83	555.31 RT Uninstructed Deviation Amount	-	-	-	-	-		
84	555.59 RT Demand Response Allocation Uplift Amount	25,077	29,964	9,769	124,671	54,801		
85	555.63 DA Ramp Product	(49,965)	(64,236)	(20,787)	(19,640)	(34,888)		
86	555.64 RT Ramp Product	(4,366)	(3,994)	(3,204)	(8,341)	(5,180)		
87	555.65 RT Schedule 49 Cost Distribution Amount	129,734	126,194	151,360	85,259	120,937		
88	555.55 RT ASM Non-Excessive Energy Amount**	-	5,141,034	5,760,517	6,391,162	5,764,237		
89	555.56 RT ASM Excessive Energy Amount**	-	14,850	18,577	12,844	15,424		
90	555.05 DA Congestion Rebate on COGA	-	-	-	-	-		
91	555.06 DA Losses Rebate on COGA	-	-	-	-	-		
92	555.22 RT Congestion Rebate on COGA	-	-	-	-	-		
93	555.23 RT Loss Rebate on COGA	-	-	-	-	-		
94	Net Congestion and Losses Adjustment & No DA Generation Schedule	-	(2,580,212)	79,514	212,104	(762,864)		
95								(1)
96	**Total MISO Wholesale Market Charges**	**(5,934,059)**	**(7,182,616)**	**(1,711,102)**	**(208,453)**	**(3,034,057)**	**(2,900,002)**	**95.58%**
97								
98	**SPP Wholesale Market Charges**							
99	555.19 DA Asset Energy Amount**	-	-	-	-	-		
100	555.03 DA Non-asset Energy Amount	-	-	-	-	-		
101	555.09 RT Asset Energy Amount**	-	-	-	-	-		
102	555.00 RT Non-Asset Energy Amount	-	-	-	-	-		
103	555.02 DA Make-Whole-Payment Distr but on Amount	-	-	-	-	-		
104	555.10 RT Make-Whole-Payment Distribution Amount	164	271	61	11,905	4,079		
105	555.18 RT Revenue Sufficiency Guarantee Distribution Amount	-	-	-	-	-		
106	555.15 RT Revenue Neutrality Uplift Distribution Amount	84	164	19	2,626	936		
107	555.04 DA Regulation-Down Distribution Amount	14	23	5	162	64		
108	555.05 DA Regulation-Up Distribution Amount	28	46	14	622	227		
109	555.06 DA Spinning Reserve Distribution Amount	16	23	13	760	265		
110	555.07 DA Supplemental Reserve Distr but on Amount	4	7	2	113	41		
111	555.08 RT Contingency Reserve Deployment Failure Amount	(0)	(0)	(0)	(21)	(7)		
112	555.11 RT Over-Collected Losses Distribution Amount	(62,459)	(55,468)	(72,693)	(123,497)	(83,886)		
113	555.12 RT Regulation-Down Distribution Amount	2	4	0	32	12		
114	555.13 RT Regulation Non-Performance Distribution Amount	(2)	(4)	(0)	(21)	(8)		
115	555.14 RT Regulation-Up Distr but on Amount	(3)	(2)	(4)	(23)	(10)		
116	555.16 RT Spinning Reserve Distribution Amount	(0)	0	(1)	(1)	(1)		
117	555.17 RT Supplemental Reserve Distribution Amount	(0)	(1)	0	(34)	(12)		
118	555.20 RT Pseudo Tie Congestion Amount	142,285	37,114	621,081	(1,207,608)	(183,138)		
119	555.21 RT Pseudo Tie Loss Amount	27,070	29,934	27,607	(207,655)	(50,038)		
120	555.23 Miscellaneous Amount	13	22	(2)	(6)	5		
121	555.26 ARR Closeout Yearly Amount	(131,973)	(128,758)	(134,462)	(88,987)	(117,402)		
122	555.28 RT Demand Reduction Distribution Amount	0	0	0	1	0		
123	555.29 RT Schedule 1A3 Amount	5	7	3	76	29		
124	555.30 RT Schedule 1A4 Amount	16	22	13	370	135		
125	555.31 DA Ramp Up Distribution Amount	2	3	2	373	126		
126	555.32 DA Ramp Down Distribution Amount	-	-	-	-	-		
127	555.33 RT Ramp Non Performance Distribution Amount	(0)	(0)	(0)	(6)	(2)		
128	555.34 RT Ramp Up Distribution Amount	(1)	(0)	(2)	(26)	(9)		
129	555.35 RT Ramp Down Distribution Amount	-	-	-	-	-		
130	555.36 ARR Auction Transaction AO Amount	(168,234)	(346,037)	-	-	(115,346)		
131	RT Uninstructed Resource Deviation Distribution Amount	(7)	-	-	-			
132	555.01 DA GFA Carve Out Distribution Deployment Daily Amount	6	6	(3)	284	96		
133	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount	(0)	4	(0)	(1)	1		
134	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount	(60)	(11)	(109)	(13)	(44)		
135								(2)
136	**Total SPP Wholesale Market Charges**	**(193,031)**	**(462,629)**	**441,544**	**(1,610,575)**	**(543,887)**	**350,856**	**-64.51%**
137								
138	**MISO ASM**							
139	DA ASM Regulation Amount	(349,966)	(354,418)	(248,706)	(148,338)	(250,487)		
140	DA ASM Spinning Reserve Amount	(166,195)	(194,415)	(115,922)	(203,312)	(171,216)		
141	DA ASM Short-Term Reserve Amount	(416,246)	(233,009)	(149,187)	(93,031)	(158,409)		
142	DA ASM Supplemental Reserve Amount	(132,162)	(259,972)	(65,855)	(121,089)	(148,972)		
143	RT ASM Regulation Amount	(119,215)	6,234	-	37,216	14,483		
144	RT ASM Spinning Reserve Amount	(5,330)	50,762	36,542	8,358	31,887		
145	RT ASM Supplemental Reserve Amount	23,959	(9,027)	10,764	4,314	2,017		
146	RT ASM Net Regulation Adjustment Amount	23,615	(99,423)	(51,426)	(45,763)	(65,537)		
147	RT ASM Excessive Deficient Energy Deployment Charge Amount	45,880	136,763	107,146	130,988	124,966		
148	RT ASM Contingency Reserve Deployment Failure Charge Amount	-	10,662	(18,461)	(38,139)	(15,312)		
149	RT ASM Regulation Cost Distribution Amount	131,770	86,302	92,594	118,092	98,996		
150	RT ASM Spinning Reserve Cost Distribution Amount	100,928	(3,965)	(4,264)	(38,226)	(15,485)		
151	RT ASM Supplemental Reserve Cost Distribution Amount	16,017	130,442	107,438	91,708	109,863		
152	RT ASM Short-Term Reserve Amount	13,979	3,188	-	-	1,063		
153	RT ASM Short-Term Reserve Cost Distribution Amount	193,911	32,631	28,074	158,579	73,095		
154	RT ASM Short-Term Reserve Deployment Failure Charge Amount	-	23,863	14,089	18,804	18,919		
155	Short-Term Reserve Deployment Failure Charge	510						(3)
156	**Total MISO ASM**	**(638,545)**	**(673,381)**	**(257,173)**	**(119,840)**	**(350,132)**	**(288,414)**	**82.37%**
157								
158	**Total Wholesale Market Charges**	**(6,765,636)**	**(8,318,626)**	**(1,526,731)**	**(1,938,869)**	**(3,928,076)**		
159								
160								
161								
162	**Purchased Power**	**[PROTECTED DATA BEGINS...**						
163	Edgeley PPA							
164	Langdon PPA							
165	Ashtabula III PPA							
166	Tribal (WAPA)							
167	WAPA Energy Imbalance							
168	Shared Loads							
169	Small Co-gen							
170	Bilateral purchases							
171	Market Purchases							
172					**...PROTECTED DATA ENDS]**			(4)
173		**64,058,034**	**38,245,371**	**44,498,485**	**54,593,968**	**45,779,275**	**18,278,759**	**39.93%**

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Expense (Revenue)						
Line No.		**2026 Forecast**	**2024 Actual**	**2023 Actual**	**2022 Actual**	**3-Year Average**	**Variance**	**Variance Percentage**
174								(5)
175	**Wind Curtailment**	**$ 68,571**	**$ 86,122**	**$ 26,256**	**$ 344,782**	**$ 152,387**	**$ (83,816)**	**-55.00%**
176								**(6)**
177	**Asset Based Sales**	**$ (4,312,442)**	**$ (10,065,913)**	**$ (11,496,793)**	**$ (17,662,312)**	**$ (13,075,006)**	**$ 8,762,564**	**-67.02%**
178	Fuel Costs	$ 2,091,132	$ 4,827,557	$ 9,150,441	$ 12,561,497	$ 8,846,498	$ (6,755,367)	-76.36%
179	Asset Based Margins	$ (2,221,311)	$ (5,238,355)	$ (2,346,352)	$ (5,100,815)	$ (4,228,508)	$ 2,007,197	-47.47%
180								(7)
181	**Minnesota Solar Generation Credit**	**$ (4,492,305)**	**$ (2,435,854)**	**$ (1,811,225)**	**$ -**	**$ (1,415,693)**	**$ (3,076,612)**	**217.32%**
182								
183	**Steam Plant Reagents**	**$ 1,224,575**	**$ 1,411,121**	**$ 1,041,396**	**$ 1,172,066**			
184								
185	**Steam/Water Sales**	**$ (489,359)**	**$ (503,108)**	**$ (388,957)**	**$ (269,147)**			
186								
187	**Planning Resource Auction Revenues**	**$ -**	**$ (226,578)**	**$ (2,013,754)**	**$ (2,451,451)**			
188								(8)
189	**Total Minnesota - Plant Level**	**$ 77,084,271**	**$ 47,485,317**	**$ 57,181,093**	**$ 63,558,707**	**$ 56,075,039**	**$ 21,009,232**	**37.47%**

* Percentage is from Annual FCA True-Up Compliance filing
** These energy related charge types are reported in Market Purchases

(1) Due to the scheduled completion of transmission outages and upgrades within the Otter Tail service territory, Otter Tail expects congestion costs and FTR revenues to decrease in 2026. This reduction results in a forecasted eliminat on of the MISO wholesale energy market credit and a return to a more typical expectation of a MISO wholesale energy market charge. See Page 19 of Otter Tail's May 1, 2023 Initial Filing for further explanation.
(2) Otter Tail has experienced increasing SPP revenue amounts in recent years and expects that to continue into 2026.
(3) Otter Tail has experienced overall increasing MISO ASM revenue amounts in recent years and expects that to continue into 2026.
(4) Increased forecasted energy market prices compared to recent years.

(5) Lower forecasted MWh compared to recent years resulted in decreased forecasted costs **[PROTECTED DATA BEGINS... ...PROTECTED DATA ENDS]**
(6) Forecasted OTP-owned resources fuel cost per MWh is higher than recent years. Forecasted MWh is higher than recent years.
(7) Hoot Lake Solar came online in 2023, with the first full year of operation beginning in 2024
(8) The combined effects of Footnotes 1 through 7, plus increased load on Otter Tail's system results in the increase.

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

	(A)	(B)	(C)	(D)	(E)	(F)
		MWh				
Line No.		**2026 Forecast**	**2024 Actual**	**2023 Actual**	**2022 Actual**	**3-Year Average**
	Percent of MN Sales Subject to FCA*					
1	**Plant Generation**					
2	***Coal***	**[PROTECTED DATA BEGINS...**				
3	Big Stone					
4	Coyote					
5	Hoot Lake					
6					**...PROTECTED DATA ENDS]**	
7	**Total Coal**	**643,929**	**594,422**	**846,398**	**833,975**	**758,265**
8						
9	***Wind***	**[PROTECTED DATA BEGINS...**				
10	Langdon Wind					
11	Ashtabula Wind					
12	Ashtabula III					
13	Luverne Wind					
14	Merricourt					
15					**...PROTECTED DATA ENDS]**	
16	**Total Wind**	**654,644**	**364,791**	**551,092**	**474,077**	**463,320**
17						
18	**Total Hydro**	**9,474**	**4,610**	**4,256**	**5,891**	**4,919**
19						
20	***Oil - Peaking Units***	**[PROTECTED DATA BEGINS...**				
21	Jamestown 1					
22	Jamestown 2					
23	Lake Preston					
24					**...PROTECTED DATA ENDS]**	
25	**Total Oil - Peaking Units**	**775**	**135**	**455**	**481**	**357**
26						
27	***Natural Gas***	**[PROTECTED DATA BEGINS...**				
28	Solway					
29	Astoria					
30					**...PROTECTED DATA ENDS]**	
31	**Total Natural Gas**	**222,078**	**198,375**	**274,547**	**119,569**	**197,497**
32						
33	***Solar***	**[PROTECTED DATA BEGINS...**				
34	Flickertail Solar					
35	Solway Solar					
36	<40 kW Solar					
37	Hoot Lake Solar					
38					**...PROTECTED DATA ENDS]**	
39	**Total Solar**	**90,294**	**62,583**	**34,889**	**99**	**32,524**
40						
41	**Total OTP-Owned**	**1,621,194**	**1,224,915**	**1,711,637**	**1,434,091**	**1,456,881**
42						

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

	(A)	(B)	(C)	(D)	(E)	(F)
				MWh		
Line		2026	2024	2023	2022	3-Year
No.		Forecast	Actual	Actual	Actual	Average
43	**Wholesale Market Charges**					
44	**MISO Wholesale Market Charges**					
45	555.02 DA Asset Energy Amount**					
46	555.04 DA FBT Loss Amount					
47	555.09 DA Non-asset Energy Amount**					
48	555.19 RT Asset Energy Amount**					
49	555.24 RT Distribution of Losses Amount					
50	555.21 RT FBT Loss Amount					
51	DA Loss Amount					
52	RT Loss Amount					
53	555.26 RT Non-Asset Energy Amount**					
54	555.08 DA Losses Rebate on Option B GFA					
55	555.12 DA Virtual Energy Amount					
56	555.32 RT Virtual Energy Amount					
57	555.01 DA Mkt Admin Amount					
58	555.18 RT Mkt Admin Amount					
59	555.13 FTR Mkt Admin Amount					
60	555.03 DA FBT Congestion Amount					
61	DA Congestion					
62	555.20 RT FBT Congestion Amount					
63	RT Congestion					
64	555.14 FTR Hourly Allocation Amount					
65	555.15 FTR Monthly Allocation Amount					
66	555.17 FTR Yearly Allocation Amount					
67	555.35 FTR Monthly Transaction Amount					
68	555.36 FTR Full Funding Guarantee Amount					
69	555.37 FTR Guarantee Uplift Amount					
70	555.38 FTR Annual Transaction Amount					
71	555.39 FTR Auction Revenue Rights Transaction Amount					
72	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount					
73	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount					
74	555.07 DA Congest on Rebate on Option B GFA					
75	555.10 DA Revenue Sufficiency Guarantee Distribution Amount					
76	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amoun					
77	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Am					
78	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount					
79	555.42 RT Pr ce Volatility Make Whole Payment					
80	555.28 RT Revenue Neutrality Uplift Amount					
81	555.25 RT Misc Amount					
82	555.27 RT Net Inadvertent Amount					
83	555.31 RT Uninstructed Deviat on Amount					
84	555.59 RT Demand Response Allocat on Uplift Amount					
85	555.63 DA Ramp Product					
86	555.64 RT Ramp Product					
87	555.65 RT Schedule 49 Cost Distribution Amount					
88	555.55 RT ASM Non-Excessive Energy Amount**					
89	555.56 RT ASM Excessive Energy Amount**					
90	555.05 DA Congest on Rebate on COGA					
91	555.06 DA Losses Rebate on COGA					
92	555.22 RT Congestion Rebate on COGA					
93	555.23 RT Loss Rebate on COGA					
94	Net Congestion and Losses Adjustment & No DA Generat on Schedule					
95						
96	**Total MISO Wholesale Market Charges**	-	-	-	-	
97						
98	**SPP Wholesale Market Charges**					
99	555.19 DA Asset Energy Amount**					
100	555.03 DA Non-asset Energy Amount					
101	555.09 RT Asset Energy Amount**					
102	555.00 RT Non-Asset Energy Amount					
103	555.02 DA Make-Whole-Payment Distribution Amount					
104	555.10 RT Make-Whole-Payment Distr but on Amount					
105	555.18 RT Revenue Sufficiency Guarantee Distribution Amount					
106	555.15 RT Revenue Neutrality Uplift Distribution Amount					
107	555.04 DA Regulat on-Down Distribution Amount					
108	555.05 DA Regulat on-Up Distribution Amount					
109	555.06 DA Spinning Reserve Distribution Amount					
110	555.07 DA Supplemental Reserve Distribution Amount					
111	555.08 RT Contingency Reserve Deployment Failure Amount					
112	555.11 RT Over-Collected Losses Distribution Amount					
113	555.12 RT Regulation-Down Distribution Amount					
114	555.13 RT Regulation Non-Performance Distribution Amount					
115	555.14 RT Regulation-Up Distribution Amount					
116	555.16 RT Spinning Reserve Distribution Amount					
117	555.17 RT Supplemental Reserve Distr but on Amount					
118	555.20 RT Pseudo Tie Congestion Amount					
119	555.21 RT Pseudo Tie Loss Amount					
120	555.23 Miscellaneous Amount					
121	555.26 ARR Closeout Yearly Amount					
122	555.28 RT Demand Reduct on Distribution Amount					
123	555.29 RT Schedule 1A3 Amount					
124	555.30 RT Schedule 1A4 Amount					
125	555.31 DA Ramp Up Distribution Amount					
126	555.32 DA Ramp Down Distr but on Amount					
127	555.33 RT Ramp Non Performance Distribution Amount					
128	555.34 RT Ramp Up Distribution Amount					
129	555.35 RT Ramp Down Distribution Amount					
130	555.36 ARR Auction Transaction AO Amount					
131	RT Uninstructed Resource Deviation Distribution Amount					
132	555.01 DA GFA Carve Out Distribution Deployment Daily Amount					
133	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount					
134	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount					
135						
136	**Total SPP Wholesale Market Charges**	-	-	-	-	
137						
138	**MISO ASM**					
139	DA ASM Regulation Amount					
140	DA ASM Spinning Reserve Amount					
141	DA ASM Short-Term Reserve Amount					
142	DA ASM Supplemental Reserve Amount					
143	RT ASM Regulation Amount					
144	RT ASM Spinning Reserve Amount					
145	RT ASM Supplemental Reserve Amount					
146	RT ASM Net Regulation Adjustment Amount					
147	RT ASM Excessive Deficient Energy Deployment Charge Amount					
148	RT ASM Contingency Reserve Deployment Failure Charge Amount					
149	RT ASM Regulation Cost Distribution Amount					
150	RT ASM Spinning Reserve Cost Distribution Amount					
151	RT ASM Supplemental Reserve Cost Distribution Amount					
152	RT ASM Short-Term Reserve Amount					
153	RT ASM Short-Term Reserve Cost Distribution Amount					
154	RT ASM Short-Term Reserve Deployment Failure Charge Amount					
155	Short-Term Reserve Deployment Failure Charge					
156	**Total MISO ASM**	-	-	-	-	
157						
158	**Total Wholesale Market Charges**	-	-	-	-	
159						
160						
161						
162	**Purchased Power**	**[PROTECTED DATA BEGINS...**				
163	Edgeley PPA					
164	Langdon PPA					
165	Ashtabula III PPA					
166	Tribal (WAPA)					
167	WAPA Energy Imbalance					
168	Shared Loads					
169	Small Co-gen					
170	Bilateral purchases					
171	Market Purchases					
172					**...PROTECTED DATA ENDS]**	
173		**1,248,704**	**1,361,872**	**1,295,737**	**1,339,196**	**1,332,268**

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

Line No.	(A)	(B) MWh 2026 Forecast	(C) 2024 Actual	(D) 2023 Actual	(E) 2022 Actual	(F) 3-Year Average
174						
175	**Wind Curtailment**	**3,653**	**2,191**	**510**	**10,371**	**4,357**
176						
177	**Asset Based Sales**	**(64,882)**	**(130,211)**	**(167,787)**	**(120,930)**	**(139,643)**
178	Fuel Costs					
179	Asset Based Margins					
180						
181	**Minnesota Solar Generation Credit**					
182						
183	**Steam Plant Reagents**					
184						
185	**Steam/Water Sales**					
186						
187	**Planning Resource Auction Revenues**					
188						
189	**Total Minnesota - Plant Level**	**2,808,668**	**2,458,766**	**2,840,097**	**2,662,729**	

* Percentage is from Annual FCA True-Up Compliance filing
** These energy related charge types are reported in Market Purchases

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

	(A)	(B)	(C)	(D)	(E)	(F)
		Cost per MWh				
Line No.		**2026 Forecast**	**2024 Actual**	**2023 Actual**	**2022 Actual**	**3-Year Average**
	Percent of MN Sales Subject to FCA*					
1	**Plant Generation**					
2	***Coal***	**[PROTECTED DATA BEGINS...**				
3	Big Stone					
4	Coyote					
5	Hoot Lake					
6						**...PROTECTED DATA ENDS]**
7	**Total Coal**	**$ 30.30**	**$ 37.17**	**$ 24.66**	**$ 24.38**	**$ 28.74**
8						
9	***Wind***	**[PROTECTED DATA BEGINS...**				
10	Langdon Wind					
11	Ashtabula Wind					
12	Ashtabula III					
13	Luverne Wind					
14	Merricourt					
15						**...PROTECTED DATA ENDS]**
16	**Total Wind**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
17						
18	**Total Hydro**	**$ -**				**$ -**
19						
20	***Oil - Peaking Units***	**[PROTECTED DATA BEGINS...**				
21	Jamestown 1					
22	Jamestown 2					
23	Lake Preston					
24						**...PROTECTED DATA ENDS]**
25	**Total Oil - Peaking Units**	**$ 262.85**	**$ 692.60**	**$ 468.69**	**$ 456.58**	**$ 539.29**
26						
27	***Natural Gas***	**[PROTECTED DATA BEGINS...**				
28	Solway					
29	Astoria					
30						**...PROTECTED DATA ENDS]**
31	**Total Natural Gas**	**$ 36.38**	**$ 35.83**	**$ 28.30**	**$ 77.06**	**$ 47.06**
32						
33	***Solar***	**[PROTECTED DATA BEGINS...**				
34	Flickertail Solar					
35	Solway Solar					
36	<40 kW Solar					
37	Hoot Lake Solar					**...PROTECTED DATA ENDS]**
38						
39	**Total Solar**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
40						
41	**Total OTP-Owned**	**$ 17.14**	**$ 23.91**	**$ 16.86**	**$ 20.76**	**$ 20.51**
42						

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

	(A)	(B)	(C)	(D)	(E)	(F)
		Cost per MWh				
Line No.		2026 Forecast	2024 Actual	2023 Actual	2022 Actual	3-Year Average
43	**Wholesale Market Charges**					
44	**MISO Wholesale Market Charges**					
45	555.02 DA Asset Energy Amount**					
46	555.04 DA FBT Loss Amount					
47	555.09 DA Non-asset Energy Amount**					
48	555.19 RT Asset Energy Amount**					
49	555.24 RT Distribution of Losses Amount					
50	555.21 RT FBT Loss Amount					
51	DA Loss Amount					
52	RT Loss Amount					
53	555.26 RT Non-Asset Energy Amount**					
54	555.08 DA Losses Rebate on Option B GFA					
55	555.12 DA Virtual Energy Amount					
56	555.32 RT Virtual Energy Amount					
57	555.01 DA Mkt Admin Amount					
58	555.18 RT Mkt Admin Amount					
59	555.13 FTR Mkt Admin Amount					
60	555.03 DA FBT Congestion Amount					
61	DA Congestion					
62	555.20 RT FBT Congestion Amount					
63	RT Congestion					
64	555.14 FTR Hourly Allocation Amount					
65	555.15 FTR Monthly Allocation Amount					
66	555.17 FTR Yearly Allocation Amount					
67	555.35 FTR Monthly Transaction Amount					
68	555.36 FTR Full Funding Guarantee Amount					
69	555.37 FTR Guarantee Uplift Amount					
70	555.38 FTR Annual Transaction Amount					
71	555.39 FTR Auction Revenue Rights Transaction Amount					
72	555.40 FTR Auction Revenue Rights Infeasible Uplift Amount					
73	555.41 FTR Auction Revenue Rights Stage 2 Distribution Amount					
74	555.07 DA Congest on Rebate on Option B GFA					
75	555.10 DA Revenue Sufficiency Guarantee Distribution Amount					
76	555.11 DA Revenue Sufficiency Guarantee Make Whole Pymt Amoun					
77	555.29 RT Revenue Sufficiency Guarantee First Pass Distribution Am					
78	555.30 RT Revenue Sufficiency Guarantee Make Whole Pymt Amount					
79	555.42 RT Pr ce Volatility Make Whole Payment					
80	555.28 RT Revenue Neutrality Uplift Amount					
81	555.25 RT Misc Amount					
82	555.27 RT Net Inadvertent Amount					
83	555.31 RT Uninstructed Deviat on Amount					
84	555.59 RT Demand Response Allocat on Uplift Amount					
85	555.63 DA Ramp Product					
86	555.64 RT Ramp Product					
87	555.65 RT Schedule 49 Cost Distribution Amount					
88	555.55 RT ASM Non-Excessive Energy Amount**					
89	555.56 RT ASM Excessive Energy Amount**					
90	555.05 DA Congest on Rebate on COGA					
91	555.06 DA Losses Rebate on COGA					
92	555.22 RT Congestion Rebate on COGA					
93	555.23 RT Loss Rebate on COGA					
94	Net Congestion and Losses Adjustment & No DA Generat on Schedule					
95						
96	**Total MISO Wholesale Market Charges**					
97						
98	**SPP Wholesale Market Charges**					
99	555.19 DA Asset Energy Amount**					
100	555.03 DA Non-asset Energy Amount					
101	555.09 RT Asset Energy Amount**					
102	555.00 RT Non-Asset Energy Amount					
103	555.02 DA Make-Whole-Payment Distribution Amount					
104	555.10 RT Make-Whole-Payment Distr but on Amount					
105	555.18 RT Revenue Sufficiency Guarantee Distribution Amount					
106	555.15 RT Revenue Neutrality Uplift Distribution Amount					
107	555.04 DA Regulat on-Down Distribution Amount					
108	555.05 DA Regulat on-Up Distribution Amount					
109	555.06 DA Spinning Reserve Distribution Amount					
110	555.07 DA Supplemental Reserve Distribution Amount					
111	555.08 RT Contingency Reserve Deployment Failure Amount					
112	555.11 RT Over-Collected Losses Distribution Amount					
113	555.12 RT Regulation-Down Distribution Amount					
114	555.13 RT Regulation Non-Performance Distribution Amount					
115	555.14 RT Regulation-Up Distribution Amount					
116	555.16 RT Spinning Reserve Distribution Amount					
117	555.17 RT Supplemental Reserve Distr but on Amount					
118	555.20 RT Pseudo Tie Congestion Amount					
119	555.21 RT Pseudo Tie Loss Amount					
120	555.23 Miscellaneous Amount					
121	555.26 ARR Closeout Yearly Amount					
122	555.28 RT Demand Reduct on Distribution Amount					
123	555.29 RT Schedule 1A3 Amount					
124	555.30 RT Schedule 1A4 Amount					
125	555.31 DA Ramp Up Distribution Amount					
126	555.32 DA Ramp Down Distr but on Amount					
127	555.33 RT Ramp Non Performance Distribution Amount					
128	555.34 RT Ramp Up Distribution Amount					
129	555.35 RT Ramp Down Distribution Amount					
130	555.36 ARR Auction Transaction AO Amount					
131	RT Uninstructed Resource Deviation Distribution Amount					
132	555.01 DA GFA Carve Out Distribution Deployment Daily Amount					
133	555.22 DA GFA Carve Out Distribution Deployment Monthly Amount					
134	555.27 DA GFA Carve Out Distribution Deployment Yearly Amount					
135						
136	**Total SPP Wholesale Market Charges**					
137						
138	**MISO ASM**					
139	DA ASM Regulation Amount					
140	DA ASM Spinning Reserve Amount					
141	DA ASM Short-Term Reserve Amount					
142	DA ASM Supplemental Reserve Amount					
143	RT ASM Regulation Amount					
144	RT ASM Spinning Reserve Amount					
145	RT ASM Supplemental Reserve Amount					
146	RT ASM Net Regulation Adjustment Amount					
147	RT ASM Excessive Deficient Energy Deployment Charge Amount					
148	RT ASM Contingency Reserve Deployment Failure Charge Amount					
149	RT ASM Regulation Cost Distribution Amount					
150	RT ASM Spinning Reserve Cost Distribution Amount					
151	RT ASM Supplemental Reserve Cost Distribution Amount					
152	RT ASM Short-Term Reserve Amount					
153	RT ASM Short-Term Reserve Cost Distribution Amount					
154	RT ASM Short-Term Reserve Deployment Failure Charge Amount					
155	Short-Term Reserve Deployment Failure Charge					
156	**Total MISO ASM**					
157						
158	**Total Wholesale Market Charges**					
159						
160						
161						
162	**Purchased Power**					
163	Edgeley PPA	$ 29.90	$ 29.90	$ 29.90	$ 29.90	$ 29.90
164	Langdon PPA	$ 39.22	$ 39.21	$ 39.19	$ 43.22	$ 40.54
165	Ashtabula III PPA	$ -	$ -	$ 31.63	$ 31.22	$ 20.95
166	Tribal (WAPA)	$ 33.25	$ 27.91	$ 27.53	$ 24.00	$ 26.48
167	WAPA Energy Imbalance	$ -	$ (11.42)	$ 44.28	$ 52.62	$ 28.49
168	Shared Loads	$ 64.00	$ 48.05	$ 49.81	$ 45.15	$ 47.67
169	Small Co-gen	$ 50.39	$ 40.75	$ 40.51	$ 38.49	$ 39.91
170	Bilateral purchases	$ 62.28	$ 61.54	$ 84.12	$ 48.14	$ 64.60
171	Market Purchases	$ 49.83	$ 23.89	$ 26.48	$ 40.61	$ 30.32
172						
173		**$ 51.30**	**$ 28.08**	**$ 34.34**	**$ 40.77**	**$ 34.40**

OTTER TAIL POWER COMPANY
ELECTRIC UTILITY - STATE OF MINNESOTA

	(A)	(B)	(C)	(D)	(E)	(F)
		Cost per MWh				
Line No.		2026 Forecast	2024 Actual	2023 Actual	2022 Actual	3-Year Average
174						
175	**Wind Curtailment**	$ 18.77	$ 39.31	$ 51.48	$ 33.24	$ 41.35
176						
177	**Asset Based Sales**	$ (66.47)	$ (77.30)	$ (68.52)	$ 146.05	$ 0.08
178	Fuel Costs	$ -	$ -	$ -	$ -	$ -
179	Asset Based Margins	$ -	$ -	$ -	$ -	$ -
180						
181	**Minnesota Solar Generation Credit**	$ -	$ -	$ -	$ -	$ -
182						
183	**Steam Plant Reagents**	$ -	$ -	$ -	$ -	$ -
184						
185	**Steam/Water Sales**	$ -	$ -	$ -	$ -	$ -
186						
187	**Planning Resource Auction Revenues**	$ -	$ -	$ -	$ -	$ -
188						
189	**Total Minnesota - Plant Level**	$ 27.45	$ 19.31	$ 20.13	$ 23.87	$ 21.11

* Percentage is from Annual FCA True-Up Compliance filing
** These energy related charge types are reported in Market Purchases

[PROTECTED DATA BEGINS…

Docket No. E017/AA-25-65
Attachment 13
is CONFIDENTIAL
in its Entirety

…PROTECTED DATA ENDS]

Bilateral (Forward) Energy Purchases **[PROTECTED DATA BEGINS…**	
	…PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS…

Docket No. E017/AA-25-65

Attachment 14.1

is CONFIDENTIAL

in its Entirety

…PROTECTED DATA ENDS]

Appendix A
Compliance Items

Appendix A Overview:

The following information is provided to address certain compliance obligations stemming from either annual reporting requirements pursuant to Minn. R. 7825.2800 to 7825.2840 governing Automatic Adjustment of Charges, or prior Commission Orders.[1] The information provided in this filing is important in the context of the submission of the forecasted rates.

SECTION 1 - MINN. R. 7825.2800 ANNUAL REPORTS - POLICIES AND ACTIONS

Otter Tail Power Company (Otter Tail) has the following *general policies* regarding energy purchases and fuel consumption, as well as dispatching procedures. These policies are identified first, and then later explained with the procedures used to implement these policies.

1. Otter Tail seeks to minimize the total cost for energy purchases and fuel for generation to Otter Tail customers, while at the same time maintaining appropriate levels of risk exposure. Furthermore, Otter Tail seeks to operate the electrical system in a safe and reliable manner within the NERC, MISO, and MRO guidelines.

2. Otter Tail generating facilities will be economically dispatched within the operating constraints of the units. This economic dispatch has been provided by the Midcontinent Independent System Operator, Inc. (MISO) energy market since April 1, 2005.

These policies involve the following procedures:

1. Otter Tail seeks to minimize the total cost of energy purchases and fuel for generation, while maintaining appropriate levels of risk exposure, because a decrease of cost in one area may cause an increase in cost in another area. As long as net savings are possible in the overall costs and the system is operated within guidelines, generation and/or energy transactions will be adjusted to affect those savings. In the long term (seasonally), computer software is used to analyze the effect of making long-term energy purchases to reduce overall costs and risk exposure. If savings can be realized by making long-term purchases, or potential risk can be mitigated, we will make such a purchase. In the short-term, the MISO energy market will automatically complete short-term energy purchases - displacing higher cost company generation.

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

Minn. R. 7825.2800 Annual Report: Policies and Actions (Continued)

[1] As outlined in Attachment 2 – Otter Tail Power FCA Reform Reporting provided in the March 1, 2019 Joint Comments of the Electric Utilities (Minnesota Power, Otter Tail Power and Xcel Energy) and Consumer Advocates (Minnesota Department of Commerce – Division of Energy Resources, Minnesota Office of Attorney General – Residential Utilities and Antitrust Division, Minnesota Chamber of Commerce, and Minnesota large industrial Group).

SECTION 1.1 - FUEL PROCUREMENT PRACTICES

COAL

Otter Tail procurement process for Big Stone Plant coal is a competitive bidding process. A complete evaluation of all bids received is performed and supplier(s) are selected based on achieving the lowest evaluated cost to Otter Tail commensurate with adequate reliability of supply, environmental compliance, and compatibility with boiler equipment. Big Stone plant has commitments for 100 percent of coal needs for 2026.

The Coyote Station in North Dakota burns lignite from an adjacent mine. The Coyote Station owners, including Otter Tail, entered into a lignite sales agreement (LSA) with Coyote Creek Mining Company, L.L.C. (CCMC), a subsidiary of The North American Coal Corporation, for the purchase of coal to meet the coal supply requirements of Coyote Station for the period beginning in May 2016 and ending in December 2040.

OIL

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

NATURAL GAS

Otter Tail purchases natural gas for the Solway unit from competitive suppliers. Since Solway is operated as a peaking facility, the dispatch of the unit is intermittent, and so is the need for gas. Because of this, long-term supply arrangements have generally not been utilized. The one exception to this occurred in the winter of 2014-15 where Otter Tail chose to hedge a portion of our expected natural gas needs. This was in response to high electricity and natural gas spot prices caused by the 2013-14 winter “Polar Vortex”. Other than this specific occurrence, gas is generally purchased on a next-day or intra-day basis using the supplier’s firm transport capability. The Solway unit is located on the Great Lakes pipeline.

Astoria Station was first offered into the MISO market on April 30th, 2021. Astoria Station is connected to the Northern Border pipeline. Otter Tail has entered into a fuel supply and fuel management services agreement with Tenaska Marketing Ventures. This agreement helps Otter Tail meet operational constraints, ensure a reliable means to purchase natural gas, and optimize balancing requirements. Under this agreement, gas is delivered directly to Astoria Station utilizing Tenaska’s firm transport. Like Solway, Astoria Station is operated as a peaking facility. The dispatch of the unit is intermittent, and so is the need for gas. To date, long-term forward natural gas purchases have not been utilized. Gas for Astoria station is purchased on a short-term, next-day or intra-day basis, as needs arise.

Minn. R. 7825.2800 Annual Report: Policies and Actions (Continued)

SECTION 1.2 - FUEL UTILIZATION

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

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

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

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

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

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

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

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

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

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

    Big Stone Plant - 30 days
    Coyote Station - 10 days
    Combustion Turbine Plants – 3 – 6 days

Minn. R. 7825.2800 Annual Report: Policies and Actions (Continued)

SECTION 1.3 - PROCUREMENT OF TRANSPORTATION SERVICES

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

Transportation services are provided under the terms of a common carrier rate between the BNSF and the co-owners of the Big Stone Plant under the BNSF freight tariff to the site. **[PROTECTED DATA BEGINS...**
. **...PROTECTED DATA ENDS]**

SECTION 2 - MINN. R. 7825.2810 SUBPART 1.A. COMMISSION APPROVED BASE COST OF FUEL

Beginning with bills rendered on and after January 1, 2021, there is no longer a base cost of fuel component in base rates. This change to Electric Rate Schedule – Section 13.01 was approved by the Commission in its December 24, 2020 Order in Docket No. E017/GR-20-719.

SECTION 2.1- MINN. R. 7825.2810 SUBPART 1.D. THE TOTAL COST OF FUEL DELIVERED TO CUSTOMERS

Forecast:

The following is a monthly breakdown of the forecasted Minnesota Total Cost of Fuel for 2026:

Date	Amount (Minnesota)
January	$ 8,776,591
February	$ 7,663,224
March	$ 6,138,139
April	$ 4,802,445
May	$ 4,659,597
June	$ 5,258,368
July	$ 6,902,831
August	$ 6,049,378
September	$ 4,765,187
October	$ 5,063,230
November	$ 7,371,582
December	$ 9,633,699
Total	**$ 77,084,271**

Amounts included on Attachment 2, Line 13.

SECTION 3 - PASSING MISO DAY 2 COSTS THROUGH FUEL CLAUSE ORDER IN DOCKET NO. E017/M-05-284

Forecast:

Otter Tail includes forecasted MISO Day 2 costs in the forecasted rates for 2025. Otter Tail's forecasted non-energy MISO (and SPP) market-related charges are provided in Attachments 4.1 through 4.3 to this filing. All market-related charge types are summarized and aggregated into three forecast categories as described in the Forecast Modeling Software, Fuel, Purchased Power Costs, and other Costs recoverable through the EAR section of Otter Tail's May 1, 2025, Petition (Section D, Subpart 6) and as reflected in Attachments 4.1 through 4.3. These forecasted charge types exclude energy purchased from the MISO (and SPP) markets. The total non-energy MISO and SPP market-related charges, including MISO ASM, is ($6,765,636) (MN Share). The forecasted market energy purchases are provided in Attachment 3.1, line 105, totaling **[PROTECTED DATA BEGINS . . . . . . PROTECTED DATA ENDS]**.

Background:

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

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

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

In accordance with the December 2006 Order Otter Tail is submitting the following additional reporting requirements:

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

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

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. . . . PROTECTED DATA ENDS]

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

[PROTECTED DATA BEGINS . . .

. . . PROTECTED DATA ENDS]

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

Forecast:

In this forecast, no additional purchases of FTRs are assumed. Total congestion costs for both MISO and SPP are included in Attachments 4.1 and 4.2 to this filing.

Background:

The Company has no specific plans to purchase additional FTRs beyond those held through the normal allocation process. In some situations, the Company may sell allocated FTRs back to the market when a unit is offline for extended maintenance and/or a unit is expected to be economically de-committed due to low wholesale energy prices. Under such circumstances these FTRs do not serve to hedge energy flows between generation and load. In addition, the Company may choose to purchase additional FTRs for bilateral purchases if a monthly or seasonal FTR is anticipated to provide a reasonable hedge against congestion costs. Historically, purchasing FTRs to hedge a bilateral purchase has been a very infrequent occurrence.

SECTION 4 - SOUTHWEST POWER POOL (SPP) ENERGY MARKET RELATED COSTS - ORDER IN DOCKET E017/GR-15-1033

Forecast:

As noted above, forecasted non-energy SPP market related charges are reflected in Attachment 4.2 to this filing.

Background:

Otter Tail began incurring Southwest Power Pool (SPP) energy market charges on October 1, 2015, as a result of Western Area Power Administration (WAPA) joining SPP. Additional SPP market exposure was incurred as a result of the expiration of an integrated transmission agreement with Central Power Electric Cooperative effective January 1, 2016. SPP charges include day ahead and real time energy charges assessed by SPP, as well as other energy-market related charges.

Otter Tail has included the monthly day ahead and real time energy charges assessed by SPP in the monthly fuel clause, consistent with paragraph 2 of the Energy Adjustment Rider, Rate Schedule 13.01 (Attachment 10.1 of this Filing):

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.*

In rate case Docket No. E017/GR-15-1033, the Commission approved Otter Tail's request to recover SPP market-related costs through the energy adjustment.

Effective with bills rendered on and after November 1, 2017, Otter Tail began to include SPP market related costs in the monthly fuel clause, consistent with paragraph 4 of the Energy Adjustment Rider, Rate Schedule 13.01.

4. *All forecasted Midwest ISO (MISO) and South 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.*

Further Information on Otter Tail Load in SPP

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

SECTION 5 - MN DOC'S REVIEW OF 2005/2006 AAA REPORT DOCKET NO. E,G999/AA-06-1208

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

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

Forecast:

No virtual transactions are considered in the development of the forecasted rates submitted in this filing. There is no meaningful or reasonable way to predict if or when the use of a virtual transaction may be beneficial.

Background: Use of Virtual Transactions / Other Hedging Tools within MISO/SPP

For retail load serving purposes, the Company may occasionally use virtual transactions to convert bilateral purchases between the day-ahead and real-time markets. For instance, some bilateral purchases are designed to settle in the real-time market while the Company clears its load in the day-ahead market. Therefore, a virtual transaction might be used to convert the real-time purchase to the day-ahead market so that the purchase more accurately hedges the Company's load.

Within SPP, where Otter Tail pseudo ties its load back into MISO, we are required to pay real time congestion and loss differences between our energy injection point into the SPP footprint (MISO/SPP boundary) and our energy withdrawal point (Otter Tail load within the SPP footprint). We are also entitled to request/nominate Transmission Congestion Rights (TCRs) between those two points due to Otter Tail ownership of Network Integrated Transmission Service (NITS) to serve our load. If nominated, and granted, TCRs would hedge against day-ahead congestion between the Otter Tail injection and withdrawal points. However, since Otter Tail's pseudo tie congestion charges are based on real time congestion, utilization of virtual transactions could potentially be used to move the real time congestion charges into the day ahead market. This would align congestion costs with the Otter Tail TCRs, potentially producing a better hedging mechanism. To date Otter Tail has not utilized TCR and virtual transactions for our SPP load because congestion pricing at the injection point tends to be higher than congestion pricing at the withdrawal point. In the future, market pricing conditions could potentially change, leaving open the possibility that Otter Tail might utilize TCRs and virtual transactions to minimize cost to Otter Tail customers.

Since the beginning of the MISO Day 2 market, Otter Tail has very rarely utilized virtual transactions on behalf of retail customers. Furthermore, at this time, Otter Tail does not expect to utilize virtual transactions on behalf of retail customers in the 2026 forecast year.

SECTION 6 - MN PUC ORDER ACTING ON ELECTRIC UTILITIES' ANNUAL REPORTS AND REQUIRING ADDITIONAL FILINGS DOCKET NOS. E999/AA-09-961 and E999/AA-10-884

22. The Commission requests Interstate, Minnesota Power, Otter Tail, and Xcel to comment on sharing lessons learned regarding the handling of forced outages. The Commission also requests the companies to discuss amongst themselves whether and what kind of information sharing would be beneficial. The companies shall provide in supplemental filings to their fiscal-year 2011 AAA reports, in Docket No. E999/AA-11-792, and in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.

Forecast:
Lessons Learned

Otter Tail believes any discussion with regard to lessons learned and information sharing around plant outages is better suited for the true-up filing as opposed to this forecast filing.

Forced Outages

Regarding forced outages, Otter Tail assumes a certain level of forced outages in the forecast and has provided a quantification of the estimated cost of those forced outages in the May 1, 2025, Petition (Section D, Part 2, subpart a.)

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

Forecast:

Otter Tail includes forecasted net congestion and firm transmission rights costs as reflected in Attachments 4.1 and 4.2.

SECTION 7 - MN OES'S REVIEW OF 2006/2007 AAA REPORT DOCKET NO. E,G999/AA-07-1130

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

Forecast:

Otter Tail provides in Attachments 4.1 through 4.3, the forecasted Non-Energy Wholesale Market Charges for 2026 which are ultimately reflected in Attachment 2, Line 6 (MISO(Non-Energy) Wholesale Market Charges) and Line 7 (SPP (Non-Energy) Wholesale Market Charges)) and Line 8 (MISO ASM charges). Forecasted Asset-Based margins are reflected on Line 11 of Attachment 2.

The OES also recommended Otter Tail address how the Auction Revenue Rights

(ARR) process will be treated for retail and wholesale purposes and provide information regarding what ARRs if any a utility purchased, how much they paid, and what FTR revenues and costs were received to date for ARRs purchases.

Forecast:

Otter Tail has no activity to report for this item.

SECTION 8 - MINN. R. 7825.2830 FIVE-YEAR PROJECTION

Otter Tail provides Attachment 12 which is the Annual Five-Year projection.

SECTION 9 - MINN. R. 7825.2840 NOTICE OF REPORTS AVAILABILITY

Appendix B is the Notice of Reports Availability.

Appendix B
Notice of Report Availability

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

OTTER TAIL POWER COMPANY

May 1, 2025

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 (Order dated June 12, 2019 in Docket No. E999/CI-03-802) and its December 18, 2019 Order in Docket No. E017/AA-19-297. The subject matter of the reports filed in this Forecast Energy Adjustment Rates Filing includes the following:

Minn. R. 7825.2800 Policies and Actions
Minn. R. 7825.2810 Automatic Adjustment Charges
Minn. R. 7825.2830 Annual Five-Year Projection Report
Minn. R. 7825.2840 Notice of Reports Availability, Certificate of Service, and Service Lists

Also included in this Forecast Energy Adjustment Rates Filing are additional fuel clause related reporting requirements under various Commission Orders as they are applicable to the forecasted rates and as approved by the Commission's June 12, 2019 Order and December 18, 2019 Order.

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/ CHRISTOPHER E. BYRNES
Christopher Byrnes
Supervisor, Regulatory Analysis
Regulatory Economics

CERTIFICATE OF SERVICE

RE: In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01
Docket No. E017/AA-25-65

I, Valerie Moxness, hereby certify that I have this day served a copy of the following, or a summary thereof, on Will Seuffert 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
Initial Filing

Dated this 1st day of May 2025.

/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	Mariah	Bevins	maria.bevins@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	AA-25-65
2	Tom	Boyko	tboyko@eastriver.coop	East River Electric Power Coop.		211 S. Harth Ave Madison SD, 57042 United States	Electronic Service		No	AA-25-65
3	Chris	Byrnes	cbyrnes@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	AA-25-65
4	Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.		12700 West Dodge Road PO Box 2047 Omaha NE, 68103-2047 United States	Electronic Service		No	AA-25-65
5	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	AA-25-65
6	Jason	Decker	jason.decker@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	AA-25-65
7	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	AA-25-65
8	Charles	Drayton	charles.drayton@enbridge.com	Enbridge Energy Company, Inc.		7701 France Ave S Ste 600 Edina MN, 55435 United States	Electronic Service		No	AA-25-65
9	Remi	Engbers	remi.engbers@woodsfuller.com	Woods, Fuller, Shultz & Smith P.C.		300 S Phillips Ave Ste 300 PO Box 5027 Sioux Falls SD, 57117-5027 United States	Electronic Service		No	AA-25-65
10	Kelly C.	Engebretson	kelly.engebretson@lawmoss.com	Moss & Barnett		150 S. 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-65
11	Michael	Fairbanks	michael.fairbanks@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	AA-25-65
12	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	AA-25-65
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				Company		MN, 56538-0496 United States				
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15	Amber	Grenier	agrenier@otpco.com	Otter Tail Power Company		215 S. Cascade St. Fergus Falls MN, 56537 United States	Electronic Service		No	AA-25-65
16	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	AA-25-65
17	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	AA-25-65
18	Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club		2101 Webster St Ste 1300 Oakland CA, 94612 United States	Electronic Service		No	AA-25-65
19	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	AA-25-65
20	Faron	Jackson, Sr.	faron.jackson@llojibwe.net			190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	AA-25-65
21	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-65
22	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	AA-25-65
23	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-65
24	Bill	Lachowitzer	blachowitzer@ibewlocal949.org	IBEW Local Union 949		12908 Nicollet Ave S Burnsville MN, 55337-3527 United States	Electronic Service		No	AA-25-65
25	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-65
26	Eric	Lipman	eric.lipman@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164-0620 United States	Electronic Service		No	AA-25-65

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28	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	AA-25-65
29	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-65
30	Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	AA-25-65
31	Marcia	Podratz	mpodratz@mnpower.com	Minnesota Power		30 W Superior S Duluth MN, 55802 United States	Electronic Service		No	AA-25-65
32	David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company		P.O. Box 496 215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	AA-25-65
33	Rate Case Inbox	Rate Case Inbox	mnratecase@otpco.com	Otter Tail		null null, null United States	Electronic Service		No	AA-25-65
34	Generic Notice	Regulatory	regulatory_filing_coordinators@otpco.com	Otter Tail Power Company		215 S. Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	AA-25-65
35	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	AA-25-65
36	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	AA-25-65
37	Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC		1742 Patriot Rd Northfield MN, 55057 United States	Electronic Service		No	AA-25-65
38	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	AA-25-65
39	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN,	Electronic Service		No	AA-25-65

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40	Cary	Stephenson	cstephenson@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	AA-25-65
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42	Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	AA-25-65
43	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	AA-25-65
44	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	AA-25-65
45	Laurie	York	laurie.york@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	AA-25-65
46	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	AA-25-65

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2	Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.		12700 West Dodge Road PO Box 2047 Omaha NE, 68103-2047 United States	Electronic Service		No	15-1033Official Service List
3	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	15-1033Official Service List
4	Charles	Drayton	charles.drayton@enbridge.com	Enbridge Energy Company, Inc.		7701 France Ave S Ste 600 Edina MN, 55435 United States	Electronic Service		No	15-1033Official Service List
5	Remi	Engbers	remi.engbers@woodsfuller.com	Woods, Fuller, Shultz & Smith P.C.		300 S Phillips Ave Ste 300 PO Box 5027 Sioux Falls SD, 57117-5027 United States	Electronic Service		No	15-1033Official Service List
6	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	15-1033Official Service List
7	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	15-1033Official Service List
8	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	15-1033Official Service List
9	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	15-1033Official Service List
10	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		Yes	15-1033Official Service List
11	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	15-1033Official Service List
12	Bill	Lachowitzer	blachowitzer@ibewlocal949.org	IBEW Local Union 949		12908 Nicollet Ave S Burnsville MN, 55337-3527 United States	Electronic Service		No	15-1033Official Service List
13	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis	Electronic Service		No	15-1033Official Service List

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55402 United States				
14	Eric	Lipman	eric.lipman@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164-0620 United States	Electronic Service		No	15-1033Official Service List
15	Joseph	Meyer	joseph.meyer@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Bremer Tower, Suite 1400 445 Minnesota Street St Paul MN, 55101-2131 United States	Electronic Service		Yes	15-1033Official Service List
16	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	15-1033Official Service List
17	David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company		P.O. Box 496 215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	15-1033Official Service List
18	Rate Case Inbox	Rate Case Inbox	mnratecase@otpco.com	Otter Tail		null null, null United States	Electronic Service		No	15-1033Official Service List
19	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	15-1033Official Service List
20	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	15-1033Official Service List
21	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		Yes	15-1033Official Service List
22	William	Taylor	bill.taylor@taylorlawsd.com	Taylor Law Firm		4820 E. 57th Street Suite B Sioux Falls SD, 57108 United States	Electronic Service		No	15-1033Official Service List
23	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	15-1033Official Service List
24	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		Yes	15-1033Official Service List

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Mariah	Bevins	maria.bevins@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	20-719Official
2	Tom	Boyko	tboyko@eastriver.coop	East River Electric Power Coop.		211 S. Harth Ave Madison SD, 57042 United States	Electronic Service		No	20-719Official
3	Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.		12700 West Dodge Road PO Box 2047 Omaha NE, 68103-2047 United States	Electronic Service		No	20-719Official
4	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	20-719Official
5	Jason	Decker	jason.decker@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	20-719Official
6	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		Yes	20-719Official
7	Charles	Drayton	charles.drayton@enbridge.com	Enbridge Energy Company, Inc.		7701 France Ave S Ste 600 Edina MN, 55435 United States	Electronic Service		No	20-719Official
8	Remi	Engbers	remi.engbers@woodsfuller.com	Woods, Fuller, Shultz & Smith P.C.		300 S Phillips Ave Ste 300 PO Box 5027 Sioux Falls SD, 57117-5027 United States	Electronic Service		No	20-719Official
9	Kelly C.	Engebretson	kelly.engebretson@lawmoss.com	Moss & Barnett		150 S. 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	20-719Official
10	Michael	Fairbanks	michael.fairbanks@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	20-719Official
11	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	20-719Official
12	Jessica	Fyhrie	jfyhrie@otpco.com	Otter Tail Power Company		PO Box 496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	20-719Official
13	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	20-719Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
14	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	20-719Official
15	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	20-719Official
16	Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club		2101 Webster St Ste 1300 Oakland CA, 94612 United States	Electronic Service		No	20-719Official
17	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		Yes	20-719Official
18	Faron	Jackson, Sr.	faron.jackson@llojibwe.net			190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	20-719Official
19	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	20-719Official
20	Nick	Kaneski	nick.kaneski@enbridge.com	Enbridge Energy Company, Inc.		11 East Superior St Ste 125 Duluth MN, 55802 United States	Electronic Service		No	20-719Official
21	Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 S 8th St Minneapolis MN, 55402 United States	Electronic Service		No	20-719Official
22	Bill	Lachowitzer	blachowitzer@ibewlocal949.org	IBEW Local Union 949		12908 Nicollet Ave S Burnsville MN, 55337-3527 United States	Electronic Service		No	20-719Official
23	James D.	Larson	james.larson@avantenergy.com	Avant Energy Services		220 S 6th St Ste 1300 Minneapolis MN, 55402 United States	Electronic Service		No	20-719Official
24	Eric	Lipman	eric.lipman@state.mn.us		Office of Administrative Hearings	PO Box 64620 St. Paul MN, 55164-0620 United States	Electronic Service		Yes	20-719Official
25	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	20-719Official
26	Joseph	Meyer	joseph.meyer@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Bremer Tower, Suite 1400 445 Minnesota Street St Paul MN, 55101-2131 United States	Electronic Service		No	20-719Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
27	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	20-719Official
28	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	20-719Official
29	Matthew	Olsen	molsen@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	20-719Official
30	Marcia	Podratz	mpodratz@mnpower.com	Minnesota Power		30 W Superior S Duluth MN, 55802 United States	Electronic Service		No	20-719Official
31	David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company		P.O. Box 496 215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	20-719Official
32	Rate Case Inbox	Rate Case Inbox	mnratecase@otpco.com	Otter Tail		null null, null United States	Electronic Service		No	20-719Official
33	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	20-719Official
34	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		Yes	20-719Official
35	Robert H.	Schulte	rhs@schulteassociates.com	Schulte Associates LLC		1742 Patriot Rd Northfield MN, 55057 United States	Electronic Service		No	20-719Official
36	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	20-719Official
37	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		Yes	20-719Official
38	Cary	Stephenson	cstephenson@otpco.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	20-719Official
39	William	Taylor	bill.taylor@taylorlawsd.com	Taylor Law Firm		4820 E. 57th Street Suite B Sioux Falls SD, 57108 United States	Electronic Service		No	20-719Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
40	Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	20-719Official
41	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	20-719Official
42	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO, 80202 United States	Electronic Service		No	20-719Official
43	Laurie	York	laurie.york@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	20-719Official
44	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	20-719Official