

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



September 16, 2024

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-24-**

Dear Mr. Kahl:

Enclosed please find copies of Otter Tail Power Company's (Otter Tail) 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'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](mailto:ndpsc@nd.gov). If you have any questions regarding this filing, please contact me at 218-739-8406 or [jsillerud@otpco.com](mailto:jsillerud@otpco.com).

Sincerely,

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

vjm  
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-24-  
APPLICATION**

**I. APPLICATION SUMMARY**

Otter Tail Power Company’s (Otter Tail or Company) Transmission Cost Recovery Rider (TCRR) includes: annual updated actual and forecasted costs and collections associated with 22 previously approved projects; regional transmission expenses and revenues recovered in the TCRR; three project timeline updates, the addition of one new transmission project, one transmission rebuild project, and four Extenda-Life projects. Also new in this filing is the proposed removal of the wholesale revenue credit, removal of the Central Power Electric Cooperative (CPEC) portion of Otter Tail Power’s Midcontinent Independent System Operator (MISO) Schedule 9 revenue and the inclusion of MISO Schedules 7, 8, and 9 true-up calculations.

The existing projects with timeline updates and the new projects are listed below.

**Project Timeline Updates:**

- Wabek-Parshall Rebuild
- Devils Lake-New Rockford Extenda-Life
- Kensal-Bordulac 41.6kV Extenda-Life

**New Transmission Projects:**

- Ivanhoe 41.6kV In Line Reclosure

**Transmission Rebuild Program:**

- Winger-reroute 41.6kV through town

**Transmission Extenda-Life Program:**

- Pekin - McVile Extenda-Life
- Hancock-Clontarf Extenda-Life
- Cyrus-Farwell Extenda-Life
- Underwood 655 - 41.6kV Extenda-Life

Otter Tail proposes a rate implementation date of January 1, 2025.

The North Dakota projected revenue requirement for the recovery period of January 1, 2025, to December 31, 2025, is \$3,134,045. A typical residential customer using 1,000

kWh will see a monthly bill decrease of approximately \$0.96. A large general service customer with 425 kW of demand will see a monthly bill decrease of \$163.20.

## **II. INTRODUCTION**

Otter Tail 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 proposes updating its TCRR rates to reflect the TCRR revenue requirements for the next recovery period (calendar year 2025). 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) the addition of six transmission projects not currently in base rates and not previously included in the Rider; (2) timeline updates for three projects; (3) forecast updates to previously approved projects; and (4) 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  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 739-8774  
[ldonofrio@otpc.com](mailto:ldonofrio@otpc.com)

**C. Title of utility employee responsible for filing**

Jordan Sillerud  
Rates Analyst, Regulatory Economics  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
(218) 739-8406  
[jsillerud@otpc.com](mailto:jsillerud@otpc.com)

Paula Foster  
Supervisor, Regulatory Analysis, Regulatory Economics  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
(218) 739-8042  
[pfoster@otpc.com](mailto:pfoster@otpc.com)

Amber Grenier  
Manager Regulatory Economics  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
(218) 739-8728  
[agrenier@otpc.com](mailto:agrenier@otpc.com)

We request that all communications regarding this proceeding, including data request, 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](mailto:regulatory_filing_coordinators@otpc.com)

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

The date of this filing is September 16, 2024. The updated TCRR rate is calculated to take effect as of January 1, 2025.

**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'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 requests 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 requested a permanent 15-day extension to allow adequate time to incorporate and review updated financial information filed annually with MISO on September 1. The Commission approved Otter Tail's request in the Order dated December 14, 2022, in Case No. PU 22-335.

Otter Tail'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's proposed TCRR rate update**

In support of Otter Tail's request to update its TCRR rate, the Company provides Attachments 1-4, which are, respectively, the Projected Revenue for 2025, Summary of Revenue Requirements, Class Allocation and Rate Design, and Tracker Summary calculations the Company used to calculate its proposed TCRR rate update.

Attachments 16-32 provide the revenue requirement calculations for each of the transmission projects identified in this filing – both those previously approved in Otter Tail's prior TCRR (Attachments 16-29) and the new projects for which Otter Tail is requesting TCRR recovery (Attachments 30-32).

Descriptions of the calculations included in Attachments 16-32 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 Otter Tail facilities by wholesale customers.
- *Return on investment (cost of capital).* In this section, Otter Tail uses the cost of capital agreed upon by the parties in the Settlement Agreement approved by the Commission<sup>1</sup> in Otter Tail's last general rate case.
- *Depreciation expense.* Otter Tail calculates depreciation expense using the Company's current composite depreciation rates.
- *Property taxes.* The property tax calculation is based on Otter Tail'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.

---

<sup>1</sup> Case No. PU-17-398, Order on Settlement, September 26, 2018.

- *Operation and maintenance (O&M) expense.* This section includes any O&M expense associated with the project. Otter Tail does not always incur O&M expenses, but when it does, these might 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'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 provides Attachment 14 to show the ADIT proration calculation impact on the revenue requirement for the recovery period.

Otter Tail also provides Attachment 15, 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(l)-1(h)(6)(ii) of the IRS regulations and to avoid a tax normalization violation.<sup>2</sup> Attachment 15 shows that the preservation of the proration of ADIT resulted in a decrease of \$1,837 plus any applicable carrying charge to the revenue requirement. This ADIT amount is included on Line No. 21 of Attachment 4.

- *Midcontinent Independent System Operator (MISO) Schedule 26 and 26A expenses.* Schedule 26 and Schedule 26A costs for the recovery period appear on Line No. 24 and 25 of the Tracker Summary (Attachment 4) and are shown separately in Attachments 10 and 11. These represent Otter Tail'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 6, refer to different types of transmission service that Otter Tail may secure for serving Otter Tail 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

---

<sup>2</sup> See Treas. Reg. SS 1.167(l)-1(h)(6)(ii).

local area. Otter Tail includes the SPP Schedule 9 expenses on Line No. 26 and SPP Schedule 11 expenses on Line No. 27 of the Tracker Summary (Attachment 4) and they are shown separately in Attachment 6.

Otter Tail also receives MISO Schedule 9 revenues related to charges paid by Central Power Electric Cooperative (CPEC) to MISO for transmission service CPEC receives. These revenues are offset by facility credits CPEC is collecting through MISO for CPEC-owned transmission facilities that are eligible for recovery under the MISO Tariff. The MISO Schedule 9 revenue from CPEC results in a reduction to Otter Tail's TCRR revenue requirement. These calculations are being removed from future years due to the Schedule 7, 8, and 9 true-up calculations included in Attachment 8.

MISO Schedule 9 revenue from CPEC appears on Line 32 of the Tracker Summary (Attachment 4) and is shown in detail in Attachment 7.

- *MISO Schedule 7, 8, and 9 revenues.* Otter Tail provides a calculation of these revenues, where applicable in the Tracker Summary on Line No. 31 and in Attachment 8. These revenues represent transmission charges passed through MISO for transmission services. Due to the partial inclusion of these charges in Otter Tail'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 (Attachment 4) on Line Nos. 33 and 34 and are shown separately on Attachment 10 and Attachment 11, respectively. These represent Otter Tail's retail share of the revenues derived from Otter Tail'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. The value of these MVP ARRs is determined during MISO's annual Financial Transmission Rights auction. The revenues are distributed to all MISO market participants in a manner similar to the way MISO Schedule 26A expenses are allocated to MISO market participants for all MVP projects. The revenue is identified in Attachment 12 and is reflected as a credit in the Tracker Summary (Attachment 4, Line No. 37).
- *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's current retail rates. The revenue credit is reflected in Attachments 10, 11 and, 13 on the line titled "Overhead Credit for Non-Retail Share" for each project. For this period, the percentage is about one percent of the total investment in the projects. This percentage was established for these costs as part of the FERC-approved MISO Tariff.

- *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'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 13, there are no forecast amounts for Schedule 37 and 38 revenues for the 2025 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 2024 is \$23,925, as can be seen in Attachment 4, on Line No. 35. The Schedule 38 revenue credit reflected in this TCRR update for 2024 is \$28,177, as seen in Attachment 4, on Line No. 36. These are actual amounts through July 2024 and are included as part of the 2024 true-up amount.

### **C. Projects and programs previously approved for recovery in Otter Tail's TCRR**

Twenty-two projects previously approved for inclusion in Otter Tail's TCRR remain in this update. Table 1 reflects the prior approved projects and the case number in which the Commission approved each for TCRR recovery.

The retail allocation of costs and revenues for these projects are updated and carried out through 2024 and 2025 and reflected in Attachments 16-29.

**Table 1**

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

***Project Timeline Updates*****Wabek-Parshall Rebuild**

Otter Tail 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'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, Otter Tail has shifted this project out in its 5-year budget plan. The project is still necessary, but additional work is required with routing alternatives before construction can begin.

**DL-New Rockford Extenda-Life**

The 41.6 kV line serves North Dakota customers in the communities around Fort Totten, Oberon, Sheyenne, and New Rockford. The line was constructed in the 1960s with minimal modifications. This line has been identified as one of the worst performing 41.6 kV lines within Otter Tail's service territory. Data from local field inspections have shown that most of the interruptions are located south of Devils Lake and around Fort Totten. Otter Tail found that most of the issues have been caused by wind, lightning, and failing insulators. Given the mixed vintage of the

poles and equipment along this line, an Extenda-Life project is preferred over a complete rebuild. This project was approved in Otter Tail’s most recent TCRR filing, Case No. PU-23-306, and is now scheduled to be completed in 2025 due to skilled labor being unavailable in 2024. The project is still necessary, and the total estimated budget remains the same.

**Kensal-Bordulac 41.6kV Extenda-Life**

The Kensal, ND to Bordulac, ND line section is part of a poor-performing 41.6kV transmission line that connects Jamestown, ND and Carrington, ND and serves the communities of Carrington, Bordulac, Kensal, Courtenay, and Wimbledon. This project was approved in Otter Tail’s most recent TCRR filing, Case No. PU-23-306, and is now scheduled to be completed in 2027 due to other higher priority needs. The project is still necessary, and the total estimated budget remains the same.

**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 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.

Otter Tail requests approval for the addition of one new transmission project, one transmission rebuild project, and four Extenda-Life projects and describes each in detail below. The map in Attachment 33 shows where these projects are located within Otter Tail’s service territory. Otter Tail verifies that the costs requested for recovery in the TCRR for each of these new projects are not included in its general rate review filings Case No. PU-17-398 or Case No. PU-23-342, and that these projects are not currently being recovered as a result of those proceedings.

**Ivanhoe 41.6kV In Line Reclosure – Attachment 30**

In 2025, Otter Tail plans to install a 41.6 kV line recloser at Ivanhoe. The Ivanhoe 41.6 kV system has approximately 57 miles of exposure, and serves the Minnesota communities of Canby, Hendricks, Elkton, Lake Benton, and Verdi, South Dakota. This project will isolate the communities of Canby, Hendricks, and Ivanhoe from downline exposure thus improving reliability to the largest customer counts within this line section. Upon completion of this reclosure, approximately 40 percent of the existing interruptions will be isolated from these communities. This line section consistently remains in the top 20 for breaker operations within Otter Tail’s

service territory and had 15 interruptions in 2023. This project has an estimated total cost of \$0.35 million (OTP Total) / \$0.14 million (OTP ND).

### **Transmission Line Rebuild and Extenda-Life Programs**

Otter Tail 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 Otter Tail'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 has undertaken a multi-year effort called the System Infrastructure and Reliability Improvement (SIRI) Initiative. As part of this initiative, Otter Tail focused on assessing overall transmission and distribution asset health conditions, which has led to the development of the "Extenda-Life" and "Line Rebuild" programs.

Otter Tail'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, Otter Tail 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 refers to these refurbishment projects internally as "Extenda-Life" projects. Otter Tail 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 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'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’s current construction and material standards to existing lines results in improved reliability of the lower voltage (41.6 kV) transmission system.

**Transmission Line Rebuild Program – Attachment 31**

As described above and listed in Table 2 below, Otter Tail has identified the following transmission project to be included in the Transmission Rebuild Program within the SIRI initiative for the 2025 calendar year, with a total estimated cost of \$0.12 million (OTP Total) / \$0.05 million (OTP ND).

**Table 2  
Transmission Line Rebuild Program – 2024 Addition**

Line Section	Voltage	State	Project Length	Total Cost	ND Share	Projected In-Service
Winger-reroute 41.6kV thru town	41.6 kV	MN	.5 Miles	\$ 115,000	\$ 45,074	2025

**Winger-reroute 41.6kV thru town**

The Winger 41.6 kV line serves the communities of Winger, Bejou, Waubun, White Earth, and Callaway. There is a half-mile section of this line that runs through a large truck salvage yard near the community of Winger that presents clearance concerns constituting safety hazards to cranes and large forklifts. To mitigate the clearance and line contact concerns, this line will be rerouted outside of the salvage yard. This not only mitigates the safety concerns but also improves crew access to maintain the line. This project is estimated to cost \$0.12 million (OTP Total) / \$0.05 million (OTP ND) and is expected to be completed in 2025.

**Transmission Extenda-Life Program – Attachment 32**

As described in further detail above, Otter Tail deploys various techniques to extend the useful lives of existing transmission lines where possible before a complete rebuild is required. This effort has been developed into a program that Otter Tail has coined the “Extenda-Life” Program and is a valuable cost saving measure that can be used to replace select equipment along existing lines to maintain a high level of reliability for customers. The list of 2024 project additions under Otter Tail’s Extenda-Life Program are shown in Table 4 with a total estimated cost of \$2.1 million (OTP Total) / \$0.82 million (OTP ND).

**Table 3  
Transmission Extenda-Life Program – 2024 Addition**

Line Section	Voltage	State	Project Length	Total Cost	ND Share	Projected In-Service
Pekin - McVille Extenda-Life	41.6 kV	ND	10.5 Miles	\$ 150,000	\$ 58,793	2025
Hancock-Clontarf Extenda-Life	41.6 kV	MN	13.5 Miles	\$ 150,000	\$ 58,793	2025
Cyrus-Farwell Extenda-Life	41.6 kV	MN	17 Miles	\$ 1,130,000	\$ 442,906	2026
Underwood 655 - 41.6kV Extenda-Life	41.6 kV	ND	75 Miles	\$ 650,000	\$ 254,769	2025

***Pekin - McVille Extenda-Life***

The Pekin- McVille project addresses a poor-performing 41.6kV transmission line that connects McVille, ND and St. Michael, ND and serves the communities of McVille, Pekin, Warwick, Tolna, Hamar and Tokio, and also provides emergency backup to the Spirit Lake Casino area. The 10.5-mile section consists of aging power poles and framing with porcelain insulators. The line was constructed without static-wire lightning protection. The poor reliability performance and overall condition of this line makes this a suitable candidate for an Extenda-Life project. Project scope predominately includes condition-based crossarm changeouts, porcelain to polymer insulator replacement, limited pole replacement, and arrester installation for lightning protection. If required, hard to access poles will be relocated to improve accessibility. This project is estimated to cost \$0.15 million (OTP Total) / \$0.06 million (OTP ND) and is expected to be completed by the end of 2026.

***Hancock-Clontarf Extenda-Life***

The Hancock-Clontarf project addresses a poor-performing 41.6kV transmission line that connects Hancock, MN to Clontarf, MN, and serves the same two communities. The 13.5-mile section consists of aging power poles and framing with porcelain insulators. The line was constructed without static-wire lightning protection. The overall condition of the line makes this a suitable candidate for an Extenda-Life project. Project scope predominately includes condition-based crossarm changeouts, porcelain to polymer insulator replacement, limited pole replacement, and arrester installation for lightning protection. If required, hard to access poles will be relocated to improve accessibility. This project is estimated to cost \$0.15 million (OTP Total) / \$0.06 million (OTP ND) and is expected to be completed by the end of 2025.

### ***Cyrus-Farwell Extenda-Life***

The Cyrus – Farwell 41.6kV transmission line section is a 17-mile section as part of an approximate 40-mile 41.6 kV line served from the Walden 115 kV substation in MN. This line serves the communities of Cyrus, Farwell, Kensington, Hoffman, and is an alternate service to Barret. The line section is shown to be of vintages ranging from the 1950s and 1960s and ranks within the top 10 with breaker operations within the Morris Customer Service Area. Of the 17 miles within this section, four miles will be largely rebuilt to new vertical framing, three miles are already adequate, and the remaining miles will be good candidates for Extenda-Life type work. This will predominately include condition-based crossarm changeouts, insulator replacement, limited pole replacement, and arresters that will be added for lightning protection. This project has an estimated total cost of \$1.13 million (OTP Total) / \$0.44 million (OTP ND).

### ***Underwood 655 - 41.6kV Extenda-Life***

The Underwood- Sykeston, ND project addresses a poor-performing 41.6kV transmission line that connects Underwood, ND and Sykeston, ND and serves the communities of Underwood, Turtle Lake, Mercer, McClusky, Denhoff, Goodrich, Hurdsfield, Bowdon, Heaton, and Sykeston. Of the 85 miles within this section, 10.5 miles are already rebuilt to new vertical framing with static wire. Extenda-Life type work is planned for the remaining 75 miles of line. Otter Tail's Extenda-Life program scope of work includes condition-based crossarm changeouts, ceramic insulator replacement, select pole upgrades, and arrester installations for lightning protection. If required, hard to access poles will be relocated to improve accessibility. This project is estimated to cost \$0.65 million (OTP Total) / \$0.25 million (OTP ND) and is expected to be completed by the end of 2026.

## **E. Removal of the Wholesale Revenue Credit and inclusion of Schedule 7, 8, and 9 true-up calculations**

Otter Tail proposes to discontinue the application of the wholesale revenue credit for projects not recovered through Attachments GG or MM. The wholesale revenue credit is a percentage of the revenue requirement based on the prior year's actual revenue credits. Revenues received through Schedule 9 are removed from the revenue credits and the total is divided by the forecasted non-levelized revenue requirements from the MISO formula rate shown in MISO Attachment O. The wholesale revenue credit percentage is applied to the in-service revenue requirement of each transmission project not included in MISO Attachments GG or MM. This methodology was established to represent the revenue Otter Tail receives for the wholesale use of its transmission system from MISO and other non-MISO users.

However, Otter Tail does not receive additional revenues for the wholesale use of its transmission system from each transmission investment, as the revenue credit suggests. Attachment O is a formulaic rate used to calculate transmission rates for firm and non-firm point-to-point transmission services under MISO Schedule 7 and MISO Schedule 8, respectively, and does not increase linearly from year-to-year. Transmission services under firm point-to-point are reserved between specified points of receipt and delivery to the Transmission Customer, and non-firm point-to-point transmission services are reserved on an available basis by the Transmission Customer. Otter Tail is not recovering its transmission project costs under Attachment O and requests the credit be removed from the revenue requirement calculation on a going-forward basis.

To maintain the intention of the wholesale revenue credit, Otter Tail proposes to instead provide a true-up calculation for its MISO schedules 7, 8, and 9 revenues, giving more transparency and accuracy to the revenues associated with these schedules. The true-up calculation will represent the difference between what Otter Tail has in its 2024 Test year and the actuals and forecasts that are being reported. This will give a more accurate representation of what the Wholesale Revenue Credit was supposed to represent and provide further transparency into our Schedule 7, 8 and 9 revenues. This change results in an increase to the revenue requirement of approximately \$314,118.

## **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's current North Dakota general rate review (Case No. PU-23-342) to allocate total revenue requirements to jurisdictions (North Dakota, 39.1952 percent) and rate classes. Should the final D2 allocation factors approved in Case No. PU-23-342 be different, the factors will be adjusted to the approved factors with the impact included as part of the true-up in the next annual filing. 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 2025 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2025, the true-up associated with an updated projection of the 2024 revenue requirement, and the carrying charge attributable to any

projected over or under-collection.

The revenue requirement attributable to calendar year 2025, as shown on Line No. 40 of Attachment 4, page 2 is \$5,120,267. This amount is based on actual net revenues and expenses included in the TCRR tracker through July 2024 and projections for August 2024 through December 2025.

By design and structure of the TCRR, the related carrying credit of (\$80,096) as computed on Attachment 4, Line No. 45, will be credited to customers as a reduction in the 2025 revenue requirement. The 2024 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, Line No. 35 and as computed in Attachment 4, Line No. 46, reflects an estimated over-collection amount of (\$1,906,126) during the 2024 collection period. The over-collection is due to delayed in-service dates and reduced costs for projects of approximately \$242,864. Also contributing to the over-collection is a reduction in the MISO Schedule 26 and 26A and SPP Schedule 9 and 11 Expenses and an increase to MISO Schedules 26A and 9 Revenue in 2024, which results in a decrease of approximately \$802,574 to the net revenue requirement for 2024. The net revenue requirement for 2025, upon which rates are developed, is \$3,134,045 as shown on Line No. 37 of Attachment 2. The proposed rates for this net revenue requirement are calculated on Line Nos. 17-20 of Attachment 3.

The TCRR is applicable to electric service under all of Otter Tail’s 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 4 with a comparison to previously approved rates:

**Table 4**

		January 1, 2024- December 31,2024 Approved Rates (PU-23-306)	January 1, 2025- December 31,2025 Proposed Rates (PU-24-XX)
Line No.	Class	\$/kWh	\$/kWh
1	Large General Service Class	\$ 1.095	\$ 0.711
2	Controlled Service	\$ 0.00051	\$ -
3	Lighting	\$ 0.00331	\$ 0.00120
4	All Other Service	\$ 0.00336	\$ 0.00240

The proposed rates are based on an effective date of January 1, 2025, through December 31, 2025. These rates represent a change to the rates currently in effect. The estimated decrease for a residential customer using 1,000 kWh is \$0.96 per month.

## **VII. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE**

Otter Tail'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 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 will include a notice of the proposed TCRR update to North Dakota customers on customer bills following submittal of this Application. Attachment 35 provides a sample of the bill message that will be included. Otter Tail will also include a bill insert implementation notice to North Dakota customers once the Commission approves the updated TCRR. Attachment 36 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, 2025. As summarized below, this update includes:

1. Updates for previously approved TCRR projects and regional transmission organization costs and revenues.
2. Changes to project timelines for three previously approved projects.
3. The inclusion of one new transmission project, one new Rebuild project and four new Extenda-Life projects.
4. Proposed removal of the Wholesale Revenue Credit.
5. Proposed inclusion of Schedule 7, 8, and 9 true-up.

Date: September 16, 2024

Respectfully submitted:  
OTTER TAIL POWER COMPANY

/s/ JORDAN M. SILLERUD

Jordan M. Sillerud  
Rates Analyst  
Regulatory Economics  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
Phone (218) 739-8406

## Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Summary
Attachment 5	Attachment O Revenue Credit for Non-MISO Projects
Attachment 6	SPP Expenses
Attachment 7	MISO Schedule 9 CPEC Revenues
Attachment 8	MISO Schedule 7, 8 & 9 Revenue True-up
Attachment 9	MISO Schedule 26 and 26A Expense
Attachment 10	MISO Schedule 26 Revenue
Attachment 11	MISO Schedule 26A Revenue
Attachment 12	MISO Multi-Value Project Auction Revenue Rights Credit
Attachment 13	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 14	ADIT Pro-Rate Projection
Attachment 15	ADIT Pro-Rate Preservation
Attachment 16	2021 Transmission Line Rebuild Program Revenue Requirements
Attachment 17	Gackle Rural Loop Project
Attachment 18	Oslo 155 kV 5 Breaker Ring Bus Revenue Requirement
Attachment 19	Casselton 115 kV Capacitor Bank Revenue Requirement
Attachment 20	Cooperstown 41.6 kV Rebuild Program Revenue Requirement
Attachment 21	2023 Transmission Line Rebuild Program Revenue Requirements
Attachment 22	2023 Transmission Extenda-Life Program Revenue Requirements
Attachment 23	Milbank Area Reliability Project
Attachment 24	Big Stone South to Alexandria 345kV (BSSa)
Attachment 25	Alexandria to Big Oaks 345kV double circuit (BSSa)
Attachment 26	Jamestown to Ellendale 345kV (JETx)
Attachment 27	Maple River Substation Addition (JETx)
Attachment 28	Jamestown 345 Substation Addition (JETx)
Attachment 29	Twin Brooks Reactor Addition (JETx)
Attachment 30	Ivanhoe 41.6kV In Line Reclosure
Attachment 31	Winger-reroute 41.6kV thru town
Attachment 32	2024 Transmission Extenda-Life Program
Attachment 33	2024 New Projects Map
Attachment 34	Electric Rate Schedule Section 13.05 Legislative and Non-Legislative
Attachment 35	Customer Notice – ND TCR Proposed Bill Message
Attachment 36	Customer Notice – ND TCR Implementation Bill Insert

**Projected Revenue for 2025**

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,326,657 kW	\$ 0.711	\$943,348
2					
3	Controlled Service	(b)	253,995,453 kWh	\$ -	\$0
4					
5	Lighting	(c)	12,038,096 kWh	\$ 0.00120	\$14,417
6					
7	All other service		908,504,838 kWh	\$ 0.00240	\$2,176,281
8					
9	Total revenue				<u>\$3,134,045</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

<b>Summary of Revenue Requirements</b>		
Line No.	Revenue Requirements	2025
1	2021 Rebuild Projects	275,026
2	Gackle Rural Loop	62,352
3	Oslo 115 kV 5 Breaker Ring Bus	467,512
4	Casselton 115 kV Capacitor Bank	80,680
5	Cooperstown 41.6 kV Relocate	48,514
6	2023 Rebuild Projects	60,719
7	2023 Extenda-Life Projects	36,984
8	Milbank Area Reliability Project	994,460
9	Big Stone South to Alexandria 345kV (BSSa)	8,136
10	Alexandria to Big Oaks 345kV double circuit (BSSa)	13,804
11	Jamestown to Ellendale 345kV (JETx)	12,075
12	Maple River Substation Addition (JETx)	529
13	Jamestown 345 Substation Addition (JETx)	832
14	Twin Brooks Reactor Addition (JETx)	1,794
15	Ivanhoe 41.6kV In Line Reclosure	3,233
16	Winger-reroute 41.6kV thru town	3,405
17	2024 Extenda-Life Projects	30,587
18		
19	<b>Total Revenue Requirement</b>	<b>\$2,100,641</b>
20		
21	MISO Schedule 26 Expense	4,353,170
22	MISO Schedule 26A Expense	3,625,891
23		
24	SPP Schedule 9 Expense	771,359
25	SPP Schedule 11 Expense	114,249
26		
27	MISO Schedule 7, 8 and 9 Revenue True-up	(326,183)
28	MISO Schedule 26 Revenue	(4,095,740)
29	MISO Schedule 26A Revenue	(1,340,876)
30	MISO Schedule 37 Revenue	0
31	MISO Schedule 38 Revenue	0
32	MISO MVP ARR Revenue	(82,243)
33		
34	Carrying Cost	(80,096)
35	True-Up	(1,906,126)
36		
37	<b>Net Revenue Requirement</b>	<b><u>\$3,134,045</u></b>

**Class Allocation and Rate Design**

Line No.		Approved PU-23-306	Proposed PU-24-XX
		2024	2025
1	North Dakota Revenue Requirements	\$4,481,941	\$3,134,045 *
2			
3	Large General Service Class	30.10%	\$1,244,456
4	Controlled Service	0.00%	\$943,348
5	Lighting	0.46%	\$0
6	All Other Service	69.44%	\$43,034
7			\$14,417
8	Total	\$3,070,253	\$2,176,281
9			
10			
11	Large General Service Class	kW	1,136,404
12	Controlled Service	kWh	1,326,657
13	Lighting	kWh	243,885,377
14	All Other Service	kWh	13,014,550
15			12,038,096
16			908,504,838
17	Large General Service Class	\$ / kW	1.095
18	Controlled Service	\$ / kWh	0.711
19	Lighting	\$ / kWh	-
20	All Other Service	\$ / kWh	0.00331
			0.00120
			0.00336
			0.00240

\* Jurisdictional transmission allocation factor (D2 = 39.195199%) is from Otter Tail's proposed general rate case in North Dakota Case No. PU-24-342.

Line No.	Att No.	TRACKER SUMMARY Requirements Compared to Billed:	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024
			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	16	2021 Rebuild Projects	17,467	17,467	18,232	18,232	18,232	18,229	18,229	18,229	19,054	19,052	19,052	19,052	220,526
2	17	Gackle Rural Loop	2,622	2,622	2,626	2,632	2,636	2,636	2,636	2,636	2,636	2,636	2,636	2,636	31,591
3	18	Oslo 115 kV 5 Breaker Ring Bus	22,083	22,083	22,083	22,083	22,083	22,083	22,083	22,083	22,083	22,083	22,083	22,083	265,001
4	19	Casselton 115 kV Capacitor Bank	5,135	5,135	5,135	5,135	5,947	5,952	5,964	5,950	5,964	5,964	5,964	5,964	68,206
5	20	Cooperstown 41.6 kV Relocate	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	13,943
6	21	2023 Rebuild Projects	619	619	619	619	619	619	619	619	619	619	619	619	7,433
7	22	2023 Extenda-Life Projects	685	685	685	685	685	685	685	685	685	685	685	774	8,393
8	23	Milbank Area Reliability Project	25,232	25,232	25,232	25,232	25,232	25,232	25,232	25,232	25,232	25,232	25,232	25,232	302,778
9	24	Big Stone South to Alexandria 345kV (BSSa)	283	283	283	283	283	283	283	283	283	283	283	283	3,401
10	25	Alexandria to Big Oaks 345kV double circuit (BSSa)	179	179	179	179	179	179	179	179	179	179	179	179	2,146
11	26	Jamestown to Ellendale 345kV (JETx)	451	451	451	451	451	451	451	451	451	451	451	451	5,409
12	27	Maple River Substation Addition (JETx)	3	3	3	3	3	3	3	3	3	3	3	30	
13	28	Jamestown 345 Substation Addition (JETx)	13	13	13	13	13	13	13	13	13	13	13	13	161
14	29	Twin Brooks Reactor Addition (JETx)	13	13	13	13	13	13	13	13	13	13	13	13	158
15	30	Ivanhoe 41.6kV In Line Reclosure													
16	31	Winger-reroute 41.6kV thru town													
17	32	2024 Extenda-Life Projects													
18															
19		<b>Total Revenue Requirements</b>	75,946	75,946	76,715	76,721	77,538	77,541	77,553	77,538	78,377	78,375	78,464	78,464	929,178
20															
21		<b>ADIT Preservation of Proration</b>	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(153)	(1,837)
22															
23		<b>MISO &amp; SPP Expenses</b>													
24		MISO Schedule 26 Expense	425,375	363,217	374,073	313,975	293,887	288,183	363,162	356,810	308,355	365,621	365,621	440,507	4,258,785
25		MISO Schedule 26A Expense	388,029	345,681	371,583	303,064	293,299	288,226	323,241	276,083	263,414	278,704	311,642	349,805	3,792,771
26		SPP Schedule 9 Expense	63,560	60,226	52,608	53,497	52,663	56,885	56,237	61,735	51,286	51,286	51,286	51,286	662,553
27		SPP Schedule 11 Expense	9,297	9,169	9,171	9,308	9,152	9,763	9,107	9,165	9,152	9,152	9,152	9,152	110,741
28		<b>Total MISO &amp; SPP Expenses</b>	886,261	778,294	807,435	679,843	649,002	643,057	751,747	703,793	632,206	704,762	737,700	850,749	8,824,850
29															
30		<b>MISO Revenues</b>													
31		MISO Schedule 7, 8 and 9 Revenue True-up													
32		MISO Schedule 9 CPEC Revenue	(136,582)	(43,607)	(80,823)	(53,425)	(35,493)	(15,852)	(29,998)	1,276	(17,276)	(34,025)	(41,361)	(36,616)	(523,782)
33		MISO Schedule 26 Revenue	(328,083)	(289,969)	(284,877)	(263,938)	(305,704)	(373,612)	(407,168)	(405,037)	(331,495)	(274,296)	(270,210)	(311,067)	(3,845,457)
34		MISO Schedule 26A Revenue	(122,852)	(107,755)	(114,865)	(103,823)	(109,150)	(120,124)	(132,425)	(144,249)	(120,463)	(117,664)	(102,273)	(133,055)	(1,428,697)
35		MISO Schedule 37 Revenue	(3,422)	(3,422)	(3,422)	(3,422)	(3,422)	(3,408)	(3,408)	0	0	0	0	0	(23,925)
36		MISO Schedule 38 Revenue	(4,007)	(4,007)	(4,007)	(4,007)	(4,007)	(4,070)	(4,070)	0	0	0	0	0	(28,177)
37		MISO MVP ARR Revenue	(14,131)	(13,761)	(14,299)	(11,846)	(10,790)	(9,614)	(1,819)	(439)	(464)	(1,452)	(1,708)	(1,919)	(82,243)
38		<b>Total MISO Revenues</b>	(609,076)	(462,521)	(502,293)	(440,462)	(468,566)	(526,680)	(578,889)	(548,449)	(469,698)	(427,437)	(415,552)	(482,657)	(5,932,280)
39															
40		<b>Net Revenue Requirement</b>	352,978	391,566	381,705	315,949	257,820	193,764	250,257	232,729	240,732	355,547	400,459	446,403	3,819,911
41															
42		Billed (forecast kWh x adj factor)	695,498	421,842	396,939	385,711	334,439	301,913	320,083	342,521	330,306	354,126	394,478	446,047	4,723,903
43															
44		Difference	(342,519)	(30,276)	(15,234)	(69,762)	(76,619)	(108,148)	(69,826)	(109,791)	(89,574)	1,421	5,981	356	(903,992)
45		Carrying Charge	(5,665)	(7,638)	(7,872)	(8,015)	(8,495)	(9,020)	(9,743)	(10,234)	(10,974)	(11,595)	(11,658)	(11,693)	(112,600)
46		Cumulative Difference	(1,237,718)	(1,275,632)	(1,298,738)	(1,376,514)	(1,461,627)	(1,578,795)	(1,658,364)	(1,778,389)	(1,878,938)	(1,889,112)	(1,894,789)	(1,906,126)	(1,906,126)
47															
48		Carrying Charge Calculation	(7,638)	(7,872)	(8,015)	(8,495)	(9,020)	(9,743)	(10,234)	(10,974)	(11,595)	(11,658)	(11,693)	(11,763)	
49		Cumulative Carrying Charge	(389,860)	(397,732)	(405,747)	(414,241)	(423,261)	(433,004)	(443,238)	(454,212)	(465,807)	(477,465)	(489,158)	(500,920)	
50		Carrying cost	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	
51															
52															
53		Forecasted Sales (MWh)	263,003	240,239	232,743	206,622	192,493	184,330	199,689	199,020	191,923	205,763	229,209	259,173	2,604,207
54															

Approved December 18, 2023 (PU-23-306);  
Rate Effective January 1, 2024

SUMMARY	Jan 2024 - Dec 2024
Revenue requirements	\$4,867,185
Carrying Charge	(18,858)
2023 True-Up	(366,386)
<b>Total requirements</b>	<b>\$4,481,941</b>
Jan 2024-Dec 2024 projected sales in MWh	2,604,207
Average Rate	\$0.00172

Line No.	Att No.	TRACKER SUMMARY	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025
			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
		<b>Requirements Compared to Billed:</b>													
		<b>Revenue Requirements</b>													
1	16	2021 Rebuild Projects	22,919	22,919	22,919	22,919	22,919	22,919	22,919	22,919	22,919	22,919	22,919	22,919	275,026
2	17	Gackle Rural Loop	5,196	5,196	5,196	5,196	5,196	5,196	5,196	5,196	5,196	5,196	5,196	5,196	62,352
3	18	Oslo 115 kV 5 Breaker Ring Bus	38,959	38,959	38,959	38,959	38,959	38,959	38,959	38,959	38,959	38,959	38,959	38,959	467,512
4	19	Casselton 115 kV Capacitor Bank	6,723	6,723	6,723	6,723	6,723	6,723	6,723	6,723	6,723	6,723	6,723	6,723	80,680
5	20	Cooperstown 41.6 kV Relocate	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	4,043	48,514
6	21	2023 Rebuild Projects	5,060	5,060	5,060	5,060	5,060	5,060	5,060	5,060	5,060	5,060	5,060	5,060	60,719
7	22	2023 Extenda-Life Projects	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,020	36,984
8	23	Milbank Area Reliability Project	82,872	82,872	82,872	82,872	82,872	82,872	82,872	82,872	82,872	82,872	82,872	82,872	994,460
9	24	Big Stone South to Alexandria 345kV (BSSa)	678	678	678	678	678	678	678	678	678	678	678	678	8,136
10	25	Alexandria to Big Oaks 345kV double circuit (BSSa)	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	13,804
11	26	Jamestown to Ellendale 345kV (JETx)	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	1,006	12,075
12	27	Maple River Substation Addition (JETx)	44	44	44	44	44	44	44	44	44	44	44	44	529
13	28	Jamestown 345 Substation Addition (JETx)	69	69	69	69	69	69	69	69	69	69	69	69	832
14	29	Twin Brooks Reactor Addition (JETx)	150	150	150	150	150	150	150	150	150	150	150	150	1,794
15	30	Ivanhoe 41.6kV In Line Reclosure	269	269	269	269	269	269	269	269	269	269	269	269	3,233
16	31	Winger-reroute 41.6kV thru town	248	248	248	248	248	248	248	248	248	248	248	248	3,405
17	32	2024 Extenda-Life Projects	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	2,496	30,587
18															
19		<b>Total Revenue Requirements</b>	174,902	174,902	174,902	174,902	174,982	175,044	175,044	175,044	175,044	175,044	175,204	175,626	2,100,641
20															
21		<b>ADIT Preservation of Proration</b>													
22															
23		<b>MISO &amp; SPP Expenses</b>													
24		MISO Schedule 26 Expense	433,583	420,575	385,889	325,187	286,165	342,530	351,202	351,202	303,508	359,874	359,874	433,583	4,353,170
25		MISO Schedule 26A Expense	368,381	339,435	322,242	284,018	268,970	262,917	279,510	277,873	263,262	283,577	318,444	357,261	3,625,891
26		SPP Schedule 9 Expense	64,280	64,280	64,280	64,280	64,280	64,280	64,280	64,280	64,280	64,280	64,280	64,280	771,359
27		SPP Schedule 11 Expense	9,521	9,521	9,521	9,521	9,521	9,521	9,521	9,521	9,521	9,521	9,521	9,521	114,249
28		<b>Total MISO &amp; SPP Expenses</b>	875,764	833,811	781,931	683,006	628,935	679,248	704,512	702,876	640,571	717,252	752,118	864,644	8,864,669
29															
30		<b>MISO Revenues</b>													
31		MISO Schedule 7, 8 and 9 Revenue True-up	(90,140)	(11,126)	(34,009)	(36,701)	(17,432)	(37,578)	(15,846)	(24,988)	(10,618)	(40,476)	(19,545)	12,276	(326,183)
32		MISO Schedule 9 CPEC Revenue													
33		MISO Schedule 26 Revenue	(341,312)	(341,312)	(341,312)	(341,312)	(341,312)	(341,312)	(341,312)	(341,312)	(341,312)	(341,312)	(341,312)	(341,312)	(4,095,740)
34		MISO Schedule 26A Revenue	(111,740)	(111,740)	(111,740)	(111,740)	(111,740)	(111,740)	(111,740)	(111,740)	(111,740)	(111,740)	(111,740)	(111,740)	(1,340,876)
35		MISO Schedule 37 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
36		MISO Schedule 38 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
37		MISO MVP ARR Revenue	(14,131)	(13,761)	(14,299)	(11,846)	(10,790)	(9,614)	(1,819)	(439)	(464)	(1,452)	(1,708)	(1,919)	(82,243)
38		<b>Total MISO Revenues</b>	(557,322)	(477,939)	(501,359)	(501,599)	(481,273)	(500,243)	(470,717)	(478,478)	(464,134)	(494,979)	(474,305)	(442,695)	(5,845,043)
39															
40		<b>Net Revenue Requirement</b>	493,344	530,774	455,474	356,310	322,644	354,049	408,840	399,442	351,481	397,316	453,018	597,575	5,120,267
41															
42		Billed (forecast kWh x adj factor)	323,889	298,320	279,110	245,666	230,370	220,171	237,232	238,732	228,724	246,820	274,340	310,671	3,134,045
43															
44		Difference	169,455	232,455	176,365	110,644	92,274	133,878	171,608	160,710	122,756	150,496	178,677	286,904	1,986,222
45		Carrying Charge	(11,763)	(10,790)	(9,422)	(8,392)	(7,761)	(7,239)	(6,457)	(5,438)	(4,480)	(3,750)	(2,845)	(1,760)	(80,096)
46		Cumulative Difference	(1,748,434)	(1,526,769)	(1,359,825)	(1,257,573)	(1,173,060)	(1,046,421)	(881,271)	(725,999)	(607,723)	(460,977)	(285,144)	0	0
47															
48		Carrying Charge Calculation	(10,790)	(9,422)	(8,392)	(7,761)	(7,239)	(6,457)	(5,438)	(4,480)	(3,750)	(2,845)	(1,760)	0	
49		Cumulative Carrying Charge	(511,710)	(521,132)	(529,523)	(537,284)	(544,523)	(550,980)	(556,419)	(560,899)	(564,649)	(567,494)	(569,253)	(569,253)	
50		Carrying cost	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	
51															
52		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
53															
54															

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

2024 Attachment O Filing

Line No.		<b>Allocated Amount</b>
1	GROSS REVENUE REQUIREMENT (page 3, line 31)	\$52,174,565
2		
3	REVENUE CREDITS (Note T)	
4	Account No. 454 (page 4, line 34)	195,525
5	Account No. 456.1 (page 4, line 37)	6,293,147
6	Revenues from Grandfathered Interzonal Transactions	0
7	Revenues from service provided by the ISO at a discount	0
8	TOTAL REVENUE CREDITS (sum lines 2-5)	6,488,673
9	To back out Schedule 9 Revenues received	(1,336,342)
10	Total Revenue Subject to the Wholesale Revenue Credit	5,152,331
11		
12	Wholesale Revenue Credit	9.88%



MISO Schedule 9 CPEC Revenues

Line No.	MISO Revenues	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	
		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 9 Revenues (CPEC Portion)	(583,355)	(323,685)	(427,627)	(351,105)	(301,022)	(278,019)	(317,527)	(206,581)	(292,584)	(339,361)	(359,850)	(346,598)	(4,127,313)	
2	CPEC Facility Credits in MISO	201,894	201,894	201,894	201,894	201,894	233,745	233,745	210,145	244,333	244,333	244,333	244,333	2,664,432	
3	Non-OTP Schedule 9 Revenues	32,996	10,535	19,526	12,907	8,575	3,830	7,247	(308)	4,174	8,220	9,992	8,846	126,539	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(348,465)	(111,257)	(206,207)	(136,305)	(90,554)	(40,444)	(76,535)	3,256	(44,078)	(86,809)	(105,525)	(93,419)	(1,336,342)	
5															
6	North Dakota share	39.195%	(136,582)	(43,607)	(80,823)	(53,425)	(35,493)	(15,852)	(29,998)	1,276	(17,276)	(34,025)	(41,361)	(36,616)	(523,782)

Line No.	MISO Revenues	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025		
		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	(167,274)	(113,496)	(117,438)	(64,690)	(64,033)	(66,321)	(76,926)	(75,409)	(67,814)	(74,401)	(64,599)	(73,088)	(1,025,488)	
3	MISO Schedule 7 True Up	(81,436)	(23,492)	(36,252)	35,597	(4,263)	(20,872)	(21,868)	(18,186)	(24,775)	(24,092)	(25,241)	(18,964)	(263,843)	
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	(86,610)	(41,357)	(34,523)	(44,864)	(25,524)	(44,150)	(31,230)	(42,660)	(24,207)	(29,948)	(50,416)	(46,094)	(501,584)	
7	MISO Schedule 8 True Up	(30,669)	20,744	(9,458)	(24,981)	(3,459)	(32,278)	(4,414)	(11,323)	3,374	6,806	9,131	32,423	(44,105)	
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	(467,799)	(308,028)	(336,499)	(265,766)	(189,884)	(166,200)	(178,575)	(130,192)	(208,211)	(277,323)	(266,395)	(266,243)	(3,061,114)	
11	MISO Schedule 9 True Up	(117,872)	(25,638)	(41,059)	(104,252)	(36,753)	(42,725)	(14,147)	(34,243)	(5,690)	(85,982)	(33,756)	17,861	(524,255)	
12															
13	<b>Total True Up Amount</b>	(229,977)	(28,386)	(86,769)	(93,636)	(44,475)	(95,874)	(40,428)	(63,752)	(27,091)	(103,268)	(49,866)	31,320	(832,202)	
14															
15	<b>North Dakota share</b>	<b>39.195%</b>	<b>(90,140)</b>	<b>(11,126)</b>	<b>(34,009)</b>	<b>(36,701)</b>	<b>(17,432)</b>	<b>(37,578)</b>	<b>(15,846)</b>	<b>(24,988)</b>	<b>(10,618)</b>	<b>(40,476)</b>	<b>(19,545)</b>	<b>12,276</b>	<b>(326,183)</b>

Schedule 26 & Schedule 26A Expense

Line No.	SCHEDULE 26	2024												
		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 26 Expense	1,085,274	926,688	954,386	801,054	749,804	735,250	926,546	910,342	786,715	932,820	932,820	1,123,879	10,865,578
2														
3	North Dakota share	39.195%	425,375	363,217	374,073	313,975	293,887	288,183	363,162	356,810	308,355	365,621	440,507	4,258,785
4														
5	MISO Schedule 26A Expense	989,991	881,948	948,031	773,218	748,305	735,360	824,695	704,379	672,058	711,066	795,102	892,469	9,676,621
6														
7	North Dakota share	39.195%	388,029	345,681	371,583	303,064	293,299	288,226	323,241	276,083	263,414	278,704	311,642	3,792,771

Line No.	SCHEDULE 26	2025												
		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 26 Expense	1,106,214	1,073,027	984,530	829,660	730,101	873,909	896,033	896,033	774,350	918,157	918,157	1,106,214	11,106,385
2														
3	North Dakota share	39.195%	433,583	420,575	385,889	325,187	286,165	342,530	351,202	351,202	303,508	359,874	433,583	4,353,170
4														
5	MISO Schedule 26A Expense	939,862	866,011	822,146	724,625	686,232	670,790	713,123	708,947	671,670	723,500	812,457	911,491	9,250,855
6														
7	North Dakota share	39.195%	368,381	339,435	322,242	284,018	268,970	262,917	279,510	277,873	263,262	283,577	318,444	3,625,891





Schedule 26A Revenue

Line No.			2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
			Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected	
1	Total Schedule 26A Revenue		(2,193,880)	(1,924,275)	(2,051,246)	(1,854,072)	(1,949,198)	(2,145,166)	(2,364,844)	(2,575,990)	(2,151,214)	(2,101,240)	(1,826,385)	(2,376,095)	(25,513,605)
2	Overhead Credit for Non-Retail Share	7.281%	(159,741)	(140,110)	(149,355)	(134,999)	(141,925)	(156,194)	(172,189)	(187,563)	(156,634)	(152,995)	(132,983)	(173,008)	(1,857,696)
3															
4															
5	<b>CAPX 2020 - Brookings</b>	12.340%	(270,714)	(237,446)	(253,114)	(228,783)	(240,521)	(264,703)	(291,810)	(317,864)	(265,449)	(259,283)	(225,367)	(293,198)	(3,148,251)
6	Retail Load Share		37.439%	37.439%	37.439%	37.439%	37.439%	37.439%	37.439%	37.439%	37.439%	37.439%	37.439%	37.439%	
7	Retail Revenue		(101,353)	(88,897)	(94,763)	(85,654)	(90,049)	(99,102)	(109,251)	(119,005)	(99,381)	(97,073)	(84,375)	(109,770)	(1,178,674)
8															
9	Overhead Credit for Non-Retail Share		(19,711)	(17,289)	(18,430)	(16,658)	(17,513)	(19,274)	(21,247)	(23,144)	(19,328)	(18,879)	(16,409)	(21,348)	(229,230)
10	Non-Retail Load Share		62.561%	62.561%	62.561%	62.561%	62.561%	62.561%	62.561%	62.561%	62.561%	62.561%	62.561%	62.561%	
11	Non-Retail Overhead Credit		(12,332)	(10,816)	(11,530)	(10,422)	(10,956)	(12,058)	(13,292)	(14,479)	(12,092)	(11,811)	(10,266)	(13,356)	(143,409)
12															
13	<b>Total Revenue Credit for CAPX Brookings</b>		(113,684)	(99,713)	(106,293)	(96,076)	(101,005)	(111,160)	(122,543)	(133,485)	(111,473)	(108,884)	(94,641)	(123,126)	(1,322,083)
14															
15															
16	<b>MVP BS South - Brookings</b>	34.378%	(754,210)	(661,525)	(705,175)	(637,391)	(670,093)	(737,463)	(812,984)	(885,571)	(739,542)	(722,362)	(627,873)	(816,852)	(8,771,042)
17	Retail Load Share		3.363%	3.363%	3.363%	3.363%	3.363%	3.363%	3.363%	3.363%	3.363%	3.363%	3.363%	3.363%	
18	Retail Revenue		(25,363)	(22,246)	(23,714)	(21,435)	(22,534)	(24,800)	(27,339)	(29,780)	(24,870)	(24,292)	(21,114)	(27,469)	(294,957)
19															
20	Overhead Credit for Non-Retail Share		(54,916)	(48,167)	(51,345)	(46,410)	(48,791)	(53,696)	(59,195)	(64,480)	(53,848)	(52,597)	(45,717)	(59,477)	(638,637)
21	Non-Retail Load Share		96.637%	96.637%	96.637%	96.637%	96.637%	96.637%	96.637%	96.637%	96.637%	96.637%	96.637%	96.637%	
22	Non-Retail Overhead Credit		(53,069)	(46,547)	(49,619)	(44,849)	(47,150)	(51,890)	(57,204)	(62,312)	(52,037)	(50,828)	(44,179)	(57,476)	(617,160)
23															
24	<b>Total Revenue Credit for MVP Brookings</b>		(78,432)	(68,793)	(73,333)	(66,284)	(69,684)	(76,690)	(84,544)	(92,092)	(76,906)	(75,120)	(65,294)	(84,946)	(912,117)
25															
26															
27	<b>MVP Ellendale - BS South</b>	51.066%	(1,120,324)	(982,648)	(1,047,487)	(946,799)	(995,376)	(1,095,448)	(1,207,629)	(1,315,452)	(1,098,537)	(1,073,017)	(932,660)	(1,213,374)	(13,028,752)
28	Retail Load Share		3.284%	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%	3.284%	
29	Retail Revenue		(36,791)	(32,270)	(34,399)	(31,093)	(32,688)	(35,975)	(39,659)	(43,199)	(36,076)	(35,238)	(30,629)	(39,847)	(427,864)
30															
31	Overhead Credit for Non-Retail Share		(81,573)	(71,549)	(76,270)	(68,938)	(72,475)	(79,762)	(87,930)	(95,781)	(79,987)	(78,129)	(67,909)	(88,348)	(948,649)
32	Non-Retail Load Share		96.716%	96.716%	96.716%	96.716%	96.716%	96.716%	96.716%	96.716%	96.716%	96.716%	96.716%	96.716%	
33	Non-Retail Overhead Credit		(78,894)	(69,199)	(73,765)	(66,674)	(70,095)	(77,142)	(85,042)	(92,635)	(77,360)	(75,563)	(65,679)	(85,447)	(917,496)
34															
35	<b>Total Revenue Credit for MVP Ellendale</b>		(115,686)	(101,469)	(108,164)	(97,767)	(102,783)	(113,117)	(124,701)	(135,835)	(113,436)	(110,801)	(96,307)	(125,294)	(1,345,360)
36															
37															
38	<b>Jamestown - Ellendale</b>	1.629%	(35,734)	(31,343)	(33,411)	(30,199)	(31,749)	(34,940)	(38,519)	(41,958)	(35,039)	(34,225)	(29,748)	(38,702)	(415,566)
39	Retail Load Share		3.519%	3.519%	3.519%	3.519%	3.519%	3.519%	3.519%	3.519%	3.519%	3.519%	3.519%	3.519%	
40	Retail Revenue		(1,257)	(1,103)	(1,176)	(1,063)	(1,117)	(1,229)	(1,355)	(1,476)	(1,233)	(1,204)	(1,047)	(1,362)	(14,622)
41															
42	Overhead Credit for Non-Retail Share		(2,602)	(2,282)	(2,433)	(2,199)	(2,312)	(2,544)	(2,805)	(3,055)	(2,551)	(2,492)	(2,166)	(2,818)	(30,258)
43	Non-Retail Load Share		96.481%	96.481%	96.481%	96.481%	96.481%	96.481%	96.481%	96.481%	96.481%	96.481%	96.481%	96.481%	
44	Non-Retail Overhead Credit		(2,510)	(2,202)	(2,347)	(2,121)	(2,230)	(2,455)	(2,706)	(2,948)	(2,461)	(2,404)	(2,090)	(2,719)	(29,194)
45															
46	<b>Total Revenue Credit for Jamestown - Ellendale</b>		(3,768)	(3,305)	(3,523)	(3,184)	(3,347)	(3,684)	(4,061)	(4,424)	(3,694)	(3,609)	(3,137)	(4,081)	(43,815)
47															
48															
49	<b>BSS Alexandria kV</b>	0.588%	(12,898)	(11,313)	(12,059)	(10,900)	(11,459)	(12,611)	(13,903)	(15,144)	(12,647)	(12,353)	(10,737)	(13,969)	(149,994)
50	Retail Load Share		7.755%	7.755%	7.755%	7.755%	7.755%	7.755%	7.755%	7.755%	7.755%	7.755%	7.755%	7.755%	
51	Retail Revenue		(1,000)	(877)	(935)	(845)	(889)	(978)	(1,078)	(1,174)	(981)	(958)	(833)	(1,083)	(11,632)
52															
53	Overhead Credit for Non-Retail Share		(939)	(824)	(878)	(794)	(834)	(918)	(1,012)	(1,103)	(921)	(899)	(782)	(1,017)	(10,921)
54	Non-Retail Load Share		92.245%	92.245%	92.245%	92.245%	92.245%	92.245%	92.245%	92.245%	92.245%	92.245%	92.245%	92.245%	
55	Non-Retail Overhead Credit		(866)	(760)	(810)	(732)	(770)	(847)	(934)	(1,017)	(849)	(830)	(721)	(938)	(10,074)
56															
57	<b>Total Revenue Credit for BSS Alexandria kV</b>		(1,866)	(1,637)	(1,745)	(1,577)	(1,658)	(1,825)	(2,012)	(2,192)	(1,830)	(1,788)	(1,554)	(2,022)	(21,706)
58															
59															
60	Retail Share of Schedule 26A Revenue		(313,436)	(274,918)	(293,058)	(264,888)	(278,478)	(306,476)	(337,861)	(368,027)	(307,340)	(300,200)	(260,932)	(339,468)	(3,645,081)
61															
62	<b>North Dakota share</b>	39.195%	(122,852)	(107,755)	(114,865)	(103,823)	(109,150)	(120,124)	(132,425)	(144,249)	(120,463)	(117,664)	(102,273)	(133,055)	(1,428,697)



MISO Multi-Value Auction Revenue Rights Distribution Revenues

Line No.		2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	
		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 MISO MVP ARR Revenue	(36,053)	(35,110)	(36,480)	(30,224)	(27,529)	(24,528)	(4,642)	(1,120)	(1,184)	(3,704)	(4,358)	(4,897)	(209,829)
2														
3	North Dakota Share 39.195%	(14,131)	(13,761)	(14,299)	(11,846)	(10,790)	(9,614)	(1,819)	(439)	(464)	(1,452)	(1,708)	(1,919)	(82,243)

Line No.		2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	2025	
		Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	Total Projected
1	Total MISO MVP ARR Revenue	(36,053)	(35,110)	(36,480)	(30,224)	(27,529)	(24,528)	(4,642)	(1,120)	(1,184)	(3,704)	(4,358)	(4,897)	(209,829)
2														
3	North Dakota Share 39.195%	(14,131)	(13,761)	(14,299)	(11,846)	(10,790)	(9,614)	(1,819)	(439)	(464)	(1,452)	(1,708)	(1,919)	(82,243)

Schedule 37 & Schedule 38 Revenues

Line No.			2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	
			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		(11,224)	(11,224)	(11,224)	(11,224)	(11,224)	(11,180)	(11,180)	0	0	0	0	0	(78,478)
2	Overhead Credit for Non-Retail Share	7.909%	(888)	(888)	(888)	(888)	(888)	(884)	(884)	0	0	0	0	0	(6,207)
3															
4															
5	<b>Fargo</b>	100.00%	(11,224)	(11,224)	(11,224)	(11,224)	(11,224)	(11,180)	(11,180)	0	0	0	0	0	(78,478)
6	Retail Load Share		75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	
7	Retail Revenue		(8,516)	(8,516)	(8,516)	(8,516)	(8,516)	(8,482)	(8,482)	0	0	0	0	0	(59,543)
8															
9	Overhead Credit for Non-Retail Share		(888)	(888)	(888)	(888)	(888)	(884)	(884)	0	0	0	0	0	(6,207)
10	Non-Retail Load Share		24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	
11	Non-Retail Overhead Credit		(214)	(214)	(214)	(214)	(214)	(213)	(213)	0	0	0	0	0	(1,498)
12															
13	<b>Total 37 Revenue Credit for Fargo</b>		(8,730)	(8,730)	(8,730)	(8,730)	(8,730)	(8,696)	(8,696)	0	0	0	0	0	(61,041)
14															
15															
16	<b>North Dakota Share</b>	39.195%	(3,422)	(3,422)	(3,422)	(3,422)	(3,422)	(3,408)	(3,408)	0	0	0	0	0	(23,925)
17															
18															
19	Total Schedule 38 Revenue		(13,144)	(13,144)	(13,144)	(13,144)	(13,144)	(13,351)	(13,351)	0	0	0	0	0	(92,424)
20	Overhead Credit for Non-Retail Share	7.909%	(1,040)	(1,040)	(1,040)	(1,040)	(1,040)	(1,056)	(1,056)	0	0	0	0	0	(7,310)
21															
22															
23	<b>Fargo</b>	100.00%	(13,144)	(13,144)	(13,144)	(13,144)	(13,144)	(13,351)	(13,351)	0	0	0	0	0	(92,424)
24	Retail Load Share		75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	75.87%	
25	Retail Revenue		(9,973)	(9,973)	(9,973)	(9,973)	(9,973)	(10,130)	(10,130)	0	0	0	0	0	(70,124)
26															
27	Overhead Credit for Non-Retail Share		(1,040)	(1,040)	(1,040)	(1,040)	(1,040)	(1,056)	(1,056)	0	0	0	0	0	(7,310)
28	Non-Retail Load Share		24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	24.13%	
29	Non-Retail Overhead Credit		(251)	(251)	(251)	(251)	(251)	(255)	(255)	0	0	0	0	0	(1,764)
30															
31	<b>Total 38 Revenue Credit for Fargo</b>		(10,224)	(10,224)	(10,224)	(10,224)	(10,224)	(10,385)	(10,385)	0	0	0	0	0	(71,888)
32															
33															
34	<b>North Dakota Share</b>	39.195%	(4,007)	(4,007)	(4,007)	(4,007)	(4,007)	(4,070)	(4,070)	0	0	0	0	0	(28,177)



**Federal ADIT Proration**

		<b>January 2025- December 2025 Recovery Period</b>		
<b>Line No.</b>	<b>Month</b>	<b>All Projects' Revenue Requirements without ADIT Prorated</b>	<b>All Projects' Revenue Requirements with ADIT-Prorated</b>	<b>Difference due to Federal ADIT Proration (B - A)</b>
1	Jan-25	\$174,711	\$174,902	\$191
2	Feb-25	\$174,711	\$174,902	\$191
3	Mar-25	\$174,711	\$174,902	\$191
4	Apr-25	\$174,711	\$174,902	\$191
5	May-25	\$174,791	\$174,982	\$191
6	Jun-25	\$174,853	\$175,044	\$191
7	Jul-25	\$174,853	\$175,044	\$191
8	Aug-25	\$174,853	\$175,044	\$191
9	Sep-25	\$174,853	\$175,044	\$191
10	Oct-25	\$174,853	\$175,044	\$191
11	Nov-23	\$175,013	\$175,204	\$191
12	Dec-25	\$175,435	\$175,626	\$191
13		\$2,098,349	\$2,100,641	\$2,292
<b>Revenue Requirement Adjustment Related to Federal ADIT Proration</b>				<b>\$2,292</b>

**Federal ADIT Proration**

January 2024 - December 2024				
Line No.	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)
1	Dec-23	(45,469)	(39,591)	\$5,878
2	Jan-24	(51,981)	(52,155)	
3	Feb-24	(57,948)	(66,289)	
4	Mar-24	(63,312)	(79,732)	
5	Apr-24	(68,092)	(94,308)	
6	May-24	(72,270)	(108,183)	
7	Jun-24	(75,864)	(121,682)	
8	Jul-24	(78,855)	(134,791)	
9	Aug-24	(81,244)	(149,844)	
10	Sep-24	(83,050)	(163,913)	
11	Oct-24	(84,253)	(177,560)	
12	Nov-24	(84,875)	(190,639)	
13	Dec-24	(85,221)	(194,170)	-\$108,949
14	Simple Average	(\$65,345)	(\$116,880)	-\$51,536
15				
16		Tax Conversion Factor	1.3228	
17		Gross Up of Equity %	6.91%	
18		Equity Return %	5.23%	
19		Gross Up Factor	1.69%	
20				
21				
22			<b>Annual</b>	<b>Monthly</b>
23		Debt Return %	2.18%	0.18%
24		Preferred Equity %	0.00%	0.00%
25		Equity Return %	5.23%	0.44%
26		Rate of Return	7.41%	0.62%
27		Tax RR on Equity Return	1.69%	0.14%
28		Rate Base Rev Req Gross Up Factor	9.09%	0.76%
29				
30		Company ADIT Proration Preservation Revenue Requirement		<b>-\$4,686</b>
31		Total ADIT Proration Preservation Revenue Requirement		<b>-\$1,837</b>













Line No.	Year>>	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
<b>RATE BASE</b>														
1	Plant Balance	0	0	0	1,798,207	1,808,885	1,835,196	1,803,494	1,835,196	1,835,196	1,835,196	1,835,196	1,835,196	1,835,196
2	Accumulated Depreciation	0	0	0	0	(2,300)	(4,614)	(6,962)	(9,269)	(11,617)	(13,965)	(16,312)	(18,660)	(18,660)
3	Net Plant in Service	0	0	0	1,798,207	1,806,585	1,830,582	1,796,532	1,825,927	1,823,579	1,821,232	1,818,884	1,816,536	1,816,536
<b>CWIP Calculation:</b>														
5	Beginning Balance	1,717,522	1,751,629	1,775,644	1,789,855	0	0	0	0	0	0	0	0	0
6	Additional CWIP	34,107	24,015	14,211	8,353	10,678	26,311	(31,702)	31,702	0	0	0	0	117,674
7	Closings from CWIP				(1,798,207)	(10,678)	(26,311)	31,702	(31,702)	0	0	0	0	0
8	AFUDC													
9	CWIP	1,751,629	1,775,644	1,789,855	0	0	0	0	0	0	0	0	0	0
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	1.0000
11	Accumulated Deferred Income Tax-Federal Only	0	0	0	(2,049)	(3,635)	(5,219)	(6,796)	(8,381)	(9,958)	(11,535)	(13,112)	(14,689)	(14,689)
12	Accumulated Deferred Income Taxes Federal & State	0	0	0	(2,488)	(4,415)	(6,338)	(8,254)	(10,179)	(12,094)	(14,009)	(15,925)	(17,840)	(17,840)
13	Ending rate base	1,751,629	1,775,644	1,789,855	1,795,719	1,802,170	1,824,243	1,788,279	1,815,748	1,811,485	1,807,222	1,802,959	1,798,696	1,798,696
14														
15	Average rate base	149,238	149,238	149,238	149,238	149,238	149,238	149,238	149,238	149,238	149,238	149,238	149,238	1,790,859
16														
17	Return on Rate Base	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	132,617
18														
19	Available for return (equity portion of rate base)	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	93,600
20														
<b>EXPENSES</b>														
<i>O&amp;M and Depreciation</i>														
23	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Property Tax	966	966	966	966	966	966	966	966	966	966	966	966	11,590
25	Book Depreciation	0	0	0	0	2,300	2,314	2,348	2,307	2,348	2,348	2,348	2,348	18,660
26	Total O&M and Depreciation Expense	966	966	966	966	3,266	3,280	3,314	3,273	3,314	3,314	3,314	3,314	30,250
27														
28	Income before Taxes													
29	Available for return (from above)	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	93,600
30	Taxable Income (grossed up)	10,318	10,318	10,318	10,318	10,318	10,318	10,318	10,318	10,318	10,318	10,318	10,318	123,817
31														
32	Income Taxes													
33	Current and Def Income Taxes	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	30,217
34	Total Income Tax Expense	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	2,518	30,217
35														
36														
<b>REVENUE REQUIRMENTS</b>														
38	Expenses	3,484	3,484	3,484	3,484	5,784	5,798	5,832	5,791	5,832	5,832	5,832	5,832	60,467
39	Return on rate base	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	11,051	132,617
40	Subtotal revenue requirements	14,535	14,535	14,535	14,535	16,836	16,849	16,883	16,843	16,883	16,883	16,883	16,883	193,085
41	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Wholesale Revenue Credit	(1,435)	(1,435)	(1,435)	(1,435)	(1,663)	(1,664)	(1,667)	(1,663)	(1,667)	(1,667)	(1,667)	(1,667)	(19,067)
43	Total revenue requirements	13,100	13,100	13,100	13,100	15,173	15,186	15,216	15,179	15,216	15,216	15,216	15,216	174,017
44														
45	North Dakota share - D2 factor	5,135	5,135	5,135	5,135	5,947	5,952	5,964	5,950	5,964	5,964	5,964	5,964	68,206











2023 Transmission Extenda-Life Program

Line No.	Year>>	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024
		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
<b>RATE BASE</b>														
1	Plant Balance	0	0	0	0	0	0	0	0	185,414	185,414	185,414	185,414	185,414
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(252)	(504)	(504)	(504)
3	Net Plant in Service	0	0	0	0	0	0	0	0	185,414	185,162	184,910	184,910	184,910
<b>CWIP Calculation:</b>														
5	Beginning Balance	0	0	0	121,666	123,303	131,522	231,445	240,241	371,608	445,383	333,744	387,519	387,519
6	Additional CWIP	0	0	121,666	1,637	8,219	99,923	8,796	131,367	73,775	73,775	53,775	0	577,258
7	Closings from CWIP	0	0	0	0	0	0	0	0	0	(185,414)	0	0	0
8	AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
9	CWIP	0	0	121,666	123,303	131,522	231,445	240,241	371,608	445,383	333,744	387,519	387,519	387,519
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	1.0000
11	Accumulated Defered Income Tax-Federal Only	0	0	0	0	0	0	0	0	0	(621)	(1,191)	(1,762)	(1,762)
12	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	(754)	(1,447)	(2,139)	(2,139)
13	Ending rate base	0	0	121,666	123,303	131,522	231,445	240,241	371,608	445,383	518,404	571,234	570,289	570,289
14	Average rate base	21,315	21,315	21,315	21,315	21,315	21,315	21,315	21,315	21,315	21,315	21,315	21,315	255,777
16	Return on Rate Base	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	18,941
18	Available for return (equity portion of rate base)	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	13,368
<b>EXPENSES</b>														
<i>O&amp;M and Depreciation</i>														
23	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Book Depreciation	0	0	0	0	0	0	0	0	0	0	252	252	504
26	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	252	252	504
28	Income before Taxes													
29	Available for return (from above)	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	13,368
30	Taxable Income (grossed up)	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	1,474	17,684
32	Income Taxes													
33	Current and Def Income Taxes	360	360	360	360	360	360	360	360	360	360	360	360	4,316
34	Total Income Tax Expense	360	360	360	360	360	360	360	360	360	360	360	360	4,316
<b>REVENUE REQUIRMENTS</b>														
38	Expenses	360	360	360	360	360	360	360	360	360	612	612	612	4,820
39	Return on rate base	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	1,578	18,941
40	Subtotal revenue requirements	1,938	1,938	1,938	1,938	1,938	1,938	1,938	1,938	1,938	1,938	2,190	2,190	23,761
41	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Wholesale Revenue Credit	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(216)	(216)	(2,346)
43	Total revenue requirements	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,747	1,974	1,974	1,974	21,415
44	North Dakota share - D2 factor	685	685	685	685	685	685	685	685	685	685	774	774	8,393

2023 Transmission Extenda-Life Program

Line No.	Year>>	2025 Projected Jan	2025 Projected Feb	2025 Projected Mar	2025 Projected Apr	2025 Projected May	2025 Projected Jun	2025 Projected Jul	2025 Projected Aug	2025 Projected Sep	2025 Projected Oct	2025 Projected Nov	2025 Projected Dec	2025 Projected Total
<b>RATE BASE</b>														
1	Plant Balance	185,414	185,414	185,414	185,414	185,414	185,414	185,414	185,414	185,414	485,414	1,277,258	1,277,258	1,277,258
2	Accumulated Depreciation	(757)	(1,009)	(1,261)	(1,513)	(1,765)	(2,018)	(2,270)	(2,522)	(2,774)	(3,027)	(3,287)	(3,542)	(5,424)
3	Net Plant in Service	184,658	184,405	184,153	183,901	183,649	183,397	183,144	182,892	182,640	482,388	1,273,571	1,271,833	1,271,833
<b>CWIP Calculation:</b>														
5	Beginning Balance	387,519	453,883	520,246	586,610	652,973	719,337	785,701	852,064	918,428	984,792	751,155	(4,325)	
6	Additional CWIP	66,364	66,364	66,364	66,364	66,364	66,364	66,364	66,364	66,364	66,364	36,364	0	700,000
7	Closings from CWIP	0	0	0	0	0	0	0	0	0	(300,000)	(791,843)	0	0
8	AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0
9	CWIP	453,883	520,246	586,610	652,973	719,337	785,701	852,064	918,428	984,792	751,155	(4,325)	(4,325)	(4,325)
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 Defered Income Tax-Federal Only	(1,986)	(2,191)	(2,376)	(2,541)	(2,685)	(2,808)	(2,911)	(2,994)	(3,056)	(3,268)	(3,719)	(3,733)	(3,733)
12	Accumulated Deferred Income Taxes Federal & State	(2,416)	(2,674)	(2,911)	(3,128)	(3,324)	(3,501)	(3,656)	(3,791)	(3,905)	(4,385)	(5,940)	(7,011)	(7,011)
13	Ending rate base	636,124	701,978	767,852	833,746	899,662	965,597	1,031,553	1,097,529	1,163,526	1,229,158	1,263,306	1,260,498	1,260,498
14														
15	Average rate base	79,621	79,621	79,621	79,621	79,621	79,621	79,621	79,621	79,621	79,621	79,621	79,621	955,448
16														
17	Return on Rate Base	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	70,753
18														
19	Available for return (equity portion of rate base)	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	49,937
20														
<b>EXPENSES</b>														
<i>O&amp;M and Depreciation</i>														
23	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Property Tax	214	214	214	214	214	214	214	214	214	214	214	214	2,565
25	Book Depreciation	252	252	252	252	252	252	252	252	252	252	660	1,737	4,920
26	Total O&M and Depreciation Expense	466	466	466	466	466	466	466	466	466	466	874	1,951	7,485
27														
28	Income before Taxes													
29	Available for return (from above)	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	4,161	49,937
30	Taxable Income (grossed up)	5,505	5,505	5,505	5,505	5,505	5,505	5,505	5,505	5,505	5,505	5,505	5,505	66,058
31														
32	Income Taxes													
33	Current and Def Income Taxes	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	16,121
34	Total Income Tax Expense	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	1,343	16,121
35														
36														
<b>REVENUE REQUIRMENTS</b>														
38	Expenses	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	1,809	2,217	3,295	23,606
39	Return on rate base	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	5,896	70,753
40	Subtotal revenue requirements	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706	8,114	9,191	94,359
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	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706	7,706	8,114	9,191	94,359
44														
45	North Dakota share - D2 factor	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,020	3,180	3,602	36,984

































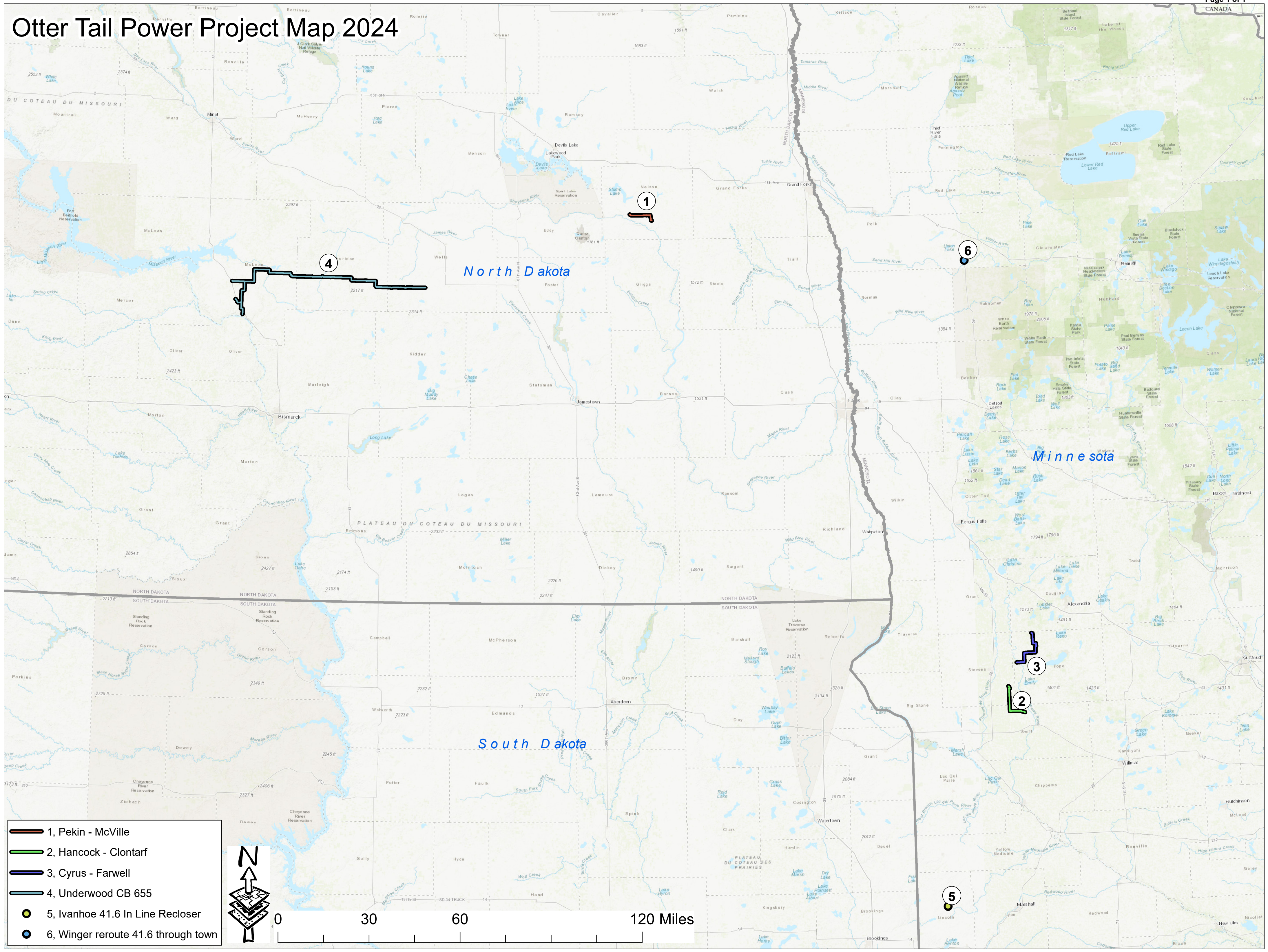










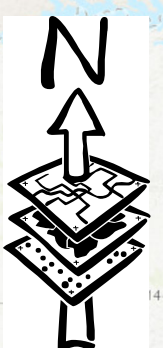




# Otter Tail Power Project Map 2024



-  1, Pekin - McVille
-  2, Hancock - Clontarf
-  3, Cyrus - Farwell
-  4, Underwood CB 655
-  5, Ivanhoe 41.6 In Line Recloser
-  6, Winger reroute 41.6 through town



**Attachment 34**  
**Legislative and Non-Legislative Versions of**  
**Electric Rate Schedule Section 13.05**  
**ND Transmission Cost Recovery Rider**

**TRANSMISSION COST RECOVERY RIDER**

<b>DESCRIPTION</b>	<b>RATE CODE</b>
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.

**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:**

<b>TRANSMISSION COST RECOVERY</b>			
<b>Energy Charge per kWh:</b>		<b>kWh</b>	<b>kW</b>
<b>Large General Service (a)</b>		N/A <del>¢/kWh</del>	<del>\$0.7114</del> <sup>095</sup>
<b>Controlled Service (b)</b>		<del>\$0.0051</del> <del>¢/kWh</del>	N/A
<b>Lighting (c)</b>		<del>\$0.00120334</del> <del>¢/kWh</del>	N/A
<b>All Other Service</b>		<del>\$0.00240336</del> <del>¢/kWh</del>	N/A

(a) Rate schedules 10.04 Large General Service, 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 Rate 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) and 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting.

**TRANSMISSION COST RECOVERY RIDER**

<b>DESCRIPTION</b>	<b>RATE CODE</b>
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.

**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:**

<b>TRANSMISSION COST RECOVERY</b>		
<b>Energy Charge per kWh:</b>	kWh	kW
<b>Large General Service (a)</b>	N/A	\$0.711
<b>Controlled Service (b)</b>	\$0.00	N/A
<b>Lighting (c)</b>	\$0.00120	N/A
<b>All Other Service</b>	\$0.00240	N/A
(a) Rate schedules 10.04 Large General Service, 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 Rate 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) and 11.04 Outdoor Lighting, and 11.07 LED Street and Area Lighting.		

CR  
CR  
CR  
CR

**Case No. PU-24-**

**Customer Notices**

**Attachment 35 – ND TCR Proposed Bill Message**

**Attachment 36 – ND TCR Implementation Bill Insert**

**On September 16, 2024, 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, 2025. This change is proposed only, and if suspended by the Commission, new rates wouldn't take effect until the Commission approves them.**

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

- **Large General Service: -\$154.43 (from \$1.095 to \$0.711 per kW)**
- **Controlled Service: -\$0.82 (from \$0.00051 to \$0.00 per kWh)**
- **Lighting: -\$0.10 (from \$0.00331 to \$0.00120 per kWh)**
- **Residential and all other service: -\$1.25 (from \$0.00336 to \$0.00240 per kWh)**

For more information, contact us at 800-257-4044 or visit [otpc.com](http://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, 2025, and are on the Transmission Rider line of your bill.

	<u>Old rates</u>		<u>New rates</u>		<u>Impact of new rates<sup>(1)</sup></u>
Large General Service	\$1.095	per kW	\$0.711	per kW	-\$163.20/month
Controlled Service	\$0.00051	per kWh	\$0.00000	per kWh	-\$0.66/month
Lighting	\$0.00331	per kWh	\$0.00120	per kWh	-\$0.19/month
Residential	\$0.00336	per kWh	\$0.00240	per kWh	-\$0.96/month
All other service	\$0.00336	per kWh	\$0.00240	per kWh	-\$1.30/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](http://otpc.com).