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September 15, 2023

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-23-**

Dear Mr. Kahl:

Enclosed please find an original and 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. If you have any questions regarding this filing, please contact me at 218-739-8406 or jsillerud@otpc.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-23-
APPLICATION**

I. EXECUTIVE SUMMARY

This filing for 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 50 previously approved projects; regional transmission expenses and revenues recovered in the TCRR; the addition of three new transmission projects, two of which have additional facilities associated with them, three transmission rebuild projects, four Extenda-Life projects, one project budget update, and one cancelation of a project.

The new projects are listed below along with the updated budget and cancelation.

New Transmission Projects:

- Milbank Area Reliability Project
- Jamestown – Ellendale 345kV Project consisting of the following facilities:
 - Jamestown to Ellendale 345 kV line
 - Jamestown Substation Addition
 - Maple River Substation Addition
 - Twin Brooks Reactor Addition
- Big Stone South – Alexandria – Big Oakes 345kV Project consisting of the following facilities:
 - Big Stone South Substation Addition (construction for this facility to begin in 2027)
 - Big Stone South to Alexandria 345 kV line
 - Alexandria to Big Oakes Double Circuit 345 kV line

Transmission Rebuild Program:

- Wahpeton-Fairmount 115kV Rebuild
- Marvin-Corona Area 41.6kV Rebuild/EL
- Buffalo 41.6kV Rebuild/EL

Transmission Extenda-Life Program:

- DL- New Rockford Extenda-Life
- Kensal-Bordulac 41.6kV Extenda-Life
- Donaldson CB-215 Re-Conductor
- Canby – 495 Line Extenda-Life

Project Budget Update:

- Oslo 115 kV Breaker Station and Oslo – Lake Ardoch 115 kV Line

Canceled Project:

- Reconductor 41.6kV Line by Milbank has been canceled. Due to the Milbank Area Reliability Project, this reconductor project is no longer needed.

Otter Tail proposes a rate implementation date of January 1, 2024.

The North Dakota projected revenue requirement for the recovery period of January 1, 2024, to December 31, 2024, is \$8,693,198, with residential customers using 1,000 kWh seeing a monthly bill increase of approximately \$0.76.

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’s TCRR rates are updated to reflect the TCRR revenue requirements for the next recovery period (calendar year 2024). 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). This update includes: (1) the addition of 16 transmission projects not currently in base rates and not previously included in the Rider; (2) the cancelation of one project; (3) forecast update to a previously approved project; and (4) details of Southwest Power Pool (SPP) related expenses.

The net revenue requirement for 2024, upon which rates are developed, is \$8,693,198. For a residential customer using 1,000 kWh per month, the bill impact of this update is an increase of \$0.76 per month. For a large general service customer with 425 kW of demand, the bill impact of this update is an increase of \$120.28 per month.

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

Cary Stephenson
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone (218) 739-8956

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

Paula Foster
Supervisor, Regulatory Analysis, Regulatory Economics
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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

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

The date of this filing is September 15, 2023. The updated TCRR rate is calculated to take effect as of January 1, 2024.

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

Articles of Incorporation. A certified copy of Otter Tail's Articles of Incorporation is on file with the Commission, as is an original Certificate of Good Standing.

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 most recent annual update, 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. TCRR rate update revenue requirement calculations

Attachments 1-4 are, respectively, the Projected Revenue for 2024, Summary of Revenue Requirements, Class Allocation and Rate Design, and Tracker Summary calculations used for Otter Tail's proposed TCRR rate update.

Attachments 15-49 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 15-40) and the updated and new projects for which Otter Tail is requesting TCRR recovery (Attachments 41-49).

Specifically, the calculations include the following:

- *Rate base section.* This section provides details on the amount of plant in service, accumulated depreciation, construction work in progress (CWIP) (if applicable), accumulated deferred taxes including the effect of proration on Federal amounts, and a 13-month average rate base calculation.
- *Expense section.* The expenses applicable to a project are listed here and include operating costs, property taxes, depreciation, and income taxes.
- *Revenue requirements section.* This section shows the components of the revenue requirements, including expenses and return on investment, and any credits to the revenue requirement for monies received for use of Otter Tail facilities by wholesale customers.
- *Return on investment (cost of capital).* Otter Tail uses the cost of capital agreed upon by the parties in the Settlement Agreement approved by the Commission¹ in Otter Tail's last general rate case.
- *Depreciation expense.* Depreciation expense is calculated 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.

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

- *Operation and maintenance (O&M) expense.* Annual O&M expense of transmission lines includes 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). Unscheduled patrols are completed 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.

- *Proration of Accumulated Deferred Income Taxes (ADIT).* Otter Tail provides Attachment 13 to this filing to show the ADIT proration calculation impact on the revenue requirement for the recovery period.

Otter Tail provides Attachment 14 calculating 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.² Attachment 14 shows the preservation of the proration of ADIT resulted in a decrease of \$77,984 plus any applicable carrying charge to the revenue requirement. This item is included on line No. 37 of Attachment 4 to this filing.

- *Midcontinent Independent System Operator (MISO) Schedule 26 and 26A expenses.* Schedule 26 and Schedule 26A costs for the recovery period appear on Lines 40 and 41 of the Tracker Summary (Attachment 4) and are shown separately in Attachment 8 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 (Attachment 6) and MISO Related Revenues (Attachment 7).* SPP Schedules 7, 8, and 9 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 local area. SPP Schedule 9 expenses appear on Line 42 and SPP Schedule 11 expenses on Line 43 of the Tracker Summary (Attachment 4). Both are shown separately in Attachment 6.

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

Otter Tail also receives MISO Schedule 9 revenues related to Central Power Electric Cooperative (CPEC) paying MISO charges for transmission service they receive through MISO. These revenues are offset by facility credits CPEC is collecting in 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 when applied against Otter Tail's SPP expenses.

MISO Schedule 9 revenue from CPEC appears on Line 47 of the Tracker Summary (Attachment 4) and is shown in detail in Attachment 7.

- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 48 and 51 of the Tracker Summary (Attachment 4) and are shown separately on Attachment 9 (Schedule 26) and Attachment 10 (Schedule 26A). 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 how MISO Schedule 26A expenses are allocated to MISO market participants for all MVP projects. The revenue is identified in Attachment 11 and is reflected as a credit in the Tracker Summary (Attachment 4, line 52).
- *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 Attachment 9 and Attachment 10 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 12, there are no forecast amounts for Schedule 37 and 38 revenues for the 2024 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 2023 is \$22,862, as can be seen in Attachment 4 on line 49. The Schedule 38 revenue credit reflected in this TCRR update for 2023 is \$27,409, as seen in Attachment 4 on line 50. These are actual amounts through July 2023 and are included as part of the 2023 true-up amount.

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

Twenty-six projects and programs previously approved for inclusion in Otter Tail's TCRR are included in this update. Table 1 reflects the prior approved projects and the case number in which they were approved for TCRR recovery.

The retail allocation of costs and revenues for these projects are updated and carried out through 2023 and 2024 and reflected in Attachments 15-40.

Table 1

	Project	Case Number	Attachment
1	BSAT-Ellendale MVP	PU-12-702	15
2	Max-Ryder 41.6 kV Line Upgrade	PU-16-624	16
3	Bagley 115 kV Switch Station	PU-17-340	17
4	Lake Norden Area Transmission	PU-18-329	18
5	Donaldson 115 kV Cap Bank	PU-19-311	19
6	Northwest MN UVLS	PU-19-311	20
7	Blair 230 kV Substation	PU-19-311	21
8	Veblen 41.6 kV Cap Bank	PU-19-311	22
9	New Effington 230/41.6 kV Line	PU-19-311	23
10	Jamestown Substation	PU-19-311	24
11	CPEC Purchase	PU-19-311	25
12	Erie 230/115kV Substation	PU-20-383	26
13	Norcross 115kV Line-115/41.6kV Sub	PU-20-383	27
14	Winger 230/115kV Transformer	PU-20-383	28
15	Jamestown 41.6 kV Source	PU-20-383	29
16	Hoot Lake Capacitor	PU-20-383	30
17	Finley/McVile 41.6 kV Rebuild	PU-20-383	31
18	Turtle Lake/Mercer 41.6 kV Rebuild	PU-20-383	32
19	Doyon/Bartlett 41.6 kV Rebuild	PU-20-383	33
20	Hoot Lake Transformer	PU-21-376	34
21	2021 Transmission Rebuild Projects	PU-21-376	35
22	2021 Transmission Extenda-Life Projects	PU-21-376	36
23	Oslo 115kV 5-Breaker Bus and Lake A	PU-22-335	37
24	Casselton 115 kV Capacitor Bank	PU-22-335	38
25	Cooperstown – Binford 41.6 kV Rebuild	PU-22-335	39
26	2022 Transmission Extenda-Life Projects	PU-22-335	40

Project Budget Update

Oslo 115 kV Breaker Station and Oslo – Lake Ardoch 115 kV Line

This project was approved last year in Case No. PU 22-335 at an estimated cost of \$6.6 million (OTP Total) / \$2.6 million (OTP ND). To calculate this estimate, Otter Tail compared similar projects that have been completed in the past and used a cost per mile estimate for the line portion of this project, with an escalator to attempt to account for inflation. Due to an unforeseen series of events, this estimate is no longer feasible. The updated estimate is now \$11.9 million (OTP Total) / \$4.7 million (OTP ND). This increase in the estimated completed costs can be attributed to the factors listed below:

1. Site grading expenses were much higher than previously estimated;
 - a) The topsoil that needed to be removed was found to be twice the depth than originally assumed after geotechnical exploration was performed.
 - b) Walsh County requires the substation final finish grade to be greater than the known floodplain elevation. As a result, seven feet of fill needed to be brought in to raise it above the existing elevation: the initial estimate only included two feet of fill.
2. The original estimate assumed 11 acres were to be purchased with a land value estimated to be close to \$5,000-\$6,000 per acre. This increased to a price of \$15,000 per acre due to commercial use.
3. Original cost estimates were from June 2021. Materials and contractor pricing has escalated by at least 20 percent each year due to supply and demand issues and factory production availability.
4. Easement costs for pole/line placement have increased.
5. Due to the poor soil conditions that were discovered, 11 concrete foundations and self-supporting steel structures are now required, as opposed to the wood poles in the original estimate.

Canceled Project
Reconductor 41.6kv Line by Milbank

The Milbank Area Reliability Project described above will upgrade the existing 41.6 kV system in the Milbank, SD to 115 kV and as such, this conductor upgrade is no longer needed and has been removed. Work had not begun on this project, and no costs have been incurred; therefore, no revenue requirement has been collected from customers.

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 three new transmission projects, two of which have additional facilities associated with them, three transmission rebuild projects, and four Extenda-Life projects in this TCRR update, which are described in detail below. Otter Tail verified that the costs requested for recovery in the TCRR for each of these new projects were not included in its last

general rate review, Case No. PU-17-398, and that no portion of these projects are currently being recovered as a result of that proceeding.

Milbank Area Reliability Project – Attachment 43

Otter Tail's 41.6 kV transmission system between the high voltage sources at Highway 12 (south of Big Stone City, SD), and Ortonville, MN has been experiencing load growth. A production facility in the Milbank, SD area is expanding and adding a significant amount of load onto the 41.6 kV transmission system. Planning studies performed in this area show that the increased load and projected future load increases will cause the existing 41.6 kV system to no longer be capable of maintaining voltage criteria. A loss of the Highway 12 115 kV source causes voltages on the 41.6 kV transmission system in the Milbank, SD area to drop below voltage criteria.

To address these reliability concerns, Otter Tail will construct a new 115 kV transmission loop from the Big Stone Plant 230/115 kV substation to a new 115/12.5 kV substation in Milbank, SD, and a new 115 kV breaker station to be located on the 115 kV line between the Big Stone 230/115 kV substation and the Marietta 115/4.6 kV substation. This project will consist of the following components:

1. Expansion of the Big Stone Plant 230/115 kV substation;
2. Construction of a new approximately 14-mile 115 kV line from Big Stone Plant 230/115 kV substation to a new 115/12.5 kV substation in Milbank, SD;
3. A new 115/12.5 kV substation in Milbank, SD to serve load and offload the existing 41.6 kV transmission system in the area;
4. Construction of a new approximately 18-mile 115 kV line from the new 115/12.5 kV substation in Milbank, SD to a new 115 kV breaker station on the 115 kV line between the Big Stone Plant 230/115 kV substation and the Marietta 115/41.6 kV substation; and
5. A new 115 kV breaker station that will be located on the 115 kV line between the Big Stone Plant 230/115 kV substation and the Marietta 115/41.6 kV substation.

Otter Tail coordinated this project with MISO through the Expedited Project Review process.³ MISO gave approval of the project and recommended its inclusion

³ See MISO's Business Practice Manual BPM 020 revision 29 Section 4.1.4 for information on the Expedited Project Review process located here: [Business Practices Manuals \(misoenergy.org\)](https://www.misoenergy.org/Business-Practices-Manuals).

in Appendix A in the 2023 MISO Transmission Expansion Plan (MTEP) at the May 31, 2023 MISO Planning Advisory Committee meeting.⁴

After obtaining project approval at the MISO Planning Advisory Committee meeting, Otter Tail encountered challenges with routing the new 115 kV line. Due to these challenges, Otter Tail determined it was necessary to leverage the existing 41.6 kV right of way to route the new 115 kV line. This plan will entail removing the existing 41.6 kV system around Milbank, SD and converting the line feeding the town of Milbank to the new 115 kV system with the routing of the new 115 kV line. This will further offload the remaining 41.6 kV system and avoid routing challenges encountered in the area. Due to these recent modifications, Otter Tail has resubmitted an Expedited Project Review request with MISO and expects to receive approval in October 2023.

The total transmission cost of the project is estimated to be \$36.2 million (OTP Total)/\$14.3 million (OTP ND). Construction is underway with a plan to have the full project energized in late 2026.

Long-Range Transmission Plan Projects

In response to the resource transformation, MISO initiated a multi-year Long Range Transmission Planning (LRTP) effort in 2020 to identify the transmission investments needed to enable the reliable delivery of energy across the region. MISO anticipates this to be a multi-portfolio effort broken into four tranches. In July 2022, MISO approved 18 transmission projects as part of the Tranche 1 portfolio of the LRTP within the MISO MTEP21 process.⁵

Otter Tail will be part owner in two of the 18 Tranche 1 projects: the Jamestown – Ellendale 345 kV Project and the Big Stone South – Alexandria – Big Oaks 345 kV Project. Details regarding these two projects are provided below.

Jamestown – Ellendale 345 kV Project – Attachments 46-49

As part of the LRTP Tranche 1 portfolio, Otter Tail and Montana Dakota Utilities (MDU) will be constructing a new approximately 95-mile, 345 kV line that will span between Otter Tail’s Jamestown, ND 345 kV substation and MDU’s Ellendale, ND 345 kV substation. Otter Tail will be expanding its solely owned Jamestown, ND 345 kV substation to allow for the new line. MDU will be expanding its solely owned Ellendale, ND 345 kV substation to allow for the new line

⁴ See the Milbank Area Reliability Project Expedited Project Review process MISO approval and recommendation for Appendix A of MTEP23 here: [20230531 PAC Item 04a Expedited Project Reviews629022.pdf \(misoenergy.org\)](#).

⁵ See MTEP21 LRTP Tranche 1 Portfolio [Previous MTEP Reports \(misoenergy.org\)](#).

termination. Otter Tail will own 50 percent of the new 345 kV line with MDU owning the remaining 50 percent of the line.

To reliably integrate the new Jamestown to Ellendale 345 kV line into the transmission system, additional system upgrades are necessary. The integration of the new 345 kV line will cause transmission system voltages to exceed voltage criteria in the Big Stone, SD and Ellendale, ND area. To mitigate these high voltage concerns, a reactor must be installed at the Otter Tail and MDU owned Twin Brooks 345 kV breaker station. This reactor addition will be owned 50 percent by Otter Tail and the remaining 50 percent will be owned by MDU.

In addition, the integration of the new 345 kV line will cause the loading to exceed its criteria on both Otter Tail owned 345/230 kV transformers at its Maple River 345/230 kV substation. Due to this, the substation will be expanded, and the existing transformers will be replaced with larger transformers. Otter Tail will own 100 percent of these new 345/230 kV transformers and the substation expansion.

The Jamestown – Ellendale 345 kV project will consist of the facilities listed below. Otter Tail will solely own or have partial ownership in facilities 1, 3, 4, and 5.

1. An expansion of the Otter Tail owned Jamestown 345 kV substation (refer to Attachment 48);
2. An expansion of the MDU owned Ellendale 345 kV substation;
3. The construction of a new approximately 95-mile 345 kV line between Otter Tail's Jamestown 345 kV substation and MDU's Ellendale 345 kV substation (refer to Attachment 46);
4. An expansion of the Twin Brooks 345 kV breaker station with an addition of a new 345 kV reactor (refer to Attachment 49);
5. An expansion of the Maple River 345 kV substation to accommodate the replacement of the existing 345/230 kV transformers with larger 345/230 kV transformers (refer to Attachment 47).

MISO approved this project as part of the MTEP21.⁶

The total transmission cost of the project at the time of approval was estimated to be \$438.7 million, with Otter Tail's portion of the project estimated at \$187.8 million. Because this project is shared by the full MISO footprint, the estimated portion of the project Otter Tail ratepayers are responsible for is about \$5.2 million (OTP Total)/\$2 million (OTP ND). This project is in the permitting phase and is expected to be completed late in 2028.

⁶ See Project LRTP-1 in Appendix A of MISO's 2021 Transmission Expansion Plan LRTP Tranche 1 Portfolio, available at: [Previous MTEP Reports \(misoenergy.org\)](https://www.misoenergy.org/previous-mtep-reports).

Big Stone South – Alexandria – Big Oakes 345 kV Project Attachments 44-45

As part of the LRTP Tranche 1 portfolio, Otter Tail, Great River Energy (GRE), Minnesota Power (MP), Missouri River Energy Services (MRES), and Xcel Energy (XEL) will be constructing and owning various portions of a 345 kV transmission line that will extend from the areas of Big Stone City, SD to Alexandria, MN and to Monticello, MN.

Otter Tail and MRES will be constructing a new approximately 128-mile 345 kV transmission line that will span between Otter Tail's Big Stone South 345 kV substation and MRES's Alexandria 345 kV substation. Otter Tail will be expanding its solely owned Big Stone South 345 kV substation to allow for the termination of the new line. MRES will be expanding its solely owned Alexandria 345 kV substation to allow for the termination of the new lines. Otter Tail will own 40 percent of the new transmission line from Big Stone South 345 kV substation to the Alexandria 345 kV substation, with MRES owning the remaining 60 percent of the transmission line.

Otter Tail, GRE, MP, MRES, and XEL as Grid North Partners constructed a 238-mile 345 kV line with double circuit capability from Fargo, ND to St. Cloud, MN to Monticello, MN.⁷ This was energized in 2015 with only one of the two circuits being strung and energized. As part of the LRTP Big Stone – Alexandria – Big Oakes 345 kV Project, a 108-mile portion of this existing Grid North Partners line from the Alexandria 345 kV substation to a point near Monticello, MN will have the second circuit strung, which will also be owned by Otter Tail, GRE, MP, MRES, and XEL. At the point the second circuit will stop near Monticello, MN, a new approximate 1.5-mile 345 kV line will be constructed to the new Big Oakes 345 kV breaker station. This new Big Oakes 345 kV breaker station will be owned by XEL.

The Big Stone South – Alexandria – Big Oakes 345 kV Project will consist of the facilities listed below. Otter Tail will solely own or have partial ownership in facilities 1, 2, and 4.

1. An expansion of the Otter Tail owned Big Stone South 345 kV substation; (Construction is anticipated to begin in 2027, so this facility is not included in the Attachments for this update);
2. The construction of a new approximately 128-mile 345 kV line between Otter Tail's Big Stone South 345 kV substation and MRES's Alexandria 345 kV substation (Attachment 44);
3. An expansion of the MRES owned Alexandria 345 kV substation;

⁷ See Grid North Projects [Projects - Grid North Partners](#).

4. The addition of the second 345 kV circuit on the existing Grid North Partners double circuit capable 345 kV line that extends from MRES's Alexandria 345 kV substation to a point near Monticello, MN (Attachment 45);
5. The construction of a new approximately 1.5-mile 345 kV line from a point near Monticello, MN to the new Big Oaks 345 kV breaker station;
6. The construction of a Big Oaks 345 kV breaker station.

MISO approved this project as part of the MTEP21.⁸

The total transmission cost of the project at the time of approval was estimated to be \$573.5 million with Otter Tail's portion of the project estimated at \$223.3 million. Because this project is shared by the full MISO footprint, Otter Tail's estimated portion of the project is about \$10 million (OTP Total)/\$4 million (OTP ND). This project is in the permitting phase and is expected to be completed 2030-2031.

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, refurbishing the line is considered. 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. Factors

⁸ See Project LRTP-2 in Appendix A of MISO's 2021 Transmission Expansion Plan LRTP Tranche 1 Portfolio, available at: [Previous MTEP Reports \(misoenergy.org\)](https://www.misoenergy.org/previous-mtep-reports).

that go into determining when a replacement is needed include 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. The ability to employ 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 41

As described above and listed in Table 3 below, Otter Tail has identified the following transmission projects to be included in the Transmission Rebuild Program within the SIRI initiative for the 2024 calendar year with a total estimated cost of \$8.87million (OTP Total) / \$3.51 million (OTP ND).

**Table 3
Transmission Line Rebuild Program – 2023 Additions**

Line Section	Voltage	State	Project Length (Miles)	Total Cost (\$MM)	ND Share (\$MM)	Projected In-Service Date
Wahpeton-Fairmount 115kV Rebuild	115 kV	ND	19	\$3.60	\$1.43	2026
Marvin-Corona Area 41.6kV Rebuild/EL	41.6 kV	SD	6 / 7	\$1.50	\$.59	2024
Buffalo 41.6 kV Rebuild/EL	41.6 kV	ND	13.8/15.2	\$3.77	\$1.49	2027

Wahpeton – Fairmount 115 kV line Rebuild

The Wahpeton to Fairmount 115 kV line is about 25 miles long with 19 of those miles in need of a complete structure replacement, other than the conductor,

which will remain. The line provides service to the communities of Tyler, Fairmount, White Rock, Wheaton, and Dumont. This line has been a top five worst performing 115 kV line on the Otter Tail system over the past few years.

This line was originally constructed in the 1960s and at 41.6 kV. The line has since been reframed to 115 kV on the original poles, which are largely 45-foot class 5 poles with porcelain insulators. These poles are considered “light” for new 115 kV construction. This project will replace all old poles with a minimum of 50-foot class 3 poles. Of the total 25 miles, about six miles have been previously converted from original build to updated build, which includes vertical framing with static, and taller, heavier poles. This line also contains galvanized grounds on the poles with some areas containing distribution underbuilds. This creates a corrosion concern and will be updated to include copper pole grounds in areas with distribution underbuilds. The current route is accessible, so a reroute is not required.

The cost of this project is estimated to be \$3.6 million (OTP Total) / \$1.4 million (OTP ND) and is scheduled to be completed by the end of 2026.

Marvin – Corona 41.6 kV line Rebuild and Extenda-Life

The Marvin – Corona 41.6 kV line is part of the larger Browns Valley Circuit Breaker 825 circuit. This was one of the worst performing 41.6 kV lines for Otter Tail in 2022. This section of line is about 13 miles long and serves communities of Browns Valley, Peever, Wilmot, Marvin, Corona, Summit, Beardsley, and Barry. The line was originally constructed in the 1950s and 1960s.

In addition to the overall condition and vintage concerns, there are six miles of 41.6 kV line with distribution underbuilds. These miles are constructed largely with 45-foot poles, which has created clearance and safety concerns with the distance between the 41.6 kV conductors and the distribution conductors. Due to the size of these poles, this section of line is to be replaced (existing conductor will remain) with taller poles to create more clearance between conductors. The remaining seven miles of the line will have Extenda-Life work performed, reusing as many of the assets on the line as possible.

This project is estimated to be \$1.5 million (OTP Total) / \$0.59 million (OTP ND) and be completed in 2024.

Buffalo 41.6 kV Rebuild and Extenda-Life

The Buffalo – Colgate 41.6 kV line was constructed in the 1950s and is around 30 miles long. This line serves the communities of Absaraka, Ayr, Erie, Nolan, Page, Galesburg, Colgate, and Clifford. This line was recently inspected and contained on average a 15 percent reject rate of poles that did not meet strength

tests. The typical reject rate is around three percent. Some sections of this line had approximately 50 percent rejects. These sections of line are not conducive to Extenda-Life and will be rebuilt. Accessibility has generally not been a concern on this line and as such, it will be rebuilt in place when a rebuild is required. Although performance has been adequate on this line over the past few years, the substantial number of strength test failures is a sign of future risk to reliability to these communities and needs to be addressed.

This project is estimated to cost \$3.77 million (OTP Total) / \$1.49 million (OTP ND) and is expected to be completed by 2028. Construction will focus on the areas with the highest rejects first, which will be the rebuild sections, with the Extenda-Life sections coming later in the construction schedule.

Transmission Extenda-Life Program – Attachment 42

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 2023 project additions under Otter Tail’s Extenda-Life Program are shown in Table 4 with a total estimated cost of \$1.58 million (OTP Total) / \$0.62 million (OTP ND).

**Table 4
Transmission Extenda-Life Program – 2023 Addition**

Line Section	Voltage	State	Project Length (Miles)	Total Cost (\$MM)	ND Share (\$MM)	Projected In-Service Date
DL-New Rockford Extenda-Life	41.6 kV	ND	30	\$0.30	\$0.12	2024
Kensal-Bordulac 41.6kV Extenda-Life	41.6 kV	ND	18	\$0.48	\$0.19	2024
Donaldson CB-215 Re-Conductor	41.6 kV	ND	10.5	\$0.60	\$0.24	2025
Canby - 495 Line Extenda-Life	41.6 kV	MN	10	\$0.20	\$0.08	2024

Devils Lake 645 Extenda-Life

The 41.6 kV line serves customers in the communities around Fort Totten, Oberon, Sheyenne, and New Rockford in North Dakota. 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 Power Company’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. Most of the issues are caused

by failing insulators, wind, and lightning. Given the mixed vintage of the poles and equipment along this line, an Extenda-Life project is preferred over a complete rebuild. To improve the performance of this line, this project will focus on re-insulating approximately 30 miles of line south of Devils Lake, along with any necessary pole replacements. In addition, down guys will be insulated to lower the number of interruptions occurring along this line. This project is estimated to cost \$0.30 million (OTP Total) / \$0.12 million (OTP ND) and is expected to be completed by 2024 end of year.

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, Bourdulac, Kensal, Courtney, and Wimbledon. The 18-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, insulator replacement, limited pole replacement, and arresters that will be added for lightning protection. Where possible, poles in water will be repositioned to allow better accessibility. This project is estimated to cost \$0.48 million (OTP Total) / \$0.19 million (OTP ND) and is expected to be completed by the end of 2024.

Donaldson CB-215 Re-Conductor Extenda-Life

The Donaldson CB-215 41.6 kV line serves customers in Drayton ND and is an alternate feed to the communities of Hensel, Crystal, Hoople, Edinburg, and St. Thomas in ND. This line was constructed in the 1950s/1960s with some poles being replaced after the 1996 flood. Data from protection equipment and local inspections/reports have shown that the majority of the interruptions are due to the conductor failing during the winter. Given the mixed vintage of the poles and equipment along this line, an Extenda-Life project is preferred over a complete rebuild. To improve the performance of this line, this project will focus on re-conductoring approximately 10.5 miles of line East of Drayton, along with any necessary pole replacements and re-insulating. In addition, down guys will be insulated to lower the number of interruptions occurring along this line. This project is estimated to cost \$0.60 million (OTP Total) / \$0.24 million (OTP ND) and is expected to be completed in 2025.

Canby 495 Extenda-Life

The Canby 495 breaker is one of the worst performing 41.6kv line in the Morris division and was in the top quartile overall for the company in 2022. This line section serves customers in the areas of Canby, Burr, Hendricks, Ivanhoe, and Lake Benton in Minnesota. In South Dakota, it also feeds Verdi and Elkton. This line contains mixed vintage equipment, making it a good candidate for an Extenda-Life type project.

The scope of this project will include replacement of reject poles, insulators, and cross arms. In addition, arresters and insulated down-guys will be added to help improve performance during lightning conditions. The conductor is of adequate shape and capacity and will remain. This project has an overall spend of \$0.20 million (OTP Total) and \$0.08 million (OTP ND) and will be completed in 2024.

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 transmission demand allocation factor, D2, from Otter Tail's most recent North Dakota general rate review (Case No. PU-17-398) to allocate total revenue requirements to jurisdictions (North Dakota, 39.5989 percent) and rate classes. The rate design uses a demand-only billing rate (dollars/kW) for the Large General Service Class (LGS) and an energy-only billing rate (cents/kWh) for all other customers. The rate design detail is included in Attachment 3.

VI. RATE APPLICATION AND IMPACT

The total 2024 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2024; the true-up associated with an updated projection of the 2023 revenue requirement; and the carrying charge attributable to any projected over or under-collection.

The revenue requirement attributable to calendar year 2024, as shown on line 55 of Attachment 4, page 2 is \$9,113,381. This amount is based on actual net revenues and expenses included in the TCRR tracker through July 2023 and projections for August 2023 through December 2024.

By design and structure of the TCRR, the related carrying credit of (\$37,327) as computed on Attachment 4, page 2, line 62, will be credited to customers as a reduction in the 2024 revenue requirement. The 2023 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, line 45 and as computed in Attachment 4, page 1, line 62, reflects an estimated over-collection amount of (\$382,856) during the 2023

collection period. The over-collection is due to delayed in-service and reduced spend on projects of approximately \$88,000 as well as a reduction to the MISO Schedule 26 and 26A Expense and decrease to Schedule 26 and 9 Revenue in 2023, netting approximately a \$360,000 increase to the Net Revenue Requirement for 2023. The net revenue requirement for 2024, upon which rates are developed, is \$8,693,198 as shown on line 46 of Attachment 2. The proposed rates for this net revenue requirement are calculated on lines 11-14 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 5 with a comparison to previously approved rates:

Table 5

A		B	C
Line No.	Class	January 1, 2023- December 31, 2023 Approved Rates (PU-22-335) <u>¢ / kWh</u>	January 1, 2024- December 31, 2024 Proposed Rates (PU-23-XX) <u>¢ / kWh</u>
1	Large General Service Class	\$1.841 /kW	\$2.124 /kW
2	Controlled Service	0.086¢	0.099¢
3	Lighting	0.496¢	0.641¢
4	All Other Service	0.575¢	0.651¢

The proposed rates are based on an effective date of January 1, 2024, through December 31, 2024. These rates represent a change to the rates currently in effect. The estimated increase for a residential customer using 1,000 kWh is \$0.76 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 Attachment 50 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 51 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 52 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, 2024. As summarized below, this update includes:

1. Updates for previously approved TCRR projects and regional transmission organization costs and revenues.
2. The inclusion of three new transmission projects, three new Rebuild project and four new Extenda-Life projects.
3. Updated cost estimates for one previously approved project.
4. Cancellation of one project.

Date: September 15, 2023

Respectfully submitted:

OTTER TAIL POWER COMPANY

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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 Revenue
Attachment 8	MISO Schedule 26 and 26A Expense
Attachment 9	MISO Schedule 26 Revenue
Attachment 10	MISO Schedule 26A Revenue
Attachment 11	MISO Multi-Value Project Auction Revenue Rights Credit
Attachment 12	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 13	ADIT Pro-Rate Projection
Attachment 14	ADIT Pro-Rate Preservation
Attachment 15	BSAT-Ellendale MVP Revenue Requirements
Attachment 16	Max to Ryder 41.6 kV Line Upgrade Revenue Requirements
Attachment 17	Bagley 115 kV Switch Station Revenue Requirements
Attachment 18	Lake Norden Area Transmission Improvements Revenue Requirements
Attachment 19	Donaldson 115 kV Cap Bank Revenue Requirements
Attachment 20	Northwest MN UVLS Revenue Requirements
Attachment 21	Blair 230 kV Substation Revenue Requirements
Attachment 22	Veblen 41.6 kV Cap Bank Revenue Requirements
Attachment 23	New Effington 230/41.6 kV Line Revenue Requirements
Attachment 24	Jamestown Substation (NERC) Revenue Requirements
Attachment 25	CPEC Facility Purchase Revenue Requirements
Attachment 26	Erie 230/115kV Substation Revenue Requirements
Attachment 27	Grant County-Norcross 115kV Line and Norcross 115/41.6kV substation Revenue Requirements
Attachment 28	Winger 230/115kV Transformer Revenue Requirements
Attachment 29	Jamestown 115/41.6 kV Transformer Addition Revenue Requirements
Attachment 30	Hoot Lake Capacitor Revenue Requirements
Attachment 31	Finley/McVile 41.6 kV Rebuild Revenue Requirements
Attachment 32	Turtle Lake/Mercer 41.6 kV Rebuild Revenue Requirements
Attachment 33	Doyon/Bartlett 41.6 kV Rebuild Revenue Requirements
Attachment 34	Hoot Lake 115/43/13.8 kV Transformer Revenue Requirements
Attachment 35	2021 Transmission Line Rebuild Program Revenue Requirements
Attachment 36	2021 Transmission Extenda-Life Program Revenue Requirement
Attachment 37	Oslo 155 kV 5 Breaker Ring Bus Revenue Requirement

Attachment 38	Casselton 115 kV Capacitor Bank Revenue Requirement
Attachment 39	Cooperstown 41.6 kV Rebuild Program Revenue Requirement
Attachment 40	2022 Transmission Extenda-Life Program Revenue Requirements
Attachment 41	2023 Transmission Line Rebuild Program Revenue Requirements
Attachment 42	2023 Transmission Extenda-Life Program Revenue Requirements
Attachment 43	Milbank Area Reliability Project
Attachment 44	Big Stone South to Alexandria 345kV (BSSa)
Attachment 45	Alexandria to Big Oaks 345kV double circuit (BSSa)
Attachment 46	Jamestown to Ellendale 345kV (JETx)
Attachment 47	Maple River Substation Addition (JETx)
Attachment 48	Jamestown 345 Substation Addition (JETx)
Attachment 49	Twin Brooks Reactor Addition (JETx)
Attachment 50	Electric Rate Schedule Section 13.05 Legislative and Non-Legislative
Attachment 51	Customer Notice – ND TCR Proposed Bill Message
Attachment 52	Customer Notice – ND TCR Implementation Bill Insert

Projected Revenue for 2024

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,136,404 kW	\$2.124	\$2,413,753
2					
3	Controlled Service	(b)	243,885,377 kWh	0.099¢	\$240,895
4					
5	Lighting	(c)	13,014,550 kWh	0.641¢	\$83,470
6					
7	All other service		914,528,403 kWh	0.651¢	\$5,955,080
8					
9	Total revenue				<u>\$8,693,198</u>

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

Summary of Revenue Requirements		
Line No.	Revenue Requirements	2024
1	MVP - Ellendale to Big Stone South	121,367
2	Max - Ryder 41.6 kV Line Upgrades	86,406
3	Bagley 115kV Switch Station	108,458
4	Lake Norden Area Transmission	1,110,620
5	Donaldson 115 kV Cap Bank	26,384
6	Blair 230 kV Substation	39,367
7	Veblen 41.6 kV Cap Bank	39,134
8	Northwest MN UVLS	28,535
9	Jamestown Substation (NERC)	45,786
10	New Effington 230/41.6 kV Line	194,620
11	CPEC Purchase	70,110
12	Erie 230/115kV Substation	330,856
13	Norcross 115kV Line-115/41.6kV substation	187,310
14	Winger 230/115kV Transformer	230,318
15	Jamestown 115 kV Source	137,870
16	Hoot Lake Capacitor	32,154
17	Finley/McVile 41.6 kV Rebuild	45,520
18	Turtle Lake/Mercer 41.6 kV Rebuild	57,360
19	Doyon/Barlett 41.6 kV Rebuild	33,710
20	Transmission Line Replacement Program	552,653
21	Transmission Extenda-Life Program	324,871
22	Hoot Lake 115/43/13.8 kV Transformer	49,300
23	Cooperstown 41.6 kV Relocate	20,144
24	Oslo 115 kV 5 Breaker Ring Bus	270,980
25	Casselton 115 kV Capacitor Bank	67,460
26	Milbank Area Reliability Project	421,811
27	Jamestown to Ellendale 345kV (JETx)	4,770
28	Big Stone South to Alexandria 345kV (BSSa)	2,732
29	Alexandria to Big Oaks 345kV double circuit (BSS)	4,056
30	Maple River Substation Addition (JETx)	2,687
31	Jamestown 345 Substation Addition (JETx)	31
32	Twin Brooks Reactor Addition (JETx)	636
33	Total Revenue Requirement	\$4,211,291
34	MISO Schedule 26 Expense	4,741,434
35	MISO Schedule 26A Expense	3,858,088
36	SPP Schedule 9 Expense	801,518
37	SPP Schedule 11 Expense	115,227
38	MISO Schedule 9 Revenue	(351,523)
39	MISO Schedule 26 Revenue	(3,903,234)
40	MISO Schedule 37 Revenue	(0)
41	MISO Schedule 38 Revenue	(0)
42	MISO Schedule 26A Revenue	(785,252)
43	MISO MVP ARR Revenue	(10,891)
44	Carrying Cost	(37,327)
45	True-Up	(382,856)
46	Net Revenue Requirement	<u>\$8,693,198</u>

Class Allocation and Rate Design

Line No.	2024		
1	North Dakota Revenue Requirements		\$8,693,198 *
2	Large General Service Class	27.77%	\$2,413,753
3	Controlled Service	2.77%	\$240,895
4	Lighting	0.96%	\$83,470
5	All Other Service	68.50%	\$5,955,080
6	Total		\$8,693,198
7	Large General Service Class	kW	1,136,404
8	Controlled Service	kWh	243,885,377
9	Lighting	kWh	13,014,550
10	All Other Service	kWh	914,528,403
11	Large General Service Class	\$ / kW	2.124
12	Controlled Service	cents / kWh	0.099
13	Lighting	cents / kWh	0.641
14	All Other Service	cents / kWh	0.651

* Jurisdictional transmission allocation factor (D2 = 39.598907%) is from Otter Tail's approved general rate case in North Dakota Case No. PU-17-398.

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2023												YE Projected
		January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Projected	September Projected	October Projected	November Projected	December Projected	
	Revenue Requirements													
1	MVP: Ellendale to Big Stone South	10,207	10,212	10,212	10,212	10,212	10,212	10,212	10,212	10,212	10,212	10,212	11,119	123,500
2	Max- Ryder 41.6 kV Line Upgrades	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	7,160	85,920
3	Bagley 115kV Switch Station	8,941	8,941	8,941	8,941	8,941	8,941	8,941	8,941	8,941	8,941	8,941	8,941	107,287
4	Lake Norden Area Transmission Improvements	93,710	93,710	93,710	93,698	93,698	93,698	93,698	93,698	93,698	93,698	93,698	93,698	1,124,415
5	Danaldson 115 kV Cap Bank	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	2,177	26,124
6	Blair 230 kV Substation	3,275	3,275	3,275	3,275	3,275	3,275	3,275	3,275	3,275	3,275	3,275	3,275	39,296
7	Veblen 41.6 kV Cap Bank	3,233	3,233	3,233	3,233	3,233	3,233	3,233	3,233	3,233	3,233	3,233	3,233	38,802
8	Northwest MN UVLS	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	27,503
9	Jamestown Substation	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	45,653
10	New Effington 230/41.6 kV Line	16,191	16,191	16,191	16,192	16,192	16,192	16,192	16,192	16,192	16,192	16,192	16,192	194,304
11	CPEC Purchase	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	6,335	76,023
12	Erle 230/115kV Substation	15,989	15,989	15,989	15,989	15,989	15,989	15,989	15,989	15,989	15,989	15,989	15,989	205,174
13	Norcross 115kV Line-115/41.6kV substation	15,565	15,565	15,565	15,565	15,565	15,565	15,565	15,565	15,565	15,565	15,565	15,565	186,778
14	Winger 230/115kV Transformer	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	107,310
15	Jamestown 41.6 kV Source	11,464	11,451	11,458	11,456	11,456	11,456	11,461	11,461	11,462	11,462	11,462	11,462	137,513
16	Hoot Lake Capacitor	2,672	2,672	2,672	2,672	2,672	2,672	2,672	2,672	2,672	2,672	2,672	2,672	32,060
17	Finley/McVillie 41.6 kV Rebuild	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	41,160
18	Turtle Lake/Mercer 41.6 kV Rebuild	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	4,756	57,068
19	Dovon/Bartlett 41.6 kV Rebuild	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	2,799	33,624
20	Hoot Lake 115/43/13.8 kV Transformer	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	44,267
21	Transmission Line Replacement Program	27,105	27,195	28,328	28,340	28,352	28,351	28,345	29,018	29,037	29,251	29,266	29,266	340,939
22	Transmission Extends-Life Program	12,636	12,856	12,858	12,858	12,858	12,858	12,976	13,050	13,447	13,792	13,792	13,792	157,714
23	Cooperstown 41.6 kV Relocate	68	68	68	68	68	68	68	68	68	68	68	68	822
24	Oslo 115 kV 5 Breaker Ring Bus	3,179	3,179	3,179	3,179	3,179	3,179	3,179	3,179	3,179	3,179	3,179	3,179	38,146
25	Casselton 115 kV Capacitor Bank	1,558	1,558	1,558	1,558	1,558	1,558	1,558	1,558	1,558	1,558	1,558	1,558	18,690
26	Millbank Area Reliability Project													
27	Big Stone South to Alexandria 345kV (BSSa)													
28	Alexandria to Big Oaks 345kV double circuit (BSSa)													
29	Jamestown to Ellendale 345kV (JETX)													
30	Maple River Substation Addition (JETX)													
31	Jamestown 345 Substation Addition (JETX)													
32	Twin Brooks Reactor Addition (JETX)													
33														
34														
35	Total Revenue Requirements	270,803	271,105	272,248	272,247	272,259	272,259	272,380	272,455	277,551	278,481	278,695	279,616	3,290,101
36														
37	ADIT Preservation of Proration	(6,499)	(6,499)	(6,499)	(6,499)	(6,499)	(6,499)	(6,499)	(6,499)	(6,499)	(6,499)	(6,499)	(6,499)	(77,984)
38														
39	MISO & SPP Expenses													
40	MISO Schedule 26 Expense	454,609	398,722	427,398	357,317	412,121	369,122	408,684	375,299	375,299	452,167	445,044	431,693	4,907,474
41	MISO Schedule 26A Expense	398,007	356,545	348,800	289,477	294,026	297,596	298,009	274,761	318,737	352,588	354,979	329,958	3,910,482
42	SPP Schedule 9 Expense	66,696	63,259	63,227	63,227	63,379	63,383	62,938	63,777	63,777	63,777	66,348	66,348	770,136
43	SPP Schedule 11 Expense	9,604	9,244	9,159	9,158	9,179	9,180	9,152	9,169	9,169	9,169	9,538	9,538	111,258
44	Total MISO & SPP Expenses	928,916	827,770	848,584	719,179	778,704	739,282	778,782	723,006	766,981	877,700	875,908	834,536	9,699,350
45														
46	MISO Revenues													
47	MISO Schedule 9 Revenue	(88,184)	(52,830)	(67,564)	(44,923)	(8,441)	(11,788)	(18,265)	52	(22,051)	(24,308)	(37,119)	(49,398)	(424,819)
48	MISO Schedule 26 Revenue	(309,711)	(299,617)	(277,460)	(262,509)	(333,438)	(351,365)	(390,928)	(398,298)	(322,943)	(264,334)	(260,147)	(302,011)	(3,772,762)
49	MISO Schedule 37 Revenue	(3,265)	(3,265)	(3,265)	(3,265)	(3,265)	(3,269)	(3,269)	(0)	(0)	(0)	(0)	(0)	(22,862)
50	MISO Schedule 38 Revenue	(3,915)	(3,915)	(3,915)	(3,915)	(3,915)	(3,918)	(3,918)	(0)	(0)	(0)	(0)	(0)	(27,409)
51	MISO Schedule 26A Revenue	(66,533)	(58,374)	(57,164)	(53,081)	(56,293)	(62,690)	(68,676)	(74,420)	(61,828)	(60,347)	(52,199)	(68,495)	(740,101)
52	MISO MVP ARR Revenue	(10,782)	(11,155)	(11,412)	(7,380)	(6,189)	(6,189)	(525)	(908)	(908)	(908)	(908)	(908)	(58,893)
53	Total MISO Revenues	(482,390)	(429,154)	(420,780)	(375,073)	(412,265)	(439,218)	(485,581)	(473,575)	(407,730)	(349,896)	(350,373)	(420,811)	(5,046,846)
54														
55	Net Revenue Requirement	710,831	663,222	693,553	609,856	632,200	565,824	559,083	515,387	630,304	799,787	797,731	686,842	7,864,621
56														
57	Billed (forecast kWh x adj factor)	704,462	735,957	726,759	688,124	562,803	573,690	571,360	542,789	533,638	508,694	627,363	719,839	7,495,460
58														
59														
60	Difference	6,369	(72,735)	(33,186)	(78,269)	69,397	(7,866)	(12,277)	(27,401)	96,666	291,093	170,368	(32,997)	369,162
61	Carrying Charge	(4,426)	(4,414)	(4,905)	(5,148)	(5,679)	(5,273)	(5,357)	(5,469)	(5,679)	(5,099)	(3,278)	(2,214)	(56,943)
62	Cumulative Difference	(693,131)	(770,280)	(808,372)	(891,789)	(828,071)	(841,211)	(858,845)	(891,715)	(800,728)	(514,735)	(347,645)	(382,856)	(382,856)
63														
64	Carrying Charge Calculation	(4,414)	(4,905)	(5,148)	(5,679)	(5,273)	(5,357)	(5,469)	(5,679)	(5,099)	(3,278)	(2,214)	(2,438)	
65	Cumulative Carrying Charge	(334,312)	(339,217)	(344,365)	(350,044)	(355,318)	(360,675)	(366,144)	(371,823)	(376,922)	(380,200)	(382,414)	(384,852)	
66	Carrying cost	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	
67														
68														
69	Forecast Sales (MWh)	189,278	184,540	165,404	148,271	120,932	112,282	118,178	122,497	120,432	114,802	141,584	162,454	1,700,653
70														

Approved December 14, 2022 (PU-22-335);
Rate Effective January 1, 2022

SUMMARY	Jan 2023 - Dec 2023
Revenue requirements	\$7,670,024
Carrying Charge	(16,759)
2022 True-Up	(117,592)
Total requirements	\$7,535,673
Jan 2023-Dec 2023 projected sales in MWh	1,700,653
Average Rate	\$0.00443

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2024												YE Projected
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	
Revenue Requirements														
1	MVP: Ellendale to Big Stone South	10,038	10,038	10,038	10,038	10,038	10,038	10,038	10,038	10,038	10,038	10,038	10,951	121,367
2	Max- Ryder 41.6 kV Line Upgrades	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	7,200	86,406
3	Baglew 115kV Switch Station	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	9,038	108,458
4	Lake Norden Area Transmission Improvements	92,552	92,552	92,552	92,552	92,552	92,552	92,552	92,552	92,552	92,552	92,552	92,552	1,110,620
5	Dunham 115 kV Cap Bank	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	26,384
6	Blair 230 kV Substation	3,281	3,281	3,281	3,281	3,281	3,281	3,281	3,281	3,281	3,281	3,281	3,281	39,367
7	Vehlan 41.6 kV Cap Bank	3,261	3,261	3,261	3,261	3,261	3,261	3,261	3,261	3,261	3,261	3,261	3,261	39,134
8	Northwest MN UVLS	2,378	2,378	2,378	2,378	2,378	2,378	2,378	2,378	2,378	2,378	2,378	2,378	28,535
9	Jamestown Substation	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	3,815	45,786
10	New Effington 230/41.6 kV Line	16,218	16,218	16,218	16,218	16,218	16,218	16,218	16,218	16,218	16,218	16,218	16,218	194,620
11	CPEC Purchase	5,843	5,843	5,843	5,843	5,843	5,843	5,843	5,843	5,843	5,843	5,843	5,843	70,110
12	Erle 230/115kV Substation	27,571	27,571	27,571	27,571	27,571	27,571	27,571	27,571	27,571	27,571	27,571	27,571	330,856
13	Narcross 115kV Line-115/41.6kV substation	15,609	15,609	15,609	15,609	15,609	15,609	15,609	15,609	15,609	15,609	15,609	15,609	187,310
14	Winger 230/115kV Transformer	19,193	19,193	19,193	19,193	19,193	19,193	19,193	19,193	19,193	19,193	19,193	19,193	230,318
15	Jamestown 41.6 kV Source	11,489	11,489	11,489	11,489	11,489	11,489	11,489	11,489	11,489	11,489	11,489	11,489	137,870
16	Hoot Lake Capacitor	2,680	2,680	2,680	2,680	2,680	2,680	2,680	2,680	2,680	2,680	2,680	2,680	32,154
17	Finley/McVillie 41.6 kV Rebuild	3,793	3,793	3,793	3,793	3,793	3,793	3,793	3,793	3,793	3,793	3,793	3,793	45,520
18	Turtle Lake/Mercer 41.6 kV Rebuild	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	57,360
19	Dovon/Bartlett 41.6 kV Rebuild	2,809	2,809	2,809	2,809	2,809	2,809	2,809	2,809	2,809	2,809	2,809	2,809	33,710
20	Hoot Lake 115/43/13.8 kV Transformer	4,108	4,108	4,108	4,108	4,108	4,108	4,108	4,108	4,108	4,108	4,108	4,108	49,300
21	Transmission Line Replacement Program	45,920	45,921	45,923	45,925	45,926	45,928	45,930	45,931	45,933	45,935	46,690	46,692	552,653
22	Transmission Extend-Life Program	27,031	27,031	27,031	27,031	27,031	27,031	27,031	27,031	27,031	27,031	27,031	27,031	324,871
23	Cooperstown 41.6 kV Relocate	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	20,144
24	Oslo 115 kv 5 Breaker Ring Bus	22,582	22,582	22,582	22,582	22,582	22,582	22,582	22,582	22,582	22,582	22,582	22,582	270,980
25	Casselton 115 kV Capacitor Bank	5,622	5,622	5,622	5,622	5,622	5,622	5,622	5,622	5,622	5,622	5,622	5,622	67,460
26	Milbank Area Reliability Project	35,151	35,151	35,151	35,151	35,151	35,151	35,151	35,151	35,151	35,151	35,151	35,151	421,811
27	Big Stone South to Alexandria 345kV (BSSa)	228	228	228	228	228	228	228	228	228	228	228	228	2,732
28	Alexandria to Big Oaks 345kV double circuit (BSSb)	338	338	338	338	338	338	338	338	338	338	338	338	4,056
29	Jamestown to Ellendale 345kV (JETx)	398	398	398	398	398	398	398	398	398	398	398	398	4,770
30	Maple River Substation Addition (JETx)	224	224	224	224	224	224	224	224	224	224	224	224	2,687
31	Jamestown 345 Substation Addition (JETx)	3	3	3	3	3	3	3	3	3	3	3	3	31
32	Twin Brooks Reactor Addition (JETx)	53	53	53	53	53	53	53	53	53	53	53	53	636
33														
34														
35	Total Revenue Requirements	387,082	387,083	387,085	387,087	387,088	387,090	387,092	387,093	387,095	387,097	388,104	389,018	4,648,013
36														
37	ADIT Preservation of Proration													
38														
39	MISO & SPP Expenses													
40	MISO Schedule 26 Expense	395,120	395,120	395,120	395,120	395,120	395,120	395,120	395,120	395,120	395,120	395,120	395,120	4,741,434
41	MISO Schedule 26A Expense	321,507	321,507	321,507	321,507	321,507	321,507	321,507	321,507	321,507	321,507	321,507	321,507	3,858,088
42	SPP Schedule 9 Expense	66,348	66,348	66,348	66,348	66,348	66,348	66,348	66,348	66,348	66,348	69,021	69,021	801,518
43	SPP Schedule 11 Expense	9,538	9,538	9,538	9,538	9,538	9,538	9,538	9,538	9,538	9,538	9,923	9,923	115,227
44	Total MISO & SPP Expenses	792,513	792,513	792,513	792,513	792,513	792,513	792,513	792,513	792,513	792,513	795,571	795,571	9,516,268
45														
46	MISO Revenues													
47	MISO Schedule 9 Revenue	(72,320)	(46,610)	(58,146)	(14,768)	(8,635)	(1,675)	(12,577)	1,289	(24,349)	(24,709)	(38,080)	(50,943)	(351,523)
48	MISO Schedule 26 Revenue	(325,269)	(325,269)	(325,269)	(325,269)	(325,269)	(325,269)	(325,269)	(325,269)	(325,269)	(325,269)	(325,269)	(325,269)	(3,903,234)
49	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
50	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
51	MISO Schedule 26A Revenue	(65,438)	(65,438)	(65,438)	(65,438)	(65,438)	(65,438)	(65,438)	(65,438)	(65,438)	(65,438)	(65,438)	(65,438)	(785,252)
52	MISO MVP ARR Revenue	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(10,891)
53	Total MISO Revenues	(463,935)	(438,224)	(449,761)	(406,383)	(400,249)	(393,290)	(404,192)	(390,326)	(415,964)	(416,323)	(429,694)	(442,558)	(5,050,900)
54														
55	Net Revenue Requirement	715,660	741,371	729,837	773,216	779,352	786,312	775,413	789,280	763,643	763,286	753,980	742,031	9,113,381
56														
57	Billed (forecast kWh x adj factor)	969,103	944,903	846,512	758,095	617,556	572,897	603,310	625,518	614,842	585,922	723,487	831,042	8,693,198
58														
59														
60	Difference	(253,449)	(203,537)	(116,675)	15,121	161,796	213,415	172,103	163,762	148,801	177,364	30,494	(89,011)	420,183
61	Carrying Charge	(2,438)	(4,068)	(5,390)	(6,167)	(6,110)	(5,119)	(3,792)	(2,720)	(1,695)	(758)	367	563	(37,327)
62	Cumulative Difference	(638,743)	(846,348)	(968,413)	(959,459)	(803,773)	(595,477)	(427,166)	(266,125)	(119,019)	57,588	88,448	(0)	(0)
63														
64	Carrying Charge Calculation	(4,068)	(5,390)	(6,167)	(6,110)	(6,119)	(5,119)	(3,792)	(2,720)	(1,695)	(758)	367	563	(0)
65	Cumulative Carrying Charge	(388,920)	(394,310)	(400,477)	(406,587)	(411,706)	(415,498)	(418,218)	(419,913)	(420,671)	(420,304)	(419,741)	(419,741)	(419,741)
66	Carrying cost	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
67														
68														
69	Forecasted Sales (MWh)	189,083	184,361	165,163	147,912	120,491	111,778	117,712	122,045	119,962	114,319	141,159	162,144	1,696,127
70														

SUMMARY		Jan 2024 - Dec 2024
Revenue requirements		\$9,113,381
Carrying Charge		(37,327)
2023 True-Up		(382,856)
Total requirements		\$8,693,198
Jan 2018-Dec 2018 projected sales in MWh		1,696,127
Average Rate		\$0.00513

2024 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$52,174,565
	REVENUE CREDITS	(Note T)	Total	Allocator	
2	Account No. 454	(page 4, line 34)	195,525	TP 1.00000	195,525
3	Account No. 456.1	(page 4, line 37)	6,293,147	TP 1.00000	6,293,147
4	Revenues from Grandfathered Interzonal Transactions		0	TP 1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP 1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)				6,488,673
7	To back out Schedule 9 Revenues received				0
8	Total Revenue Subject to the Wholesale Revenue Credit				6,488,673
9				Wholesale Revenue Credit	12.44%

2023 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$51,258,987
	REVENUE CREDITS	(Note T)	Total	Allocator	
2	Account No. 454	(page 4, line 34)	222,051	TP 1.00000	222,051
3	Account No. 456.1	(page 4, line 37)	8,420,585	TP 1.00000	8,420,585
4	Revenues from Grandfathered Interzonal Transactions		0	TP 1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP 1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)				8,642,636
7	To back out Schedule 9 Revenues received				(1,072,806)
8	Total Revenue Subject to the Wholesale Revenue Credit				7,569,830
9				Wholesale Revenue Credit	14.77%

		2023												
Line No.	<i>SPP Schedules</i>	Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	SPP Schedule 7,8 or 9 Expenses	168,429	159,748	159,669	159,669	160,052	160,064	158,939	161,058	161,058	161,058	167,549	167,549	1,944,842
2	North Dakota share 39.599%	66,696	63,259	63,227	63,227	63,379	63,383	62,938	63,777	63,777	63,777	66,348	66,348	770,136
3	SPP Schedule 11 Expense	24,254	23,343	23,129	23,127	23,180	23,183	23,112	23,154	23,154	23,154	24,087	24,087	280,963
4	North Dakota share 39.599%	9,604	9,244	9,159	9,158	9,179	9,180	9,152	9,169	9,169	9,169	9,538	9,538	111,258

		2024												
Line No.	<i>SPP Schedules</i>	Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	SPP Schedule 7,8 or 9 Expenses	167,549	167,549	167,549	167,549	167,549	167,549	167,549	167,549	167,549	167,549	174,301	174,301	2,024,092
2	North Dakota share 39.599%	66,348	66,348	66,348	66,348	66,348	66,348	66,348	66,348	66,348	66,348	69,021	69,021	801,518
3	SPP Schedule 11 Expense	24,087	24,087	24,087	24,087	24,087	24,087	24,087	24,087	24,087	24,087	25,058	25,058	290,986
4	North Dakota share 39.599%	9,538	9,538	9,538	9,538	9,538	9,538	9,538	9,538	9,538	9,538	9,923	9,923	115,227

		2023												
Line No.	MISO Revenues	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)	(440,782)	(343,047)	(383,779)	(321,187)	(220,335)	(234,480)	(252,387)	(206,474)	(267,581)	(273,822)	(309,242)	(343,189)	(3,596,308)
	CPEC Facility Credits in MISO	197,001	197,001	197,001	197,001	197,001	201,894	201,894	206,617	206,617	206,617	206,617	206,617	2,421,877
2	Non-OTP Schedule 9 Revenues	21,087	12,633	16,156	10,742	2,018	2,819	4,368	(12)	5,280	5,820	8,887	11,827	101,625
3	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(222,694)	(133,413)	(170,622)	(113,444)	(21,316)	(29,768)	(46,126)	130	(55,685)	(61,385)	(93,738)	(124,745)	(1,072,806)
4	North Dakota share 39.599%	(88,184)	(52,830)	(67,564)	(44,923)	(8,441)	(11,788)	(18,265)	52	(22,051)	(24,308)	(37,119)	(49,398)	(424,819)

		2024												
Line No.	MISO Revenues	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 9 Revenues (CPEC Portion)	(406,563)	(335,481)	(367,376)	(247,448)	(230,489)	(214,722)	(244,917)	(206,581)	(277,465)	(278,458)	(315,425)	(350,990)	(3,475,915)
	CPEC Facility Credits in MISO	206,617	206,617	206,617	206,617	206,617	210,090	210,145	210,145	210,145	210,145	210,145	210,145	2,504,042
2	Non-OTP Schedule 9 Revenues	17,315	11,160	13,922	3,536	2,067	401	3,011	(309)	5,830	5,916	9,117	12,197	84,164
3	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(182,631)	(117,704)	(146,837)	(37,295)	(21,805)	(4,231)	(31,761)	3,255	(61,490)	(62,397)	(96,163)	(128,648)	(887,709)
4	North Dakota share 39.599%	(72,320)	(46,610)	(58,146)	(14,768)	(8,635)	(1,675)	(12,577)	1,289	(24,349)	(24,709)	(38,080)	(50,943)	(351,523)

Line No.	2023	2023												Total Projected
		Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	
1	Total Schedule 26 Revenue	(1,099,666)	(1,063,824)	(985,154)	(932,070)	(1,183,912)	(1,247,561)	(1,388,035)	(1,414,206)	(1,146,648)	(938,548)	(923,684)	(1,072,327)	(13,395,634)
2	Overhead Credit for Non-Retail Share	0.980%	(10,777)	(10,425)	(9,655)	(9,134)	(11,602)	(12,226)	(13,859)	(11,237)	(9,198)	(9,052)	(10,509)	(131,277)
3														
4														
5	Fargo	65.997%	(725,747)	(702,092)	(650,172)	(615,139)	(781,346)	(823,353)	(916,061)	(933,333)	(756,753)	(619,413)	(609,603)	(707,703)
6	Retail Load Share		75.142%	75.14%	75.14%	75.14%	75.14%	75.14%	75.14%	75.14%	75.14%	75.14%	75.14%	75.14%
7	Retail Revenue		(545,341)	(527,566)	(488,552)	(462,227)	(587,119)	(618,684)	(688,347)	(701,325)	(568,640)	(465,440)	(458,068)	(531,782)
8														
9	Overhead Credit for Non-Retail Share		(7,112)	(6,880)	(6,372)	(6,028)	(7,657)	(8,069)	(8,977)	(9,147)	(7,416)	(6,070)	(5,974)	(6,935)
10	Non-Retail Load Share		24.86%	24.86%	24.86%	24.86%	24.86%	24.86%	24.86%	24.86%	24.86%	24.86%	24.86%	24.86%
11	Non-Retail Overhead Credit		(1,768)	(1,710)	(1,584)	(1,499)	(1,903)	(2,006)	(2,274)	(1,844)	(1,509)	(1,485)	(1,724)	(21,537)
12														
13	Total Revenue Credit for Fargo		(547,109)	(529,276)	(490,136)	(463,726)	(589,023)	(620,690)	(690,578)	(703,599)	(570,483)	(469,553)	(533,506)	(6,664,628)
14														
15														
16	Bemidji	13.563%	(149,148)	(144,286)	(133,616)	(126,417)	(160,574)	(169,207)	(188,259)	(191,809)	(155,520)	(127,295)	(125,279)	(145,440)
17	Retail Load Share		92.427%	92.43%	92.43%	92.43%	92.43%	92.43%	92.43%	92.43%	92.43%	92.43%	92.43%	92.43%
18	Retail Revenue		(137,853)	(133,360)	(123,498)	(116,843)	(148,414)	(156,393)	(174,002)	(177,283)	(143,742)	(117,655)	(115,792)	(134,426)
19														
20	Overhead Credit for Non-Retail Share		(1,462)	(1,414)	(1,309)	(1,239)	(1,574)	(1,658)	(1,845)	(1,880)	(1,524)	(1,247)	(1,228)	(1,425)
21	Non-Retail Load Share		7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%
22	Non-Retail Overhead Credit		(111)	(107)	(99)	(94)	(119)	(126)	(140)	(142)	(115)	(94)	(93)	(108)
23														
24	Total Revenue Credit for Bemidji		(137,963)	(133,467)	(123,597)	(116,937)	(148,533)	(156,518)	(174,142)	(177,425)	(143,858)	(117,750)	(115,885)	(134,533)
25														
26														
27	Cass Lake - Nary - Helga - Bemidji	5.864%	(64,484)	(62,383)	(57,769)	(54,657)	(69,425)	(73,157)	(81,394)	(82,929)	(67,239)	(55,036)	(54,165)	(62,881)
28	Retail Load Share		35.55%	35.55%	35.55%	35.55%	35.55%	35.55%	35.55%	35.55%	35.55%	35.55%	35.55%	35.55%
29	Retail Revenue		(22,922)	(22,175)	(20,535)	(19,429)	(24,678)	(26,005)	(28,933)	(29,479)	(23,902)	(19,564)	(19,254)	(22,352)
30														
31	Overhead Credit for Non-Retail Share		(632)	(611)	(566)	(536)	(680)	(717)	(798)	(813)	(659)	(539)	(531)	(616)
32	Non-Retail Load Share		64.45%	64.45%	64.45%	64.45%	64.45%	64.45%	64.45%	64.45%	64.45%	64.45%	64.45%	64.45%
33	Non-Retail Overhead Credit		(407)	(394)	(365)	(345)	(439)	(462)	(514)	(524)	(425)	(348)	(342)	(397)
34														
35	Total Revenue Credit for Bemidji		(23,330)	(22,569)	(20,900)	(19,774)	(25,117)	(26,467)	(29,447)	(30,003)	(24,326)	(19,911)	(19,596)	(22,750)
36														
37														
38	Rugby	0.043%	(473)	(457)	(424)	(401)	(509)	(536)	(597)	(608)	(493)	(404)	(397)	(461)
39	Retail Load Share		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
40	Retail Revenue		(473)	(457)	(424)	(401)	(509)	(536)	(597)	(608)	(493)	(404)	(397)	(461)
41														
42	Total Revenue Credit for Rugby		(473)	(457)	(424)	(401)	(509)	(536)	(597)	(608)	(493)	(404)	(397)	(461)
43														
44														
45	Casselton	11.959%	(131,509)	(127,223)	(117,815)	(111,466)	(141,584)	(149,196)	(165,995)	(169,125)	(137,128)	(112,241)	(110,463)	(128,240)
46	Retail Load Share		52.08%	52.08%	52.08%	52.08%	52.08%	52.08%	52.08%	52.08%	52.08%	52.08%	52.08%	52.08%
47	Retail Revenue		(68,486)	(66,254)	(61,354)	(58,048)	(73,733)	(77,697)	(86,445)	(88,075)	(71,412)	(58,452)	(57,526)	(66,783)
48														
49	Overhead Credit for Non-Retail Share		(1,289)	(1,247)	(1,155)	(1,092)	(1,388)	(1,462)	(1,627)	(1,657)	(1,344)	(1,100)	(1,083)	(1,257)
50	Non-Retail Load Share		47.92%	47.92%	47.92%	47.92%	47.92%	47.92%	47.92%	47.92%	47.92%	47.92%	47.92%	47.92%
51	Non-Retail Overhead Credit		(618)	(597)	(553)	(523)	(665)	(701)	(780)	(794)	(644)	(527)	(519)	(602)
52														
53	Total Revenue Credit for Casselton		(69,104)	(66,851)	(61,908)	(58,572)	(74,398)	(78,397)	(87,225)	(88,869)	(72,056)	(58,979)	(58,045)	(67,386)
54														
55														
56	Spiritwood	0.626%	(6,884)	(6,660)	(6,167)	(5,835)	(7,411)	(7,810)	(8,689)	(8,853)	(7,178)	(5,875)	(5,782)	(6,713)
57	Retail Load Share		53.99%	53.99%	53.99%	53.99%	53.99%	53.99%	53.99%	53.99%	53.99%	53.99%	53.99%	53.99%
58	Retail Revenue		(3,717)	(3,596)	(3,330)	(3,150)	(4,002)	(4,217)	(4,692)	(4,780)	(3,876)	(3,172)	(3,122)	(3,624)
59														
60	Overhead Credit for Non-Retail Share		(67)	(65)	(60)	(57)	(73)	(77)	(85)	(87)	(70)	(58)	(57)	(66)
61	Non-Retail Load Share		46.01%	46.01%	46.01%	46.01%	46.01%	46.01%	46.01%	46.01%	46.01%	46.01%	46.01%	46.01%
62	Non-Retail Overhead Credit		(31)	(30)	(28)	(26)	(33)	(35)	(39)	(40)	(32)	(26)	(26)	(30)
63														
64	Total Revenue Credit for Spiritwood		(3,748)	(3,626)	(3,358)	(3,177)	(4,035)	(4,252)	(4,731)	(4,820)	(3,908)	(3,199)	(3,148)	(3,655)
65														
66														
67	Courtenay Wind	0.179%	(1,968)	(1,904)	(1,763)	(1,668)	(2,119)	(2,233)	(2,485)	(2,531)	(2,053)	(1,680)	(1,653)	(1,919)
68	Retail Load Share		0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%	0.90%
69	Retail Revenue		(18)	(17)	(16)	(15)	(19)	(20)	(22)	(23)	(19)	(15)	(15)	(17)
70														
71	Overhead Credit for Non-Retail Share		(19)	(19)	(17)	(16)	(21)	(22)	(24)	(25)	(20)	(16)	(16)	(19)
72	Non-Retail Load Share		99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%	99.10%
73	Non-Retail Overhead Credit		(19)	(18)	(17)	(16)	(21)	(22)	(24)	(25)	(20)	(16)	(16)	(19)
74														
75	Total Revenue Credit for Courtenay Wind		(37)	(36)	(33)	(31)	(40)	(42)	(47)	(47)	(38)	(31)	(31)	(36)
76														
77														
78	Astoria BSSB	1.768%	(19,442)	(18,808)	(17,418)	(16,479)	(20,932)	(22,057)	(24,540)	(25,003)	(20,273)	(16,594)	(16,331)	(18,959)
79	Retail Load Share		0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%	0.87%
80	Retail Revenue		(169)	(163)	(151)	(143)	(182)	(192)	(213)	(217)	(176)	(144)	(142)	(165)
81														
82	Overhead Credit for Non-Retail Share		(191)	(184)	(171)	(161)	(205)	(216)	(240)	(245)	(199)	(163)	(160)	(186)
83	Non-Retail Load Share		99.13%	99.13%	99.13%	99.13%	99.13%	99.13%	99.13%	99.13%	99.13%	99.13%	99.13%	99.13%
84	Non-Retail Overhead Credit		(189)	(183)	(169)	(160)	(203)	(214)	(238)	(243)	(197)	(161)	(159)	(184)
85														
86	Total Revenue Credit for Astoria BSSB		(358)	(346)	(321)	(303)	(385)	(406)	(452)	(460)	(373)	(305)	(301)	(349)
87														
88	Retail Share of Schedule 26 Revenue		(782,121)	(756,628)	(700,676)	(662,921)	(842,039)	(887,309)	(987,218)	(1,005,832)	(815,536)	(667,528)	(656,956)	(762,676)
89														
90	North Dakota Share	39.599%	(309,711)	(299,617)	(277,460)	(262,509)	(333,438)	(351,365)	(390,928)	(398,298)	(322,943)	(264,334)	(260,147)	(302,011)

Line No.	2023	2023												Total Projected	
		Jan Actual	Feb Actual	Mar Actual	Apr Actual	May Actual	Jun Actual	Jul Actual	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected		
1	Total Schedule 26A Revenue	(2,225,602)	(1,952,660)	(1,912,191)	(1,775,613)	(1,883,062)	(2,097,040)	(2,297,267)	(2,489,434)	(2,068,217)	(2,018,662)	(1,746,110)	(2,291,214)	(24,757,070)	
2	Overhead Credit for Non-Retail Share	0.980%	(21,811)	(19,136)	(18,739)	(17,401)	(18,454)	(20,551)	(22,513)	(24,396)	(20,269)	(19,783)	(17,112)	(22,454)	(242,619)
4															
5	CAPX 2020 - Brookings	12.591%	(280,228)	(245,861)	(240,766)	(223,569)	(237,098)	(264,040)	(289,251)	(313,447)	(260,411)	(254,172)	(219,854)	(288,489)	(3,117,187)
6	Retail Load Share		32.628%	32.628%	32.628%	32.628%	32.628%	32.628%	32.628%	32.628%	32.628%	32.628%	32.628%	32.628%	
7	Retail Revenue		(91,433)	(80,220)	(78,557)	(72,946)	(77,360)	(86,151)	(94,377)	(102,272)	(84,967)	(82,931)	(71,734)	(94,128)	(1,017,076)
8															
9	Overhead Credit for Non-Retail Share		(2,746)	(2,409)	(2,360)	(2,191)	(2,324)	(2,588)	(2,835)	(3,072)	(2,552)	(2,491)	(2,155)	(2,827)	(30,548)
10	Non-Retail Load Share		67.372%	67.372%	67.372%	67.372%	67.372%	67.372%	67.372%	67.372%	67.372%	67.372%	67.372%	67.372%	
11	Non-Retail Overhead Credit		(1,850)	(1,623)	(1,590)	(1,476)	(1,565)	(1,743)	(1,910)	(2,070)	(1,719)	(1,678)	(1,452)	(1,905)	(20,581)
12															
13	Total Revenue Credit for CAPX Brookings		(93,283)	(81,843)	(80,147)	(74,422)	(78,926)	(87,894)	(96,287)	(104,341)	(86,686)	(84,609)	(73,186)	(96,033)	(1,037,657)
14															
15															
16	MVP BS South - Brookings	35.523%	(790,600)	(693,643)	(679,268)	(630,751)	(668,920)	(744,932)	(816,058)	(884,322)	(734,693)	(717,089)	(620,271)	(813,908)	(8,794,454)
17	Retail Load Share		2.931%	2.931%	2.931%	2.931%	2.931%	2.931%	2.931%	2.931%	2.931%	2.931%	2.931%	2.931%	
18	Retail Revenue		(23,172)	(20,330)	(19,909)	(18,487)	(19,606)	(21,833)	(23,918)	(25,919)	(21,533)	(21,017)	(18,180)	(23,855)	(257,758)
19															
20	Overhead Credit for Non-Retail Share		(7,748)	(6,798)	(6,657)	(6,181)	(6,555)	(7,300)	(7,997)	(8,666)	(7,200)	(7,027)	(6,079)	(7,976)	(86,186)
21	Non-Retail Load Share		97.069%	97.069%	97.069%	97.069%	97.069%	97.069%	97.069%	97.069%	97.069%	97.069%	97.069%	97.069%	
22	Non-Retail Overhead Credit		(7,521)	(6,598)	(6,462)	(6,000)	(6,363)	(7,086)	(7,763)	(8,412)	(6,989)	(6,822)	(5,900)	(7,743)	(83,660)
23															
24	Total Revenue Credit for MVP Brookings		(30,693)	(26,929)	(26,371)	(24,487)	(25,969)	(28,920)	(31,681)	(34,331)	(28,522)	(27,839)	(24,080)	(31,598)	(341,418)
25															
26															
27	MVP Ellendale - BS South	51.886%	(1,154,771)	(1,013,153)	(992,156)	(921,291)	(977,042)	(1,088,066)	(1,191,955)	(1,291,663)	(1,073,111)	(1,047,399)	(905,983)	(1,188,815)	(12,845,404)
28	Retail Load Share		2.862%	2.862%	2.862%	2.862%	2.862%	2.862%	2.862%	2.862%	2.862%	2.862%	2.862%	2.862%	
29	Retail Revenue		(33,050)	(28,996)	(28,395)	(26,367)	(27,963)	(31,140)	(34,114)	(36,967)	(30,712)	(29,977)	(25,929)	(34,024)	(367,635)
30															
31	Overhead Credit for Non-Retail Share		(11,317)	(9,929)	(9,723)	(9,029)	(9,575)	(10,663)	(11,681)	(12,658)	(10,516)	(10,265)	(8,879)	(11,650)	(125,885)
32	Non-Retail Load Share		97.138%	97.138%	97.138%	97.138%	97.138%	97.138%	97.138%	97.138%	97.138%	97.138%	97.138%	97.138%	
33	Non-Retail Overhead Credit		(10,993)	(9,645)	(9,445)	(8,770)	(9,301)	(10,358)	(11,347)	(12,296)	(10,216)	(9,971)	(8,625)	(11,317)	(122,282)
34															
35	Total Revenue Credit for MVP Ellendale		(44,042)	(38,641)	(37,840)	(35,138)	(37,264)	(41,498)	(45,461)	(49,263)	(40,928)	(39,947)	(34,554)	(45,341)	(489,918)
36															
37															
38	Retail Share of Schedule 26A Revenue		(168,018)	(147,413)	(144,358)	(134,047)	(142,159)	(158,312)	(173,428)	(187,936)	(156,136)	(152,395)	(131,820)	(172,971)	(1,868,993)
39															
40	North Dakota share	39.599%	(66,533)	(58,374)	(57,164)	(53,081)	(56,293)	(62,690)	(68,676)	(74,420)	(61,828)	(60,347)	(52,199)	(68,495)	(740,101)

Federal ADIT Proration

	A	B	C	D
1		January 2024- December 2024 Recovery Period		
		All Projects' Revenue Requirements without ADIT Prorated	All Projects' Revenue Requirement s with ADIT- Prorated	Difference due to Federal ADIT Proration (B - A)
2	Month			
3	Jan-24	\$386,339	\$387,082	\$743
4	Feb-24	\$386,341	\$387,083	\$743
5	Mar-24	\$386,342	\$387,085	\$743
6	Apr-24	\$386,344	\$387,087	\$743
7	May-24	\$386,346	\$387,088	\$743
8	Jun-24	\$386,347	\$387,090	\$743
9	Jul-24	\$386,349	\$387,092	\$743
10	Aug-24	\$386,351	\$387,093	\$743
11	Sep-24	\$386,352	\$387,095	\$743
12	Oct-24	\$386,354	\$387,097	\$743
13	Nov-23	\$387,361	\$388,104	\$743
14	Dec-24	\$388,275	\$389,018	\$743
15		\$4,639,100	\$4,648,013	\$8,913

16	Revenue Requirement Adjustment Related to Federal ADIT Proration	\$8,913
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Federal ADIT Proration

	A	B	C	D	E
1			Tax Conversion Factor	1.3228	(1/(1-24.4%))
2			Gross Up of Equity %	6.78%	(D1 * D8)
3			Equity Return %	5.13%	(D8)
4			Gross Up Factor	1.66%	(D2-D3)

		Annual	Monthly
5			
6		Debt Return %	2.51%
7		Preferred Equity %	0.00%
8		Equity Return %	5.13%
9		Rate of Return	7.64%
10		Tax RR on Equity Return	1.66%
11		Rate Base Rev Req Gross Up Factor	9.30%

January 2021 - December 2021			
Month	Original ADIT Balance - All Projects with ADIT Pro-Rated	Updated ADIT Balance - All Projects without ADIT Pro-Rated	Difference due to Federal ADIT Proration (B - A)
13			
14	Dec-23	(7,416,892)	(9,406,668)
15	Jan-24	(7,582,473)	(9,579,875)
16	Feb-24	(7,734,145)	(9,740,243)
17	Mar-24	(7,870,420)	(9,886,404)
18	Apr-24	(7,991,812)	(10,018,821)
19	May-24	(8,097,906)	(10,137,028)
20	Jun-24	(8,189,196)	(10,241,484)
21	Jul-24	(8,264,966)	(10,331,843)
22	Aug-24	(8,325,436)	(10,408,013)
23	Sep-24	(8,371,129)	(10,470,451)
24	Oct-24	(8,401,559)	(10,518,701)
25	Nov-24	(8,417,253)	(10,553,221)
26	Dec-24	(8,417,743)	(10,718,464)
27	ADIT Simple Average	(\$7,917,317)	(\$10,062,566)
			-\$2,145,249

28	Rate Base Rev Req Gross Up Factor	9.18%
29	Total Company Revenue Requirement	-\$196,934

30	ND Revenue Requirement Related to Federal ADIT Proration-Preservation	-\$77,984
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Line No.	Year>>	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total	
RATE BASE															
1	Plant Balance	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102	106,343,102
2	Accumulated Depreciation	(6,400,314)	(6,534,533)	(6,668,753)	(6,802,972)	(6,937,192)	(7,071,411)	(7,205,631)	(7,339,850)	(7,474,070)	(7,608,289)	(7,742,509)	(7,876,728)	(8,010,947)	(8,145,167)
3	Net Plant in Service	99,942,788	99,808,569	99,674,349	99,540,130	99,405,910	99,271,691	99,137,471	99,003,252	98,869,032	98,734,813	98,600,593	98,466,374	98,332,154	98,197,935
4	CWIP (Project #104593 & 105643)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	ADIT Federal Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.3370	0.2548	0.1699	0.0877	0.0027	0.0000
6	Accumulated Deferred Income Tax-Federal Only	(5,408,744)	(5,505,179)	(5,601,614)	(5,698,049)	(5,794,484)	(5,890,919)	(5,987,354)	(6,083,789)	(6,180,224)	(6,276,659)	(6,373,094)	(6,469,529)	(6,565,964)	(6,662,399)
7	Accumulated Deferred Income Taxes Federal & State	(6,568,824)	(6,685,943)	(6,803,061)	(6,920,180)	(7,037,299)	(7,154,417)	(7,271,536)	(7,324,717)	(7,369,971)	(7,407,036)	(7,436,174)	(7,457,122)	(7,457,122)	(7,457,122)
8	Ending rate base	93,373,964	93,122,626	92,871,288	92,619,950	92,368,612	92,117,274	91,865,936	91,678,535	91,499,061	91,327,777	91,164,420	91,009,252	91,009,252	91,009,252
9															
10	OTP Load Percentage	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%
11	Remove Non-OTP Load Portion	(90,701,601)	(90,457,456)	(90,213,312)	(89,969,167)	(89,725,022)	(89,480,877)	(89,236,733)	(89,054,696)	(88,880,358)	(88,713,976)	(88,555,294)	(88,404,568)	(88,404,568)	(88,404,568)
12	Retail Ending Rate Base	2,672,363	2,665,170	2,657,976	2,650,783	2,643,590	2,636,396	2,629,203	2,623,840	2,618,703	2,613,801	2,609,126	2,604,685	2,604,685	2,604,685
13															
14	Average rate base	220,565	220,565	220,565	220,565	220,565	220,565	220,565	220,565	220,565	220,565	220,565	220,565	220,565	220,565
15															
16	Return on Rate Base	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856
17															
18	Available for return (equity portion of rate base)	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313
19															
EXPENSES															
20	O&M and Depreciation														
21	Operating Costs	(437)	0	0	0	0	0	0	0	0	0	0	80,000	79,563	79,563
22	Property Tax	50,322	50,322	50,322	50,322	50,322	50,322	50,322	50,322	50,322	50,322	50,322	50,322	50,322	50,322
23	Book Depreciation	134,219	134,219	134,219	134,219	134,219	134,219	134,219	134,219	134,219	134,219	134,219	134,219	134,219	134,219
24	Total O&M and Depreciation Expense	184,104	184,542	184,542	184,542	184,542	184,542	184,542	184,542	184,542	184,542	184,542	184,542	184,542	184,542
25															
26															
27	OTP Load Percentage	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%	2.86%
28	Remove Non-OTP Load Portion	(178,835)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)	(179,260)
29	Retail O&M and Depreciation Expenses	5,269	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282
30															
31	Income before Taxes														
32	Available for return (from above)	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313	11,313
33	Taxable Income (grossed up)	14,966	14,966	14,966	14,966	14,966	14,966	14,966	14,966	14,966	14,966	14,966	14,966	14,966	14,966
34															
35	Income Taxes														
36	Current and Def Income Taxes	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652
37	Total Income Tax Expense	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652	3,652
38															
39															
REVENUE REQUIREMENTS															
40	Expenses	8,921	8,934	8,934	8,934	8,934	8,934	8,934	8,934	8,934	8,934	8,934	8,934	11,224	2,337,892
41	Return on rate base	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	16,856	202,267
42	Subtotal revenue requirements	25,777	25,790	25,790	25,790	25,790	25,790	25,790	25,790	25,790	25,790	25,790	25,790	28,079	2,540,159
43	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0
45	Total revenue requirements	25,777	25,790	25,790	25,790	25,790	25,790	25,790	25,790	25,790	25,790	25,790	25,790	28,079	2,540,159
46															
47															
48	North Dakota share - D2 factor	10,207	10,212	10,212	10,212	10,212	10,212	10,212	10,212	10,212	10,212	10,212	10,212	11,119	123,450

Line No.	SUPPORTING INFORMATION / DATA
1	
2	
3	
4	ND Cap Structure with allowed ROE per order.
5	Capital Structure
6	Debt
7	Preferred equity
8	Common equity
9	Total
10	
11	Project life (years)
12	
13	Effective Tax Rate
14	Tax conversion factor
15	Wholesale Revenue Credit
16	ND share - D2 factor
17	
18	Deferred Tax
19	Book depreciation
20	Tax depreciation-Federal
21	Tax depreciation-ND
22	Federal deferred income taxes
23	State deferred income taxes

LineNo.	Year>>	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total		
RATE BASE																
1	Plant Balance	128,390	128,390	128,390	128,390	128,390	128,390	128,390	6,510,758	7,755,906	7,755,906	7,755,906	7,755,906	7,755,906	7,755,906	
2	Accumulated Depreciation	(1,568)	(1,741)	(1,914)	(2,087)	(2,260)	(2,433)	(2,606)	(2,779)	(11,551)	(22,002)	(32,452)	(42,903)	(42,903)	(42,903)	
3	Net Plant in Service	126,823	126,650	126,477	126,304	126,131	125,958	125,785	6,507,979	7,744,355	7,733,904	7,723,454	7,713,003	7,713,003	7,713,003	
CWIP Calculation:																
	Beginning Balance	2,902,187	3,153,930	3,459,315	4,114,914	4,491,862	5,283,391	5,466,636	5,682,160	0	0	0	0	0	0	
	Additional CWIP	251,743	305,385	655,598	376,948	791,529	183,245	215,524	700,208	1,245,148	0	0	0	0	4,725,329	
	Closings from CWIP	0	0	0	0	0	0	0	(6,382,368)	(1,245,148)	0	0	0	0	0	
	AFUDC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP (Project #T02031.039)	3,153,930	3,459,315	4,114,914	4,491,862	5,283,391	5,466,636	5,682,160	0	0	0	0	0	0	0	
5	ADIT Promotion Factors	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	
6	Accumulated Defered Income Tax-Federal Only	(7,566)	(14,122)	(20,677)	(27,233)	(33,789)	(40,345)	(46,901)	(53,457)	(58,285)	(62,775)	(67,266)	(71,757)	(71,757)	(71,757)	
7	Accumulated Deferred Income Taxes Federal & State	(9,188)	(17,150)	(25,112)	(33,074)	(41,036)	(48,999)	(56,961)	(64,923)	(70,786)	(76,240)	(81,694)	(87,147)	(87,147)	(87,147)	
8	Ending rate base	3,271,565	3,568,814	4,216,278	4,585,091	5,368,485	5,543,595	5,750,984	6,443,057	7,673,569	7,657,665	7,641,760	7,625,856	7,625,856	7,625,856	
9																
10	Average rate base	463,940	463,940	463,940	463,940	463,940	463,940	463,940	463,940	463,940	463,940	463,940	463,940	463,940	463,940	
11																
12	Return on Rate Base	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	
13																
14	Available for return (equity portion of rate base)	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	
15																
16	EXPENSES															
17	O&M and Depreciation															
18	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
19	Property Tax	4,063	4,063	4,063	4,063	4,063	4,063	4,063	4,063	4,063	4,063	4,063	4,063	4,063	48,757	
20	Book Depreciation	173	173	173	173	173	173	173	173	8,773	10,450	10,450	10,450	10,450	41,508	
21	Total O&M and Depreciation Expense	4,236	4,236	4,236	4,236	4,236	4,236	4,236	4,236	12,836	14,513	14,513	14,513	14,513	90,265	
22																
23	Income before Taxes															
24	Available for return (from above)	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	23,797	285,560	
25	Taxable Income (grossed up)	31,479	31,479	31,479	31,479	31,479	31,479	31,479	31,479	31,479	31,479	31,479	31,479	31,479	377,749	
26																
27	Income Taxes															
28	Current and Def Income Taxes	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	92,189	
29	Total Income Tax Expense	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	7,682	92,189	
30																
31																
32	REVENUE REQUIRMENTS															
33	Expenses	11,918	11,918	11,918	11,918	11,918	11,918	11,918	11,918	11,918	20,518	22,196	22,196	22,196	182,454	
34	Return on rate base	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	35,454	425,452	
35	Subtotal revenue requirements	47,373	47,373	47,373	47,373	47,373	47,373	47,373	47,373	55,973	57,650	57,650	57,650	57,650	607,906	
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
37	Wholesale Revenue Credit	(6,996)	(6,996)	(6,996)	(6,996)	(6,996)	(6,996)	(6,996)	(6,996)	(6,996)	(8,266)	(8,514)	(8,514)	(8,514)	(89,774)	
38	Total revenue requirements	40,377	40,377	40,377	40,377	40,377	40,377	40,377	40,377	47,707	49,137	49,137	49,137	49,137	518,131	
39																
40	North Dakota share - D2 factor	15,989	15,989	15,989	15,989	15,989	15,989	15,989	15,989	15,989	18,891	19,458	19,458	19,458	205,174	

Line No.	SUPPORTING INFORMATION / DATA																
1	ND Cap Structure with allowed ROE per order.																
2	Capital Structure																
3		Ratio	Cost	WA Cost													Property tax
4	Debt	47.50%	5.29%	2.51%													2023 composite rate
5	Preferred equity	0.00%	0.00%	0.00%													1.68%
6	Common equity	52.50%	9.77%	5.13%													
7	Total	100.00%		7.64%	Overall Return												
8																	
9																	
10		Book	Tax														
11	Project life (years)	50	15-year	MACRS													
12																	
13					Fed Portion	State Portion											
14	Effective Tax Rate	24.40%	20.09%	4.31%													
15	Tax conversion factor	1.32284															
16	Wholesale Revenue Credit	14.77%															
17	ND share - D2 factor	39.5989%															
18	Deferred Tax																
19	Book depreciation	173	173	173	173	173	173	173	173	173	8,773	10,450	10,450	10,450	41,508		
20	Tax depreciation-Federal	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	393,573		
21	Tax depreciation-ND	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	32,798	393,573		
22	Federal deferred income taxes	(6,556)	(6,556)	(6,556)	(6,556)	(6,556)	(6,556)	(6,556)	(6,556)	(6,556)	(4,828)	(4,491)	(4,491)	(4,491)	(70,747)		
23	State deferred income taxes	(1,406)	(1,406)	(1,406)	(1,406)	(1,406)	(1,406)	(1,406)	(1,406)	(1,406)	(1,035)	(963)	(963)	(963)	(15,174)		

Line No.	Year>>	2023												2023 Projected Total	
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec		
RATE BASE															
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	6,228,161	6,228,161
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	6,228,161	6,228,161
CWIP Calculation:															
	Beginning Balance	1,246,036	1,285,762	1,355,046	1,605,885	1,622,307	1,926,484	2,149,904	3,044,722	4,057,229	5,012,476	5,855,861	6,213,161		
	Additional CWIP	39,726	69,285	250,839	16,422	304,177	223,420	894,818	1,012,508	955,247	843,385	357,300	15,000		4,982,125
	Closings from CWIP												(6,228,161)		
	AFDUC														
4	CWIP (Project #T05031.0122)	1,285,762	1,355,046	1,605,885	1,622,307	1,926,484	2,149,904	3,044,722	4,057,229	5,012,476	5,855,861	6,213,161	0		0
5	ADIT Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000		
6	Accumulated Deferred Income Tax-Federal Only	0	0	0	0	0	0	0	0	0	0	0	(62,577)		(62,577)
7	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	0		(75,999)
9	Ending rate base	1,285,762	1,355,046	1,605,885	1,622,307	1,926,484	2,149,904	3,044,722	4,057,229	5,012,476	5,855,861	6,213,161	6,152,163		6,152,163
10	Average rate base	266,199	266,199	266,199	266,199	266,199	266,199	266,199	266,199	266,199	266,199	266,199	266,199		3,194,387
12	Return on Rate Base	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343		244,115
14	Available for return (equity portion of rate base)	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654		163,848
EXPENSES															
O&M and Depreciation															
19	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0		0
20	Property Tax	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744		20,933
21	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0		0
22	Total O&M and Depreciation Expense	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744	1,744		20,933
24	Income before Taxes	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654		163,848
25	Available for return (from above)	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654	13,654		163,848
26	Taxable Income (grossed up)	18,062	18,062	18,062	18,062	18,062	18,062	18,062	18,062	18,062	18,062	18,062	18,062		216,744
28	Income Taxes														
29	Current and Def Income Taxes	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408		52,896
30	Total Income Tax Expense	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408	4,408		52,896
REVENUE REQUIREMENTS															
34	Expenses	6,152	6,152	6,152	6,152	6,152	6,152	6,152	6,152	6,152	6,152	6,152	6,152		73,830
35	Return on rate base	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343	20,343		244,115
36	Subtotal revenue requirements	26,495	26,495	26,495	26,495	26,495	26,495	26,495	26,495	26,495	26,495	26,495	26,495		317,945
37	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0		0
38	Wholesale Revenue Credit	(3,913)	(3,913)	(3,913)	(3,913)	(3,913)	(3,913)	(3,913)	(3,913)	(3,913)	(3,913)	(3,913)	(3,913)		(46,953)
39	Total revenue requirements	22,583	22,583	22,583	22,583	22,583	22,583	22,583	22,583	22,583	22,583	22,583	22,583		270,991
40															
41	North Dakota share - D2 factor	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942	8,942		107,310

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		Ratio	Cost	WA Cost									Property tax		
4	Debt	47.50%	5.29%	2.51%									2023 composite rate	1.68%	
5	Preferred equity	0.00%	0.00%	0.00%											
6	Common equity	52.50%	9.77%	5.13%											
7	Total	100.00%					7.64%	Overall Return							
8															
9															
10	Project life (years)	Book	Tax												
11		50	15-year MACRS												
12															
13															
14															
15															
16															
17															
18	Deferred Tax														
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	0	0	311,408	311,408
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	0	311,408	311,408
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	(62,577)	(62,577)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	(13,422)	(13,422)

Line No.	Year>>	2023												2023 Projected Total
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Projected	Projected	Projected	Projected	
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
RATE BASE														
1	Plant Balance	3,543,048	3,559,230	3,554,949	3,554,949	3,555,388	3,565,678	3,566,092	3,569,355	3,569,355	3,569,355	3,569,355	3,569,355	3,569,355
2	Accumulated Depreciation	(6,739)	(11,346)	(15,975)	(20,598)	(25,221)	(29,844)	(34,481)	(39,119)	(43,760)	(48,402)	(53,043)	(57,685)	(57,685)
3	Net Plant In Service	3,536,309	3,547,884	3,538,974	3,534,351	3,530,167	3,535,834	3,531,611	3,530,236	3,525,595	3,520,953	3,516,311	3,511,670	3,511,670
CWIP Calculation:														
	Beginning Balance	3,263	3,263	3,263	3,263	3,263	3,263	3,263	3,263	0	0	0	0	0
	Additional CWIP	(30,065)	16,182	(4,281)	0	439	10,291	414	0	0	0	0	0	(7,022)
	Closings from CWIP AFUDC	30,065	(16,182)	4,281	0	(439)	(10,291)	(414)	(3,263)	0	0	0	0	0
4	CWIP (Project #T03032.038)	107332	3,263	3,263	3,263	3,263	3,263	3,263	0	0	0	0	0	0
5	ADIT Proration Factors	107332	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
6	Accumulated Deferred Income Tax-Federal Only	(40,228)	(44,983)	(49,734)	(54,486)	(59,238)	(63,990)	(68,740)	(73,489)	(78,237)	(82,986)	(87,734)	(92,482)	(92,482)
7	Accumulated Deferred Income Taxes Federal & S	107362	(48,856)	(54,631)	(60,401)	(66,172)	(71,944)	(77,715)	(83,483)	(89,251)	(95,018)	(100,785)	(106,551)	(112,318)
8	Ending rate base	107363	3,490,717	3,496,516	3,481,836	3,471,442	3,461,486	3,461,382	3,451,391	3,440,985	3,430,577	3,420,168	3,409,760	3,399,351
9	Average rate base		288,121	288,121	288,121	288,121	288,121	288,121	288,121	288,121	288,121	288,121	288,121	288,121
10	Return on Rate Base		22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018
11	Available for return (equity portion of rate base)		14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778
12														
13														
14														
15														
16														
EXPENSES														
17	O&M and Depreciation													
18	Operating Costs		0	0	0	0	0	0	0	0	0	0	0	0
19	Property Tax		2,531	2,531	2,531	2,531	2,531	2,531	2,531	2,531	2,531	2,531	2,531	30,371
20	Book Depreciation		4,647	4,607	4,628	4,623	4,623	4,637	4,637	4,642	4,642	4,642	4,642	55,593
21	Total O&M and Depreciation Expense		7,177	7,138	7,159	7,154	7,154	7,168	7,168	7,173	7,173	7,173	7,173	85,964
22														
23	Income before Taxes		14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	177,341
24	Available for return (from above)		14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	14,778	177,341
25	Taxable Income (grossed up)		19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549	19,549	234,593
26														
27	Income Taxes													
28	Current and Def Income Taxes		4,771	4,771	4,771	4,771	4,771	4,771	4,771	4,771	4,771	4,771	4,771	57,252
29	Total Income Tax Expense		4,771	4,771	4,771	4,771	4,771	4,771	4,771	4,771	4,771	4,771	4,771	57,252
30														
31														
32														
REVENUE REQUIREMENTS														
33	Expenses		11,949	11,909	11,930	11,925	11,925	11,925	11,939	11,939	11,944	11,944	11,944	143,216
34	Return on rate base		22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018	22,018	264,218
35	Subtotal revenue requirements		33,967	33,928	33,949	33,943	33,943	33,943	33,957	33,958	33,962	33,962	33,962	407,434
36	Adjustments		0	0	0	0	0	0	0	0	0	0	0	0
37	Wholesale Revenue Credit		(5,016)	(5,010)	(5,013)	(5,013)	(5,013)	(5,013)	(5,015)	(5,015)	(5,015)	(5,015)	(5,015)	(60,169)
38	Total revenue requirements		28,951	28,917	28,935	28,930	28,930	28,931	28,942	28,943	28,946	28,946	28,946	347,265
39														
40	North Dakota share - D2 factor		11,464	11,451	11,458	11,456	11,456	11,456	11,461	11,461	11,462	11,462	11,462	137,513

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio	Cost	WA Cost	Property tax									
3	Debt	47.50%	5.29%	2.51%	2023 composite rate									
4	Preferred equity	0.00%	0.00%	0.00%	0.85%									
5	Common equity	52.50%	9.77%	5.13%										
6	Total	100.00%		7.64%	Overall Return									
7														
8														
9														
10	Project life (years)	Book	Tax	15-year MACRS										
11		50												
12														
13					Fed Portion	State Portion								
14	Effective Tax Rate	24.40%	20.09%	4.31%										
15	Tax conversion factor	1.32284												
16	Wholesale Revenue Credit	14.77%												
17	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	4,647	4,607	4,628	4,623	4,623	4,623	4,637	4,637	4,642	4,642	4,642	4,642	55,593
20	Tax depreciation-Federal	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	339,258
21	Tax depreciation-ND	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	28,271	339,258
22	Federal deferred income taxes	(4,747)	(4,755)	(4,751)	(4,752)	(4,752)	(4,752)	(4,749)	(4,749)	(4,748)	(4,748)	(4,748)	(4,748)	(57,002)
23	State deferred income taxes	(1,018)	(1,020)	(1,019)	(1,019)	(1,019)	(1,019)	(1,019)	(1,019)	(1,018)	(1,018)	(1,018)	(1,018)	(12,226)

Line No.	Year>>	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	
		Projected 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			
RATE BASE																	
	Transmission Plant - Station Equipment (353)	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	518,237.18	
	Transmission Plant - Poles & Fixtures (355)	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	
1	Plant Balance	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	1,295,593	
2	Accumulated Depreciation	(53,532)	(55,277)	(57,023)	(58,769)	(60,515)	(62,260)	(64,006)	(65,752)	(67,497)	(69,243)	(70,989)	(72,734)	(74,479)	(76,225)	(77,971)	
3	Net Plant in Service	1,242,061	1,240,316	1,238,570	1,236,824	1,235,078	1,233,333	1,231,587	1,229,841	1,228,096	1,226,350	1,224,604	1,222,859	1,221,113	1,219,368	1,217,622	
CWIP Calculation:																	
	Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Additional CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	AFDUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP (Project #T05008.027) 130717	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	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	0.0000	0.0000	0.0000	
6	Accumulated Deferred Income Tax-Federal Only	(42,934)	(44,098)	(45,146)	(46,079)	(46,894)	(47,596)	(48,181)	(48,647)	(49,000)	(49,235)	(49,357)	(49,360)	(49,360)	(49,360)	(49,360)	
7	Accumulated Deferred Income Taxes Federal & State	(52,167)	(53,628)	(54,972)	(56,203)	(57,315)	(58,314)	(59,196)	(59,959)	(60,609)	(61,141)	(61,560)	(61,860)	(62,140)	(62,400)	(62,650)	
8	Ending rate base	1,189,895	1,186,687	1,183,597	1,180,621	1,177,763	1,175,018	1,172,391	1,169,882	1,167,487	1,165,209	1,163,045	1,160,998	1,159,061	1,157,234	1,155,517	
9	Average rate base	97,986	97,986	97,986	97,986	97,986	97,986	97,986	97,986	97,986	97,986	97,986	97,986	97,986	97,986	97,986	
10	Return on Rate Base	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	
11	Available for return (equity portion of rate base)	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	
12																	
13																	
14																	
15																	
16	EXPENSES																
17	O&M and Depreciation																
18	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
19	Property Tax	918	918	918	918	918	918	918	918	918	918	918	918	918	918	918	
	Book depreciation - Summary																
	Transmission Plant - Station Equipment (353)	674	674	674	674	674	674	674	674	674	674	674	674	674	674	674	
	Transmission Plant - Poles & Fixtures (355)	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	
20	Book Depreciation	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	1,879	
21	Total O&M and Depreciation Expense	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	4,675	
22	Income before Taxes																
23	Available for return (from above)	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	5,026	
24	Taxable Income (grossed up)	6,649	6,649	6,649	6,649	6,649	6,649	6,649	6,649	6,649	6,649	6,649	6,649	6,649	6,649	6,649	
25																	
26																	
27	Income Taxes																
28	Current and Def Income Taxes	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	
29	Total Income Tax Expense	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	1,623	
30																	
31																	
32	REVENUE REQUIREMENTS																
33	Expenses	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	
34	Return on rate base	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	7,488	
35	Subtotal revenue requirements	13,785	13,785	13,785	13,785	13,785	13,785	13,785	13,785	13,785	13,785	13,785	13,785	13,785	13,785	13,785	
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
37	Wholesale Revenue Credit	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	(1,714)	
38	Total revenue requirements	12,071	12,071	12,071	12,071	12,071	12,071	12,071	12,071	12,071	12,071	12,071	12,071	12,071	12,071	12,071	
39																	
40	North Dakota share - D2 factor	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	4,780	

Line No.	SUPPORTING INFORMATION / DATA
1	ND Cap Structure with allowed ROE per order:
2	Capital Structure
3	Debt
4	Preferred equity
5	Common equity
6	Total
7	
8	
9	
10	Project life (years)
11	
12	
13	
14	
15	
16	
17	
18	Deferred Tax
19	Book depreciation
20	Tax depreciation-Federal
21	Tax depreciation-ND
22	Federal deferred income taxes
23	State deferred income taxes

Line No.	Year>>	2023		2023		2023		2023		2023		2023		2023	
		Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Projected Aug	Projected Sep	Projected Oct	Projected Nov	Projected Dec	Projected Total	
RATE BASE															
1	Plant Balance	0	0	0	0	0	0	0	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	(1,803)	(3,605)	(5,408)	(7,211)	(7,211)	
3	Net Plant In Service	0	0	0	0	0	0	0	1,337,895	1,336,093	1,334,290	1,332,487	1,330,684	1,330,684	
CWIP Calculation:															
	Beginning Balance	1,337,657	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	0	0	0	0	0	
	Additional CWIP	239	0	0	0	0	0	0	0	0	0	0	0	239	
	Closings from CWIP AFUDC	0	0	0	0	0	0	0	(1,337,895)	0	0	0	0	0	
4	CWIP (Project #T03032.031)	107308	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	0	0	0	0	0	
5	ADIT Proration Factors	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	
6	Accumulated Deferred Income Tax-Federal Only	0	0	0	0	0	0	0	(2,688)	(5,015)	(7,341)	(9,667)	(11,993)	(11,993)	
7	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	(3,265)	(6,090)	(8,915)	(11,741)	(14,566)	(14,566)	
8	Ending rate base	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,337,895	1,334,630	1,330,002	1,325,374	1,320,747	1,316,119	1,316,119	
9	Average rate base	111,088	111,088	111,088	111,088	111,088	111,088	111,088	111,088	111,088	111,088	111,088	111,088	111,088	
11	Return on Rate Base	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	
13	Available for return (equity portion of rate base)	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	
EXPENSES															
O&M and Depreciation															
18	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
19	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0	
20	Book Depreciation	0	0	0	0	0	0	0	0	1,803	1,803	1,803	1,803	7,211	
21	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	1,803	1,803	1,803	1,803	7,211	
23	Income before Taxes														
24	Available for return (from above)	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	5,698	
25	Taxable Income (grossed up)	7,538	7,538	7,538	7,538	7,538	7,538	7,538	7,538	7,538	7,538	7,538	7,538	90,450	
26	Income Taxes														
28	Current and Def Income Taxes	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	22,074	
29	Total Income Tax Expense	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	22,074	
REVENUE REQUIREMENTS															
33	Expenses	1,840	1,840	1,840	1,840	1,840	1,840	1,840	1,840	3,642	3,642	3,642	3,642	29,285	
34	Return on rate base	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	8,489	101,873	
35	Subtotal revenue requirements	10,329	10,329	10,329	10,329	10,329	10,329	10,329	10,329	12,132	12,132	12,132	12,132	131,158	
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	
37	Wholesale Revenue Credit	(1,525)	(1,525)	(1,525)	(1,525)	(1,525)	(1,525)	(1,525)	(1,525)	(1,792)	(1,792)	(1,792)	(1,792)	(19,369)	
38	Total revenue requirements	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	10,340	10,340	10,340	10,340	111,789	
39	North Dakota share - D2 factor	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	4,095	4,095	4,095	4,095	44,267	

Line No.	SUPPORTING INFORMATION / DATA																
1	ND Cap Structure with allowed ROE per order.																
2	Capital Structure																
3		Ratio	Cost	WA Cost													Property tax
4	Debt	47.50%	5.29%	2.51%													2023 composite rate
5	Preferred equity	0.00%	0.00%	0.00%													1.68%
6	Common equity	52.50%	9.77%	5.13%													
7	Total	100.00%		7.64%	Overall Return												
8																	
9																	
10	Project life (years)																
11		Book	Tax														
12		50	15-year MACRS														
13																	
14		Fed Portion		State Portion													
15	Effective Tax Rate	24.40%	20.09%	4.31%													
16	Tax conversion factor	1.32284															
17	Wholesale Revenue Credit	14.77%															
18	ND share - D2 factor	39.5989%															
19	Deferred Tax																
20	Book depreciation	0	0	0	0	0	0	0	0	1,803	1,803	1,803	1,803	7,211			
21	Tax depreciation-Federal	0	0	0	0	0	0	0	13,379	13,379	13,379	13,379	13,379	66,895			
22	Tax depreciation-ND	0	0	0	0	0	0	0	13,379	13,379	13,379	13,379	13,379	66,895			
23	Federal deferred income taxes	0	0	0	0	0	0	0	(2,688)	(2,326)	(2,326)	(2,326)	(2,326)	(11,993)			
24	State deferred income taxes	0	0	0	0	0	0	0	(577)	(499)	(499)	(499)	(499)	(2,572)			

Line No.	Year>>	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023
		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total	
RATE BASE															
1	Plant Balance	2,920,935	5,237,702	5,262,700	5,286,193	5,286,346	5,283,872	5,272,247	6,649,031	6,687,022	7,123,759	7,154,624	10,033,420	10,033,420	
2	Accumulated Depreciation	(15,704)	(19,937)	(27,528)	(35,155)	(42,816)	(50,477)	(58,135)	(65,776)	(75,412)	(85,103)	(95,427)	(105,796)	(105,796)	
3	Net Plant in Service	2,905,231	5,217,764	5,235,172	5,251,038	5,243,529	5,233,394	5,214,112	6,583,255	6,611,610	7,038,656	7,059,197	9,927,624	9,927,624	
4	CWIP (Project #)	4,647,599	2,553,812	2,935,848	3,133,533	3,577,946	4,059,892	4,256,918	3,930,852	4,437,751	4,573,237	5,086,137	2,463,901	2,463,901	
5	ADIT Federal Proration Factors	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	
6	Accumulated Deferred Income Tax-Federal Only	(39,699)	(45,619)	(50,864)	(56,102)	(61,333)	(66,564)	(71,796)	(79,337)	(86,478)	(94,869)	(103,133)	(139,533)	(139,533)	
7	Accumulated Deferred Income Taxes Federal & State	(48,213)	(55,403)	(61,773)	(68,135)	(74,488)	(80,841)	(87,195)	(96,354)	(105,026)	(115,217)	(125,253)	(169,460)	(169,460)	
8	Accumulated Deferred Income Taxes Federal & State - No Proration	(48,213)	(55,403)	(61,773)	(68,135)	(74,488)	(80,841)	(87,195)	(96,354)	(105,026)	(115,217)	(125,253)	(169,460)	(169,460)	
9	Ending rate base	7,504,617	7,716,173	8,109,246	8,316,436	8,746,987	9,212,445	9,383,835	10,417,753	10,944,336	11,496,677	12,020,081	12,222,065	12,222,065	
10	Average rate base	791,576	791,576	791,576	791,576	791,576	791,576	791,576	791,576	791,576	791,576	791,576	791,576	791,576	
11	Return on Rate Base	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	
12	Return on Rate Base	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	
13	Return on Rate Base	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	
14	Available for return (equity portion of rate base)	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	
15	Available for return (equity portion of rate base)	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	
16	Available for return (equity portion of rate base)	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	
EXPENSES															
O&M and Depreciation															
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
18	Property Tax	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	2,742	
19	Book Depreciation	3,968	4,233	7,591	7,627	7,661	7,661	7,658	7,641	9,636	9,691	10,324	10,369	94,059	
20	Total O&M and Depreciation Expense	6,709	6,975	10,332	10,369	10,403	10,403	10,399	10,382	12,378	12,433	13,066	13,110	126,958	
21	Total O&M and Depreciation Expense	6,709	6,975	10,332	10,369	10,403	10,403	10,399	10,382	12,378	12,433	13,066	13,110	126,958	
22	Total O&M and Depreciation Expense	6,709	6,975	10,332	10,369	10,403	10,403	10,399	10,382	12,378	12,433	13,066	13,110	126,958	
23	Income before Taxes	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	
24	Available for return (from above)	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	40,602	
25	Taxable Income (grossed up)	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	
26	Taxable Income (grossed up)	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	53,710	
27	Income Taxes	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	
28	Current and Def Income Taxes	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	
29	Total Income Tax Expense	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	
30	Total Income Tax Expense	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	
31	Total Income Tax Expense	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	13,108	
REVENUE REQUIREMENTS															
32	Expenses	19,817	20,083	23,440	23,476	23,510	23,511	23,507	23,490	25,485	25,541	26,173	26,218	284,252	
33	Return on rate base	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	725,907	
34	Subtotal revenue requirements	80,309	80,575	83,932	83,969	84,003	84,003	83,999	83,982	85,978	86,033	86,666	86,710	1,010,158	
35	Subtotal revenue requirements	80,309	80,575	83,932	83,969	84,003	84,003	83,999	83,982	85,978	86,033	86,666	86,710	1,010,158	
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	
37	Wholesale Revenue Credit	(11,860)	(11,899)	(12,395)	(12,400)	(12,405)	(12,405)	(12,405)	(12,402)	(12,697)	(12,705)	(12,799)	(12,800)	(149,178)	
38	Total revenue requirements	68,449	68,676	71,537	71,568	71,597	71,597	71,594	71,580	73,281	73,328	73,867	73,905	860,980	
39	Total revenue requirements	68,449	68,676	71,537	71,568	71,597	71,597	71,594	71,580	73,281	73,328	73,867	73,905	860,980	
40	North Dakota share - D2 factor	27,105	27,195	28,328	28,340	28,352	28,352	28,351	28,345	29,018	29,037	29,251	29,266	340,939	

Line No.	SUPPORTING INFORMATION / DATA															
1	ND Cap Structure with allowed ROE per order.															
2	Capital Structure															
3	Debt															
4	Preferred equity															
5	Common equity															
6	Total															
7	Overall Return															
8	Book Tax															
9	Project life (years)															
10	50 15-year MACRS															
11	Fed Portion State Portion															
12	Effective Tax Rate															
13	Tax conversion factor															
14	Wholesale Revenue Credit															
15	ND share - D2 factor															
16	Deferred Tax															
17	Book depreciation															
18	Tax depreciation-Federal															
19	Tax depreciation-ND															
20	Federal deferred income taxes															
21	State deferred income taxes															

Line No.	Year>>	2024 Projected January	2024 Projected February	2024 Projected March	2024 Projected April	2024 Projected May	2024 Projected June	2024 Projected July	2024 Projected August	2024 Projected September	2024 Projected October	2024 Projected November	2024 Projected December	2024 Projected Total
RATE BASE														
1	Plant Balance	10,036,754	10,040,087	10,043,420	10,046,754	10,050,087	10,053,420	10,056,754	10,060,087	10,063,420	10,066,754	10,070,087	11,133,258	11,133,258
2	Accumulated Depreciation	(120,337)	(134,883)	(149,433)	(163,989)	(178,549)	(193,114)	(207,684)	(222,259)	(236,838)	(251,423)	(266,012)	(280,606)	(280,606)
3	Net Plant in Service	9,916,417	9,905,204	9,893,987	9,882,765	9,871,538	9,860,306	9,849,070	9,837,828	9,826,582	9,815,331	9,804,075	10,852,652	10,852,652
4	CWIP (Project #)	2,527,670	2,591,439	2,655,207	2,718,976	2,782,745	2,846,514	2,910,283	2,974,052	3,037,820	3,101,589	3,165,358	2,169,289	2,169,289
5	ADIT Federal Proration Factors	0.9178	0.9411	0.9562	0.9740	0.9890	0.9968	0.4219	0.3370	0.2548	0.1699	0.0877	0.0027	0.0027
6	Accumulated Deferred Income Tax-Federal Only	(151,411)	(162,296)	(172,081)	(180,802)	(188,423)	(194,980)	(200,439)	(204,798)	(208,093)	(210,290)	(211,424)	(211,477)	(211,477)
7	Accumulated Deferred Income Taxes Federal & State	(184,114)	(197,775)	(210,335)	(221,832)	(232,228)	(241,560)	(249,793)	(256,926)	(262,966)	(267,967)	(271,875)	(276,036)	(276,036)
8	Accumulated Deferred Income Taxes Federal & State - No Proration	(185,178)	(200,895)	(216,611)	(232,326)	(248,039)	(263,751)	(279,462)	(295,172)	(310,881)	(326,588)	(342,295)	(365,561)	(365,561)
9	Ending rate base	12,259,972	12,298,868	12,338,859	12,379,910	12,422,055	12,465,260	12,509,360	12,554,954	12,601,406	12,648,953	12,697,558	12,745,905	12,745,905
10	Average rate base	1,039,393	1,039,393	1,039,393	1,039,393	1,039,393	1,039,393	1,039,393	1,039,393	1,039,393	1,039,393	1,039,393	1,039,393	12,472,717
11	Return on Rate Base	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	953,165
12	Return on Rate Base	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	953,165
13	Return on Rate Base	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	953,165
14	Available for return (equity portion of rate base)	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	639,757
15	Available for return (equity portion of rate base)	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	639,757
16	EXPENSES													
17	O&M and Depreciation													
18	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Property Tax	6,977	6,977	6,977	6,977	6,977	6,977	6,977	6,977	6,977	6,977	6,977	6,977	83,722
20	Book Depreciation	14,541	14,546	14,551	14,555	14,560	14,565	14,570	14,575	14,580	14,584	14,589	14,594	174,810
21	Total O&M and Depreciation Expense	21,518	21,523	21,527	21,532	21,537	21,542	21,547	21,552	21,556	21,561	21,566	21,571	258,532
22	Income before Taxes													
23	Available for return (from above)	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	53,313	639,757
24	Taxable Income (grossed up)	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	846,294
25	Taxable Income (grossed up)	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	70,525	846,294
26	Income Taxes													
27	Current and Def Income Taxes	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	206,537
28	Total Income Tax Expense	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	206,537
29	Total Income Tax Expense	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	17,211	206,537
30	REVENUE REQUIREMENTS													
31	Expenses													
32	Return on rate base	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	79,430	953,165
33	Subtotal revenue requirements	118,160	118,164	118,169	118,174	118,179	118,184	118,189	118,193	118,198	118,203	118,208	118,213	1,418,234
34	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Wholesale Revenue Credit	(14,695)	(14,695)	(14,695)	(14,697)	(14,697)	(14,698)	(14,698)	(14,699)	(14,700)	(14,700)	(14,701)	(14,701)	(176,378)
36	Total revenue requirements	103,465	103,469	103,473	103,477	103,482	103,486	103,490	103,494	103,499	103,503	103,507	103,511	1,241,856
37	Total revenue requirements	103,465	103,469	103,473	103,477	103,482	103,486	103,490	103,494	103,499	103,503	103,507	103,511	1,241,856
38	North Dakota share - D2 factor	40,971	40,973	40,974	40,976	40,978	40,979	40,981	40,983	40,984	40,986	40,988	40,989	491,761
39	North Dakota share - D2 factor	40,971	40,973	40,974	40,976	40,978	40,979	40,981	40,983	40,984	40,986	40,988	40,989	491,761
40	North Dakota share - D2 factor	40,971	40,973	40,974	40,976	40,978	40,979	40,981	40,983	40,984	40,986	40,988	40,989	491,761
SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio		Cost		WA Cost		Property tax						
3	Debt	47.50%		5.29%		2.51%		2024 composite rate						
4	Preferred equity	0.00%		0.00%		0.00%								
5	Common equity	52.50%		9.77%		5.13%								
6	Total	100.00%				7.64%		Overall Return						
7														
8														
9														
10	Project life (years)	Book		Tax										
11		50		15-year MACRS										
12				Fed Portion		State Portion								
13	Effective Tax Rate	24.40%		20.09%		4.31%								
14	Tax conversion factor	1.32284												
15	Wholesale Revenue Credit	12.44%												
16	ND share - D2 factor	39.5989%												
17														
18	Deferred Tax													
19	Book depreciation	14,541	14,546	14,551	14,555	14,560	14,565	14,570	14,575	14,580	14,584	14,589	14,594	174,810
20	Tax depreciation-Federal	78,947	78,947	78,947	78,947	78,947	78,947	78,947	78,947	78,947	78,947	78,947	109,927	978,340
21	Tax depreciation-ND	78,947	78,947	78,947	78,947	78,947	78,947	78,947	78,947	78,947	78,947	78,947	109,927	978,340
22	Federal deferred income taxes	(12,942)	(12,941)	(12,940)	(12,939)	(12,938)	(12,937)	(12,936)	(12,935)	(12,934)	(12,933)	(12,932)	(19,157)	(161,469)
23	State deferred income taxes	(2,776)	(2,776)	(2,775)	(2,775)	(2,775)	(2,775)	(2,775)	(2,774)	(2,774)	(2,774)	(2,774)	(4,109)	(34,632)

Line No.	Year>>	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	
		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total	
RATE BASE															
1	Plant Balance	1,901,823	1,905,983	1,905,983	1,905,983	1,905,983	2,147,130	2,297,041	3,109,594	3,109,594	3,109,594	3,109,594	3,296,196	3,296,196	
2	Accumulated Depreciation	(17,154)	(19,910)	(22,672)	(25,434)	(28,197)	(30,959)	(34,071)	(37,399)	(41,906)	(46,413)	(50,919)	(55,426)	(55,426)	
3	Net Plant in Service	1,884,670	1,886,073	1,883,311	1,880,549	1,877,786	2,116,171	2,262,970	3,072,195	3,067,688	3,063,181	3,058,675	3,240,770	3,240,770	
4	CWIP (Project #)	537,379	613,950	1,044,911	1,062,390	1,116,881	972,234	899,156	86,602	86,602	111,602	161,602	0	0	
5	ADIT-Federal Proration Factors	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	
6	Accumulated Deferred Income Tax-Federal Only	(29,507)	(32,586)	(35,665)	(38,743)	(41,822)	(44,900)	(47,909)	(50,873)	(53,601)	(56,329)	(59,057)	(63,312)	(63,312)	
7	Accumulated Deferred Income Taxes Federal & State	(35,835)	(39,576)	(43,314)	(47,053)	(50,792)	(54,531)	(58,184)	(61,785)	(65,098)	(68,411)	(71,724)	(76,892)	(76,892)	
8	Ending rate base	2,386,213	2,460,447	2,884,908	2,895,885	2,943,876	3,033,874	3,103,941	3,097,012	3,089,192	3,106,372	3,148,553	3,163,879	3,163,879	
9	Average rate base	241,261	241,261	241,261	241,261	241,261	241,261	241,261	241,261	241,261	241,261	241,261	241,261	2,895,133	
10	Return on Rate Base	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	221,246	
11	Available for return (equity portion of rate base)	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	148,499	
12	EXPENSES														
O&M and Depreciation															
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
18	Property Tax	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	1,945	23,341	
19	Book Depreciation	2,103	2,756	2,762	2,762	2,762	2,762	3,112	3,329	4,507	4,507	4,507	4,507	40,375	
20	Total O&M and Depreciation Expense	4,048	4,701	4,707	4,707	4,707	4,707	5,057	5,274	6,452	6,452	6,452	6,452	63,717	
21	Income before Taxes	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	12,375	148,499	
22	Available for return (from above)	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	196,439	
23	Taxable Income (grossed up)	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	16,370	196,439	
24	Income Taxes	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	47,941	
25	Current and Def Income Taxes	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	47,941	
26	Total Income Tax Expense	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	3,995	47,941	
27	REVENUE REQUIREMENTS														
28	Expenses	8,043	8,696	8,702	8,702	8,702	8,702	9,052	9,269	10,447	10,447	10,447	10,447	111,658	
29	Return on rate base	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	18,437	221,246	
30	Subtotal revenue requirements	26,480	27,134	27,140	27,140	27,140	27,140	27,489	27,706	28,884	28,884	28,884	28,884	332,904	
31	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	
32	Wholesale Revenue Credit	(3,911)	(4,007)	(4,008)	(4,008)	(4,008)	(4,008)	(4,060)	(4,092)	(4,266)	(4,266)	(4,266)	(4,266)	(49,163)	
33	Total revenue requirements	22,570	23,127	23,132	23,132	23,132	23,132	23,430	23,614	24,618	24,618	24,618	24,618	283,741	
34	North Dakota share - D2 factor	8,937	9,158	9,160	9,160	9,160	9,160	9,278	9,351	9,749	9,749	9,749	9,749	112,358	
SUPPORTING INFORMATION / DATA															
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure	Ratio		Cost		WA Cost		Property tax							
3	Debt	47.50%		5.29%		2.51%		2023 composite rate							
4	Preferred equity	0.00%		0.00%		0.00%									
5	Common equity	52.50%		9.77%		5.13%									
6	Total	100.00%				7.64%		Overall Return							
7															
8															
9															
10	Project life (years)	Book		Tax											
11		50		15-year MACRS											
12															
13				Fed Portion		State Portion									
14	Effective Tax Rate	24.40%		20.09%		4.31%									
15	Tax conversion factor	1.32284													
16	Wholesale Revenue Credit	14.77%													
17	ND share - D2 factor	39.5989%													
18	Deferred Tax														
19	Book depreciation	2,103	2,756	2,762	2,762	2,762	2,762	3,112	3,329	4,507	4,507	4,507	4,507	40,375	
20	Tax depreciation-Federal	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	224,584	
21	Tax depreciation-ND	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	18,082	224,584	
22	Federal deferred income taxes	(3,211)	(3,080)	(3,079)	(3,079)	(3,079)	(3,079)	(3,079)	(2,965)	(2,728)	(2,728)	(2,728)	(2,728)	(37,017)	
23	State deferred income taxes	(689)	(661)	(660)	(660)	(660)	(660)	(645)	(636)	(585)	(585)	(585)	(585)	(7,939)	

Line No.	Year>>	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	
		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total	
RATE BASE															
1	Plant Balance	0	0	0	0	0	0	0	0	704,973	704,973	1,943,459	1,943,459		
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	(1,022)	(2,043)	(3,065)	(3,065)		
3	Net Plant in Service	0	0	0	0	0	0	0	0	704,973	703,951	1,940,394	1,940,394		
4	CWIP (Project #)	27,366	436,560	883,933	998,887	1,101,951	1,183,951	1,320,064	1,846,792	1,452,430	1,834,235	2,125,394	1,138,717		
5	ADIT Federal 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		
6	Accumulated Deferred Income Tax- Federal Only	0	0	0	0	0	0	0	0	0	205	411	(18,911)		
7	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	249	499	(22,967)		
8	Ending rate base	27,366	436,560	883,933	998,887	1,101,951	1,183,951	1,320,064	1,846,792	2,157,403	2,538,435	2,828,822	3,056,144		
9															
10	Average rate base	117,854	117,854	117,854	117,854	117,854	117,854	117,854	117,854	117,854	117,854	117,854	117,854		
11															
12	Return on Rate Base	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006		
13															
14	Available for return (equity portion of rate base)	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045		
15															
16	EXPENSES														
O&M and Depreciation															
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0		
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0		
19	Book Depreciation	0	0	0	0	0	0	0	0	0	1,022	1,022	1,022		
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	1,022	1,022	1,022		
21															
22															
23	Income before Taxes														
24	Available for return (from above)	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045	6,045		
25	Taxable Income (grossed up)	7,997	7,997	7,997	7,997	7,997	7,997	7,997	7,997	7,997	7,997	7,997	7,997		
26															
27	Income Taxes														
28	Current and Def Income Taxes	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952		
29	Total Income Tax Expense	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952		
30															
31															
32	REVENUE REQUIREMENTS														
33	Expenses	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	1,952	2,973	2,973	2,973		
34	Return on rate base	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006	9,006		
35	Subtotal revenue requirements	10,958	10,958	10,958	10,958	10,958	10,958	10,958	10,958	10,958	11,980	11,980	11,980		
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0		
37	Wholesale Revenue Credit	(1,618)	(1,618)	(1,618)	(1,618)	(1,618)	(1,618)	(1,618)	(1,618)	(1,618)	(1,769)	(1,769)	(1,769)		
38	Total revenue requirements	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	10,211	10,211	10,211		
39															
40	North Dakota share - D2 factor	3,698	3,698	3,698	3,698	3,698	3,698	3,698	3,698	3,698	4,043	4,043	4,043		
SUPPORTING INFORMATION / DATA															
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16															
17															
18															
19	Deferred Tax														
20	Book depreciation	0	0	0	0	0	0	0	0	0	1,022	1,022	1,022		
21	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	97,173	97,173		
22	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	97,173	97,173		
23	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	205	205	(19,322)		
24	State deferred income taxes	0	0	0	0	0	0	0	0	0	44	44	(4,144)		

Line No.	Year>>	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024
		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total
RATE BASE														
1	Plant Balance	1,943,459	1,943,459	1,943,459	1,943,459	1,943,459	1,943,459	1,943,459	1,943,459	1,943,459	1,943,459	1,943,459	1,943,459	2,743,460
2	Accumulated Depreciation	(5,882)	(8,698)	(11,515)	(14,331)	(17,148)	(19,964)	(22,781)	(25,598)	(28,414)	(31,231)	(34,047)	(36,864)	(36,864)
3	Net Plant in Service	1,937,578	1,934,761	1,931,945	1,929,128	1,926,311	1,923,495	1,920,678	1,917,862	1,915,045	1,912,229	1,909,412	1,906,596	2,706,596
4	CWIP (Project #)	1,378,300	1,617,883	1,857,467	2,097,050	2,336,633	2,576,217	2,815,800	3,055,383	3,294,967	3,534,550	3,774,133	3,213,716	3,213,716
5	ADIT Federal Promotion 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	0.0027
6	Accumulated Deferred Income Tax-Federal Only	(21,229)	(23,353)	(25,263)	(26,966)	(28,453)	(29,734)	(30,799)	(31,650)	(32,294)	(32,723)	(32,944)	(32,973)	(32,973)
7	Accumulated Deferred Income Taxes Federal & State	(25,827)	(28,493)	(30,945)	(33,189)	(35,218)	(37,040)	(38,647)	(40,040)	(41,226)	(42,196)	(42,960)	(43,254)	(45,254)
8	Ending rate base	3,290,051	3,524,151	3,758,467	3,992,989	4,227,727	4,462,671	4,697,831	4,933,205	5,168,786	5,404,582	5,640,586	5,875,058	5,875,058
9	Average rate base	372,002	372,002	372,002	372,002	372,002	372,002	372,002	372,002	372,002	372,002	372,002	372,002	4,464,019
10	Return on Rate Base	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	341,140
11	Available for return (equity portion of rate base)	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	228,971
12	EXPENSES													
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	26,396
19	Book Depreciation	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	33,799
20	Total O&M and Depreciation Expense	5,016	5,016	5,016	5,016	5,016	5,016	5,016	5,016	5,016	5,016	5,016	5,016	60,195
21	Income before Taxes	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	228,971
22	Available for return (from above)	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	19,081	228,971
23	Taxable Income (grossed up)	25,241	25,241	25,241	25,241	25,241	25,241	25,241	25,241	25,241	25,241	25,241	25,241	302,891
24	Income Taxes	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	73,920
25	Current and Def Income Taxes	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	73,920
26	Total Income Tax Expense	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	6,160	73,920
27	REVENUE REQUIREMENTS													
28	Expenses	11,176	11,176	11,176	11,176	11,176	11,176	11,176	11,176	11,176	11,176	11,176	11,176	134,115
29	Return on rate base	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	28,428	341,140
30	Subtotal revenue requirements	39,605	39,605	39,605	39,605	39,605	39,605	39,605	39,605	39,605	39,605	39,605	39,605	475,255
31	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Wholesale Revenue Credit	(4,925)	(4,925)	(4,925)	(4,925)	(4,925)	(4,925)	(4,925)	(4,925)	(4,925)	(4,925)	(4,925)	(4,925)	(59,105)
33	Total revenue requirements	34,679	34,679	34,679	34,679	34,679	34,679	34,679	34,679	34,679	34,679	34,679	34,679	416,150
34	North Dakota share - D2 factor	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	13,733	164,791

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio	Cost	WA Cost										
3	Debt	47.50%	5.29%	2.51%	Property tax									
4	Preferred equity	0.00%	0.00%	0.00%	2024 composite rate									
5	Common equity	52.50%	9.77%	5.13%										
6	Total	100.00%		7.64%	Overall Return									
7		Book	Tax											
8	Project life (years)	50	15-year MACRS											
9			Fed Portion	State Portion										
10	Effective Tax Rate	24.40%	20.09%	4.31%										
11	Tax conversion factor	1.32284												
12	Wholesale Revenue Credit	12.44%												
13	ND share - D2 factor	39.5989%												
14	Deferred Tax													
15	Book depreciation	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	2,817	33,799
16	Tax depreciation-Federal	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	224,629
17	Tax depreciation-ND	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	15,386	224,629
18	Federal deferred income taxes	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(10,564)	(38,347)
19	State deferred income taxes	(542)	(542)	(542)	(542)	(542)	(542)	(542)	(542)	(542)	(542)	(542)	(2,266)	(8,225)

Line No.	Year>>	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023																							
		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total																							
RATE BASE																																					
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	0																							
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0																							
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	0																							
4	CWIP (Project #)	0	0	2,445	3,337	5,495	6,115	10,539	37,761	49,696	54,602	59,535	61,462	61,462																							
5	ADIT Federal Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000																							
6	Accumulated Deferred Income Tax-Federal Only	0	0	0	0	0	0	0	0	0	0	0	0	0																							
7	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	0	0																							
8	Accumulated Deferred Income Taxes Federal & State - No Proration	0	0	0	0	0	0	0	0	0	0	0	0	0																							
8	Ending rate base	0	0	2,445	3,337	5,495	6,115	10,539	37,761	49,696	54,602	59,535	61,462	61,462																							
9	Average rate base	0	0	0	0	0	0	0	0	0	0	0	0	0																							
11	Return on Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0																							
12	Return on Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0																							
13	Return on Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0																							
14	Available for return (equity portion of rate base)	0	0	0	0	0	0	0	0	0	0	0	0	0																							
EXPENSES																																					
17	O&M and Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0																							
18	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0																							
19	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0																							
20	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0																							
21	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0																							
22	Income before Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0																							
24	Available for return (from above)	0	0	0	0	0	0	0	0	0	0	0	0	0																							
25	Taxable Income (grossed up)	0	0	0	0	0	0	0	0	0	0	0	0	0																							
26	Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0																							
28	Current and Def Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0																							
29	Total Income Tax Expense	0	0	0	0	0	0	0	0	0	0	0	0	0																							
REVENUE REQUIREMENTS																																					
33	Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0																							
34	Return on rate base	0	0	0	0	0	0	0	0	0	0	0	0	0																							
35	Subtotal revenue requirements	0	0	0	0	0	0	0	0	0	0	0	0	0																							
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0																							
37	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0																							
38	Total revenue requirements	0	0	0	0	0	0	0	0	0	0	0	0	0																							
39	North Dakota share - D2 factor	0	0	0	0	0	0	0	0	0	0	0	0	0																							
SUPPORTING INFORMATION / DATA																																					
1	ND Cap Structure with allowed ROE per order.																																				
2	Capital Structure																																				
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Line No.	Year>>	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024	2024																					
		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total																						
RATE BASE																																				
1	Plant Balance	0	0	0	0	0	0	0	0	0	500,000	500,000	975,000	975,000																						
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(725)	(1,449)	(1,449)																							
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	500,000	499,275	973,551																							
4	CWIP (Project #)	89,583	179,167	268,750	358,333	447,917	580,357	712,798	845,238	977,679	610,119	692,559	300,000																							
5	ADIT Federal 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																							
6	Accumulated Deferred Income Tax- Federal Only	0	0	0	0	0	0	0	0	0	(284)	(418)	(436)																							
7	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	(644)	(1,106)	(2,474)																							
8	Accumulated Deferred Income Taxes Federal & State - No Pro	0	0	0	0	0	0	0	0	0	(2,034)	(3,891)	(11,544)																							
8	Ending rate base	89,583	179,167	268,750	358,333	447,917	580,357	712,798	845,238	977,679	1,109,475	1,190,729	1,271,076																							
9	Average rate base	51,481	51,481	51,481	51,481	51,481	51,481	51,481	51,481	51,481	51,481	51,481	51,481																							
11	Return on Rate Base	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934																							
12	Return on Rate Base	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934																							
13	Available for return (equity portion of rate base)	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641																							
14	Available for return (equity portion of rate base)	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641																							
15	Available for return (equity portion of rate base)	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641																							
16	Available for return (equity portion of rate base)	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641																							
16	EXPENSES																																			
17	O&M and Depreciation																																			
18	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0																							
19	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0																							
20	Book Depreciation	0	0	0	0	0	0	0	0	0	0	725	725																							
21	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	725	725																							
22	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	725	725																							
23	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	725	725																							
23	Income before Taxes	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641																							
24	Available for return (from above)	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641	2,641																							
25	Taxable Income (grossed up)	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493																							
26	Taxable Income (grossed up)	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493	3,493																							
27	Income Taxes	852	852	852	852	852	852	852	852	852	852	852	852																							
28	Current and Def Income Taxes	852	852	852	852	852	852	852	852	852	852	852	852																							
29	Total Income Tax Expense	852	852	852	852	852	852	852	852	852	852	852	852																							
30	Total Income Tax Expense	852	852	852	852	852	852	852	852	852	852	852	852																							
31	Total Income Tax Expense	852	852	852	852	852	852	852	852	852	852	852	852																							
32	Total Income Tax Expense	852	852	852	852	852	852	852	852	852	852	852	852																							
32	REVENUE REQUIREMENTS																																			
33	Expenses	852	852	852	852	852	852	852	852	852	852	1,577	1,577																							
34	Return on rate base	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934	3,934																							
35	Subtotal revenue requirements	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787	4,787	5,511	5,511																							
36	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0																							
37	Wholesale Revenue Credit	(595)	(595)	(595)	(595)	(595)	(595)	(595)	(595)	(595)	(595)	(685)	(7,324)																							
38	Total revenue requirements	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,826	4,826																							
39	Total revenue requirements	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,191	4,826	4,826																							
40	North Dakota share - D2 factor	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,911	1,911																							
40	North Dakota share - D2 factor	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,911	1,911																							
11	SUPPORTING INFORMATION / DATA																																			
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20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	8,333	8,333	32,083																							
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	8,333	8,333	32,083																							
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	(1,675)	(1,529)	(6,302)																							
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	(359)	(328)	(1,352)																							

Attachment 50
Legislative and Non-Legislative Versions of
Electric Rate Schedule Section 13.05
ND Transmission Cost Recovery Rider

TRANSMISSION COST RECOVERY RIDER

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

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

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company’s retail rate schedules.

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

RATE:

TRANSMISSION COST RECOVERY			
Energy Charge per kWh:	kWh		kW
Large General Service (a)	N/A	¢/kWh	\$2,1241.841
Controlled Service (b)	0.09986	¢/kWh	N/A
Lighting (c)	0.641496	¢/kWh	N/A
All Other Service	0.651575	¢/kWh	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

DESCRIPTION	RATE CODE
Large General Service – Demand Charge	NTCRD
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RATE:

TRANSMISSION COST RECOVERY			
Energy Charge per kWh:	kWh		kW
Large General Service (a)	N/A	¢/kWh	\$2.124
Controlled Service (b)	0.099	¢/kWh	N/A
Lighting (c)	0.641	¢/kWh	N/A
All Other Service	0.651	¢/kWh	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.
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**Case No. PU-23-
Customer Notices**

Attachment 51 – ND TCR Proposed Bill Message

Attachment 52 – ND TCR Implementation Bill Insert

On September 15, 2023, 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 on and after January 1, 2024. This change is proposed only, and if suspended by the Commission, new rates won't take effect until the Commission approves them.

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

- Large General Service: \$120.29 (from \$1.841 to \$2.124 per kW)**
- Controlled Service: \$0.17 (from 0.086 cents to 0.099 cents per kWh)**
- Lighting: \$0.13 (from 0.496 cents to 0.641 cents per kWh)**
- Residential and all other service: \$0.76 / \$1.03 (from 0.575 cents to 0.651 cents per kWh)**

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

Changes to our North Dakota Transmission Cost Recovery Rider

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

The changes below apply to bill usage on and after January 1, 2024, and are on the Transmission Rider line of your bill.

	<u>Old rates</u>		<u>New rates</u>		<u>Impact of new rates⁽¹⁾</u>
Large General Service	\$ 1.841	per kW	\$ 2.124	per kW	\$120.29/month
Controlled Service	\$ 0.00086	per kWh	\$ 0.00099	per kWh	\$0.17/month
Lighting	\$ 0.00496	per kWh	\$ 0.00641	per kWh	\$0.13/month
Residential	\$ 0.00575	per kWh	\$ 0.00651	per kWh	\$0.76/month
All other service	\$ 0.00575	per kWh	\$ 0.00651	per kWh	\$1.03/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 Customer Service at 800-257-4044 or visit otpc.com.