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September 15, 2025

Mr. Steve Kahl
Director of Administration/Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

**RE: In the Matter of Otter Tail Power Company's Application for
Approval of the Annual Rate Update to Rate Schedule, Section 13.05,
Transmission Cost Recovery Rider
Case No. PU-25-**

Dear Mr. Kahl:

Enclosed please find copies of Otter Tail Power Company's (Otter Tail Power) Application to the North Dakota Public Service Commission for approval of the annual update to its Transmission Cost Recovery Rider rate as required by the Order in Case No. PU-11-153.

Also enclosed is Otter Tail Power's check in the amount of \$10,000 for the filing fee.

An electronic copy of this filing is also being sent to the North Dakota Public Service Commission at ndpsc@nd.gov. If you have any questions regarding this filing, please contact me at 218-739-8406 or jsillerud@otpco.com.

Sincerely,

/s/ JORDAN M. SILLERUD
Jordan M. Sillerud
Rates Analyst
Regulatory Economics

kaw
Enclosures
By electronic filing and U.S. mail

**STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**In the Matter of Otter Tail Power
Company's Application for Approval
of the Annual Rate Update to Rate
Schedule, Section 13.05,
Transmission Cost Recovery Rider**

**Case No. PU-25-
APPLICATION**

I. APPLICATION SUMMARY

Otter Tail Power Company's (Otter Tail Power or the Company) Transmission Cost Recovery Rider (TCRR) includes (1) annual updated actual and forecasted costs and collections associated with 28 previously approved projects; (2) regional transmission expenses and revenues recovered in the TCRR; (3) project timeline updates, phase removals, and complete project removals; and (4) the addition of Generator Interconnection Projects (GIPs).

The existing projects with timeline updates are listed below and discussed further in Section IV., C.

- **Project Timeline Delays:**
 - Pickert-McVille Rebuild
 - Wahpeton-Fairmount 115 kV Rebuild
 - Marvin-Corona Area 41.6 kV Rebuild
 - Buffalo Extenda-Life
 - Kensal-Bordulac 41.6 kV Extenda-Life
 - Cyrus-Farwell Extenda-Life
- **Phase Removal:**
 - Grenville-Veblen Rebuild
- **Project Removals:**
 - Wabek-Parshall Rebuild
 - Ivanhoe 41.6 kV In Line Reclosure

Otter Tail Power proposes a rate implementation date of January 1, 2026.

The North Dakota projected revenue requirement for the recovery period of January 1, 2026, to December 31, 2026, is \$5,137,664. A typical residential customer using 1,000 kWh will see a monthly bill increase of approximately \$1.48. A large general

service customer with 425 kW of demand will see a monthly bill increase of approximately \$224.43.

II. INTRODUCTION

Otter Tail Power hereby applies to the North Dakota Public Service Commission (Commission) for approval of an annual rate update to its TCRR in compliance with N.D.C.C. § 49-05-04.3 and Ordering Paragraph 6 of the Commission's April 25, 2012 Order in Case Nos. PU-11-153 and PU-11-682 (the TCRR Order).

In this filing, Otter Tail Power proposes updating its TCRR rates to reflect the TCRR revenue requirements for the next recovery period (calendar year 2026). The update includes the tracker balance estimated for the end of the current period to minimize over-or under-recovery of TCRR costs (in compliance with Ordering Paragraph 6 of the TCRR Order). As stated above, this update includes: (1) timeline updates; (2) phase removal; (3) project removal; (4) addition of the GIPs and their associated revenues; (5) forecast updates to previously approved projects; and (6) details of Southwest Power Pool (SPP) related expenses.

III. GENERAL FILING INFORMATION

Pursuant to N.D.A.C. § 69-02-02-04 of the Commission's Rules of Practice and Procedure, the following information is provided:

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

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

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

Lauren Donofrio
Senior Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
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Fergus Falls, MN 56538-0496
Phone (218) 739-8774
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C. Title of utility employee responsible for filing

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We request that all communications regarding this proceeding, including data requests, also be directed to:

Regulatory Filing Coordinator
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
regulatory_filing_coordinators@otpc.com

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

The date of this filing is September 15, 2025. The updated TCRR rate is calculated to take effect as of January 1, 2026.

E. Other requirements of North Dakota Rules Part 69-02-02-04

Pursuant to [N.D. Admin. Code § 69-02-02-04](#), a certified copy of Otter Tail Power's articles of incorporation is on file with the Commission in Case No. PU-09-677 and a current certificate of good standing is on file with the Commission

in Case No. PU-24-93. The certificate and amendments are hereby incorporated by reference.

IV. TRANSMISSION COST RECOVERY

A. Background

In this Application, Otter Tail Power requests approval for an annual update to its rate schedule, Section 13.05, in compliance with the TCRR Order referenced above. Paragraph 6 of that Order requires the following:

By September 1 of each year, OTP shall file with the Commission an annual TCR Rider rate on a going forward basis. In the annual filing, the tracker account will be updated so that any over- or under-recoveries at the end of the previous recovery period will be reflected in the TCR Rider adjustment for the upcoming recovery period.

In its 2022 annual TCRR filing, Otter Tail Power requested a permanent 15-day extension to allow adequate time to incorporate and review updated financial information filed annually with Midcontinent Independent System Operator (MISO) on September 1. The Commission approved the Company's request in the Order dated December 14, 2022, in Case No. PU 22-335.

Otter Tail Power's TCRR was approved by the Commission pursuant to N.D.C.C. § 49-05-04.3 which provides:

The commission may approve, reject, or modify a tariff filed under section 49-05-06 which provides for an adjustment of rates to recover jurisdictional capital, and operating costs incurred by a public utility for new or modified electric transmission facilities. For purposes of this section, an electric transmission facility includes an electric transmission line as defined in chapter 49-21.1 and other transmission line equipment, including substations, transformers, and other equipment constructed to improve the power delivery capability or reliability of the electric transmission system; and operating costs include federally regulated costs charged to or incurred by the public utility to increase regional transmission capacity or reliability. The tariff must:

- a. Allow the public utility to recover on a timely basis its investment and associated costs for new or modified electric transmission facilities not reflected in the utility's general rate schedule;

- b. Allow a return on the public utility's investment made for new or modified electric transmission facilities at the level approved in the utility's most recent general rate case;
- c. Provide a current return on construction work in progress for new or modified electric transmission facilities, provided the cost recovery from retail customers of the allowance for funds used during construction is not sought through any other means; and
- d. Terminate cost recovery after the public utility's costs for new or modified electric transmission facilities have been recovered fully or have been reflected in the utility's general rate tariff.

B. Revenue Requirement Calculations supporting Otter Tail Power's proposed TCRR rate update

In support of Otter Tail Power's request to update its TCRR rate, the Company provides Attachments 1-4, which are, respectively, the Projected Revenue for 2026, Summary of Revenue Requirements, Class Allocation and Rate Design, and Tracker Summary calculations the Company used to calculate its proposed TCRR rate update.

Attachments 14-31 provide the revenue requirement calculations for each of the transmission projects identified in this filing – both those previously approved in Otter Tail Power's prior TCRR (Attachments 15-31) and the added GIPs projects for which the Company is requesting TCRR recovery (Attachment 14).

Descriptions of the calculations included in Attachments 14-31 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.* This section lists the expenses applicable to a project and includes operating costs, property taxes, depreciation, and income taxes.
- *Revenue requirements section.* This section shows the components of the revenue requirements, including expenses, return on investment, and any credits to the revenue requirement for monies received for use of the Company's facilities by wholesale customers.

- *Return on investment (cost of capital).* In this section, Otter Tail Power uses the cost of capital agreed upon by the parties in the Settlement Agreement approved by the Commission¹ in Otter Tail Power's last general rate case.
- *Depreciation expense.* Otter Tail Power calculates depreciation expense using the Company's current composite depreciation rates.
- *Property taxes.* The property tax calculation is based on Otter Tail Power'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.
- *GIPs and Facility Service Agreement Revenues.* Revenues collected for Facility Service Agreements (FSA) on the GIPs are included in Attachment 14 on Line No. 20. These FSA revenues are also shown in Attachment 4 on Line 22 as a reduction to the revenue requirement.
- *Operation and maintenance (O&M) expense.* This section includes any O&M expense associated with the project. Otter Tail Power 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 of new lines is typically limited during the first five years, since Otter Tail Power'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 expense.

- *Proration of Accumulated Deferred Income Taxes (ADIT).* Otter Tail Power provides Attachment 14 to show the ADIT proration calculation impact on the revenue requirement for the recovery period.

Otter Tail Power also provides Attachment 13, which calculates its Accumulated Deferred Income Tax (ADIT) balances to preserve the effect of the application of the proration methodology for the true-up period. This calculation methodology is necessary to comply with Section 1.167(D)-1(h)(6)(ii) of the IRS regulations and to avoid a tax

¹ Case No. PU-17-398, Order on Settlement, September 26, 2018.

normalization violation.² Attachment 13 shows that the preservation of the proration of ADIT resulted in a decrease of \$905 plus any applicable carrying charge to the revenue requirement. This ADIT amount is included on Line No. 24 of the Tracker Summary provided as Attachment 4.

- *MISO Schedules 26 and 26A expenses.* Schedule 26 and Schedule 26A costs for the recovery period appear on Line Nos. 27 and 28 of the Tracker Summary and are shown separately in Attachment 7. These represent the Company's retail share of the costs for projects that qualify for regional cost allocation under MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff).
- *Southwest Power Pool (SPP) Related Expenses.* SPP Schedules 7, 8, and 9, shown in Attachment 5, refer to different types of transmission service that Otter Tail Power 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. Otter Tail Power includes the SPP Schedule 9 expenses on Line No. 29 and SPP Schedule 11 expenses on Line No. 30 of the Tracker Summary and they are shown separately in Attachment 5.

- *MISO Schedule 7, 8, and 9 revenues.* Otter Tail Power provides a calculation of these revenues, where applicable in the Tracker Summary on Line No. 34 and in Attachment 6. These revenues represent transmission charges passed through MISO for transmission services. Due to the partial inclusion of these charges in the Company's base rates, a true-up calculation is provided to account for the total of these schedules.
- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear in the Tracker Summary on Line Nos. 35 and 36 and are shown separately on Attachment 8 and Attachment 9, respectively. These represent Otter Tail Power's retail share of the revenues derived from the Company's investment in projects that qualify for regional cost allocation under MISO's Tariff. These revenues are applicable to projects in the TCRR as well as projects that will be recovered in base rates.
- *MISO Multi-Value Project Auction Revenue Rights (MVP ARR).* The MVP ARR revenues are derived from increased transmission capacity attributable to MVP projects placed in service within the MISO footprint.

² See Treas. Reg. SS 1.167(l)-1(h)(6)(ii).

The value of these MVP ARR 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 10 and is reflected as a credit in the Tracker Summary (Attachment 4, Line No. 39).

- *Revenue credit for administrative and general expenses recovered through MISO Tariff for non-retail portion of projects qualifying for regional cost allocation.* These 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 Otter Tail Power's current retail rates. The revenue credit is reflected in Attachments 8, 9 and, 11 on the line 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.016,
- *Revenue credit adjustment for MISO Tariff Schedules 37 and 38.* 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 Otter Tail Power'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.

In Attachment 11, there are no forecast amounts for Schedule 37 and 38 revenues for the 2026 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 revenue credit reflected in this TCRR update for 2025 is \$21,456, as can be seen in the Tracker Summary provided as Attachment 4, on Line No. 37. The Schedule 38 revenue credit reflected in this TCRR update for 2025 is \$25,935, as seen in Attachment 4, on Line No. 38. These are actual amounts through July 2025 and are included as part of the 2025 true-up amount.

C. Projects and programs previously approved for recovery in Otter Tail Power’s TCRR

Twenty-eight projects previously approved for inclusion in Otter Tail Power’s TCRR remain in this update. Table 1 reflects these approved projects and the case numbers in which the Commission approved each project for TCRR recovery.

The retail allocation of costs and revenues for these projects is updated for 2025 and 2026 and reflected in Attachments 15-31.

Table 1

	Project	Case Number	Attachment
1	Wabek-Parshall Rebuild	PU-21-376	15
2	Pickert - McVilleville Rebuild	PU-21-376	15
3	Grenville-Veblen Rebuild	PU-21-376	15
4	Michigan-Mapes Rebuild	PU-21-376	15
5	Gackle Rural Loop	PU-22-335	16
6	Oslo 115kV 5-Breaker Bus and Lake A	PU-22-335	17
7	Casselton NDSP Capacitor Bank	PU-22-335	18
8	Cooperstown - Relocate 41.6kV	PU-22-335	19
9	Wahpeton-Fairmount 115kV Rebuild	PU-23-306	20
10	Marvin-Corona Area 41.6kV Rebuild	PU-23-306	20
11	Buffalo Extenda-Life	PU-23-306	20
12	DL-New Rockford Extenda-Life	PU-23-306	21
13	Kensal-Bordulac 41.6kV Extenda-Life	PU-23-306	21
14	Donaldson CB-215 Re-Conductor	PU-23-306	21
15	Canby - 495 Line Extenda-Life	PU-23-306	21
16	Milbank Area Reliability Project	PU-23-306	22
17	BSS to Alexandria 345 (BSSa)	PU-23-306	23
18	Alexandria to Big Oaks 345 (BSSa)	PU-23-306	24
19	Jamestown to Ellendale 345 (JETx)	PU-23-306	25
20	Maple River Substation Add (JETx)	PU-23-306	26
21	Jamestown 345 Substation Add (JETx)	PU-23-306	27
22	Twin Brooks Reactor Add (JETx)	PU-23-306	28
23	Ivanhoe 41.6kV In Line Reclosure	PU-24-336	29
24	Winger-reroute 41.6kV thru town	PU-24-336	30
25	Pekin - Mcville Extenda-Life	PU-24-336	31
26	Hancock-Clontarf Extenda-Life	PU-24-336	31
27	Cyrus-Farwell Extenda-Life	PU-24-336	31
28	Underwood 655 - 41.6kV Extenda-Life	PU-24-336	31

Project Timeline Delays

Pickert – McVille Rebuild

Since 2021, Otter Tail Power has rebuilt 5.8 miles of 41.6 kV transmission line between Pickert, ND and McVille, ND. Power interruptions have been reduced due to the newly rebuilt line from south of Kloten, ND to Aneta, ND. Approximately 21 miles have yet to be rebuilt within this same line section. These projects are expected to be completed late in the Company's current 5-year budget period for 2026-2030.

Wahpeton-Fairmount 115 kV Rebuild

Delays in obtaining land rights for the Wahpeton-Fairmount 115 kV Rebuild have caused construction to start in 2026 rather than 2025, as originally planned. The Company's current five-year capital budget plan reflects line construction beginning in 2026 with completion estimated by late 2028. The total project estimate remains unchanged from the original petition.

Marvin-Corona Area 41.6 kV Rebuild

Due to reliability issues in other parts of Otter Tail Power's system, various other projects have become more urgent and have been reprioritized ahead of the Marvin-Corona project. This project is still necessary and is forecasted to be completed by the end of 2027, within the estimated original budget.

Buffalo Extenda-Life

The Buffalo Extenda-Life project includes multiple phases, some of which have been completed. The upgrade to the radial 41.6 kV transmission feed to Page, ND was completed in the second quarter of 2025. Otter Tail Power is currently developing designs for the next phase(s) of construction.

The multiple remaining phases of the project were approved in the 2024 TCR filing and consist of both Extenda-Life and Rebuild construction, which will be completed between 2026 and 3032.

Kensal-Bordulac 41.6 kV Extenda-Life

Due to storm damage on a portion of the Kensal-Bordulac 41.6 kV line in August 2025, Otter Tail Power completed a full rebuild of 1.5 miles of 41.6 kV line north of Kensal, ND. This will improve that area of the line tremendously but has led to delays with the remaining work. The Company expects the work for this line to be completed in 2028.

Cyrus-Farwell Extenda-Life

Both Extenda-Life and Rebuild phases are included in the Cyrus to Farwell project. The Extenda-Life portion of the project, which is estimated at \$270,000, is currently under construction and will be completed in the first quarter of 2026. The rebuild portion of the project, which is estimated at \$450,000, is on hold due to the Big Stone South to Alexandria (BSSA) 345 kV line route study. Otter Tail Power's project team is waiting for the results of the routing studies for BSSA before commencing work on the second phase.

Phase Removal

Grenville - Veblen Rebuild

Since 2022, Otter Tail Power has rebuilt 16 miles along the Veblen, SD to Grenville, SD 41.6 kV transmission line. The completed portion of this project was rolled into base rates during the most recent ND rate case. Approximately 14 miles still need to be completed within this total section of line. Some of the remaining mileage has encountered routing, land rights, and easement delays. As such, Otter Tail Power divided the remaining portion of this project into smaller phases that are expected to be completed during the 2026-2030 5-year budget period at an estimated cost of \$3.17 million. The future phases of the Grenville – Veblen Rebuild project are not reflected in the revenue requirement for this filing and the Company will seek to add them to the TCR rider when construction draws closer. This reduces the revenue requirement by approximately \$1.6 million.

Project Removals

Wabek-Parshall Rebuild

Otter Tail Power included a 41.6 kV rebuild project from Wabek to Parshall in its 2021 TCR filing, which was approved in Case No. PU-21-376 at a total cost of \$1.6 million. The project's main drivers included performance, accessibility, age, and condition. Otter Tail Power's land agents have been working with landowners to find a suitable route that is more accessible than the current route of the existing line. However, due to challenges with landowners, the Company has shifted this project out in its 5-year budget plan. The project is still necessary, but additional work is required to identify routing alternatives before

construction can begin. As such, Otter Tail Power removed this project from the revenue requirement and will seek to include it again at a future date when the final route/project can be set. In the meantime, the Company will continue to monitor the performance of the line and make minor improvements as necessary to ensure reliable service.

Ivanhoe 41.6 kV In Line Recloser

Otter Tail Power included this project in its 2024 TCR filing, which was approved in Case No. PU 24-336 at a total cost of \$350,000. Recent Extenda-Life work has significantly improved the performance of this portion of Otter Tail Power's system. As a result, the anticipated benefits of installing a recloser in this area have diminished. The Company will continue to evaluate other locations for sectionalizing and future recloser installation. This project has been removed from the revenue requirement in this filing.

D. New transmission projects included in this TCRR rate update

N.D.C.C. § 49-05-04.3 authorizes an approved TCRR to provide "for an adjustment of rates to recover jurisdictional capital and operating costs incurred by a public utility for new or modified electric transmission facilities." Each year, Otter Tail Power reviews the performance and reliability of its transmission system and identifies any existing facilities that need to be upgraded and any new facilities that are needed to ensure the continued reliable delivery of energy to its customers.

In this TCR filing, Otter Tail Power does not submit any new projects for Commission approval.

Transmission Line Rebuild and Extenda-Life Programs

Otter Tail Power has approximately 5,800 miles of transmission lines across its service territory. Of those, approximately 3,800 miles are 41.6 kV transmission lines and are a core part of the Company's delivery network to serve customers. Just over one-third of the Company's transmission poles are older than 55 years, which leaves a substantial portion of the poles either at or reaching the end of their useful life.

Due to this growing concern, Otter Tail Power has undertaken a multi-year effort called the System Infrastructure and Reliability Improvement (SIRI) Initiative. As part of this initiative, the Company focused on assessing overall

transmission and distribution asset health conditions, which led to the development of the “Extenda-Life” and “Line Rebuild” programs.

Otter Tail Power’s O&M and capital programs seek to extend the life of line sections to the greatest extent possible; however, once the overall condition and performance of a line reaches certain deterioration levels, it needs to be replaced. Prior to deeming a line in need of a total replacement, the Company considers whether it might refurbish the line instead. Refurbishing of line sections can include a combination of activities including, but not limited to, changing out rotting cross arms, replacing failed insulators, replacing poles that have failed strength tests, applying ground treatment for poles that pass strength tests, mitigating vegetation issues, and reattaching guy wires. Otter Tail Power refers to these refurbishment projects internally as “Extenda-Life” projects. The Company considers several factors in determining when a replacement is needed, including line framing style and pole height, reliability performance, hard-to-access areas (i.e., water), conductor condition, and overall line vintage.

Although the Extenda-Life and Rebuild programs differ, each improves the reliability of the transmission system. Any time replacement of equipment along an existing line or replacement of the entire line occurs, the line has inherently better performance. This is not only due to new assets performing better, but also because Otter Tail Power implements updated construction and material standards that now include new framing styles. More specifically, the Company’s new standards include higher rated insulators (72 kV rather than 45 kV), different conductors, more spacing between energized conductors, as well as a static wire above the energized conductors. This static wire protects against interruptions caused by weather events, such as lightning. Lastly, the current standard for Otter Tail Power’s 41.6 kV lines is T2 (twisted pair) conductor that improves the line’s performance during icing and frost conditions over the standard single conductor utilized in older lines. Applying Otter Tail Power’s current construction and material standards to existing lines results in improved reliability of the lower voltage (41.6 kV) transmission system.

Otter Tail Power acknowledges the deviations observed in the timelines and budgets of previously approved SIRI projects. To address this concern, the Company will refrain from including any new SIRI projects in future filings until such projects are either nearing completion or fully in service. This approach is intended to enhance the accuracy of reported timeframes and budgets associated with the requested recovery of forecasted projects.

E. Addition of GIPs and Associated Revenues

Generator Interconnection Projects, or GIPs, are upgrades to Otter Tail Power's transmission facilities that are located beyond a generator's point of interconnection with the MISO transmission grid. New generators typically require such upgrades to connect to the grid.

Generators are responsible for contributing to the cost of GIPs. Under the MISO Tariff, the entire cost of facilities that are specific to accommodate the generator itself and provide the initial point of interconnection to the MISO transmission system are paid for in advance by the generator.

The MISO tariff also provides two alternatives to be elected by a transmission owner (TO) for the types of network upgrades included in Otter Tail Power's GIPs:

- (1) Pre-funding by the generator – The generator pays the full cost of network upgrades upfront before construction begins.
- (2) TO Provided Funding – The TO funds the upgrades initially, and the generator reimburses the cost based on voltage level: 100 percent for upgrades to facilities of 230 kV or below; and 90 percent for upgrades to facilities 345 kV or above with the remaining 10 percent allocated to utilities throughout the MISO region.

Otter Tail Power has selected TO Provided Funding for all GIPs requiring network upgrades to the Company's system.

MISO's tariff is designed so that the generator must pay for the full life of the transmission assets over the expected life of the generation assets. The expected life of the generation assets typically is shorter (approximately 20 years) than the life of the transmission assets.

While the MISO tariff utilizes a 20-year repayment period for calculation of the GIPs revenue, Otter Tail Power continues to depreciate the facilities according to their actual useful life (between 40 and 60 years, depending on the assets), in accordance with GAAP. This means there will continue to be return of and return on the GIPs investments in years after MISO revenue concludes. Once the MISO Tariff revenue ends, there will not be a credit to the retail revenue requirement. The Company estimates that the effect will be a net savings to North Dakota retail rates over the life of the projects.

In this TCRR filing, Otter Tail Power proposes to include the FSA Portion of the GIPs, which decreases the revenue requirement by \$221,818.

V. ALLOCATIONS AND RATE DESIGN

The allocations and rate design for this annual update are the same as approved by the Commission in the April 25, 2012 TCRR Order. Specifically, the class allocations use the proposed transmission demand allocation factor, D2, from Otter Tail Power's most recent North Dakota general rate review (Case No. PU-23-342) to allocate total revenue requirements to jurisdictions (North Dakota, 40.027 percent) and rate classes. The rate design uses a demand-only billing rate (dollars/kW) for the Large General Service Class (LGS) and an energy-only billing rate (cents/kWh) for all other customers. The rate design detail is included in Attachment 3.

VI. RATE APPLICATION AND IMPACT

The total 2026 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2026, the true-up associated with an updated projection of the 2025 revenue requirement, and the carrying charge attributable to any projected over or under-collection.

The proposed revenue requirement attributable to calendar year 2026, as shown on Line No. 42 of Tracker Summary (Attachment 4), page 2 is \$6,468,753. This amount is based on actual net revenues and expenses included in the TCRR tracker through July 2025 and projections for August 2025 through December 2026.

By design and structure of the TCRR, the related carrying credit of (\$41,671) as computed in Attachment 4, Line No. 47, will be credited to customers as a reduction in the 2026 revenue requirement. The 2025 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, Line No. 37 and as computed in Attachment 4, Line No. 48, reflects an estimated over-collection amount of (\$1,289,418) for the 2025 collection period. The over-collection is due to delayed in-service dates, reduced project costs, and ADIT proration factor changes. Also contributing to the over-collection is an increase to MISO Schedules 7, 8 and 9 Revenue in 2025. The net revenue requirement for 2026, upon which rates are developed, is \$5,137,664 as shown on Line No. 39 of Attachment 2. The proposed rates for this net revenue requirement are reflected on Line Nos. 17-20 of Attachment 3.

The TCRR is applicable to electric service under all of Otter Tail Power's non-controllable retail rate schedules. The charge is included as part of the Transmission Rider line on customers' bills. The proposed rates, as calculated in Attachment 3, are provided in Table 2 with a comparison to previously approved rates:

Table 2

		January 1, 2025- December 31, 2025 Approved Rates (PU-24-336)	January 1, 2026- December 31, 2026 Proposed Rates (PU-25-XX)
Line No.	Class	\$/kWh	\$/kWh
1	Large General Service Class	\$ 0.711	\$ 1.239
2	Controlled Service	\$ -	\$ -
3	Lighting	\$ 0.00120	\$ 0.00213
4	All Other Service	\$ 0.00240	\$ 0.00387

The proposed rates are based on an effective date of January 1, 2026, through December 31, 2026. These rates represent a change to the rates currently in effect. The estimated increase for a residential customer using 1,000 kWh is \$1.48 per month.

VII. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE

Otter Tail Power’s legislative and non-legislative update to the Transmission Cost Recovery Rider (Section 13.05) is provided as Attachment 34 to this Application.

VIII. FILING FEE

As allowed under N.D.C.C. § 49-05-04.3, subd. 2.d, Otter Tail Power includes a filing fee of \$10,000 and will pay such additional fees as are reasonably necessary for completion of the application process as determined by the Commission.

IX. NOTICE TO CUSTOMERS

Otter Tail Power will include a notice of the proposed TCRR update to North Dakota customers on customer bills following submittal of this Application. Attachment 33 provides a sample of the bill message that will be included. The Company will also include, as a bill insert, an implementation notice to North Dakota customers once the Commission approves the updated TCRR. Attachment 34 is a sample of the bill insert implementation notice.

X. CONCLUSION

For all the foregoing reasons, Otter Tail Power Company respectfully requests approval to implement this update to its Transmission Cost Recovery Rider, Section 13.05, effective January 1, 2026. As summarized below, this update includes:

1. Updates for previously approved TCRR projects and
2. Regional transmission organization costs and revenues.
3. Changes to project timelines for previously approved projects.
4. Removal of a portion of a previously approved project
5. Removal of previously approved projects
6. The inclusion of GIPs and associated revenues

Date: September 15, 2025

Respectfully submitted:
OTTER TAIL POWER COMPANY

/s/ JORDAN M. SILLERUD

Jordan M. Sillerud

Rates Analyst

Regulatory Economics

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Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Summary
Attachment 5	SPP Expenses
Attachment 6	MISO Schedule 7, 8 & 9 Revenue True-up
Attachment 7	MISO Schedule 26 and 26A Expense
Attachment 8	MISO Schedule 26 Revenue
Attachment 9	MISO Schedule 26A Revenue
Attachment 10	MISO Multi-Value Project Auction Revenue Rights Credit
Attachment 11	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 12	ADIT Pro-Rate Projection
Attachment 13	ADIT Pro-Rate Preservation
Attachment 14	GIPs FSA portion
Attachment 15	2021 Transmission Line Rebuild Program Revenue Requirements
Attachment 16	Gackle Rural Loop Project
Attachment 17	Oslo 155 kV 5 Breaker Ring Bus Revenue Requirement
Attachment 18	Casselton 115 kV Capacitor Bank Revenue Requirement
Attachment 19	Cooperstown 41.6 kV Rebuild Program Revenue Requirement
Attachment 20	2023 Transmission Line Rebuild Program Revenue Requirements
Attachment 21	2023 Transmission Extenda-Life Program Revenue Requirements
Attachment 22	Milbank Area Reliability Project
Attachment 23	Big Stone South to Alexandria 345kV (BSSa)
Attachment 24	Alexandria to Big Oaks 345kV double circuit (BSSa)
Attachment 25	Jamestown to Ellendale 345kV (JETx)
Attachment 26	Maple River Substation Addition (JETx)
Attachment 27	Jamestown 345 Substation Addition (JETx)
Attachment 28	Twin Brooks Reactor Addition (JETx)
Attachment 29	Ivanhoe 41.6kV In Line Reclosure
Attachment 30	Winger-reroute 41.6kV thru town
Attachment 31	2024 Transmission Extenda-Life Program
Attachment 32	Electric Rate Schedule Section 13.05 Legislative and Non-Legislative
Attachment 33	Customer Notice – ND TCR Proposed Bill Message
Attachment 34	Customer Notice – ND TCR Implementation Bill Insert

Projected Revenue for 2025

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,247,986 kW	\$1.239	\$1,546,437
2					
3	Controlled Service	(b)	241,190,864 kWh	\$0.00000	\$0
4					
5	Lighting	(c)	11,075,181 kWh	\$0.00213	\$23,633
6					
7	All other service		921,063,572 kWh	\$0.00387	\$3,567,594
8					
9	Total revenue				<u>\$5,137,664</u>

- (a) Rate Schedules 10.04 Large General Service and 10.05 Large General Service - Time of Day, 10.06 Super Large General Service, 14.02 Real Time Pricing Rider, 14.03 Large General Service Rider, and 14.13 Economic Development Rider
- (b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load (CT Metering), 14.05 Interruptible Load (Self-Contained Metering), 14.06 Deferred Load, and 14.07 Fixed Time of Delivery
- (c) Rate Schedules 11.03 Outdoor Lighting (Energy only), 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting

Summary of Revenue Requirements		
Line No.	Revenue Requirements	2026
1	2021 Rebuild Projects	310,408
2	Gackle Rural Loop	52,796
3	Oslo 115 kV 5 Breaker Ring Bus	376,838
4	Casselton 115 kV Capacitor Bank	79,647
5	Cooperstown 41.6 kV Relocate	46,709
6	2023 Rebuild Projects	104,173
7	2023 Extenda-Life Projects	90,483
8	Milbank Area Reliability Project	1,402,915
9	Big Stone South to Alexandria 345kV (BSSa)	20,696
10	Alexandria to Big Oaks 345kV double circuit (BSS)	66,903
11	Jamestown to Ellendale 345kV (JETx)	40,822
12	Maple River Substation Addition (JETx)	1,503
13	Jamestown 345 Substation Addition (JETx)	2,829
14	Twin Brooks Reactor Addition (JETx)	3,155
15	Winger-reroute 41.6kV thru town	5,942
16	2024 Extenda-Life Projects	67,174
17		
18	Total Revenue Requirement	\$2,672,993
19		
20	FSA Portion of the GIPS Projects	(221,818)
21		
22	MISO Schedule 26 Expense	4,701,983
23	MISO Schedule 26A Expense	4,734,088
24		
25	SPP Schedule 9 Expense	786,525
26	SPP Schedule 11 Expense	128,776
27		
28	MISO Schedule 7, 8 and 9 Revenue True-up	(472,065)
29	MISO Schedule 26 Revenue	(4,083,472)
30	MISO Schedule 26A Revenue	(1,728,858)
31	MISO Schedule 37 Revenue	0
32	MISO Schedule 38 Revenue	0
33	MISO MVP ARR Revenue	(49,399)
34		
35	Carrying Cost	(41,671)
36	True-Up	(1,289,418)
37		
38	Net Revenue Requirement	\$5,137,664

Class Allocation and Rate Design

Line No.		Approved PU-24-336	Proposed PU-25-XX
		2025	2026
1	North Dakota Revenue Requirements	\$3,134,045	\$5,137,664 *
2			
3	Large General Service Class 30.10%	\$943,348	\$1,546,437
4	Controlled Service 0.00%	\$0	\$0
5	Lighting 0.46%	\$14,417	\$23,633
6	All Other Service 69.44%	\$2,176,281	\$3,567,594
7			
8	Total	\$3,134,045	\$5,137,664
9			
10			
11	Large General Service Class kW	1,326,657	1,247,986
12	Controlled Service kWh	253,995,453	241,190,864
13	Lighting kWh	12,038,096	11,075,181
14	All Other Service kWh	908,504,838	921,063,572
15			
16			
17	Large General Service Class \$ / kW	0.711	1.239
18	Controlled Service \$ / kWh	-	-
19	Lighting \$ / kWh	0.00120	0.00213
20	All Other Service \$ / kWh	0.00240	0.00387

* Jurisdictional transmission allocation factor (D2 = 40.02665%) is from Otter Tail's approved general rate case in North Dakota Case No. PU-23-342.

Otter Tail Power Company
North Dakota Transmission Cost Recovery Rider

Line No.	Att No.	TRACKER SUMMARY Requirements Compared to Billed:	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025
			January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Projected	September Projected	October Projected	November Projected	December Projected	YE Projected
1	15	Revenue Requirements													
2	16	2021 Rebuild Projects	23,812	23,812	23,800	23,800	23,800	23,800	23,800	23,800	23,886	23,886	23,886	23,886	285,967
3	17	Gackle Rural Loop	3,256	3,256	3,262	3,262	3,262	3,262	3,327	3,328	3,328	3,328	3,328	3,328	39,526
4	18	Oslo 115 kV 5 Breaker Ring Bus	27,076	27,076	29,769	31,179	31,195	31,200	31,201	31,202	31,203	31,210	31,210	31,210	364,729
5	19	Casselton 115 kV Capacitor Bank	6,811	6,811	6,811	6,811	6,811	6,811	6,811	6,811	6,811	6,811	6,811	6,811	81,727
6	20	Cooperstown 41.6 kV Relocate	3,351	3,351	3,351	3,867	3,868	3,839	3,836	3,836	3,884	3,884	3,884	3,884	44,838
7	21	2023 Rebuild Projects	3,810	3,807	4,075	4,106	4,116	4,114	4,114	4,114	4,114	4,114	4,114	4,114	48,714
8	22	2023 Extend-a-Life Projects	4,795	4,799	4,998	5,093	5,179	5,204	5,204	5,204	5,204	5,204	5,376	5,686	61,948
9	23	Milbank Area Reliability Project	71,577	73,757	73,600	74,372	74,404	74,515	74,543	74,597	74,597	74,597	74,597	74,597	889,755
10	24	Big Stone South to Alexandria 345kV (BSSa)	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	14,415
11	25	Alexandria to Big Oaks 345kV double circuit (BSSa)	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137	13,641
12	26	Jamestown to Ellendale 345kV (JETx)	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	21,601
13	27	Maple River Substation Addition (JETx)	60	60	60	60	60	60	60	60	60	60	60	60	724
14	28	Jamestown 345 Substation Addition (JETx)	84	84	84	84	84	84	84	84	84	84	84	84	1,008
15	29	Twin Brooks Reactor Addition (JETx)	64	64	64	64	64	64	64	64	64	64	64	64	768
16	30	Ivanhoe 41.6kV In Line Reclosure	0	0	0	0	0	0	0	0	0	0	0	0	0
17	31	Winger-reroute 41.6kV thru town	216	216	216	216	216	216	216	216	216	216	216	216	2,592
18		2024 Extend-a-Life Projects	1,989	1,989	1,989	1,989	1,989	1,989	1,989	1,989	1,989	1,989	1,989	1,989	23,869
19		Total Revenue Requirements	151,037	153,219	156,217	159,041	159,187	159,298	159,389	159,445	159,579	159,586	159,757	160,067	1,895,822
20		GIPS Projects													
21		FSA Portion of the GIPS Projects													
22		ADIT Preservation of Proration	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(905)
23		MISO & SPP Expenses													
24		MISO Schedule 26 Expense	405,403	356,434	326,105	244,513	279,988	259,193	355,600	377,837	326,525	387,166	387,166	466,465	4,172,394
25		MISO Schedule 26A Expense	404,814	358,699	362,322	327,379	325,408	311,119	338,229	306,533	289,651	318,785	362,967	404,926	4,110,831
26		SPP Schedule 9 Expense	53,060	61,170	59,362	60,254	60,354	59,319	59,759	67,417	67,417	67,417	67,417	67,417	750,364
27		SPP Schedule 11 Expense	8,919	10,469	10,185	10,327	10,357	10,364	10,552	10,477	10,477	10,477	10,477	10,477	123,559
28		Total MISO & SPP Expenses	872,196	786,772	757,974	642,473	676,107	639,994	764,139	762,264	694,071	783,846	828,028	949,285	9,157,148
29		MISO Revenues													
30		MISO Schedule 7, 8 and 9 Revenue True-up	(173,047)	(150,702)	(77,640)	(172,880)	(51,053)	(121,065)	(121,683)	(83,989)	(11,505)	(77,454)	(25,157)	(43,644)	(1,109,819)
31		MISO Schedule 26 Revenue	(307,623)	(263,534)	(271,718)	(239,482)	(303,557)	(380,897)	(389,033)	(423,582)	(347,337)	(288,036)	(283,800)	(326,158)	(3,824,757)
32		MISO Schedule 26A Revenue	(120,662)	(103,957)	(106,099)	(99,636)	(105,901)	(121,381)	(127,537)	(131,892)	(108,039)	(105,233)	(89,799)	(120,667)	(1,340,804)
33		MISO Schedule 37 Revenue	(3,041)	(2,937)	(3,114)	(3,111)	(3,098)	(3,126)	(3,031)	0	0	0	0	0	(21,456)
34		MISO Schedule 38 Revenue	(3,787)	(3,611)	(3,891)	(3,401)	(3,870)	(3,775)	(3,600)	0	0	0	0	0	(25,935)
35		MISO MVP ARR Revenue	(8,146)	(63)	(15,853)	(5,604)	(5,323)	(5,106)	(2,106)	(1,954)	(1,810)	(1,001)	(1,160)	(1,274)	(49,399)
36		Total MISO Revenues	(616,306)	(524,804)	(478,314)	(524,113)	(472,801)	(635,349)	(646,991)	(641,417)	(468,692)	(471,725)	(399,916)	(491,743)	(6,372,170)
37		Net Revenue Requirement	406,852	415,111	435,801	277,326	362,417	163,867	276,462	280,217	384,883	471,631	587,794	617,534	4,679,895
38		Billed (forecast kWh x adj factor)	466,577	332,335	277,637	274,742	226,116	222,710	236,555	238,732	228,724	246,820	274,340	310,671	3,335,960
39		Difference	(59,726)	82,776	158,164	2,584	136,301	(58,843)	39,907	41,485	156,159	224,812	313,454	306,863	1,343,936
40		Carrying Charge	(15,477)	(15,949)	(15,530)	(14,634)	(14,710)	(13,947)	(14,404)	(14,243)	(14,072)	(13,180)	(11,852)	(9,958)	(167,956)
41		Cumulative Difference	(2,540,600)	(2,473,773)	(2,331,138)	(2,343,188)	(2,221,597)	(2,294,386)	(2,268,883)	(2,241,642)	(2,099,555)	(1,887,924)	(1,586,322)	(1,289,418)	(1,289,418)
42		Carrying Charge Calculation	(15,949)	(15,530)	(14,634)	(14,710)	(13,947)	(14,404)	(14,243)	(14,072)	(13,180)	(11,852)	(9,958)	(8,095)	
43		Cumulative Carrying Charge	(539,657)	(555,186)	(569,820)	(584,530)	(598,477)	(612,880)	(627,124)	(641,196)	(654,377)	(666,228)	(676,187)	(684,211)	
44		Carrying cost	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	
45		Forecasted Sales (MWh)	271,862	250,400	234,276	206,204	193,365	184,805	199,125	200,384	191,984	207,173	230,273	260,768	2,630,619

Approved December 18, 2024 (PU-24-336);
Rate Effective January 1, 2024

SUMMARY	Jan 2025 - Dec 2025
Revenue requirements	\$5,120,267
Carrying Charge	(80,096)
2024 True-Up	(1,906,126)
Total requirements	\$3,134,045
Jan 2024-Dec 2024 projected sales in MWh	2,630,619
Average Rate	\$0.00119

Otter Tail Power Company
North Dakota Transmission Cost Recovery Rider

Line No.	Att No.	TRACKER SUMMARY Requirements Compared to Billed:	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026
			January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	YE Projected	
1	15	Revenue Requirements														
2	16	2021 Rebuild Projects	25,867	25,867	25,867	25,867	25,867	25,867	25,867	25,867	25,867	25,867	25,867	25,867	25,867	310,408
3	17	Gackle Rural Loop	4,400	4,400	4,400	4,400	4,400	4,400	4,400	4,400	4,400	4,400	4,400	4,400	4,400	52,796
4	18	Oslo 115 kV 5 Breaker Ring Bus	31,403	31,403	31,403	31,403	31,403	31,403	31,403	31,403	31,403	31,403	31,403	31,403	31,403	376,838
5	19	Casselton 115 kV Capacitor Bank	6,637	6,637	6,637	6,637	6,637	6,637	6,637	6,637	6,637	6,637	6,637	6,637	6,637	79,647
6	20	Cooperstown 41.6 kV Relocate	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	46,709
7	21	2023 Rebuild Projects	8,681	8,681	8,681	8,681	8,681	8,681	8,681	8,681	8,681	8,681	8,681	8,681	8,681	104,173
8	22	2023 Extend-Life Projects	7,540	7,540	7,540	7,540	7,540	7,540	7,540	7,540	7,540	7,540	7,540	7,540	7,540	90,483
9	23	Milbank Area Reliability Project	116,910	116,910	116,910	116,910	116,910	116,910	116,910	116,910	116,910	116,910	116,910	116,910	116,910	1,402,915
10	24	Big Stone South to Alexandria 345kV (BSSa)	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	20,696
11	25	Alexandria to Big Oaks 345kV double circuit (BSSa)	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	66,903
12	26	Jamestown to Ellendale 345kV (JETx)	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	3,402	40,822
13	27	Maple River Substation Addition (JETx)	125	125	125	125	125	125	125	125	125	125	125	125	125	1,503
14	28	Jamestown 345 Substation Addition (JETx)	236	236	236	236	236	236	236	236	236	236	236	236	236	2,829
15	29	Twin Brooks Reactor Addition (JETx)	263	263	263	263	263	263	263	263	263	263	263	263	263	3,155
16	30	Ivanhoe 41.6kV In Line Reclosure	495	495	495	495	495	495	495	495	495	495	495	495	495	5,942
17	31	Winger-reroute 41.6kV thru town	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,984	67,174
18		2024 Extend-Life Projects														
19		Total Revenue Requirements	222,672	222,672	222,672	222,672	222,672	222,672	222,672	222,672	222,672	222,672	222,672	222,672	223,135	2,672,993
20		GIPS Projects														
21		FSA Portion of the GIPS Projects	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(18,485)	(221,818)
22		ADIT Preservation of Proration														
23		MISO & SPP Expenses														
24		MISO Schedule 26 Expense	468,325	454,275	416,809	351,244	309,095	369,977	379,343	379,343	327,827	388,710	388,710	468,325	4,701,983	
25		MISO Schedule 26A Expense	481,939	439,852	426,166	373,568	356,622	345,994	361,794	356,343	335,685	370,955	419,571	465,598	4,734,088	
26		SPP Schedule 9 Expense	70,134	70,134	69,122	70,134	70,134	70,134	70,134	70,134	56,616	56,616	56,616	56,616	786,525	
27		SPP Schedule 11 Expense	10,899	10,899	10,742	10,899	10,899	10,899	10,899	10,899	10,435	10,435	10,435	10,435	128,776	
28		Total MISO & SPP Expenses	1,031,298	975,161	922,839	805,845	746,750	797,005	822,171	816,720	730,563	826,716	875,331	1,000,974	10,351,373	
29		MISO Revenues														
30		MISO Schedule 7, 8 and 9 Revenue True-up	(46,893)	(24,464)	2,837	(62,465)	(27,138)	(34,448)	(25,359)	(93,857)	(12,081)	(78,270)	(25,754)	(44,173)	(472,065)	
31		MISO Schedule 26 Revenue	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(340,289)	(4,083,472)
32		MISO Schedule 26A Revenue	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(144,071)	(1,728,858)
33		MISO Schedule 37 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34		MISO Schedule 38 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35		MISO MVP ARR Revenue	(8,146)	(63)	(15,853)	(5,604)	(5,323)	(5,106)	(2,106)	(1,954)	(1,810)	(1,001)	(1,160)	(1,274)	(49,399)	
36		Total MISO Revenues	(539,400)	(508,887)	(497,377)	(552,430)	(516,822)	(523,915)	(511,826)	(580,171)	(498,252)	(563,632)	(511,275)	(529,808)	(6,333,795)	
37		Net Revenue Requirement	714,570	688,946	648,134	476,087	452,600	495,762	533,017	459,222	454,983	485,756	587,192	694,301	6,468,753	
38		Billed (forecast kWh x adj factor)	529,832	485,759	461,713	408,523	374,706	365,251	390,645	386,396	373,625	399,613	451,420	510,182	5,137,664	
39		Difference	184,738	203,187	186,421	67,565	77,894	130,511	142,372	72,826	81,358	86,143	135,772	184,120	1,331,089	
40		Carrying Charge	(8,095)	(6,986)	(5,754)	(4,620)	(4,225)	(3,762)	(2,966)	(2,091)	(1,647)	(613)	235	(41,671)		
41		Cumulative Difference	(1,112,774)	(916,573)	(735,906)	(672,961)	(599,292)	(472,542)	(333,137)	(262,402)	(182,691)	(97,695)	37,463	221,818		
42		Carrying Charge Calculation	(6,986)	(5,754)	(4,620)	(4,225)	(3,762)	(2,966)	(2,091)	(1,647)	(1,147)	(613)	235	1,393		
43		Cumulative Carrying Charge	(691,267)	(697,021)	(701,641)	(705,866)	(709,628)	(712,594)	(714,686)	(716,333)	(717,480)	(718,093)	(717,858)	(716,465)		
44		Carrying cost	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%		
45		Forecasted Sales (MWh)	261,754	239,981	228,101	201,823	185,117	180,446	192,991	190,892	184,583	197,422	223,016	252,046	2,538,172	

SUMMARY		Jan 2026 - Dec 2026
Revenue requirements		\$6,468,753
Carrying Charge		(41,671)
2025 True-Up		(1,289,418)
Total requirements		\$5,137,664
Jan 2024-Dec 2024 projected sales in MWh		2,538,172
Average Rate		\$0.00202

Otter Tail Power Company
North Dakota Transmission Cost Recovery Rider
Schedule 7,8, or 9 & Schedule 11 Expense

		2025												
Line No.	<i>SPP Schedules</i>	2025 Jan Actual	2025 Feb Actual	2025 Mar Actual	2025 Apr Actual	2025 May Actual	2025 Jun Actual	2025 Jul Actual	2025 Aug Projected	2025 Sep Projected	2025 Oct Projected	2025 Nov Projected	2025 Dec Projected	2025 YE Projected
1	SPP Schedule 7,8 or 9 Expenses	132,561	152,824	148,306	150,534	150,785	148,198	149,298	168,431	168,431	168,431	168,431	168,431	1,874,662
2														
3	North Dakota share	40.027%	53,060	61,170	59,362	60,254	60,354	59,319	59,759	67,417	67,417	67,417	67,417	750,364
4														
5	SPP Schedule 11 Expense	22,283	26,156	25,445	25,799	25,875	25,892	26,362	26,176	26,176	26,176	26,176	26,176	308,691
6														
7	North Dakota share	40.027%	8,919	10,469	10,185	10,327	10,357	10,364	10,552	10,477	10,477	10,477	10,477	123,559

		2026												
Line No.	<i>SPP Schedules</i>	2026 Jan Projected	2026 Feb Projected	2026 Mar Projected	2026 Apr Projected	2026 May Projected	2026 Jun Projected	2026 Jul Projected	2026 Aug Projected	2026 Sep Projected	2026 Oct Projected	2026 Nov Projected	2026 Dec Projected	2026 YE Projected
1	SPP Schedule 7,8 or 9 Expenses	175,219	175,219	172,689	175,219	175,219	175,219	175,219	175,219	141,446	141,446	141,446	141,446	1,965,004
2														
3	North Dakota share	40.027%	70,134	70,134	69,122	70,134	70,134	70,134	70,134	56,616	56,616	56,616	56,616	786,525
4														
5	SPP Schedule 11 Expense	27,230	27,230	26,837	27,230	27,230	27,230	27,230	27,230	26,069	26,069	26,069	26,069	321,727
6														
7	North Dakota share	40.027%	10,899	10,899	10,742	10,899	10,899	10,899	10,899	10,435	10,435	10,435	10,435	128,776

		2025													
Line No.		2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	
	<i>MISO Revenues</i>	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected	
1	MISO Schedule 7 Revenues in Rate Base from 2024 TY	(85,838)	(90,004)	(81,186)	(100,287)	(59,770)	(45,449)	(55,058)	(57,223)	(43,039)	(50,309)	(39,358)	(54,124)	(761,645)	
2	MISO Schedule 7 Revenues	(122,594)	(108,257)	(77,584)	(83,748)	(77,748)	(73,723)	(92,546)	(58,969)	(47,610)	(48,090)	(44,750)	(44,734)	(880,353)	
3	MISO Schedule 7 True Up	(36,756)	(18,253)	3,602	16,539	(17,978)	(28,274)	(37,488)	(1,746)	(4,571)	2,219	(5,392)	9,390	(118,708)	
4															
5	MISO Schedule 8 Revenues in Rate Base from 2024 TY	(55,941)	(62,101)	(25,065)	(19,883)	(22,065)	(11,872)	(26,816)	(31,337)	(27,581)	(36,754)	(59,547)	(78,517)	(457,479)	
6	MISO Schedule 8 Revenues	(93,251)	(69,741)	(44,128)	(131,223)	(43,716)	(29,299)	(20,614)	(32,427)	(22,896)	(39,888)	(48,809)	(58,497)	(634,488)	
7	MISO Schedule 8 True Up	(37,310)	(7,640)	(19,063)	(111,340)	(21,651)	(17,427)	6,202	(1,090)	4,685	(3,134)	10,739	20,020	(177,009)	
8															
9	MISO Schedule 9 Revenues in Rate Base from 2024 TY	(349,927)	(282,390)	(295,440)	(161,514)	(153,131)	(123,475)	(164,428)	(95,949)	(202,521)	(191,341)	(232,639)	(284,104)	(2,536,859)	
10	MISO Schedule 9 Revenues	(754,798)	(633,003)	(473,950)	(498,625)	(241,049)	(380,235)	(437,147)	(302,945)	(231,378)	(383,933)	(300,836)	(422,551)	(5,060,451)	
11	MISO Schedule 9 True Up	(404,871)	(350,613)	(178,510)	(337,111)	(87,918)	(256,760)	(272,719)	(206,996)	(28,857)	(192,592)	(68,197)	(138,447)	(2,523,592)	
12															
13	Total True Up Amount	(478,938)	(376,505)	(193,971)	(431,912)	(127,547)	(302,461)	(304,005)	(209,832)	(28,743)	(193,507)	(62,851)	(109,037)	(2,819,309)	
14															
15	MISO Settlements	46,609	0	0	0	0	0	0						46,609	
16	North Dakota share	40.027%	(173,047)	(150,702)	(77,640)	(172,880)	(51,053)	(121,065)	(121,683)	(83,989)	(11,505)	(77,454)	(25,157)	(43,644)	(1,109,819)

		2026													
Line No.		2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	2026	
	<i>MISO Revenues</i>	Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected	
1	MISO Schedule 7 Revenues in Rate Base from 2024 TY	(85,838)	(90,004)	(81,186)	(100,287)	(59,770)	(45,449)	(55,058)	(57,223)	(43,039)	(50,309)	(39,358)	(54,124)	(761,645)	
2	MISO Schedule 7 Revenues	(88,138)	(57,871)	(49,233)	(38,049)	(49,393)	(51,411)	(66,765)	(60,805)	(49,271)	(48,984)	(46,318)	(44,923)	(651,160)	
3	MISO Schedule 7 True Up	(2,300)	32,133	31,953	62,238	10,377	(5,962)	(11,707)	(3,582)	(6,232)	1,325	(6,960)	9,201	110,485	
4															
5	MISO Schedule 8 Revenues in Rate Base from 2024 TY	(55,941)	(62,101)	(25,065)	(19,883)	(22,065)	(11,872)	(26,816)	(31,337)	(27,581)	(36,754)	(59,547)	(78,517)	(457,479)	
6	MISO Schedule 8 Revenues	(93,603)	(57,265)	(42,160)	(100,293)	(36,856)	(35,706)	(22,315)	(31,909)	(22,674)	(41,031)	(48,732)	(59,630)	(592,174)	
7	MISO Schedule 8 True Up	(37,662)	4,836	(17,095)	(80,410)	(14,791)	(23,834)	4,501	(572)	4,907	(4,277)	10,815	18,887	(134,695)	
8															
9	MISO Schedule 9 Revenues in Rate Base from 2024 TY	(349,927)	(282,390)	(295,440)	(161,514)	(153,131)	(123,475)	(164,428)	(95,949)	(202,521)	(191,341)	(232,639)	(284,104)	(2,536,859)	
10	MISO Schedule 9 Revenues	(427,121)	(380,478)	(303,210)	(299,402)	(216,517)	(179,743)	(220,578)	(326,280)	(231,378)	(383,933)	(300,836)	(422,551)	(3,692,027)	
11	MISO Schedule 9 True Up	(77,194)	(98,088)	(7,770)	(137,888)	(63,386)	(56,268)	(56,150)	(230,331)	(28,857)	(192,592)	(68,197)	(138,447)	(1,155,168)	
12															
13	Total True Up Amount	(117,155)	(61,119)	7,088	(156,060)	(67,800)	(86,063)	(63,356)	(234,485)	(30,182)	(195,544)	(64,343)	(110,359)	(1,179,378)	
14															
15	MISO Settlements													0	
16	North Dakota share	40.027%	(46,893)	(24,464)	2,837	(62,465)	(27,138)	(34,448)	(25,359)	(93,857)	(12,081)	(78,270)	(25,754)	(44,173)	(472,065)

Otter Tail Power Company
North Dakota Transmission Cost Recovery Ride
Schedule 26 & Schedule 26A Expense

		2025												
Line No.	SCHEDULE 26	2025 Jan Actual	2025 Feb Actual	2025 Mar Actual	2025 Apr Actual	2025 May Actual	2025 Jun Actual	2025 Jul Actual	2025 Aug Projected	2025 Sep Projected	2025 Oct Projected	2025 Nov Projected	2025 Dec Projected	2025 YE Projected
1	MISO Schedule 26 Expense	1,043,763	923,319	814,720	640,621	737,379	647,551	894,262	943,963	815,770	967,270	967,270	1,165,386	10,561,274
2														
3	MISO Settlements	(12,381)	(13,140)	0	(11,906)	(15,160)	0	(2,343)						(54,930)
4														
5	North Dakota share	40.027%	405,403	356,434	326,105	244,513	279,988	259,193	355,600	377,837	326,525	387,166	387,166	466,465
6														
7	MISO Schedule 26A Expense	1,045,997	902,153	905,201	820,121	823,896	777,279	848,783	765,821	723,647	796,432	906,814	1,011,640	10,327,785
8														
9	MISO Settlements	(13,863)	(2,403)	0	(888)	(4,370)	0	(1,511)						(23,035)
10														
11	North Dakota share	40.027%	404,814	358,699	362,322	327,379	325,408	311,119	338,229	306,533	289,651	318,785	362,967	4,110,831

		2026												
Line No.	SCHEDULE 26	2026 Jan Projected	2026 Feb Projected	2026 Mar Projected	2026 Apr Projected	2026 May Projected	2026 Jun Projected	2026 Jul Projected	2026 Aug Projected	2026 Sep Projected	2026 Oct Projected	2026 Nov Projected	2026 Dec Projected	2026 YE Projected
1	MISO Schedule 26 Expense	1,170,033	1,134,932	1,041,329	877,525	772,222	924,326	947,727	947,727	819,023	971,127	971,127	1,170,033	11,747,131
2														
3	North Dakota share	40.027%	468,325	454,275	416,809	351,244	309,095	369,977	379,343	379,343	327,827	388,710	388,710	468,325
4														
5	MISO Schedule 26A Expense	1,204,046	1,098,898	1,064,706	933,297	890,961	864,410	903,883	890,265	838,653	926,771	1,048,230	1,163,221	11,827,341
6														
7	North Dakota share	40.027%	481,939	439,852	426,166	373,568	356,622	345,994	361,794	356,343	335,685	370,955	419,571	465,598

Otter Tail Power Company
North Dakota Transmission Cost Recovery Rider
Schedule 26 Revenue

Line No.	2025	2025												2025	
		Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected		Total Projected
1	Total Schedule 26 Revenue	(1,059,121)	(920,671)	(900,443)	(847,397)	(1,011,440)	(1,262,252)	(1,347,006)	(1,403,706)	(1,151,039)	(954,520)	(940,483)	(1,080,854)	(12,878,933)	
2	Overhead Credit for Non-Retail Share	7.236%	(76,638)	(66,619)	(65,156)	(61,317)	(73,187)	(91,336)	(97,469)	(101,572)	(83,289)	(69,069)	(68,053)	(78,210)	(931,914)
4	Fargo	66.074%	(699,804)	(608,324)	(594,959)	(559,909)	(668,289)	(834,020)	(890,021)	(927,485)	(760,538)	(630,690)	(621,415)	(714,163)	(8,509,626)
5	Retail Load Share		78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	
7	Retail Revenue		(546,897)	(475,405)	(464,960)	(437,569)	(522,276)	(651,787)	(695,551)	(724,830)	(594,360)	(492,884)	(485,636)	(558,119)	(6,650,273)
8	Overhead Credit for Non-Retail Share		(50,638)	(44,018)	(43,051)	(40,515)	(48,358)	(60,349)	(64,402)	(67,112)	(55,032)	(45,636)	(44,965)	(51,677)	(615,753)
9	Non-Retail Load Share		21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	
10	Non-Retail Overhead Credit		(11,064)	(9,618)	(9,407)	(8,852)	(10,566)	(13,186)	(14,072)	(14,664)	(12,025)	(9,972)	(9,825)	(11,291)	(134,542)
11	Total Revenue Credit for Fargo		(557,961)	(485,023)	(474,367)	(446,421)	(532,842)	(664,973)	(709,623)	(739,494)	(606,385)	(502,856)	(495,461)	(569,410)	(6,784,815)
14	Bemidji	13.403%	(141,954)	(123,398)	(120,686)	(113,577)	(135,563)	(169,180)	(180,539)	(188,139)	(154,274)	(127,934)	(126,053)	(144,867)	(1,726,163)
15	Retail Load Share		96.13%	96.13%	96.13%	96.13%	96.13%	96.13%	96.13%	96.13%	96.13%	96.13%	96.13%	96.13%	
17	Retail Revenue		(136,458)	(118,620)	(116,013)	(109,179)	(130,314)	(162,629)	(173,549)	(180,854)	(148,300)	(122,981)	(121,172)	(139,258)	(1,659,326)
18	Overhead Credit for Non-Retail Share		(10,272)	(8,929)	(8,733)	(8,218)	(9,809)	(12,242)	(13,064)	(13,614)	(11,163)	(9,257)	(9,121)	(10,483)	(124,904)
19	Non-Retail Load Share		3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	3.87%	
20	Non-Retail Overhead Credit		(398)	(346)	(338)	(318)	(380)	(474)	(506)	(527)	(432)	(358)	(353)	(406)	(4,836)
21	Total Revenue Credit for Bemidji		(136,855)	(118,965)	(116,352)	(109,497)	(130,694)	(163,103)	(174,055)	(181,381)	(148,733)	(123,339)	(121,525)	(139,663)	(1,664,163)
23	Cass Lake - Nary - Helga - Bemidji	6.020%	(63,759)	(55,424)	(54,207)	(51,013)	(60,889)	(75,988)	(81,090)	(84,503)	(69,293)	(57,462)	(56,617)	(65,067)	(775,312)
24	Retail Load Share		36.97%	36.97%	36.97%	36.97%	36.97%	36.97%	36.97%	36.97%	36.97%	36.97%	36.97%	36.97%	
27	Retail Revenue		(23,572)	(20,491)	(20,041)	(18,860)	(22,511)	(28,093)	(29,980)	(31,242)	(25,618)	(21,244)	(20,932)	(24,056)	(286,641)
28	Overhead Credit for Non-Retail Share		(4,614)	(4,010)	(3,922)	(3,691)	(4,406)	(5,498)	(5,868)	(6,115)	(5,014)	(4,158)	(4,097)	(4,708)	(56,101)
29	Non-Retail Load Share		63.03%	63.03%	63.03%	63.03%	63.03%	63.03%	63.03%	63.03%	63.03%	63.03%	63.03%	63.03%	
30	Non-Retail Overhead Credit		(2,908)	(2,528)	(2,472)	(2,327)	(2,777)	(3,466)	(3,698)	(3,854)	(3,160)	(2,621)	(2,582)	(2,968)	(35,360)
31	Total Revenue Credit for Bemidji		(26,480)	(23,019)	(22,513)	(21,187)	(25,288)	(31,559)	(33,678)	(35,096)	(28,778)	(23,865)	(23,514)	(27,024)	(322,001)
32	Rugby	0.043%	(455)	(396)	(387)	(364)	(435)	(543)	(579)	(604)	(495)	(410)	(404)	(465)	(5,538)
33	Retail Load Share		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
34	Retail Revenue		(455)	(396)	(387)	(364)	(435)	(543)	(579)	(604)	(495)	(410)	(404)	(465)	(5,538)
35	Total Revenue Credit for Rugby		(455)	(396)	(387)	(364)	(435)	(543)	(579)	(604)	(495)	(410)	(404)	(465)	(5,538)
36	Casselton	11.831%	(125,305)	(108,925)	(106,531)	(100,255)	(119,664)	(149,337)	(159,364)	(166,073)	(136,179)	(112,929)	(111,269)	(127,876)	(1,523,707)
37	Retail Load Share		54.16%	54.16%	54.16%	54.16%	54.16%	54.16%	54.16%	54.16%	54.16%	54.16%	54.16%	54.16%	
38	Retail Revenue		(67,867)	(58,996)	(57,700)	(54,300)	(64,812)	(80,884)	(86,315)	(89,948)	(73,758)	(61,165)	(60,265)	(69,260)	(825,270)
39	Overhead Credit for Non-Retail Share		(9,067)	(7,882)	(7,709)	(7,254)	(8,659)	(10,806)	(11,532)	(12,017)	(9,854)	(8,172)	(8,051)	(9,253)	(110,255)
40	Non-Retail Load Share		45.84%	45.84%	45.84%	45.84%	45.84%	45.84%	45.84%	45.84%	45.84%	45.84%	45.84%	45.84%	
41	Non-Retail Overhead Credit		(4,156)	(3,613)	(3,533)	(3,325)	(3,969)	(4,953)	(5,286)	(5,508)	(4,517)	(3,746)	(3,691)	(4,241)	(50,539)
42	Total Revenue Credit for Casselton		(72,024)	(62,609)	(61,233)	(57,626)	(68,781)	(85,837)	(91,601)	(95,457)	(78,274)	(64,910)	(63,956)	(73,502)	(875,809)
43	Spiritwood	0.615%	(6,514)	(5,662)	(5,538)	(5,211)	(6,220)	(7,763)	(8,284)	(8,633)	(7,079)	(5,870)	(5,784)	(6,647)	(79,205)
44	Retail Load Share		56.16%	56.16%	56.16%	56.16%	56.16%	56.16%	56.16%	56.16%	56.16%	56.16%	56.16%	56.16%	
45	Retail Revenue		(3,658)	(3,180)	(3,110)	(2,927)	(3,493)	(4,359)	(4,652)	(4,848)	(3,975)	(3,297)	(3,248)	(3,733)	(44,479)
46	Overhead Credit for Non-Retail Share		(471)	(410)	(401)	(377)	(450)	(562)	(599)	(625)	(512)	(425)	(419)	(481)	(5,731)
47	Non-Retail Load Share		43.84%	43.84%	43.84%	43.84%	43.84%	43.84%	43.84%	43.84%	43.84%	43.84%	43.84%	43.84%	
48	Non-Retail Overhead Credit		(207)	(180)	(176)	(165)	(197)	(246)	(263)	(274)	(225)	(186)	(183)	(211)	(2,513)
49	Total Revenue Credit for Spiritwood		(3,864)	(3,359)	(3,285)	(3,092)	(3,690)	(4,606)	(4,915)	(5,122)	(4,200)	(3,483)	(3,432)	(3,944)	(46,991)
50	Courtenay Wind	0.172%	(1,822)	(1,584)	(1,549)	(1,458)	(1,740)	(2,171)	(2,317)	(2,414)	(1,980)	(1,642)	(1,618)	(1,859)	(22,152)
51	Retail Load Share		0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	0.94%	
52	Retail Revenue		(17)	(15)	(15)	(14)	(16)	(20)	(22)	(23)	(19)	(15)	(15)	(17)	(208)
53	Overhead Credit for Non-Retail Share		(132)	(115)	(112)	(105)	(126)	(157)	(168)	(175)	(143)	(119)	(117)	(135)	(1,603)
54	Non-Retail Load Share		99.06%	99.06%	99.06%	99.06%	99.06%	99.06%	99.06%	99.06%	99.06%	99.06%	99.06%	99.06%	
55	Non-Retail Overhead Credit		(131)	(114)	(111)	(104)	(125)	(156)	(166)	(173)	(142)	(118)	(116)	(133)	(1,588)
56	Total Revenue Credit for Courtenay Wind		(148)	(128)	(126)	(118)	(141)	(176)	(188)	(196)	(160)	(133)	(131)	(151)	(1,796)
57	Astoria BSSB	0.796%	(8,431)	(7,329)	(7,168)	(6,745)	(8,051)	(10,048)	(10,722)	(11,174)	(9,162)	(7,598)	(7,486)	(8,604)	(102,516)
58	Retail Load Share		0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	
59	Retail Revenue		(76)	(66)	(65)	(61)	(73)	(91)	(97)	(101)	(83)	(69)	(68)	(78)	(927)
60	Overhead Credit for Non-Retail Share		(610)	(530)	(519)	(488)	(583)	(727)	(776)	(809)	(663)	(550)	(542)	(623)	(7,418)
61	Non-Retail Load Share		99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	
62	Non-Retail Overhead Credit		(605)	(525)	(514)	(484)	(577)	(720)	(769)	(801)	(657)	(545)	(537)	(617)	(7,351)
63	Total Revenue Credit for Astoria BSSB		(681)	(592)	(579)	(545)	(650)	(811)	(866)	(902)	(740)	(614)	(604)	(695)	(8,278)
64	Retail Share of Schedule 26 Revenue		(798,468)	(694,091)	(678,842)	(638,850)	(762,522)	(951,608)	(1,015,504)	(1,058,250)	(867,765)	(719,610)	(709,028)	(814,853)	(9,709,389)
65	MISO Settlements		11,977	14,287	0	16,228	1,655	0	17,439						61,586
66	North Dakota Share	40.027%	(307,623)	(263,534)	(271,718)	(239,482)	(303,557)	(380,897)	(389,033)	(423,582)	(347,337)	(288,036)	(283,800)	(326,158)	(3,824,757)

Otter Tail Power Company
North Dakota Transmission Cost Recovery Rider
Schedule 26A Revenue

Line No.	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	
		Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	Total Projected		
1	Total Schedule 26A Revenue															
2	Overhead Credit for Non-Retail Share	6.234%	(2,338,546)	(1,952,532)	(1,974,036)	(1,857,485)	(1,997,582)	(2,258,381)	(2,439,796)	(2,453,944)	(2,010,145)	(1,957,934)	(1,670,770)	(2,245,097)	(1,568,282)	(25,156,250)
3			(145,789)	(121,724)	(123,065)	(115,799)	(124,533)	(140,791)	(152,101)	(152,983)	(125,316)	(122,061)	(104,159)	(139,963)		
4																
5	CAPX 2020 - Brookings	11.501%	(268,952)	(224,557)	(227,030)	(213,626)	(229,738)	(259,732)	(280,596)	(282,223)	(231,183)	(225,178)	(192,152)	(258,204)	(2,893,170)	
6	Retail Load Share		38.694%	38.694%	38.694%	38.694%	38.694%	38.694%	38.694%	38.694%	38.694%	38.694%	38.694%	38.694%	38.694%	
7	Retail Revenue		(104,068)	(86,890)	(87,847)	(82,660)	(88,895)	(100,501)	(108,574)	(109,203)	(89,454)	(87,130)	(74,351)	(99,910)	(1,119,483)	
8																
9	Overhead Credit for Non-Retail Share		(16,767)	(13,999)	(14,153)	(13,318)	(14,322)	(16,192)	(17,493)	(17,594)	(14,412)	(14,038)	(11,979)	(16,097)	(180,365)	
10	Non-Retail Load Share		61.306%	61.306%	61.306%	61.306%	61.306%	61.306%	61.306%	61.306%	61.306%	61.306%	61.306%	61.306%	61.306%	
11	Non-Retail Overhead Credit		(10,279)	(8,582)	(8,677)	(8,165)	(8,780)	(9,927)	(10,724)	(10,786)	(8,836)	(8,606)	(7,344)	(9,868)	(110,575)	
12																
13	Total Revenue Credit for CAPX Brookings		(114,347)	(95,472)	(96,524)	(90,825)	(97,675)	(110,427)	(119,298)	(119,990)	(98,289)	(95,737)	(81,695)	(109,778)	(1,230,058)	
14																
15																
16	MVP BS South - Brookings	32.484%	(759,649)	(634,257)	(641,242)	(603,382)	(648,891)	(733,608)	(792,538)	(797,134)	(652,972)	(636,011)	(542,730)	(729,293)	(8,171,706)	
17	Retail Load Share		3.476%	3.476%	3.476%	3.476%	3.476%	3.476%	3.476%	3.476%	3.476%	3.476%	3.476%	3.476%	3.476%	
18	Retail Revenue		(26,402)	(22,044)	(22,287)	(20,971)	(22,552)	(25,497)	(27,545)	(27,705)	(22,694)	(22,105)	(18,863)	(25,347)	(284,011)	
19																
20	Overhead Credit for Non-Retail Share		(47,358)	(39,541)	(39,976)	(37,616)	(40,453)	(45,734)	(49,408)	(49,695)	(40,707)	(39,650)	(33,835)	(45,465)	(509,438)	
21	Non-Retail Load Share		96.524%	96.524%	96.524%	96.524%	96.524%	96.524%	96.524%	96.524%	96.524%	96.524%	96.524%	96.524%	96.524%	
22	Non-Retail Overhead Credit		(45,712)	(38,166)	(38,587)	(36,308)	(39,047)	(44,145)	(47,691)	(47,968)	(39,293)	(38,272)	(32,659)	(43,885)	(491,732)	
23																
24	Total Revenue Credit for MVP Brookings		(72,114)	(60,210)	(60,873)	(57,279)	(61,599)	(69,642)	(75,236)	(75,672)	(61,987)	(60,377)	(51,522)	(69,232)	(775,743)	
25																
26																
27	MVP Ellendale - BS South	47.795%	(1,117,715)	(933,219)	(943,497)	(887,791)	(954,751)	(1,079,400)	(1,166,108)	(1,172,870)	(960,755)	(935,800)	(798,550)	(1,073,051)	(12,023,505)	
28	Retail Load Share		3.394%	3.394%	3.394%	3.394%	3.394%	3.394%	3.394%	3.394%	3.394%	3.394%	3.394%	3.394%	3.394%	
29	Retail Revenue		(37,935)	(31,673)	(32,022)	(30,132)	(32,404)	(36,635)	(39,578)	(39,807)	(32,608)	(31,761)	(27,103)	(36,419)	(408,078)	
30																
31	Overhead Credit for Non-Retail Share		(69,680)	(58,178)	(58,819)	(55,346)	(59,521)	(67,292)	(72,697)	(73,119)	(59,895)	(58,339)	(49,783)	(66,896)	(749,565)	
32	Non-Retail Load Share		96.606%	96.606%	96.606%	96.606%	96.606%	96.606%	96.606%	96.606%	96.606%	96.606%	96.606%	96.606%	96.606%	
33	Non-Retail Overhead Credit		(67,315)	(56,204)	(56,823)	(53,468)	(57,501)	(65,008)	(70,230)	(70,637)	(57,862)	(56,359)	(48,093)	(64,625)	(724,125)	
34																
35	Total Revenue Credit for MVP Ellendale		(105,251)	(87,877)	(88,845)	(83,599)	(89,905)	(101,643)	(109,807)	(110,444)	(90,470)	(88,120)	(75,196)	(101,045)	(1,132,203)	
36																
37																
38	Jamestown - Ellendale	4.818%	(112,681)	(94,081)	(95,117)	(89,501)	(96,252)	(108,818)	(117,559)	(118,241)	(96,857)	(94,341)	(80,504)	(108,178)	(1,212,129)	
39	Retail Load Share		3.567%	3.567%	3.567%	3.567%	3.567%	3.567%	3.567%	3.567%	3.567%	3.567%	3.567%	3.567%	3.567%	
40	Retail Revenue		(4,019)	(3,356)	(3,393)	(3,193)	(3,433)	(3,882)	(4,193)	(4,218)	(3,455)	(3,365)	(2,872)	(3,859)	(43,237)	
41																
42	Overhead Credit for Non-Retail Share		(7,025)	(5,865)	(5,930)	(5,580)	(6,000)	(6,784)	(7,329)	(7,371)	(6,038)	(5,881)	(5,019)	(6,744)	(75,566)	
43	Non-Retail Load Share		96.433%	96.433%	96.433%	96.433%	96.433%	96.433%	96.433%	96.433%	96.433%	96.433%	96.433%	96.433%	96.433%	
44	Non-Retail Overhead Credit		(6,774)	(5,656)	(5,718)	(5,381)	(5,786)	(6,542)	(7,067)	(7,108)	(5,823)	(5,672)	(4,840)	(6,503)	(72,871)	
45																
46	Total Revenue Credit for Jamestown - Ellendale		(10,793)	(9,012)	(9,111)	(8,573)	(9,220)	(10,424)	(11,261)	(11,326)	(9,278)	(9,037)	(7,711)	(10,362)	(116,108)	
47																
48																
49	BSS Alexandria kV	3.402%	(79,550)	(66,419)	(67,151)	(63,186)	(67,952)	(76,823)	(82,995)	(83,476)	(68,379)	(66,603)	(56,835)	(76,371)	(855,740)	
50	Retail Load Share		8.783%	8.783%	8.783%	8.783%	8.783%	8.783%	8.783%	8.783%	8.783%	8.783%	8.783%	8.783%	8.783%	
51	Retail Revenue		(6,987)	(5,833)	(5,898)	(5,549)	(5,968)	(6,747)	(7,289)	(7,331)	(6,006)	(5,850)	(4,992)	(6,707)	(75,157)	
52																
53	Overhead Credit for Non-Retail Share		(4,959)	(4,141)	(4,186)	(3,939)	(4,236)	(4,789)	(5,174)	(5,204)	(4,263)	(4,152)	(3,543)	(4,761)	(53,348)	
54	Non-Retail Load Share		91.217%	91.217%	91.217%	91.217%	91.217%	91.217%	91.217%	91.217%	91.217%	91.217%	91.217%	91.217%	91.217%	
55	Non-Retail Overhead Credit		(4,524)	(3,777)	(3,819)	(3,593)	(3,864)	(4,369)	(4,720)	(4,747)	(3,888)	(3,787)	(3,232)	(4,343)	(48,663)	
56																
57	Total Revenue Credit for BSS Alexandria kV		(11,510)	(9,610)	(9,716)	(9,143)	(9,832)	(11,116)	(12,009)	(12,078)	(9,894)	(9,637)	(8,224)	(11,050)	(123,820)	
58																
59																
60	Retail Share of Schedule 26A Revenue		(314,015)	(262,182)	(265,070)	(249,419)	(268,231)	(303,251)	(327,611)	(329,511)	(269,918)	(262,908)	(224,348)	(301,467)	(3,377,932)	
61																
62	MISO Settlements		5,028	986	0	198	1,463	0	3,594						11,269	
63																
64	North Dakota share	40.027%	(120,662)	(103,957)	(106,099)	(99,636)	(105,901)	(121,381)	(127,537)	(131,892)	(108,039)	(105,233)	(89,799)	(120,667)	(1,340,804)	

Otter Tail Power Company
North Dakota Transmission Cost Recovery Rider
Schedule 37 & Schedule 38 Revenues

Line No.	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	
		Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	Total Projected	
1	Total Schedule 37 Revenue		(9,757)	(9,757)	(9,757)	(9,757)	(9,757)	(9,794)	(9,794)	0	0	0	0	0	(68,374)
2	Overhead Credit for Non-Retail Share	7.236%	(706)	(706)	(706)	(706)	(706)	(709)	(709)	0	0	0	0	0	(4,948)
3															
4															
5	Fargo	100.00%	(9,757)	(9,757)	(9,757)	(9,757)	(9,757)	(9,794)	(9,794)	0	0	0	0	0	(68,374)
6	Retail Load Share		78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	
7	Retail Revenue		(7,625)	(7,625)	(7,625)	(7,625)	(7,625)	(7,654)	(7,654)	0	0	0	0	0	(53,434)
8															
9	Overhead Credit for Non-Retail Share		(706)	(706)	(706)	(706)	(706)	(709)	(709)	0	0	0	0	0	(4,948)
10	Non-Retail Load Share		21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	
11	Non-Retail Overhead Credit		(154)	(154)	(154)	(154)	(154)	(155)	(155)	0	0	0	0	0	(1,081)
12	Total 37 Revenue Credit for Fargo		(7,780)	(7,780)	(7,780)	(7,780)	(7,780)	(7,809)	(7,809)	0	0	0	0	0	(54,515)
13															
14															
15															
16	MISO Settlements		73.30	176.84	0.00	3.36	15.90	0.00	95.06						364
17															
18	North Dakota Share	40.027%	(3,041)	(2,937)	(3,114)	(3,111)	(3,098)	(3,126)	(3,031)	0	0	0	0	0	(21,456)
19															
20															
21	Total Schedule 38 Revenue		(12,193)	(12,193)	(12,193)	(12,193)	(12,193)	(11,828)	(11,828)	0	0	0	0	0	(84,619)
22	Overhead Credit for Non-Retail Share	7.236%	(882)	(882)	(882)	(882)	(882)	(856)	(856)	0	0	0	0	0	(6,123)
23															
24															
25	Fargo	100.00%	(12,193)	(12,193)	(12,193)	(12,193)	(12,193)	(11,828)	(11,828)	0	0	0	0	0	(84,619)
26	Retail Load Share		78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	78.15%	
27	Retail Revenue		(9,529)	(9,529)	(9,529)	(9,529)	(9,529)	(9,243)	(9,243)	0	0	0	0	0	(66,129)
28															
29	Overhead Credit for Non-Retail Share		(882)	(882)	(882)	(882)	(882)	(856)	(856)	0	0	0	0	0	(6,123)
30	Non-Retail Load Share		21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	21.85%	
31	Non-Retail Overhead Credit		(193)	(193)	(193)	(193)	(193)	(187)	(187)	0	0	0	0	0	(1,338)
32															
33	Total 38 Revenue Credit for Fargo		(9,721)	(9,721)	(9,721)	(9,721)	(9,721)	(9,430)	(9,430)	0	0	0	0	0	(67,467)
34															
35															
36	MISO Settlements		103.65	280.14	0.00	490.47	21.39	0.00	174.17						1,070
37															
38	North Dakota Share	40.027%	(3,787)	(3,611)	(3,891)	(3,401)	(3,870)	(3,775)	(3,600)	0	0	0	0	0	(25,935)

Federal ADIT Proration

January 2026 - December 2026 Recovery Period			
A	B	C	D
Month	All Projects' Revenue Requirements without ADIT Prorated	All Projects' Revenue Requirements with ADIT-Prorated	Difference due to Federal ADIT Proration (B - A)
Jan-26	\$222,301	\$222,672	\$372
Feb-26	\$222,301	\$222,672	\$372
Mar-26	\$222,301	\$222,672	\$372
Apr-26	\$222,301	\$222,672	\$372
May-26	\$222,301	\$222,672	\$372
Jun-26	\$222,301	\$222,672	\$372
Jul-26	\$222,301	\$222,672	\$372
Aug-26	\$222,301	\$222,672	\$372
Sep-26	\$222,301	\$222,672	\$372
Oct-26	\$222,301	\$222,672	\$372
Nov-26	\$222,764	\$223,135	\$372
Dec-26	\$222,764	\$223,135	\$372
	\$2,668,535	\$2,672,993	\$4,458

Revenue Requirement Adjustment Related to Federal ADIT Proration	\$4,458
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Federal ADIT Proration

	A	B	C	D	E
1			Tax Conversion Factor	1.3228	(1/(1-24.4%))
2			Gross Up of Equity %	7.15%	(D1 * D8)
3			Equity Return %	5.40%	(D8)
4			Gross Up Factor	1.74%	(D2-D3)

		Annual	Monthly
5			
6	Debt Return %	2.13%	0.18%
7	Preferred Equity %	0.00%	0.00%
8	Equity Return %	5.40%	0.45%
9	Rate of Return	7.53%	0.63%
10	Tax RR on Equity Return	1.74%	0.15%
11	Rate Base Rev Req Gross Up Factor	9.28%	0.77%

January 2025 - December 2025				
Month	Original ADIT Balance - All Projects with ADIT Pro-Rated	Updated ADIT Balance - All Projects without ADIT Pro-Rated	Difference due to Federal ADIT Proration (B - A)	
13				
14	Dec-24	(234,446)	(196,986)	\$37,460
15	Jan-25	(258,672)	(222,213)	
16	Feb-25	(280,872)	(252,753)	
17	Mar-25	(300,831)	(282,026)	
18	Apr-25	(318,733)	(308,742)	
19	May-25	(334,440)	(333,969)	
20	Jun-25	(347,940)	(357,762)	
21	Jul-25	(359,177)	(380,089)	
22	Aug-25	(368,153)	(400,969)	
23	Sep-25	(374,939)	(420,446)	
24	Oct-25	(379,634)	(438,041)	
25	Nov-25	(382,398)	(453,517)	
26	Dec-25	(382,551)	(468,769)	-\$86,218
27	ADIT Simple Average	(\$308,499)	(\$332,878)	-\$24,379

28	Rate Base Rev Req Gross Up Factor	9.28%
29	Total Company Revenue Requirement	-\$2,262

30	ND Revenue Requirement Related to Federal ADIT Proration-Preservation	-\$905
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2021 Rebuild Projects

Line No.	Year>>	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total
RATE BASE														
1	Plant Balance	5,508,491	5,488,107	5,488,107	5,488,107	5,488,107	5,488,107	5,488,107	5,642,564	5,642,564	5,642,564	5,642,564	5,642,564	
2	Accumulated Depreciation	(104,635)	(112,233)	(119,804)	(127,374)	(134,944)	(142,515)	(150,085)	(157,656)	(165,439)	(173,222)	(181,006)	(188,789)	
3	Net Plant in Service	5,403,856	5,375,873	5,368,303	5,360,733	5,353,162	5,345,592	5,338,021	5,484,908	5,477,125	5,469,341	5,461,558	5,453,774	
CWIP Calculation:														
5	Beginning Balance	915,721	922,789	924,873	942,887	950,344	951,853	952,281	953,373	859,502	878,691	897,880	917,069	
6	Additional CWIP	7,068	(18,300)	18,014	7,457	1,509	428	1,092	60,586	19,189	19,189	19,189	19,195	
7	Closings from CWIP	0	20,384	0	0	0	0	0	(154,457)	0	0	0	0	
8	AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	
9	CWIP	922,789	924,873	942,887	950,344	951,853	952,281	953,373	859,502	878,691	897,880	917,069	936,264	
10	ADIT Proration Factors	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	
11	Accumulated Defered Income Tax-Federal Only	(87,126)	(94,114)	(101,109)	(108,103)	(115,097)	(122,091)	(129,086)	(136,080)	(143,032)	(149,983)	(156,934)	(163,886)	
12	Accumulated Deferred Income Taxes Federal & State	(105,813)	(114,300)	(122,795)	(131,289)	(139,783)	(148,278)	(156,772)	(165,267)	(173,709)	(182,152)	(190,594)	(199,037)	
13	Ending rate base	6,220,832	6,186,446	6,188,395	6,179,787	6,165,232	6,149,595	6,134,622	6,179,143	6,182,107	6,185,070	6,188,033	6,191,002	
14	Average rate base	515,256	515,256	515,256	515,256	515,256	515,256	515,256	515,256	515,256	515,256	515,256	515,256	
15	Return on Rate Base	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	
16														
17	Return on Rate Base	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	
18														
19	Available for return (equity portion of rate base)	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	
20														
21	EXPENSES													
<i>O&M and Depreciation</i>														
22	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	
23	Property Tax	4,088	4,088	4,088	4,088	4,088	4,088	4,088	4,088	4,088	4,088	4,088	4,088	
24	Book Depreciation	7,599	7,599	7,570	7,570	7,570	7,570	7,570	7,570	7,783	7,783	7,783	7,783	
25	Total O&M and Depreciation Expense	11,686	11,686	11,658	11,658	11,658	11,658	11,658	11,658	11,871	11,871	11,871	11,871	
26														
27	Income before Taxes													
28	Available for return (from above)	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	27,840	
29	Taxable Income (grossed up)	36,827	36,827	36,827	36,827	36,827	36,827	36,827	36,827	36,827	36,827	36,827	36,827	
30														
31	Income Taxes													
32	Current and Def Income Taxes	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	
33	Total Income Tax Expense	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	
34														
35														
36														
37	REVENUE REQUIRMENTS													
38	Expenses	20,674	20,674	20,646	20,646	20,646	20,646	20,646	20,646	20,859	20,859	20,859	20,859	
39	Return on rate base	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	38,816	
40	Subtotal revenue requirements	59,489	59,489	59,461	59,461	59,461	59,461	59,461	59,461	59,674	59,674	59,674	59,674	
41	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	
42	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	
43	Total revenue requirements	59,489	59,489	59,461	59,461	59,461	59,461	59,461	59,461	59,674	59,674	59,674	59,674	
44														
45	North Dakota share - D2 factor	23,812	23,812	23,800	23,800	23,800	23,800	23,800	23,800	23,886	23,886	23,886	23,886	

Oslo 115kV 5-Breaker Bus and Lake A

Line No.	Year>>	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total
RATE BASE														
1	Plant Balance	347,459	5,536,499	8,254,715	8,284,933	8,295,004	8,296,580	8,298,577	8,299,512	8,312,824	8,312,824	8,312,824	8,312,824	8,312,824
2	Accumulated Depreciation	(5,783)	(6,234)	(13,412)	(24,115)	(34,857)	(45,613)	(56,370)	(67,130)	(77,891)	(88,669)	(99,447)	(110,225)	(110,225)
3	Net Plant in Service	341,676	5,530,265	8,241,303	8,260,818	8,260,146	8,250,968	8,242,207	8,232,382	8,234,934	8,224,155	8,213,377	8,202,599	8,202,599
CWIP Calculation:														
	Beginning Balance	7,527,777	7,612,703	2,776,985	0	0	0	0	0	0	0	0	0	0
	Additional CWIP	84,926	353,322	(58,769)	30,218	10,071	1,577	1,996	935	13,313	0	0	0	437,588
	Closings from CWIP AFUDC	0	(5,189,040)	(2,718,216)	(30,218)	(10,071)	(1,577)	(1,996)	(935)	(13,313)	0	0	0	0
4	CWIP	7,612,703	2,776,985	0	0	0	0	0	0	0	0	0	0	0
5	ADIT Proration Factors	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000
6	Accumulated Defered Income Tax-Federal Only	(9,444)	(17,127)	(23,458)	(29,080)	(34,695)	(40,307)	(45,918)	(51,529)	(57,140)	(62,747)	(68,355)	(73,962)	(73,962)
7	Accumulated Deferred Income Taxes Federal & State	(11,470)	(20,800)	(28,489)	(35,317)	(42,136)	(48,952)	(55,767)	(62,581)	(69,396)	(76,206)	(83,016)	(89,826)	(89,826)
8	Ending rate base	7,942,909	8,286,450	8,212,814	8,225,501	8,218,010	8,202,016	8,186,440	8,169,801	8,165,538	8,147,950	8,130,362	8,112,773	8,112,773
9														
10	Average rate base	678,586	678,586	678,586	678,586	678,586	678,586	678,586	678,586	678,586	678,586	678,586	678,586	8,143,038
11														
12	Return on Rate Base	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	613,436
13														
14	Available for return (equity portion of rate base)	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	439,973
15														
EXPENSES														
17	O&M and Depreciation													
18	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Property Tax	4,237	4,237	4,237	4,237	4,237	4,237	4,237	4,237	4,237	4,237	4,237	4,237	50,848
20	Book Depreciation	451	451	7,179	10,703	10,742	10,755	10,757	10,760	10,761	10,778	10,778	10,778	104,893
21	Total O&M and Depreciation Expense	4,688	4,688	11,416	14,940	14,979	14,993	14,995	14,997	14,998	15,016	15,016	15,016	155,741
22														
23	Income before Taxes													
24	Available for return (from above)	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	36,664	439,973
25	Taxable Income (grossed up)	48,501	48,501	48,501	48,501	48,501	48,501	48,501	48,501	48,501	48,501	48,501	48,501	582,012
26														
27	Income Taxes													
28	Current and Def Income Taxes	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	142,040
29	Total Income Tax Expense	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	11,837	142,040
30														
31														
REVENUE REQUIRMENTS														
33	Expenses	16,525	16,525	23,253	26,777	26,816	26,829	26,831	26,834	26,835	26,852	26,852	26,852	297,781
34	Return on rate base	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	51,120	613,436
35	Subtotal revenue requirements	67,644	67,644	74,372	77,897	77,936	77,949	77,951	77,953	77,955	77,972	77,972	77,972	911,216
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Total revenue requirements	67,644	67,644	74,372	77,897	77,936	77,949	77,951	77,953	77,955	77,972	77,972	77,972	911,216
39														
40	North Dakota share - D2 factor	27,076	27,076	29,769	31,179	31,195	31,200	31,201	31,202	31,203	31,210	31,210	31,210	364,729

Cooperstown - Relocate 41.6kV

Line No.	Year>>	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total
RATE BASE														
1	Plant Balance	0	0	993,487	995,774	940,555	934,781	934,781	1,027,586	1,027,586	1,027,586	1,027,586	1,027,586	1,027,586
2	Accumulated Depreciation	0	0	0	(1,288)	(2,579)	(3,799)	(5,011)	(6,223)	(7,555)	(8,887)	(10,220)	(11,552)	(11,552)
3	Net Plant in Service	0	0	993,487	994,486	937,976	930,982	929,770	1,021,363	1,020,031	1,018,698	1,017,366	1,016,034	1,016,034
CWIP Calculation:														
	Beginning Balance	925,617	990,724	1,049,962	91,016	92,125	92,443	92,805	92,805	0	0	0	0	0
	Additional CWIP	65,107	59,238	34,541	3,396	(54,901)	(3,366)	0	0	0	0	0	0	0
	Closings from CWIP	0	0	(993,487)	(2,287)	55,219	5,775	0	(92,805)	0	0	0	0	0
	AFUDC													
4	CWIP	990,724	1,049,962	91,016	92,125	92,443	92,805	92,805	0	0	0	0	0	0
5	ADIT Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
6	Accumulated Deferred Income Tax-Federal Only	0	0	(1,032)	(1,806)	(2,579)	(3,366)	(4,155)	(4,944)	(5,709)	(6,474)	(7,238)	(8,003)	(8,003)
7	Accumulated Deferred Income Taxes Federal & State	0	0	(1,254)	(2,193)	(3,132)	(4,089)	(5,047)	(6,005)	(6,934)	(7,862)	(8,791)	(9,720)	(9,720)
8	Ending rate base	990,724	1,049,962	1,083,249	1,084,417	1,027,287	1,019,699	1,017,529	1,015,358	1,013,097	1,010,836	1,008,575	1,006,314	1,006,314
9	Average rate base	84,953	84,953	84,953	84,953	84,953	84,953	84,953	84,953	84,953	84,953	84,953	84,953	1,019,436
11	Return on Rate Base	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	76,797
12														
13														
14	Available for return (equity portion of rate base)	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	55,081
15														
EXPENSES														
17	O&M and Depreciation													
18	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Property Tax	491	491	491	491	491	491	491	491	491	491	491	491	5,890
20	Book Depreciation	0	0	0	1,288	1,291	1,220	1,212	1,212	1,332	1,332	1,332	1,332	11,552
21	Total O&M and Depreciation Expense	491	491	491	1,779	1,782	1,710	1,703	1,703	1,823	1,823	1,823	1,823	17,442
22														
23	Income before Taxes													
24	Available for return (from above)	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	4,590	55,081
25	Taxable Income (grossed up)	6,072	6,072	6,072	6,072	6,072	6,072	6,072	6,072	6,072	6,072	6,072	6,072	72,863
26														
27	Income Taxes													
28	Current and Def Income Taxes	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	17,782
29	Total Income Tax Expense	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	1,482	17,782
30														
31														
REVENUE REQUIRMENTS														
33	Expenses	1,973	1,973	1,973	3,261	3,264	3,192	3,185	3,185	3,305	3,305	3,305	3,305	35,224
34	Return on rate base	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	6,400	76,797
35	Subtotal revenue requirements	8,372	8,372	8,372	9,661	9,663	9,592	9,584	9,584	9,705	9,705	9,705	9,705	112,021
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Total revenue requirements	8,372	8,372	8,372	9,661	9,663	9,592	9,584	9,584	9,705	9,705	9,705	9,705	112,021
39														
40	North Dakota share - D2 factor	3,351	3,351	3,351	3,867	3,868	3,839	3,836	3,836	3,884	3,884	3,884	3,884	44,838

2023 Extenda-Life Projects

Line No.	Year>>	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total
RATE BASE														
1	Plant Balance	220,796	582,658	754,659	910,703	955,711	955,711	955,711	955,711	955,711	1,266,482	1,828,046	1,828,046	1,828,046
2	Accumulated Depreciation	(331)	(636)	(1,440)	(2,481)	(3,737)	(5,055)	(6,373)	(7,692)	(9,010)	(10,328)	(12,075)	(14,597)	
3	Net Plant in Service	220,465	582,022	753,219	908,222	951,974	950,656	949,337	948,019	946,701	1,256,154	1,815,971	1,813,449	1,813,449
CWIP Calculation:														
	Beginning Balance	278,419	642,857	457,200	499,271	637,541	591,627	653,753	675,958	879,001	917,335	644,897	91,666	
	Additional CWIP	371,213	176,205	214,072	292,965	(2,535)	62,127	22,205	203,043	38,333	38,333	8,333	8,333	1,432,629
	Closings from CWIP	(6,775)	(361,862)	(172,001)	(156,044)	(45,008)	0	0	0	0	(310,771)	(561,564)	0	0
	AFUDC	0	0	0	1,348	1,629	0	0	0	0	0	0	0	0
4	CWIP	642,857	457,200	499,271	637,541	591,627	653,753	675,958	879,001	917,335	644,897	91,666	100,000	100,000
5	ADIT Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
6	Accumulated Deferred Income Tax-Federal Only	(2,430)	(3,587)	(5,299)	(6,964)	(8,585)	(10,194)	(11,803)	(13,412)	(15,021)	(16,630)	(18,153)	(19,520)	(19,520)
7	Accumulated Deferred Income Taxes Federal & State	(2,951)	(4,356)	(6,436)	(8,458)	(10,427)	(12,381)	(14,335)	(16,289)	(18,243)	(20,197)	(22,046)	(23,706)	(23,706)
8	Ending rate base	860,370	1,034,866	1,246,055	1,537,305	1,533,174	1,592,028	1,610,961	1,810,732	1,845,793	1,880,854	1,885,591	1,889,742	1,889,742
10	Average rate base	123,188	123,188	123,188	123,188	123,188	123,188	123,188	123,188	123,188	123,188	123,188	123,188	1,478,252
11														
12	Return on Rate Base	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	111,361
13														
14	Available for return (equity portion of rate base)	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	79,871
15														
EXPENSES														
<i>O&M and Depreciation</i>														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	255	255	255	255	255	255	255	255	255	255	255	255	3,059
19	Book Depreciation	295	305	804	1,041	1,256	1,318	1,318	1,318	1,318	1,318	1,747	2,522	14,561
20														
21	Total O&M and Depreciation Expense	550	559	1,059	1,296	1,511	1,573	1,573	1,573	1,573	1,573	2,002	2,777	17,620
22														
23	Income before Taxes													
24	Available for return (from above)	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	6,656	79,871
25	Taxable Income (grossed up)	8,805	8,805	8,805	8,805	8,805	8,805	8,805	8,805	8,805	8,805	8,805	8,805	105,656
26														
27	Income Taxes													
28	Current and Def Income Taxes	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	25,785
29	Total Income Tax Expense	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	2,149	25,785
30														
31														
REVENUE REQUIRMENTS														
32	Expenses	2,699	2,708	3,207	3,445	3,660	3,722	3,722	3,722	3,722	3,722	4,151	4,925	43,405
33	Return on rate base	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	9,280	111,361
34	Subtotal revenue requirements	11,979	11,988	12,487	12,725	12,940	13,002	13,002	13,002	13,002	13,002	13,431	14,205	154,766
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
37														
38	Total revenue requirements	11,979	11,988	12,487	12,725	12,940	13,002	13,002	13,002	13,002	13,002	13,431	14,205	154,766
39														
40	North Dakota share - D2 factor	4,795	4,799	4,998	5,093	5,179	5,204	5,204	5,204	5,204	5,204	5,376	5,686	61,948

2024 Extenda-Life Projects

Line No.	Year>>	2026 Projected Jan	2026 Projected Feb	2026 Projected Mar	2026 Projected Apr	2026 Projected May	2026 Projected Jun	2026 Projected Jul	2026 Projected Aug	2026 Projected Sep	2026 Projected Oct	2026 Projected Nov	2026 Projected Dec	2026 Projected Total
RATE BASE														
1	Plant Balance	924,514	924,514	924,514	924,514	924,514	924,514	924,514	924,514	924,514	1,762,952	1,762,952	1,762,952	1,762,952
2	Accumulated Depreciation	(1,275)	(2,551)	(3,826)	(5,101)	(6,376)	(7,652)	(8,927)	(10,202)	(11,478)	(12,753)	(15,185)	(17,617)	(17,617)
3	Net Plant in Service	923,238	921,963	920,688	919,412	918,137	916,862	915,587	914,311	913,036	1,750,199	1,747,767	1,745,335	1,745,335
CWIP Calculation:														
4	Beginning Balance	338,438	388,438	438,438	488,438	538,438	588,438	638,438	688,438	738,438	788,438	0	0	0
6	Additional CWIP	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	0	0	500,000
7	Closings from CWIP	0	0	0	0	0	0	0	0	0	(838,438)	0	0	(838,438)
8	AFUDC													
9	CWIP	388,438	438,438	488,438	538,438	588,438	638,438	688,438	738,438	788,438	0	0	0	0
10	ADIT Proration Factors	0.9178	0.8411	0.7562	0.6740	0.5890	0.5068	0.4219	0.3370	0.2548	0.1699	0.0877	0.0027	
11	Accumulated Deferred Income Tax-Federal Only	(10,404)	(11,425)	(12,344)	(13,162)	(13,877)	(14,493)	(15,005)	(15,415)	(15,724)	(16,407)	(16,740)	(16,750)	(16,750)
12	Accumulated Deferred Income Taxes Federal & State	(12,656)	(13,938)	(15,117)	(16,196)	(17,172)	(18,048)	(18,821)	(19,491)	(20,061)	(21,607)	(22,752)	(23,575)	(23,575)
13	Ending rate base	1,299,020	1,346,463	1,394,009	1,441,654	1,489,403	1,537,252	1,585,204	1,633,259	1,681,414	1,728,592	1,725,015	1,721,760	1,721,760
14														
15	Average rate base	127,146	127,146	127,146	127,146	127,146	127,146	127,146	127,146	127,146	127,146	127,146	127,146	1,525,747
16														
17	Return on Rate Base	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	114,938
18														
19	Available for return (equity portion of rate base)	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	82,437
20														
EXPENSES														
22	O&M and Depreciation													
23	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Property Tax	721	721	721	721	721	721	721	721	721	721	721	721	8,654
25	Book Depreciation	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	2,432	2,432	17,617
26	Total O&M and Depreciation Expense	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	1,996	3,153	3,153	26,270
27														
28	Income before Taxes													
29	Available for return (from above)	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	6,870	82,437
30	Taxable Income (grossed up)	9,088	9,088	9,088	9,088	9,088	9,088	9,088	9,088	9,088	9,088	9,088	9,088	109,051
31														
32	Income Taxes													
33	Current and Def Income Taxes	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	26,614
34	Total Income Tax Expense	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	2,218	26,614
35														
36														
REVENUE REQUIREMENTS														
38	Expenses	4,214	4,214	4,214	4,214	4,214	4,214	4,214	4,214	4,214	4,214	5,371	5,371	52,884
39	Return on rate base	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	9,578	114,938
40	Subtotal revenue requirements	13,792	13,792	13,792	13,792	13,792	13,792	13,792	13,792	13,792	13,792	14,949	14,949	167,823
41	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total revenue requirements	13,792	13,792	13,792	13,792	13,792	13,792	13,792	13,792	13,792	13,792	14,949	14,949	167,823
44														
45	North Dakota share - D2 factor	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,521	5,984	5,984	67,174

Attachment 32
Legislative and Non-Legislative Versions of
Electric Rate Schedule Section 13.05
ND Transmission Cost Recovery Rider

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service – Demand Charge	NTCRD
Large General Service – Energy Charge	NTCR
Controlled Service	NTCRC
Lighting	NTCRL
All Other Service	NTCRO

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

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company’s retail rate schedules as described in the Mandatory Rider – Applicability Matrix.

COST RECOVERY FACTOR: There shall be included on each North Dakota Customer’s monthly bill a Transmission Cost Recovery charge, which shall be calculated before any applicable municipal payment adjustments and sales taxes as provided in the General Rules and Regulations for the Company’s electric service. The following charges are applicable in addition to all charges for service being taken under the Company’s standard rate schedules.

RATE:

TRANSMISSION COST RECOVERY		
Energy Charge per kWh:	kWh	kW
Large General Service (a)	N/A	\$1.2390 ⁷¹¹
Controlled Service (b)	\$0.00	N/A
Lighting (c)	\$0.00213 ¹²⁰	N/A
All Other Service	\$0.00387 ²⁴⁰	N/A

(a) Rate schedules 10.04 Large General Service, 10.05 Large General Service – Time of Day, 10.06 Super Large General Service, 11.01 Standby Service, 14.02 Real Time Pricing Rider, 14.03 Large General Service Rider, and 14.13 Economic Development Rate Rider.
(b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load Self-Contained and CT Metering, 14.06 Deferred Load, and 14.07 Fixed Time of Delivery.
(c) Rate Schedules 11.03 Outdoor Lighting (Energy only) and 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting.

NORTH DAKOTA PUBLIC
SERVICE COMMISSION

EFFECTIVE with bills rendered on
and after ~~January~~^{March} 15, 202~~6~~⁵, in North
Dakota

Case No. PU-25-3-342
Approved by order dated ~~December 30, 2024~~

APPROVED: Stuart D. Tommerdahl
Manager, Regulation & Retail Energy Solutions

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service – Demand Charge	NTCRD
Large General Service – Energy Charge	NTCR
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RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this rider.

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company’s retail rate schedules as described in the Mandatory Rider – Applicability Matrix.

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RATE:

TRANSMISSION COST RECOVERY		
Energy Charge per kWh:	kWh	kW
Large General Service (a)	N/A	\$1.239
Controlled Service (b)	\$0.00	N/A
Lighting (c)	\$0.00213	N/A
All Other Service	\$0.00387	N/A

(a) Rate schedules 10.04 Large General Service, 10.05 Large General Service – Time of Day, 10.06 Super Large General Service, 11.01 Standby Service, 14.02 Real Time Pricing Rider, 14.03 Large General Service Rider, and 14.13 Economic Development Rate Rider.
 (b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load Self-Contained and CT Metering, 14.06 Deferred Load, and 14.07 Fixed Time of Delivery.
 (c) Rate Schedules 11.03 Outdoor Lighting (Energy only) and 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting.

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Customer Notices

Attachment 33 – ND TCR Proposed Bill Message

Attachment 34 – ND TCR Implementation Bill Insert

On September 15, 2025, we filed a request with the North Dakota Public Service Commission to update our Transmission Cost Recovery Rider, which is on the Transmission Rider line of your bill.

The proposed change is for bill usage beginning January 1, 2026. This rate adjustment is currently a proposal; if the Commission suspends it, the new rates will not become effective until the Commission grants approval.

If approved, customers can expect the following average monthly bill impacts:

- **Large General Service: \$201.29 (from \$0.711 to \$1.239 per kW)**
- **Controlled Service: \$0.00 (from \$0.00 to \$0.00 per kWh)**
- **Lighting: \$0.04 (from \$0.00120 to \$0.00213 per kWh)**
- **Residential and all other service: \$1.96 (from \$0.00240 to \$0.00387 per kWh)**

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

Changes to our North Dakota Transmission Cost Recovery Rider

The North Dakota Public Service Commission approved our request to update our Transmission Cost Recovery Rider. This rider recovers costs incurred for regional transmission projects that are necessary to provide our North Dakota customers with safe, reliable, and low-cost service.

The changes below apply to bill usage beginning January 1, 2026, and are on the Transmission Rider line of your bill.

	<u>Old rates</u>		<u>New rates</u>		<u>Impact of new rates</u> ⁽¹⁾
Large General Service	\$0.711	per kW	\$1.239	per kW	\$224.43/month
Controlled Service	\$0.00000	per kWh	\$0.00000	per kWh	\$0/month
Lighting	\$0.00120	per kWh	\$0.00213	per kWh	\$0.08/month
Residential	\$0.00240	per kWh	\$0.00387	per kWh	\$1.48/month
All other service	\$0.00240	per kWh	\$0.00387	per kWh	\$1.99/month

(1) Assumes Large General Service uses 425 kW of demand, Controlled Service uses 1,300 kWh, Lighting uses 90 kWh per fixture, Residential uses 1,000 kWh, and all other service uses 1,350 kWh.

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