Docket No. EL26-
Analyst Assigned: Paula Foster

STATE OF SOUTH DAKOTA
BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Rate Update to Rate Schedule, Section 13.05, Transmission Cost Recovery Rider	**Docket No. EL26-** **PETITION**

I. PETITION SUMMARY

Otter Tail Power Company's (OTP or the Company) Transmission Cost Recovery Rider (TCRR) includes the following:

- Annual updated actual and forecasted costs and collections associated with Phase 2 of the previously approved Milbank Area Reliability project;
- Addition of one new project – Appleton to Benson 115 kV Line;
- Updated regional transmission expenses and revenues recovered in the TCRR;
- Updated D2 allocation factor to reflect the D2 allocation factor calculated based on the actual financial results from the prior year;
- Proposed rate implementation date of March 1, 2027;
- The South Dakota projected revenue requirement for the recovery period of March 1, 2027, to February 29, 2028, is $823,254. Residential customers using 1,000 kWh monthly will see a bill decrease of approximately $0.75.

II. INTRODUCTION

In compliance with the South Dakota Public Utilities Commission's (Commission) Orders,[1] OTP respectfully petitions for approval of its annual update to its TCRR rate.

In this filing, OTP proposes updating its TCRR rates to reflect the calculated revenue requirements for the 12-month period from March 1, 2027, through February 29, 2028. This update includes actual project costs through August 2026 and forecasted costs for the remainder of the current recovery period ending February 28, 2027, and projections for the proposed recovery period ending February 29, 2028. This update

[1] Previous TCRR Docket Nos. EL10-015, EL12-054, EL13-029, EL14-090, EL15-045, EL16-035, EL17-048, EL18-048, EL19-039, EL20-032, EL21-031, EL22-031, EL23-033 EL24-034, EL25-040.

includes the proposed addition of the Appleton to Benson 115 kV line, which includes two parts – Shible Lake to Moyer and Moyer to Danvers.

As shown in Attachment 2, the proposed revenue requirement for the March 1, 2027, through February 29, 2028, recovery period is $823,254, which reflects an increase of $166,437 compared to the prior period revenue requirement of $656,817.[2] The rate change by class and the bill impact for residential and large general service customers can be found in Section IX below.

III. GENERAL FILING INFORMATION

A. Name, address, and telephone number of the utility making the filing

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B. Name, address, and telephone number of the attorney for Otter Tail Power Company

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C. Title of utility employee responsible for filing

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[2] Approved in Commission's February 24, 2026, Order in Docket No. EL25-040.

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D. The Company also requests that the following contact(s) be placed on the Commission's official service list for this matter

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E. The date of filing and the date changes will take effect

The date of this filing is November 2, 2026. OTP proposes the update to the Rider factor to go into effect for usage on and after March 1, 2027.

F. Statutes controlling schedule for processing the filing

OTP files this Rider for Commission approval consistent with the 30-day notice requirement set forth in South Dakota Codified Laws 49-34A-12. OTP will provide notice of this proceeding to its customers in the month of November as a bill message as shown in Attachment 15 to this Petition.

In accordance with ARSD 20:10:16:01 (2), which requires the Utility to provide notice of all rate schedule changes and customer impacts, OTP plans to provide notice to customers in the form of a bill insert. Attachment 16 to this Petition is the language proposed for this customer notice. This notice will be included with customer bills the month this rate is effective.

OTP includes Attachment 17 to comply with ARSD 20:10:13:26, which requires the Utility to report all rate schedule changes and customer impacts.

IV. BACKGROUND

In this Petition, OTP provides a proposed update to its rate schedule, Section 13.05, in compliance with Paragraph 10 of the Settlement Stipulation approved by the Commission's Docket No. EL10-015 TCRR Order, referenced above. This Petition also incorporates the filing date approved by the Commission's Docket No. EL13-029 TCRR Order, referenced above, which requires the following:

> **Annual Reporting:** The Parties agree OTP will submit an annual TCR filing on a going forward basis to be received by the PUC by November 1 of each year. Based on this annual report, OTP will adjust the TCR rate each year based on actual costs and collections.

The Commission's TCRR Order in Docket No. EL10-015 was made pursuant to SDCL 49-34A-25.1 and 49-34A-25.2. Annual updates to the approved tariff rate schedule are governed by SDCL 49-34A-25.3 and 49-34A-25.4, which read as follows:

> 49-34A-25.3. Filing for annual rate adjustments—Contents. A public utility may file annual rate adjustments to be applied to customer bills paid under the tariff approved pursuant to §49-34A-25.2. In the utility's filing, the public utility shall provide:
>
> (1) A description of and context for the facilities included for recovery;
> (2) A schedule for implementation of applicable projects;
> (3) The public utility's costs for these projects;
> (4) A description of the public utility's efforts to ensure the lowest reasonable costs to ratepayers for the project; and
> (5) Calculations to establish that the rate adjustment is consistent with the terms of the tariff established in §49-34A-25.2.
>
> 49-34A-25.4. Standards for approval of annual rate adjustments. Upon receiving a filing under §49-34A-25.3 for a rate adjustment pursuant to the tariff established in §49-34A-25.2, the commission shall approve the annual rate adjustments if, after notice, hearing, and comment, the costs included for recovery through the tariff were or are expected to be prudently incurred and achieve transmission system improvements at the lowest reasonable cost to ratepayers.

Consistent with these statutory requirements, the Commission Approved Settlement Stipulation in Docket No. EL10-015 required as follows:

> In the future, OTP's investment in new transmission projects will require Commission approval in a future TCR annual update filing through which Commission Staff shall be provided an opportunity to review such projects for statutory compliance. Such projects may be regional, like those described in this Settlement or they may be local (projects that do not

qualify for regional cost allocation through MISO's FERC authorized rates). (EL10-015 TCR Settlement Stipulation, page 4, paragraph 3).

This Petition is prepared in compliance with the above referenced statutes and Settlement Stipulations.

V. TCRR Revenue Requirements Calculations

In support of OTP's request to update its TCRR rate, the Company provides Attachments 1-4A, which are, respectively, the Projected Revenue, Summary of Revenue Requirements, Rate Design, Tracker Summary, and True-up by Class.

Attachments 5-10 provide MISO transmission revenues, MISO/SPP transmission expenses, MISO Schedule 26 revenues, MISO Schedule 26A revenues, MISO Schedule 37 and 38 revenues, and Accumulated Deferred Income Tax (ADIT) proration preservation.

Attachment 11 contains the revenue requirement calculations for the previously approved Milbank Area Reliability Project (MARP), and Attachment 12 provides the revenue requirement calculations for the proposed addition of the Appleton to Benson project.

Descriptions of the calculations included in Attachments 5-12 are listed below.

- *Rate base section*. This section provides details on the amount of plant in service, accumulated depreciation, construction work in progress (CWIP) (if applicable), accumulated deferred taxes including the effect of proration on Federal amounts, and a 13-month average rate base calculation.
- *Expense section*. The expenses applicable to a project are listed here and include operating costs, property taxes, depreciation, and income taxes.
- *Revenue requirements section*. This section shows the components of the revenue requirements, including expenses and return on investment and any credits to the revenue requirement for monies received for use of OTP facilities by wholesale customers.
- *Return on investment (cost of capital)*. Pursuant to Section III, 3. The rate of return methodology agreed to in the EL 12-054 Settlement Stipulation uses the Company's actual capital structure as of December 31 of the prior year for the following year's calculation and the return on equity ordered by the Commission in OTP's most recent rate case, Docket No. EL25-022.
- *Depreciation expense*. Depreciation expense is calculated using the Company's current depreciation rates.

- *Property taxes*. The property tax calculation is based on OTP's composite tax rate for the jurisdiction in which the transmission facilities are located and is calculated in accordance with the procedures specified by that state.
- *Operation and Maintenance (O&M) expense*. This section includes any O&M expenses associated with the project. OTP does not always incur O&M expenses, but when it does, these may include costs related to line patrol and inspections, vegetation management, small repair items, storm restoration, and supervision of this work. Scheduled transmission line patrols are typically done annually on high voltage transmission lines (115 kV and above). The Company completes unscheduled patrols for line sections with unexplained interruptions. Vegetation management for new lines is typically limited during the first five years, since OTP's construction standard is to remove as many trees as possible within a specified easement area prior to construction. After five years, vegetation management is completed based on information gathered during line patrols. Costs of the initial clearing of trees to prepare the route for a new line are not O&M expenses.
- *Proration of Federal Accumulated Deferred Income Taxes (ADIT)*. Attachment 10 provides the calculation of OTP's ADIT balance to preserve the effect of the application of the proration methodology for the true-up period. This calculation methodology is necessary to comply with 26 C.F.R. § 1.167(*l*)-l(h)(6)(ii) of the IRS regulations and to avoid a tax normalization violation.[3] Attachment 10 shows that the preservation of the proration of ADIT resulted in a decrease of $1,444, plus any applicable carrying charge to the revenue requirement. This ADIT amount is included in the Tracker Summary (Attachment 4).
- *MISO Schedule 26 and 26A expenses*. Schedule 26 and Schedule 26A costs for the recovery period are included on the Tracker Summary and are shown separately in Attachment 5. As stated in the EL12-054 Settlement Stipulation, Section III, 4.b., "the TCR will flow through the jurisdictional share of Schedule 26 and Schedule 26A expenses incurred by OTP as an active member of MISO, adjusted for the amount of such expenses associated with OTP's investment in projects that are not included in the rider."
- *Southwest Power Pool (SPP) Related Expenses (Attachment 5) and MISO Related Revenues (Attachment 6)*. SPP Schedules 7, 8, and 9 refer to different

[3] *See* Treas. Reg. §§ 1.167(l)-1(h)(6)(ii).

types of transmission service that OTP may secure for serving the Company's load in SPP, which represent firm point-to-point, non-firm point-to-point, and network integration transmission service, respectively.

SPP Schedule 11 expenses are for new projects approved through SPP's Integrated Transmission Planning process that have benefits beyond the local area. OTP includes the SPP expenses in the ISO Transmission Expenses line of the Tracker Summary, and they are shown separately in Attachment 5.

- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period are included in the Tracker Summary and are shown separately in Attachments 7 and 8, respectively. Projects qualifying for regional cost allocation through the Midcontinent Independent System Operator (MISO) tariff are accounted for using the "refined split" method. As stated in the EL12-054 Settlement Stipulation, Section III, 2.c:

  > Retail customers will be credited a pro-rata share of FERC-authorized MISO Schedule 26 revenues associated with the Company's MISO-determined responsibility for OTP's investment in the regional transmission projects, offsetting corresponding Schedule 26 expenses. The Company will retain the portion of its Schedule 26 revenues associated with other MISO members' responsibility for OTP's investment in the projects in order to cover the remaining revenue requirements for such projects.

- *MISO Tariff Schedule 37 and Schedule 38 Revenue Credits.* The TCRR rate update calculation includes revenue credits to reflect revenues received from MISO, pursuant to Schedules 37 and 38 of the MISO Tariff. The Schedule 37 and 38 revenues represent OTP's share of the Schedule 26 cost allocation assigned to former MISO transmission owners that withdrew from MISO. These owners have an ongoing obligation to pay for MISO Schedule 26 transmission projects due to their prior MISO membership. OTP notes that there are no forecast amounts for Schedules 37 and 38 revenues for the 2027 recovery period. MISO does not provide a separate forecast for those revenues but includes any Schedule 37 and 38 revenues within the Schedule 26 revenue forecasts that MISO develops. MISO does delineate Schedule 37 and 38 revenues when reporting actuals. The Schedule 37 and 38 revenue credit reflected in this TCRR update can be found in Attachment 9. These are actual amounts through July 2026 and are included as part of the 2026 true-up amount.

- *MISO Multi-Value Project Auction Revenue Rights (MVP ARR) Revenue.* The MVP ARR revenues are derived from increased transmission capacity attributable to MVP projects placed in service within the MISO footprint. The value of these MVP ARRs is determined during MISO's annual Financial Transmission Rights auction. The revenues are distributed to all MISO market participants in a manner similar to the way MISO Schedule 26A expenses are allocated to MISO market participants for all MVP projects. The revenue is identified in Attachment 6 and is included in the Tracker Summary on the ISO Transmission Revenues line.
- *Revenue credit for administrative and general expenses recovered through MISO tariff for non-retail portion of projects qualifying for regional cost allocation.* The TCRR rate update calculations include a revenue credit (reduction to TCRR revenue requirements) to account for reimbursements through MISO's tariff for administrative and general operating and maintenance expenses. The revenue credit is for the entire amount of such revenues received through the MISO tariff, whether related to the retail or non-retail portion of projects that qualify for regional cost allocations. This application of revenues to reduce the retail revenue requirement provides reimbursement to retail customers for any such costs that may already be recovered through OTP's current retail rates. The revenue credit is reflected in Attachments 7, 8, and 9 on the lines titled "Overhead Credit for Non-Retail Share" for each project. This percentage was established for these costs as part of the FERC-approved MISO Tariff.

VI. Project Previously Approved for Recovery

The Milbank Area Reliability project was approved for TCRR recovery in Docket No. EL 23-033. The total project cost was estimated at $36.2 million (OTP Total)/$3.82 million (OTP SD). Phase 1 of the project, at a cost of $11.5 million, rolled into base rates in the most recent rate case. Phase 2 of the project, which is estimated at $19 million, remains in the rider for the proposed recovery period. OTP placed Phase 2 in service in June 2026 and will continue to incur costs through 2027 as OTP completes final project closeout activities.

OTP expects the final project cost will be approximately $30.6 million (OTP Total)/$3.5 million (OTP SD), which is $5.6 million (OTP Total)/$0.6 million (OTP SD) under budget. OTP attributes the favorable variance primarily to its very competitive bidding process along with its inclusion of a conservative contingency to address potential

COVID-19-related inflationary impacts, which were less significant than anticipated.

VII. New Transmission Project Proposed for Recovery

In this TCR filing, OTP submits a new transmission project, which is referred to as the Appleton to Benson 115kV Line, for Commission approval. This large project is broken into two smaller projects – the Shible Lake to Moyer project and the Moyer to Danvers project.

Appleton to Benson 115 kV Line – Attachment 27

OTP, Great River Energy (GRE), Missouri River Energy Services (MRES), and Xcel Energy have collaborated on a planning study for the transmission system in west central Minnesota between three 230/115 kV transmission sources at the Morris (near Morris, MN), Willmar (near Willmar, MN), and Minnesota Valley (near Granite Falls, MN) substations. A 115 kV network stretches between these three 230/115 kV sources feeding multiple 69 kV and 41.6 kV networks that serve many OTP, GRE, and MRES communities. The study was performed to identify necessary system reinforcements to the high voltage transmission system for load growth within the area and the retirement of the 55 MW FibroMinn Energy Center near Benson, Minnesota.

The study found the transmission system is unable to meet voltage criteria for the loss of either the Morris or the Minnesota Valley 230/115 kV sources. Under either of these outages, low voltages on the 115 kV system were observed in the Morris and Benson areas. In addition, low voltages were observed for these same outages, on the 41.6 kV systems fed from the Walden and Benson 115/41.6 kV substations. Under the outage of the Morris to Morris OTP 115 kV line, thermal loading violations were observed on the Kerkhoven to Kerkhoven Junction 115 kV line. Additionally, with the loss of the Appleton 115/41.6 kV source, low voltages occurred on the 41.6 kV system between Appleton and Benson substations. The voltage and thermal loading violations were most prevalent during summer peak conditions.

To address the reliability concerns identified in the study, the parties outlined a transmission plan that included the following components:

1. Construction of approximately 27.3 miles of 115 kV line between the new Appleton 115 kV substation and the Benson 115 kV substation.
    a. Approximately 18.3 miles of existing 41.6 kV line will be upgraded to 115 kV line.
    b. Approximately 1.0 mile of existing 115 kV line will be reconductored or rebuilt.

c. Approximately 8.0 miles of the 115 kV transmission line will be new construction.

2. Retirement of the 41.6 kV line between the Appleton 115 kV substation and the Benson 115 kV substation. Retirement of a small portion of the Benson - Kerkhoven 115 kV line.
3. Construction of a new Appleton 115 kV substation.
4. Modifications to the existing Benson 115 kV substation and the Benson Municipal 115 kV substation.
5. Construction of approximately 1.7 miles of 115 kV line between the Benson Municipal substation and the Benson – Kerkhoven 115 kV line.
6. Conversion of the Appleton, Shible Lake, Moyer, Holloway, and Danvers distribution substations from the 41.6 kV system to the 115 kV system.

When completed, this project will significantly improve the reliability of the transmission system in the area.

OTP will own approximately 16.7 miles of the proposed 27.3 miles of the 115 kV transmission line between the Appleton 115 kV and Benson 115 kV substations. The rest of the 115 kV line between the Appleton 115 kV substation and Benson 115 kV substation will be owned by GRE, along with the 1.7 miles of 115 kV line between the Benson Municipal substation and the Benson – Kerkhoven 115 kV line. MRES will own the new Appleton 115 kV substation, and all other substations will maintain current ownership after the project is completed.

The total cost for OTP's transmission portion of the project is estimated to be $21.0 million (OTP Total) / $2.4 million (OTP SD), with the Shible Lake to Moyer portion of the project estimated at $8.3 million (OTP Total) / $0.9 million (OTP SD), and the Moyer to Danvers portion estimated at $12.7 million (OTP Total)/$1.4 million (OTP SD).

MISO approved the Appleton – Benson 115 kV Line project in its 2021 Transmission Expansion Plan (MTEP21) and the Minnesota Public Utilities Commission approved it in Docket No. E017/TL-24-264, Order dated February 4, 2026. The project is anticipated to be in-service in December 2029.

VIII. RATE DESIGN

In the most recent rate case filing,[4] the Commission approved a new D5 allocation factor to allocate MISO Schedule 26 expenses to the jurisdiction and classes. The Commission also approved the use of an energy allocation factor (E2) to allocate MISO

[4] In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in South Dakota, Docket No. EL25-022.

Schedule 26A expenses. All other TCRR charges and credits are allocated to the jurisdiction and classes using the D2 allocation factor.

The February 12, 2019 Staff Memorandum in Docket No. EL18-048, outlines the methodology for incorporating class allocations of prior period true-up amounts. Attachment 4A includes revenue requirements, billings, and the resulting over-or-under recovery by rate class. The projected true-up is based on actual data from March through September 2026 and forecasted data for October 2026 through February 2027. OTP reviewed actual sales and the net revenue requirement for each class to determine the true-up balance, including applicable carrying charges. The change in allocation factors and LGS rate design was implemented in the revenue requirement calculation for the March 2026 through February 2027 recovery period.[5] Attachment 4A has been updated with this filing to ensure this allocation change is reflected in the true up by class. The total prior period true-up incorporated in the proposed revenue requirement is ($952,634), as reflected in Attachment 3.

As outlined in Docket No. EL10-015 Settlement Stipulation Order, OTP's Large General Service (LGS) rate design still incorporates the forecasted demand and energy revenue components ($/kW-month and ¢/kWh, respectively) to recover the transmission project costs in alignment with the existing LGS base rate design. For this update, the LGS rate design is similarly based on forecasted demand and energy revenue components for the proposed recovery period, using a 35 percent demand and 65 percent energy split for costs and revenues other than the MISO Schedules 26 and 26A expenses. For non-LGS retail rate classes, OTP proposes to continue an energy-only rate, consistent with the current Commission-approved rate structure. Each rate class is calculated as a separate energy-based (kWh) charge determined by dividing the total class revenue requirement by the corresponding kilowatt-hour sales.

IX. RATE APPLICATION AND IMPACT

As previously noted, the annual revenue requirement for the proposed recovery period of March 2027 through February 2028 increases from $656,817 for the March 2026 through February 2027 period to $823,254, which includes a projected true-up balance credit of ($952,634) for the current collection period.

The table below compares the summaries of revenue requirements approved in Docket No. EL25-040 (2025 TCRR Update) to this filing and helps illustrate the factors that contribute to the difference between the current revenue requirement (in the 2025

[5] In the Matter of Otter Tail Power Company's Petition for Approval of the Annual Rate Update to Rate Schedule, Section 13.05, Transmission Cost Recovery Rider, Docket No. EL25-040, Supplemental Filing dated February 2, 2026.

TCRR Update) and the proposed revenue requirement. As noted above, the proposed effective date of the change in rates is March 1, 2027.

Table 1
Summary of Revenue Requirements

Line No.	Description	Approved March 2026 - February 2027	Proposed March 2027 - February 2028
1	Milbank Area Reliability	184,123	224,812
2	Appleton to Benson		50,356
3			
4	SD Filing Fee	4,000	4,000
5			
6	ISO Transmission Expenses	2,646,569	2,921,930
7			
8	ISO Transmission Revenue	(519,151)	(541,049)
9	MISO Schedule 26 Revenue	(436,798)	(469,918)
10	MISO Schedule 26A Revenue	(358,217)	(368,805)
11			
12	Carrying Cost	(32,475)	(45,438)
13	True-Up	(831,234)	(952,634)
14			
15	Total	656,817	823,254

Table 2 provides the current rates and proposed rates and calculates the difference.

Table 2
Current Rates Compared to Proposed Rates

Class	Rate Type	Current Rates Mar '26 - Feb '27	Proposed Rates Mar '28 - Feb '28	Difference
Large General Service Class	$ / kW	$ 0.711	$ 0.716	$ 0.005
Large General Service Class	$ / kWh	$ 0.00017	$ 0.00069	$ 0.00052
Controlled Service	$ / kWh	$ 0.00057	$ 0.00205	$ 0.00148
Lighting	$ / kWh	$ 0.00055	$ 0.00092	$ 0.00037
All Other Service	$ / kWh	$ 0.00086	$ 0.00011	$ (0.00075)

As shown in Table 3, an LGS customer using 486 kW and 222,350 kWh will see a monthly increase of $118.81. A residential customer with 1,000 kWh of usage will see a monthly decrease of $0.75.

Table 3
Bill Impact for LGS and Residential Customers

Class	Change in Rates	Usage	Rate Type	Monthly Bill Impact
Residential	$ (0.00075)	1,000	$ / kWh	$ (0.75)
LGS Demand charge	$ 0.005	486	$ / kW	$ 2.27
LGS Energy charge	$ 0.00052	222,350	$ / kWh	$ 116.54
Total LGS				$ 118.81

Per the TCRR Settlement Stipulation dated February 10, 2014, that the Commission approved in Docket No. EL13-029, if the annual updates for MISO Schedules 26 and 26A are available in January, and result in a five percent or greater change in the overall revenue requirement than what was proposed in the initial filing, OTP will submit a supplemental filing with the updated information by the end of January. Because January 31, 2027, is a Sunday, OTP will submit a supplemental filing, if necessary, by February 1, 2027, to revise the TCRR rates. If submitted, the tracker will be updated with actuals through December 2026.

X. TCRR TARIFF SHEET

Attachment 14 to this Petition includes both the redline and clean versions of OTP's TCRR tariff sheet, Section 13.05. The RATE section of the tariff sheet has been updated to reflect the proposed changes outlined in this annual update.

XI. SPP BYPASS UPDATE

OTP renewed its transmission service with the Southwest Power Pool (SPP) in 2021, extending service through the end of 2027. The Company intends to extend this agreement for an additional five years, through 2032.

The Company continues to monitor the SPP-related expenses and the potential cost of building new facilities to bypass some or all of the SPP system. Any new updates and related decisions will be provided in future TCRR filings.

XII. FILING FEE

Under SDCL 49-1A-8, the Commission may require a deposit of up to fifty thousand dollars for the filing of a tariff for approval under the provisions of 49-34A-4 and 49-34A-25.1 to 49-34A-25.4, inclusive, or makes a filing pursuant to 49-34A-97 to 49-34A-100. OTP will pay such deposit amount as the Commission determines appropriate upon the Commission's Order assessing such fee.

XIII. CONCLUSION

For the foregoing reasons, OTP respectfully requests the Commission approve OTP's proposals to approve the TCRR recovery of the Appleton to Benson 115kV line and to implement updated rates in the Company's Transmission Cost Recovery Rider, Section 13.05, effective March 1, 2027.

Date: November 2, 2026

Respectfully submitted,

OTTER TAIL POWER COMPANY

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