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September 15, 2022

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-22-335**

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 218-739-8282 or cbyrnes@otpc.com.

Sincerely,

/s/ CHRISTOPHER E. BYRNES
Christopher E. Byrnes
Rates Analyst
Regulatory Administration

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-22-335

APPLICATION

I. EXECUTIVE SUMMARY

A. 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 twenty-two previously approved projects; regional transmission expenses and revenues recovered in the TCRR; the addition of three new transmission projects, one transmission rebuild project, and six Extenda-life projects; a change to the scope of a previously approved transmission project. The modified and new projects are summarized below.

New Transmission Projects

- Oslo 115 kV Breaker Station and Oslo – Lake Ardoch 115 kV Line
- Milbank 41.6 kV Reconductor
- Casselton 115 kV Capacitor Bank

Transmission Rebuild Program:

- Cooperstown-Binford 41.6 kV Rebuild

Transmission Extenda-Life Programs:

- Langdon-CB 885 41.6 kV Extenda-Life
- Gackle-CB 865 41.6 kV Extenda-Life
- Washburn-CB 555 41.6 kV Extenda-Life
- Plummer-CB 425 41.6 kV Extenda-Life
- Crookston-CB 655 41.6 kV Extenda-Life
- Donaldson-CB 235 41.6 kV Extenda-Life

Modified Project:

- Jamestown 115/41.6 kV Transformer Addition

B. Otter Tail proposes a rate implementation date of January 1, 2023.

C. The North Dakota projected revenue requirement for the recovery period of January 1, 2023, to December 31, 2023, is \$7,535,673 with residential customers using 1,000 kWh seeing a monthly bill increase of approximately \$1.13.

D. Otter Tail requests to permanently change the filing date of the application for the annual rate update its Transmission Cost Recovery Rider to September 15 for future filings to allow the incorporation of updated financial data that Otter Tail is required to submit to the Midcontinent Independent System Operator (MISO) at the end of August.

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 2023). 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 ten new transmission projects/program additions not currently in base rates and not previously included in the Rider; (2) a modification to the scope of a previously approved project (3) forecast updates to previously approved projects (4) details of the Midcontinent Independent System Operator (MISO) Return on Equity complaint and (5) details of Southwest Power Pool (SPP) related expenses

In addition to updating the TCRR revenue requirements, Otter Tail respectfully requests a permanent change to the filing date for the ND TCRR Annual update as per Ordering Paragraph 6 of the TCRR Order. Otter Tail requests a revised filing date of September 15 from September 1 for future filings to allow for the incorporation of the most current financial information used to populate Otter Tail’s Attachment O, GG, and MM for the upcoming calendar year, which is filed with MISO by September 1 of each year.

The net revenue requirement for 2023, upon which rates are developed, is \$7,535,673. For a residential customer using 1,000 kWh per month, the bill impact of this update is an increase of \$1.13 per month. For a large general service customer with 425 kW of demand, the bill impact of this update is an increase of \$116.03per 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

Christopher E. Byrnes
Rates Analyst, Regulatory Administration
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
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Paula Foster
Supervisor, Regulatory Analysis, Regulatory Administration
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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, 2022. The updated TCRR rate is calculated to take effect as of January 1, 2023.

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.

Otter Tail filed for a 15-day extension on July 26, 2022, to allow adequate time to incorporate and review updated financial information filed with MISO on September 1 into this filing. The Commission granted this 15-day extension for Otter Tail's 2023 annual update on August 18, 2022.

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 2023, Summary of Revenue Requirements, Class Allocation and Rate Design, and Tracker Summary calculations used for Otter Tail's proposed TCRR rate update.

Attachments 5-31 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 5-26) and the updated and new projects for which Otter Tail is requesting TCRR recovery (Attachments 27-31).

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.

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

- *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.
- *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 40 to this filing to show the ADIT proration calculation impact on the revenue requirement for the recovery period.

Otter Tail provides Attachment 41 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(J)-1(h)(6)(ii) of the IRS regulations and to avoid a tax normalization violation.² Attachment 41 shows the preservation of the proration of ADIT resulted in an increase of \$1,799 plus any applicable carrying charge to the revenue requirement. This item is included on Line No. 31 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 34 and 35 of the Tracker Summary (Attachment 4) and are shown separately in Attachment 36. 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 33) and MISO Related Revenues (Attachment 34).* 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.

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

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 36 and SPP Schedule 11 expenses on Line 37 of the Tracker Summary (Attachment 4). Both are shown separately in Attachment 33.

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 41 of the Tracker Summary (Attachment 4) and is shown in detail in Attachment 34.

- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 42 and 45 of the Tracker Summary (Attachment 4) and are shown separately on Attachment 36 (Schedule 26) and Attachment 37 (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 Return on Equity (ROE) Complaint.* On November 12, 2013, and February 12, 2015, two groups of industrial customers and other stakeholders filed complaints at FERC seeking to reduce the ROE component of the transmission rates that MISO Transmission Owners (TO), including Otter Tail, may collect under the MISO Tariff. The two groups of complainants sought to reduce the, then current, ROE of 12.38 percent to 9.15 percent and 8.67 percent, respectively.

FERC issued its decision on the first complaint on September 28, 2016, granting approval of a 10.32 percent base ROE plus any applicable adder effective prospectively from that date. Otter Tail and other MISO TOs were granted a 50-basis point adder for participation in a Regional Transmission Organization (RTO) to be applied to the base ROE.

On November 21, 2019, FERC issued [Opinion No. 569](#),³ a ruling on the two MISO complaint cases. The opinion adopted in part and rejected in part a new approach for evaluating base ROEs, which FERC had proposed in response to the D.C. Circuit Court's action to vacate and remand FERC's standing ROE methodology that was used to set the MISO ROE at 10.32 percent in the first complaint. The November 21, 2019, Order granted rehearing on the first complaint and reaffirmed its prior finding that the existing 12.38 percent

³169 FERC ¶ 61,129 (2019).

ROE is unjust and unreasonable. FERC set the MISO base ROE at 9.88 percent plus any applicable adders effective September 28, 2016, and required refunds be made within 30 days of the Order for the period where the 10.32 percent base ROE was in effect (the fifteen-month refund period of November 12, 2013, to February 11, 2015, and the period from September 28, 2016, to December 31, 2019). As of January 1, 2020, MISO implemented the new base ROE of 9.88 percent in its rates and began processing refunds. On May 21, 2020, FERC issued Opinion 569-A, granting rehearing in part of Opinion 569. Opinion 569-A refines the methodology used for determining ROE. Under Opinion 569-A the base ROE was determined to increase from 9.88 percent to 10.02 percent. In addition to the increase in ROE, Opinion 569-A affirmed the dismissal of the second ROE complaint. On November 19, 2020, FERC issued Opinion 569-B which largely affirmed Opinion 569-A, including the base ROE of 10.02 percent. Both ROE complaint cases remain pending at the D.C. Circuit Court of Appeals.

On September 10, 2020, an extension of time to process the refunds was filed with the Commission by MISO. FERC granted an extension of time until September 23, 2021. Revised calculations for the latest Commission-approved ROE may result in either refunds or surcharges to customers. It became clear that given the complexity of the refunds related to Opinions 569, 569-A, and 569-B the September 2021 deadline was very difficult to achieve. On June 30, 2021, MISO requested an additional extension of time to process the refunds and surcharges until June 30, 2022. In its June 2021 request for an additional extension of time, MISO explained the majority of refunds will still take place in 2021. FERC partially accepted the MISO request for extension of time on August 2, 2021, granting MISO until February 28, 2022, to finalize processing refunds and surcharges. In February of 2022, MISO completed the ROE resettlement process for Opinions 569, 569-A, and 569-B.

Because Otter Tail uses a forward-looking rate formula in MISO, it makes an annual true-up filing with MISO. The true-up is generally calculated by determining the difference between the projected revenue requirement used in developing the rates for billing and the actual revenue requirements and billings based on actual operating results. Otter Tail includes the impacts of the 2021 refunds/surcharges within this filing in Attachments 34, 35, 36, 37, and 39 collectively.

- *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 38 and is reflected as a credit in the Tracker Summary (Attachment 4, line 46).

- *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 36 and Attachment 37 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 39, there are no forecast amounts for Schedule 37 and 38 revenues for the 2023 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 2022 is \$21,850, as can be seen in Attachment 4 on line 43. The Schedule 38 revenue credit reflected in this TCRR update for 2022 is \$27,988, as seen in Attachment 4 on line 44. These are actual amounts through July 2022 and are included as part of the 2021 true-up amount.

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

Twenty-two 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 2022 and 2023 and reflected in Attachments 5-26.

Table 1

	Project	Case Number	Attachment
1	BSAT-Ellendale MVP	PU-12-702	5
2	Max-Ryder 41.6 kV Line Upgrade	PU-16-624	6
3	Bagley 115 kV Switch Station	PU-17-340	7
4	Lake Norden Area Transmission	PU-18-329	8
5	Donaldson 115 kV Cap Bank	PU-19-311	9
6	Northwest MN UVLS	PU-19-311	10
7	Blair 230 kV Substation	PU-19-311	11
8	Veblen 41.6 kV Cap Bank	PU-19-311	12
9	New Effington 230/41.6 kV Line	PU-19-311	13
10	Jamestown Substation	PU-19-311	14
11	CPEC Purchase	PU-19-311	15
12	Erie 230/115kV Substation	PU-20-383	16
13	Norcross 115kV Line-115/41.6kV Sub	PU-20-383	17
14	Winger 230/115kV Transformer	PU-20-383	18
15	Jamestown 41.6 kV Source	PU-20-383	19
16	Hoot Lake Capacitor	PU-20-383	20
17	Finley/McVile 41.6 kV Rebuild	PU-20-383	21
18	Turtle Lake/Mercer 41.6 kV Rebuild	PU-20-383	22
19	Doyon/Bartlett 41.6 kV Rebuild	PU-20-383	23
20	Hoot Lake Transformer	PU-21-376	24
21	2021 Transmission Rebuild Projects	PU-21-376	25
22	2021 Transmission Extenda-Life Projects	PU-21-376	26

Modified Jamestown 41.6 kV Source Project

Otter Tail obtained approval for a new project called the “Jamestown 41.6 kV Source” during its 2020 North Dakota Transmission Cost Recovery Rider Filing.⁴ This project was initiated by Otter Tail in response to Central Power Electric Cooperative’s (CPEC) plan to disconnect its 41.6 kV facilities from Otter Tail’s 41.6 kV facilities near the Pipestem Dam west of Jamestown, North Dakota.

At the time of the 2020 ND TCRR filing, Otter Tail envisioned the “Jamestown 41.6 kV Source” to involve establishing a new 41.6 kV interconnection between Otter Tail and CPEC that would be operated ‘normally open’ resulting in customers normally being served from a 115 kV source at Otter Tail’s Jamestown Peaking Plant, with back-up service available from CPEC’s 41.6 kV system if the Otter Tail transmission source is unavailable. MISO approved this project as part of its 2019 Transmission Expansion Plan (MTEP19).⁵

⁴ Otter Tail’s August 31, 2020, Application, p. 13-15

⁵ See MTEP Project Number 16146 in Appendix A of MISO’s 2019 Transmission Expansion Plan, available at:

<https://www.misoenergy.org/planning/planning/previous-mtep-reports/#t=10&p=0&s=FileName&sd=desc>.

Since the time of the 2020 ND TCRR filing, Otter Tail has determined through further analysis that the new 41.6 kV interconnection with CPEC would not have adequate capability to serve all of the existing load currently served by the 41.6 kV system in this area. The 2020 ND TCRR filing had indicated that the most robust alternatives to support the 41.6 kV system in this area were projects that involved extending a new 115 kV source from Otter Tail's existing 115 kV system around Jamestown. However, the 115 kV alternatives were previously dismissed due to routing concerns through parts of downtown Jamestown and crossing the Pipestem Dam or Pipestem Reservoir.

Through a redesign of the project in coordination with the City of Jamestown, Otter Tail has identified a transmission plan that involves adding a new 115/41.6 kV transformer at the existing Jamestown Downtown Substation, extending 41.6 kV line (rather than 115 kV) from the Downtown Jamestown Substation a distance of approximately 1.5 miles west to a new 115/41.6 kV Substation that will be constructed on the southwest side of the Jamestown city limits. Although this alternative transmission plan has a higher cost, it offers several benefits over the original plan of a new 41.6 kV interconnection with CPEC, including:

- The ability to serve higher amounts of load in the future (i.e. load growth);
- Less line exposure between circuit breakers resulting in less interruptions to customers;
- The addition of a shield wire on the new 41.6 kV line to reduce lightning-induced interruptions;
- The elimination of incremental transmission service charges from CPEC and Southwest Power Pool; and
- The ability for Otter Tail to operate the transmission system serving customers in this area without reliance or dependence on third parties.

The original transmission plan approved by MISO in MTEP19 has been updated to reflect this new transmission plan in MISO's transmission planning process. Otter Tail is currently constructing this project with a planned in-service date in October 2022. The project is estimated to cost approximately \$4.0 million (Total) / \$1.6 million (ND). Attachment 19 includes the financial details of the updated transmission plan for Jamestown.

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 a change to the scope of a previously approved transmission project, the addition of three new transmission projects, one transmission rebuild project, and six 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.

Oslo 115 kV Breaker Station and Oslo – Lake Ardoch 115 kV Line – Attachment 27

Within Otter Tail’s 2019 and 2020 TCRR filings⁶, Otter Tail described a phased transmission plan that has been developed in coordination with Minnkota Power Cooperative (MPC) to address reliability concerns in Northwest Minnesota as load continues to grow in that area. The transmission plan has not changed since the 2020 TCRR filing, and includes the following projects (in sequence):

1. 115 kV Capacitor Banks at Donaldson (OTP) and Thief River Falls (MPC)
2. Under Voltage Load Shedding (UVLS) at Donaldson (OTP), Plummer (OTP), Crookston (OTP), and Thief River Falls (MPC)
3. Winger – Plummer 115 kV structure replacements (MPC) and substation improvements (OTP)
4. Winger 230/115 kV Transformer #2 (OTP/MPC)
5. Lake Ardoch 230/115 kV Substation (OTP/MPC)
6. Winger – Plummer 115 kV Line #2 (OTP/MPC)

Transmission planning studies have indicated that it is necessary for Otter Tail and MPC to move forward with the fifth step in the phased transmission plan, the Lake Ardoch 230/115 kV Substation, in order to maintain reliability of the transmission system in Northwest Minnesota.

The Northwest Minnesota transmission system is an extensive network of 115 kV transmission lines with 230 kV sources at Drayton (North Dakota), Grand Forks (North Dakota) and Winger (Minnesota). Transmission planning studies have identified that existing 115 kV lines can overload in the future if there is an outage of the Winger 230 kV source. Likewise, studies have also shown that depressed

⁶ Otter Tail’s August 30, 2019 Application, p. 8-9 and August 31, 2020 Application, p. 12-13.

voltages can occur throughout Northwest Minnesota in the future if there is a prior outage of an existing transmission facility followed by the unplanned outage of another facility.

In order to address the reliability concerns expected to begin in the winter of 2024-2025, Otter Tail and MPC have agreed to work collaboratively to build a new 230 kV source into the existing 115 kV system. This new source will consist of a new Lake Ardoch 230/115 kV Substation just east of Ardoch, North Dakota, that will tap the existing Drayton to Prairie 230 kV line and extend a new 115 kV line east a distance of approximately seven miles to a new Oslo 115 kV switching station just west of Oslo, Minnesota.

Transmission planning studies have shown that the new Lake Ardoch 230/115 kV Substation, Oslo 115 kV Switching Station, and the associated 115 kV line between these stations will maintain the reliability of the transmission system for an outage of the Winger source and offer a more resilient system capable of meeting voltage criteria following an unplanned outage during a prior outage condition. Otter Tail and MPC have coordinated this project with MISO and received approval for the Lake Ardoch 230/115 kV Substation, Oslo 115 kV Switching Station and Lake Ardoch to Oslo 115 kV line during MISO's 2019 Transmission Expansion Plan (MTEP19).⁷

Otter Tail and MPC have agreed that MPC will construct the Lake Ardoch 230/115 kV Substation and Otter Tail will construct the Oslo 115 kV Switching Station and the Lake Ardoch to Oslo 115 kV line. Otter Tail expects to start local permitting and design of the project in first quarter of 2023 with procurement occurring in the second quarter of 2023 in order for the project to be completed in late 2024.

Otter Tail's portion of the Lake Ardoch to Oslo 115 kV Project and Oslo 115 kV Switching Station is estimated to be approximately \$6.6 million (OTP Total) / \$2.6 million (OTP ND).

Milbank 41.6 kV Reconductor – Attachment 28

The communities of Milbank and Twin Brooks are served by 41.6 kV transmission lines which are a mix of old delta framing and vertical framing with 1/0 ACSR conductor. During both transmission and distribution studies, the 1/0 ACSR conductor was identified to be insufficient for N-1 conditions creating voltage

⁷ See Project Number 4232 in Appendix A of MISO's 2019 Transmission Expansion Plan, available at: <https://www.misoenergy.org/planning/planning/previous-mtep-reports/#t=10&p=0&s=FileName&sd=desc>.

concerns for both communities. Two primary alternatives were studied to increase voltage support to these communities: (1) installing larger conductor; or (2) installing additional capacitor banks. After evaluating both options, the most effective solution for mitigating reliability concerns to customers in the area both near term and long term was determined to be reconductoring the existing line with 477 ACSR.

Of the three miles of 41.6 kV line that is currently 1/0 ACSR, two miles utilize poles that have Otter Tail's delta (3050) framing, and one mile has been upgraded to vertical (3102) framing. New construction for Otter Tail's transmission lines utilizes poles with vertical framing to allow for a shield wire to be added that offers improved lightning protection. In addition, a shield wire allows for the use of an Optical Ground Wire (OPGW). An OPGW is a fiber optic cable surrounded by strands of wire that offers the benefits of a shield wire and meets various protective relaying and business communication needs. The existing poles that have delta framing along this line are not adequate to support the weight of the heavier conductor and will need to be replaced, whereas the existing poles that have vertical framing will be adequate for the 477 ACSR conductor. Therefore, this project will involve replacing three miles of conductor and two miles of poles with an OPGW shield wire being added along the entire three miles of line. The OPGW will be used to strengthen Otter Tail's communication circuits that are used for providing real-time control and visibility of distribution substations and switches along this 41.6 kV line. The estimated cost for this project is \$430,000(OTP Total)/\$172,000 (OTP ND) and it is estimated to be complete by the end of 2023.

Casselton 115 kV Capacitor Bank – Attachment 29

Otter Tail is extending retail service from the existing Casselton 115/12.5 kV Substation just west of the city of Casselton, to a new load being developed by North Dakota Soybean Processors immediately east of the Tharaldson Ethanol Plant.⁸ The Casselton 115/12.5 kV Substation is served off of a 115 kV loop with the western side of the loop connected to the Buffalo 345/115/41.6 kV Substation and the eastern side of the loop connected to the Sheyenne 230/115 kV Substation in Fargo. The eastern side of the loop between the Casselton Substation and the Sheyenne Substation also has a 115 kV tap near Mapleton.

Transmission planning studies completed for serving the new load from the Casselton 115/12.5 kV Substation have identified that voltage support is needed at Casselton for an outage of the Mapleton – Sheyenne 115 kV line or the Buffalo –

⁸ The Electric Service Agreement was approved by the North Dakota Public Service Commission in Case No. PU-22-322.

Casselton 115 kV line during winter peak conditions. In order to alleviate these voltage concerns, Otter Tail is expanding the 115 kV bus at the Casselton 115/12.5 kV Substation and installing a 15 MVAR capacitor bank. This capacitor bank will help support the entire 115 kV transmission system served between the Buffalo 345/115/41.6 kV Substation and the Sheyenne 230/115 kV Substation, which normally serves customers in and around the communities of Enderlin, Alice, Mapleton, Davenport, Kindred, Amenia and Casselton.

Otter Tail is estimating the 115 kV substation expansion and 115 kV capacitor bank to cost approximately \$1.2 million (Total) / \$0.48 million (ND) with construction starting in 2023 and ending in mid-2024 to align with the schedule provided by North Dakota Soybean Processors. Otter Tail will be requesting MISO to include this project within the 2023 MISO Transmission Expansion Plan (MTEP23). MISO is expected to evaluate this project and approve it as part of the MTEP23 report in December 2023.

Transmission Line Rebuild Program and Extenda-Life Program

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 large portion of the poles either at or reaching the end of their useful life.

In light of 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 has put a focus on assessing overall transmission and distribution asset health conditions, which has led to the development of two new programs at Otter Tail called "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 first considered. Refurbishing of line sections includes any combination of activities including, but not limited to, changing out rotten cross arms, replacing failed insulators, replacing poles that have failed strength tests, applying ground treatment for poles that pass strength tests, mitigating any vegetation issues, and reattaching guy wires. Otter Tail refers to these refurbishment projects internally as "Extenda-Life" projects. Factors 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.

Otter Tail has always had projects that involved refurbishment and replacement of existing lines,⁹ but it was not until 2019 when more targeted efforts were undertaken through the SIRI initiative. Since that time, Otter Tail has been closely monitoring the performance of both Rebuild and Extenda-Life type projects and has observed a significant improvement in reliability as shown below. The Extenda-Life program is fairly new, so teams continue to monitor performance of past projects.

**Table 2
Line Breaker Operations both Pre and Post Investment**

Transmission Breaker Operations	2018	2019	2020	2021	2022*
Extenda-Life Henning 625	8	5	3	4	7
Extenda-Life Elbow Lake 525	15	7	9	10	6
GFN & Extenda-Life Rugby 165	18	15	16	0	11
Rebuild & Extenda-Life Underwood 655	17	24	11	9	5
<ul style="list-style-type: none"> • Black text represents breaker operations pre-investment • Green text represents breaker operations post investment • *2022 Performance through August 31 (Note: Two Major Event Days in 2022) 					

Although the Extenda-Life and Rebuild programs are different, each improves the reliability of the Company’s transmission system. Any time replacement of certain equipment along an existing line or replacement of the entire line occurs, the line has inherently better performance, not only because of new assets performing better, but also because it allows Otter Tail to implement its 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 provides for shielding protection against interruptions caused by weather events; specifically, 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

⁹ Examples of past rebuild and refurbishment projects in Otter Tail’s TCRR prior to the SIRI initiative have included Max – Ryder (2016), Finley – McVillie (2020), Turtle Lake – Mercer (2020) and Bartlett – Doyon (2020).

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 30

As described above and listed in Table 3 below, Otter Tail has identified the following transmission project to be included in the Transmission Rebuild Program within the SIRI initiative for the 2023 calendar year with a total estimated cost of \$0.1 million (OTP Total) / \$0.04 million (OTP ND).

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

Line Section	Voltage	State	Project Length (Miles)	Total Cost (\$M)	ND Share (\$M)	Projected In-Service Date
Cooperstown – Binford Rebuild	41.6 kV	ND	4.5	\$1.15	\$0.41	2024

Cooperstown – Binford 41.6 kV Rebuild

The Cooperstown to Binford 41.6 kV line section is approximately five miles long and is served from the Spiritwood 115/41.6 kV Substation and the Pickert 230/69/41.6 kV Substation. This area of the system includes over 60 miles of 41.6 kV line exposure to customers in this area and has ranked in the top ten worst performing line sections over the past few years due to the number of breaker operations that have occurred. This particular line was primarily constructed in the 1960s with much of the line today running through marshland and water making it inaccessible most times of the year. To fix the leaning poles and improve the performance of this line, the Company plans to rebuild approximately 4.5 miles of the existing 41.6 kV line and perform refurbishments along other targeted sections of this line. Furthermore, the existing line will be rerouted such that it is more accessible from roadways and out of marshland to provide for long term reliability improvements.

The cost of the Cooperstown to Binford project is estimated to be \$1.15 million (OTP Total) / \$0.41 million (OTP ND) and is scheduled to be placed in service in the fourth quarter of 2024. Costs in 2023 are expected to be around \$0.1 million (OTP Total) / \$0.04 million (OTP ND).

Transmission Extenda-Life Program – Attachment 31

As described in further detail above, Otter Tail deploys various techniques to extend the life 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 \$3.6 million (OTP Total) / \$1.43 million (OTP ND).

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

Line Section	Voltage	State	Project Length (Miles)	Total Cost (\$MM)	ND Share (\$MM)	Projected In-Service Date
Langdon-CB 885	41.6 kV	ND	13	\$0.4	\$0.16	2023
Gackle-CB 865	41.6 kV	ND	35	\$1.0	\$0.40	2024
Washburn-CB 555	41.6 kV	ND	29	\$0.2	\$0.07	2023
Plummer-CB 425	41.6 kV	ND	11	\$0.5	\$0.20	2023
Crookston-CB 425	41.6 kV	MN	23	\$0.7	\$0.28	2023
Donaldson CB 235	41.6 kV	MN	9	\$0.8	\$0.32	2024
Total =			120	\$3.6	\$1.43	

Langdon 885 41.6 kV Extenda-Life:

The 41.6 kV line connected to Langdon circuit breaker 885 serves customers in the communities around Osnabrock, Nekoma, Fairdale, Adams, Milton, and Edmore in North Dakota. The line was constructed in 1952 with very few modifications since it was originally built about 70 years ago. This line has been identified as the second worst performing 41.6 kV line within Otter Tail’s service territory. Data gathered from local field inspections and protective relays have shown that a majority of the service interruptions are occurring close to Langdon and are believed to be caused by windy conditions. This transmission line has distribution underbuild on the same transmission structures near Langdon where windy conditions may be causing the distribution underbuild to come into contact with the transmission circuit or the transmission circuit coming into contact with itself (conductor-to-conductor) or the wooden cross-arm or pole. In addition, momentary interruptions are also being caused by 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 13 miles of 41.6 kV transmission line south of Langdon, along with any necessary pole replacements. In addition, down guys will be insulated, and lightning arresters will be added to lower the number of interruptions occurring along this line. The cost of the Langdon 885 41.6 kV Extenda-Life project is estimated to be \$0.40 million (OTP Total) / \$0.16 million (OTP ND) and is scheduled to be placed in service in 2023.

Gackle 865 41.6 kV Extenda-Life:

In 2021, Otter Tail petitioned for a 2022 Extenda-Life project around the Gackle area. The project scope involved relocating several poles located in water near Gackle and replacing several poles in water near Streeter. Some minor insulator and guy wire work was also performed in the area to improve the performance of the line. Work will continue in this area in 2023 and 2024, as discussed in further detail below.

Between Jamestown and Gackle, Otter Tail has approximately 70 miles of 41.6 kV line that serves the communities of Gackle, Streeter, Medina, Cleveland, Windsor, and Eldridge in North Dakota. This line has a mix of different vintages, but most sections of this line are over 50 years old. Inspections are showing that there are concentrations of poles along this line that are nearing a 5 percent failure rate during strength tests.¹⁰ In addition, this line section has a large number of poles located in or around water, which are only accessible during limited times of the year. This line section experienced approximately 40 interruptions during 2021 making it the worst performing line section within Otter Tail's system. The bulk of these issues occurred in February of 2021 due to a large frost event. In frost and ice events, research has shown that the transmission circuit has sagged into the distribution circuit that is in the underbuild position of the same structures indicating a need to remove the distribution underbuild from the transmission poles. However, even excluding that event, this line section continues to be a poor performer and Otter Tail has a long-term plan to address the entire line over the course of the next 5-7 years between a mix of different Rebuild projects and Extenda-Life projects for various segments.

In 2023 and 2024, the majority of the work expected along this 70 mile line will involve Extenda-Life projects around Eldridge, Cleveland, Medina, and Gackle. The overall scope will be around 35 miles of Extenda-Life work, which includes replacement of poles that have failed strength tests, flashed over insulators, adding arresters and insulated guy wires, as well as burying the distribution underbuild currently residing on the same structures along this 41.6 kV line. The total 2023 and 2024 Extenda-Life work on this line is estimated to be \$2,185,000 with \$1,685,000 occurring in 2023.

Washburn 555 41.6 kV Extenda-Life:

This 41.6 kV line serves customers in the communities around Washburn, Wilton, Regan, Wing, and Tuttle in North Dakota. The line was constructed in the 1960s with very few modifications. This line is in the top 15 worst performing 41.6

¹⁰ A reject rate above 1.5 percent is considered below average for poles owned by Otter Tail.

kV lines within Otter Tail Power Company's service territory. Data from both local field inspections and protective relays have shown that a majority of the interruptions are located between Washburn and Wilton and between Regan and Wing. A majority of the issues have been caused by lightning and wind. 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 17 miles of line between Washburn and Wilton and 12 miles of line between Regan and Wing, along with any necessary pole replacements. In addition, down guys will be insulated, and arresters added to lower the number of interruptions occurring along this line.

Plummer-CB 425 41.6 kV Extenda-Life:

The Plummer to Mentor 41.6 kV line section is approximately 40 miles long and serves customers in and around the communities of Brooks, Mentor, and Erskine in Minnesota. This line is around 60 years old with insulators that are largely porcelain and showing some signs of deterioration. Many cross arms are cracked and showing signs of deterioration as well. The wooden poles are built with western red cedar trees and are showing signs of damage by carpenter ants with 6.4 percent of the poles failing strength tests. Although this 41.6 kV transmission line currently experiences around five interruptions a year, this line does contain several insulators, cross arms and poles that are nearing the end of their useful lives.

To improve the condition of this line, Otter Tail plans to undertake a project to completely re-pole two miles of line within an 11-mile stretch where the bulk of the rejected poles are located. The remaining nine miles will be reinsulated by replacing deteriorating insulators and cross arms. Lastly, guy wires will be insulated to help reduce interruptions caused from a flash-over between the energized circuit and the down guy. Based on Otter Tail's field assessment, the conductor is in adequate condition and will be reused along the 11-mile line section. Additionally, the existing poles will remain along the nine miles of line that will be reinsulated. This project is estimated to be \$500,000 and in service by the end of 2023.

Crookston-CB 655 41.6 kV Extenda-Life:

The Crookston to Argyle 41.6 kV line section is approximately 46 miles long and serves customers in and around the communities of Angus-Roan, Fanny Rural, Fisher, and Ross in Minnesota. This line contains equipment that is between 20 and 70 years old with insulators and cross arms that are showing some signs of deterioration. This line section experienced 14 interruptions in 2021 and ranks within the top ten worst transmission performers within the Company. The fault data analyzed from protective relays shows concentrations of equipment issues within the

first 15 miles from Crookston and the last eight miles towards Argyle. The conductor and most poles are in acceptable condition, which makes this line a great candidate for the Extenda-Life program.

For the concentrated areas of concern along this line (approximately 23 miles), the cross arms and insulators will be replaced to improve performance of this line. In addition, lightning arrestors and insulated guy wires will be added to the structures. Poles that do not meet strength tests will also be replaced where necessary. Lastly, there is a five-mile section of line out of Crookston that is orientated east-west that experiences galloping during icing conditions, which can cause service interruptions when the energized conductors come into contact with each other. To improve the performance of this five-mile east-west line segment during icing conditions, additional equipment (e.g. air spoilers) will be added to reduce line galloping. This project is expected to be completed by end of year 2023 and is estimated to be \$700,000.

Donaldson-CB 235 41.6 kV Extenda-Life:

The Donaldson to Argyle 41.6 kV line section is approximately 21 miles long and serves customers in and around the communities of Argyle and Stephen in Minnesota. This line is over 70 years old with insulators and cross arms that are showing some signs of deterioration. Field inspections have shown that some insulators on this line are stamped with dates from the 1920's! This line section has experienced around a half-dozen interruptions annually over the past few years. In aggregate, its performance is average in comparison to other 41.6 kV line sections across the Otter Tail transmission system. However, the interruptions being experienced along this line mostly appear between the Donaldson sub and Stephen (73 percent of total faults). With such a concentration of faults in this area, this project is an ideal candidate for the Extenda-Life program.

For the concentrated areas of concern along this line (nine miles), the cross arms, insulators, and poles will be replaced while reusing the existing conductor. The age of the poles in this section, along with the fact that they are of a lighter class and duty does not make them suitable for future use. Using new poles will also allow us to install vertical framing and add shield wire to this section of line. In addition, arrestors and insulated guy wires will be added to the structures to improve the reliability performance of this line. This project is expected to be completed by end of year 2023 and is estimated to be \$800,000.

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 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 2023 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2023; the true-up associated with an updated projection of the 2022 revenue requirement; and the carrying charge attributable to any projected over or under-collection.

The revenue requirement attributable to calendar year 2023, as shown on line 49 of Attachment 4, page 2 is \$7,670,024. This amount is based on actual net revenues and expenses included in the TCRR tracker through July 2022 and projections for August 2022 through December 2023.

By design and structure of the TCRR, the related carrying credit of (\$16,759), as computed on Attachment 4, page 2, line 55, will be credited to customers as a reduction in the 2023 revenue requirement. The 2022 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, line 40 and as computed in Attachment 4, page 1, line 56, reflects an estimated over-collection amount of (\$117,592) during the 2022 collection period. The over-collection is due to delayed in-service and reduced spend on projects of approximately \$30,000 as well as a reduction to the MISO Schedule 26 and 26A Expense and decrease to Schedule 26 and 9 Revenue in 2022, netting approximately a \$63,000 reduction to the Net Revenue Requirement for 2022. The net revenue requirement for 2023, upon which rates are developed, is \$7,535,673 as shown on line 40 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, 2022- December 31, 2022 Approved Rates (PU-21-376) <u>¢ / kWh</u>	January 1, 2023- December 31, 2023 Proposed Rates (PU-22-335) <u>¢ / kWh</u>
1	Large General Service	\$1.568 /kW	\$ 1.841
2	Controlled Service	0.067¢	0.086¢
3	Lighting	0.303¢	0.496¢
4	All Other	0.462¢	0.575¢

The proposed rates are based on an effective date of January 1, 2023, through December 31, 2023. These rates represent a change to the rates currently in effect. The estimated increase for a residential customer using 1,000 kWh is \$1.13 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 42 to this Application.

In addition to changes to the rates, Otter Tail has included a correction to the Large General Service – Energy Charge Rate Code.

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 September customer bills. Attachment 43 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 44 is a sample of the bill insert implementation notice.

X. REQUEST FOR CHANGE OF ANNUAL FILING DATE

Otter Tail respectfully requests a permanent change to the filing date for the ND TCRR Annual update as per Ordering Paragraph 6 of the Commission's April 5, 2012, Order in Case Nos. PU-11-153 and PU-11-682 (the TCRR Order). Otter Tail requests a revised filing date of September 15 from September 1 for future filings in order to incorporate the most recent MISO Attachment O, GG, and MM information, which are filed with MISO by September 1 of each year. Adjusting the annual filing date to September 15 will allow Otter Tail time to incorporate the most current information in the annual update.

XI. CONCLUSION

For all of 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, 2023. 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, one new Rebuild project and six new Extenda-Life projects.
3. Scope modification to one previously approved project.
4. Otter Tail's request for approval to permanently change the annual filing date from September 1 to September 15.

Date: September 15, 2022

Respectfully submitted:

OTTER TAIL POWER COMPANY

/s/ Christopher E. Byrnes

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Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Summary
Attachment 5	BSAT-Ellendale MVP Revenue Requirements
Attachment 6	Max to Ryder 41.6 kV Line Upgrade Revenue Requirements
Attachment 7	Bagley 115 kV Switch Station Revenue Requirements
Attachment 8	Lake Norden Area Transmission Improvements Revenue Requirements
Attachment 9	Donaldson 115 kV Cap Bank Revenue Requirements
Attachment 10	Northwest MN UVLS Revenue Requirements
Attachment 11	Blair 230 kV Substation Revenue Requirements
Attachment 12	Veblen 41.6 kV Cap Bank Revenue Requirements
Attachment 13	New Effington 230/41.6 kV Line Revenue Requirements
Attachment 14	Jamestown Substation (NERC) Revenue Requirements
Attachment 15	CPEC Facility Purchase Revenue Requirements
Attachment 16	Erie 230/115kV Substation Revenue Requirements
Attachment 17	Grant County-Norcross 115kV Line and Norcross 115/41.6kV substation Revenue Requirements
Attachment 18	Winger 230/115kV Transformer Revenue Requirements
Attachment 19	Jamestown 115/41.6 kV Transformer Addition Revenue Requirements
Attachment 20	Hoot Lake Capacitor Revenue Requirements
Attachment 21	Finley/McVile 41.6 kV Rebuild Revenue Requirements
Attachment 22	Turtle Lake/Mercer 41.6 kV Rebuild Revenue Requirements
Attachment 23	Doyon/Bartlett 41.6 kV Rebuild Revenue Requirements
Attachment 24	Hoot Lake 115/43/13.8 kV Transformer Revenue Requirements
Attachment 25	2021 Transmission Line Rebuild Program Revenue Requirements
Attachment 26	2021 Transmission Extenda-Life Program Revenue Requirement
Attachment 27	Oslo 155 kV 5 Breaker Ring Bus Revenue Requirement
Attachment 28	Milbank 41.6 kV Reconductor Revenue Requirement
Attachment 29	Casselton 115 kV Capacitor Bank Revenue Requirement
Attachment 30	Cooperstown 41.6 kV Rebuild Program Revenue Requirement
Attachment 31	2022 Transmission Extenda-Life Program Revenue Requirements
Attachment 32	Attachment O Revenue Credit for Non-MISO Projects
Attachment 33	MISO Schedule 26 and 26A Expense
Attachment 34	SPP Expenses
Attachment 35	MISO Schedule 9 Revenue
Attachment 36	MISO Schedule 26 Revenue
Attachment 37	MISO Schedule 26A Revenue

Attachment 38	MISO Multi-Value Project Auction Revenue Rights Credit
Attachment 39	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 40	ADIT Pro-Rate Projection
Attachment 41	ADIT Pro-Rate Preservation
Attachment 42	Electric Rate Schedule Section 13.05 Legislative and Non-Legislative
Attachment 43	ND TCR Filing Bill Message
Attachment 44	Proposed Customer Notice

Projected Revenue for 2023

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,136,530 kW	\$1.841	\$2,092,355
2					
3	Controlled Service	(b)	243,130,352 kWh	0.086¢	\$208,820
4					
5	Lighting	(c)	14,573,309 kWh	0.496¢	\$72,355
6					
7	All other service		897,962,534 kWh	0.575¢	\$5,162,144
8					
9	Total revenue				<u>\$7,535,673</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	2023
1	MVP - Ellendale to Big Stone South	\$118,858
2	Max - Ryder 41.6 kV Line Upgrades	\$85,069
3	Bagley 115kV Switch Station	\$108,310
4	Lake Norden Area Transmission	\$1,140,378
5	Donaldson 115 kV Cap Bank	\$26,369
6	Blair 230 kV Substation	\$40,876
7	Veblen 41.6 kV Cap Bank	\$39,781
8	Northwest MN UVLS	\$27,665
9	Jamestown Substation (NERC)	\$45,128
10	New Effington 230/41.6 kV Line	\$196,488
11	CPEC Purchase	\$78,803
12	Erie 230/115kV Substation	\$192,409
13	Norcross 115kV Line-115/41.6kV substation	\$194,487
14	Winger 230/115kV Transformer	\$104,600
15	Jamestown 115 kV Source	\$152,359
16	Hoot Lake Capacitor	\$32,349
17	Finley/McVile 41.6 kV Rebuild	\$47,142
18	Turtle Lake/Mercer 41.6 kV Rebuild	\$56,668
19	Doyon/Barlett 41.6 kV Rebuild	\$33,395
20	Transmission Line Replacement Program	\$404,793
21	Transmission Extenda-Life Program	\$178,523
22	Hoot Lake 115/43/13.8 kV Transformer	\$52,588
23	Cooperstown 41.6 kV Relocate	\$1,317
24	Oslo 115 kV 5 Breaker Ring Bus	\$7,181
25	Milbank 41.6 kV Reconductor	\$7,423
26	Casselton 115 kV Capacitor Bank	\$4,825
27	Total Revenue Requirement	\$3,377,784
28	MISO Schedule 26 Expense	\$4,539,755
29	MISO Schedule 26A Expense	\$3,442,797
30	SPP Schedule 9 Expense	\$749,791
31	SPP Schedule 11 Expense	\$118,853
32	MISO Schedule 9 Revenue	(\$289,995)
33	MISO Schedule 26 Revenue	(\$3,591,693)
34	MISO Schedule 37 Revenue	(\$0)
35	MISO Schedule 38 Revenue	(\$0)
36	MISO Schedule 26A Revenue	(\$666,378)
37	MISO MVP ARR Revenue	(\$10,891)
38	Carrying Cost	(\$16,759)
39	True-Up	(\$117,592)
40	Net Revenue Requirement	<u>\$7,535,673</u>

Class Allocation and Rate Design

Line No.	2023		
1	North Dakota Revenue Requirements		\$7,535,673 *
2	Large General Service Class	27.77%	\$2,092,355
3	Controlled Service	2.77%	\$208,820
4	Lighting	0.96%	\$72,355
5	All Other Service	68.50%	\$5,162,144
6	Total		\$7,535,673
7	Large General Service Class	kW	1,136,530
8	Controlled Service	kWh	243,130,352
9	Lighting	kWh	14,573,309
10	All Other Service	kWh	897,962,534
11	Large General Service Class	\$ / kW	1.841
12	Controlled Service	cents / kWh	0.086
13	Lighting	cents / kWh	0.496
14	All Other Service	cents / kWh	0.575

* 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:	2022												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	6,882	7,452	7,452	7,471	7,452	7,452	7,452	7,452	7,452	7,452	7,452	8,086	89,508
2	Max- Ryder 41.6 kV Line Upgrades	6,849	6,849	6,849	6,849	6,849	6,849	6,849	6,849	6,849	6,849	6,849	6,849	82,188
3	Bagley 115kV Switch Station	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	8,700	104,404
4	Lake Norden Area Transmission Improvement	89,174	88,935	91,120	91,135	91,118	91,102	91,103	91,095	91,095	91,095	91,095	1,089,163	
5	Donaldson 115 kV Cap Bank	2,120	2,120	2,120	2,120	2,120	2,120	2,120	2,120	2,120	2,120	2,120	2,120	25,445
6	Blair 230 kV Substation	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	3,207	38,483
7	Veblen 41.6 kV Cap Bank	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205	3,205	38,459
8	Northwest MN UVLS	2,361	2,361	2,361	2,361	2,361	2,361	2,361	2,361	2,361	2,361	2,361	2,361	28,327
9	Jamestown Substation	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	43,665
10	New Effington 230/41.6 kV Line	15,583	15,583	15,782	15,794	15,794	15,793	15,793	15,782	15,782	15,782	15,782	15,782	189,033
11	CPEC Purchase	6,343	6,343	6,343	6,343	6,343	6,343	6,343	6,343	6,343	6,343	6,343	6,343	76,117
12	Erie 230/115kV Substation	2,341	2,341	2,341	2,341	2,399	2,396	2,396	2,396	2,396	2,396	2,396	2,396	28,537
13	Norcross 115kV Line-115/41.6kV substation	10,739	10,739	10,739	10,823	10,823	10,823	10,936	10,936	12,712	12,712	12,712	12,712	137,405
14	Winger 230/115kV Transformer	540	540	540	540	540	540	540	540	540	540	540	540	6,481
15	Jamestown 41.6 kV Source	5,843	5,843	5,843	5,916	5,916	5,917	5,917	5,917	7,193	7,447	7,476	7,480	76,706
16	Hoot Lake Capacitor	1,893	1,893	1,893	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	25,561
17	Finley/McVile 41.6 kV Rebuild	3,016	3,016	3,016	3,016	3,016	3,016	3,060	3,060	3,539	3,539	3,539	3,539	38,373
18	Turtle Lake/Mercer 41.6 kV Rebuild	3,267	3,940	3,940	3,940	3,940	4,330	4,330	4,330	4,330	4,330	4,330	4,330	49,337
19	Doyon/Bartlett 41.6 kV Rebuild	2,180	2,208	2,209	2,189	2,190	2,191	2,517	2,517	2,539	2,539	2,539	2,539	28,359
20	Hoot Lake 115/43/13.8 kV Transformer	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	12,852
21	Transmission Line Replacement Program	10,194	10,194	10,268	10,267	10,269	10,267	10,267	10,267	10,267	10,267	10,267	10,358	123,152
22	Transmission Extenda-Life Program	4,777	4,837	4,837	4,877	4,876	4,876	4,947	4,947	5,238	5,291	5,342	5,533	60,377
23	Cooperstown 41.6 kV Relocate													
25	Oslo 115 kV 5 Breaker Ring Bus													
26	Milbank 41.6 kV Reconductor													
27	Casselton 115 kV Capacitor Bank													
28	Total Revenue Requirements	193,926	195,017	197,476	198,013	198,038	198,407	198,962	198,944	202,787	203,094	203,174	204,093	2,391,930
30	ADIT Preservation of Proration	150	150	150	150	150	150	150	150	150	150	150	150	1,799
32	MISO & SPP Expenses													
34	MISO Schedule 26 Expense	448,530	391,865	375,401	350,605	292,965	366,582	388,552	387,770	335,110	397,345	397,345	478,729	4,610,798
35	MISO Schedule 26A Expense	378,116	329,518	299,045	278,412	260,687	263,672	281,892	263,933	250,961	264,793	323,746	361,737	3,556,512
36	SPP Schedule 9 Expense	74,530	65,762	65,486	65,940	67,982	65,342	66,377	62,652	63,492	59,102	59,102	59,102	774,419
37	SPP Schedule 11 Expense	9,924	9,571	9,571	9,574	9,925	9,507	9,535	9,593	9,521	9,521	9,521	9,521	115,281
38	Total MISO & SPP Expenses	911,099	796,717	749,503	704,080	631,559	705,102	746,357	723,948	659,084	730,760	789,713	909,088	9,057,010
40	MISO Revenues													
41	MISO Schedule 9 Revenue	(36,472)	(25,151)	(35,481)	(1,012)	(6,965)	4,423	(8,217)	(15,877)	(11,657)	(32,921)	(43,705)	(55,716)	(268,752)
42	MISO Schedule 26 Revenue	(320,268)	(272,897)	(277,501)	(254,524)	(332,927)	(390,605)	(404,421)	(388,411)	(319,817)	(266,466)	(262,655)	(300,763)	(3,791,255)
43	MISO Schedule 37 Revenue	(3,115)	(3,128)	(3,128)	(3,128)	(3,128)	(3,133)	(3,090)	(0)	(0)	(0)	(0)	(0)	(21,850)
44	MISO Schedule 38 Revenue	(4,629)	(3,935)	(3,935)	(3,935)	(3,935)	(3,836)	(3,783)	(0)	(0)	(0)	(0)	(0)	(27,988)
45	MISO Schedule 26A Revenue	(45,410)	(43,383)	(40,376)	(36,852)	(39,235)	(46,161)	(48,725)	(51,797)	(42,673)	(41,600)	(35,696)	(47,503)	(519,410)
46	MISO MVP ARR Revenue	(1,162)	(1,124)	(1,111)	(1,754)	(1,744)	(1,472)	(1,894)	(908)	(908)	(908)	(908)	(908)	(14,798)
47	Total MISO Revenues	(411,056)	(349,618)	(361,531)	(301,205)	(387,934)	(440,783)	(470,128)	(456,993)	(375,055)	(341,894)	(342,965)	(404,891)	(4,644,054)
48	Net Revenue Requirement	694,118	642,266	585,598	601,037	441,812	462,876	475,341	466,049	486,966	592,110	650,072	708,440	6,806,685
50	Billed (forecast kWh x adj factor)	611,816	637,622	616,561	525,530	470,664	437,090	468,919	431,627	424,442	404,670	498,375	571,008	6,098,323
52	Big Stone II True-Up													
53	Difference	82,302	4,643	(30,963)	75,508	(28,852)	25,786	6,422	34,422	62,524	187,440	151,698	137,432	708,362
54	Carrying Charge	(4,955)	(4,463)	(4,461)	(4,687)	(4,236)	(4,447)	(4,311)	(4,297)	(4,105)	(3,733)	(2,564)	(1,614)	(47,873)
55	Cumulative Difference	(700,735)	(700,554)	(735,978)	(665,157)	(698,245)	(676,905)	(674,794)	(644,670)	(586,251)	(402,544)	(253,410)	(117,592)	(117,592)
57	Carrying Charge Calculation	(4,463)	(4,461)	(4,687)	(4,236)	(4,447)	(4,311)	(4,297)	(4,105)	(3,733)	(2,564)	(1,614)	(749)	
59	Cumulative Carrying Charge	(270,136)	(274,598)	(279,285)	(283,521)	(287,967)	(292,278)	(296,575)	(300,681)	(304,414)	(306,978)	(308,592)	(309,341)	
60	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%	
61														
62														
63	Forecasted Sales (MWh)	191,350	174,486	161,766	136,008	119,728	113,082	124,097	123,096	121,047	115,409	142,132	162,847	1,685,049
64														

Approved December 1, 2021 (PU-21-376);
Rate Effective January 1, 2022

SUMMARY	Jan 2022 - Dec 2022
Revenue requirements	\$6,712,343
Carrying Charge	(28,724)
2021 True-Up	(604,302)
Total requirements	\$6,079,317
Jan 2022-Dec 2022 projected sales in MWh	1,733,771
Average Rate	\$0.00351

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2023												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	9,832	9,832	9,832	9,832	9,832	9,832	9,832	9,832	9,832	9,832	9,832	10,704	118,858
2	Max- Ryder 41.6 kV Line Upgrades	7,089	7,089	7,089	7,089	7,089	7,089	7,089	7,089	7,089	7,089	7,089	7,089	85,069
3	Bagley 115kV Switch Station	9,026	9,026	9,026	9,026	9,026	9,026	9,026	9,026	9,026	9,026	9,026	9,026	108,310
4	Lake Norden Area Transmission Improverment	95,032	95,032	95,032	95,032	95,032	95,032	95,032	95,032	95,032	95,032	95,032	95,032	1,140,378
5	Donaldson 115 kV Cap Bank	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	2,197	26,369
6	Blair 230 kV Substation	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	40,876
7	Veblen 41.6 kV Cap Bank	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	3,315	39,781
8	Northwest MN UVLS	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	27,665
9	Jamestown Substation	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	3,761	45,128
10	New Effington 230/41.6 kV Line	16,374	16,374	16,374	16,374	16,374	16,374	16,374	16,374	16,374	16,374	16,374	16,374	196,488
11	CPEC Purchase	6,567	6,567	6,567	6,567	6,567	6,567	6,567	6,567	6,567	6,567	6,567	6,567	78,803
12	Erie 230/115kV Substation	14,439	14,439	14,439	14,439	14,439	16,503	16,841	17,201	17,291	17,426	17,471	17,471	192,409
13	Norcross 115kV Line-115/41.6kV substation	16,207	16,207	16,207	16,207	16,207	16,207	16,207	16,207	16,207	16,207	16,207	16,207	194,487
14	Winger 230/115kV Transformer	8,504	8,504	8,504	8,504	8,504	8,504	8,504	8,504	8,504	8,504	8,504	11,057	104,600
15	Jamestown 41.6 kV Source	12,697	12,697	12,697	12,697	12,697	12,697	12,697	12,697	12,697	12,697	12,697	12,697	152,359
16	Hoot Lake Capacitor	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	2,696	32,349
17	Finley/McVillie 41.6 kV Rebuild	3,928	3,928	3,928	3,928	3,928	3,928	3,928	3,928	3,928	3,928	3,928	3,928	47,142
18	Turtle Lake/Mercer 41.6 kV Rebuild	4,722	4,722	4,722	4,722	4,722	4,722	4,722	4,722	4,722	4,722	4,722	4,722	56,668
19	Doyon/Bartlett 41.6 kV Rebuild	2,783	2,783	2,783	2,783	2,783	2,783	2,783	2,783	2,783	2,783	2,783	2,783	33,395
20	Hoot Lake 115/43/13.8 kV Transformer	4,382	4,382	4,382	4,382	4,382	4,382	4,382	4,382	4,382	4,382	4,382	4,382	52,588
21	Transmission Line Replacement Program	33,733	33,733	33,733	33,733	33,733	33,733	33,733	33,733	33,733	33,733	33,733	33,733	404,793
22	Transmission Extenda-Life Program	14,633	14,677	14,721	14,766	14,810	14,855	14,899	14,943	14,988	15,032	15,077	15,121	178,523
23	Cooperstown 41.6 kV Relocate	110	110	110	110	110	110	110	110	110	110	110	110	1,317
25	Oslo 115 kV 5 Breaker Ring Bus	598	598	598	598	598	598	598	598	598	598	598	598	7,181
26	Milbank 41.6 kV Reconductor	619	619	619	619	619	619	619	619	619	619	619	619	7,423
27	Casselton 115 kV Capacitor Bank	402	402	402	402	402	402	402	402	402	402	402	402	4,825
28														
29	Total Revenue Requirements	279,357	279,401	279,446	279,490	279,535	281,643	282,026	282,430	282,565	282,744	282,833	286,314	3,377,784
30														
31	ADIT Preservation of Proration													
32														
33	MISO & SPP Expenses													
34	MISO Schedule 26 Expense	452,167	438,602	402,429	339,125	298,430	357,212	366,255	366,255	316,517	375,299	375,299	452,167	4,539,755
35	MISO Schedule 26A Expense	345,140	313,551	306,766	272,703	257,672	251,903	270,324	270,307	256,551	271,089	295,790	331,001	3,442,797
36	SPP Schedule 9 Expense	61,774	61,774	61,774	61,774	61,774	61,774	61,774	66,135	66,135	61,702	61,702	61,702	749,791
37	SPP Schedule 11 Expense	9,904	9,904	9,904	9,904	9,904	9,904	9,904	9,904	9,904	9,904	9,904	9,904	118,853
38	Total MISO & SPP Expenses	868,985	823,831	780,873	683,506	627,780	680,793	708,257	712,603	649,108	717,993	742,695	854,774	8,851,196
39														
40	MISO Revenues													
41	MISO Schedule 9 Revenue	(42,437)	(25,151)	(35,481)	(1,012)	(6,965)	4,423	(23,495)	(15,877)	(11,657)	(32,921)	(43,705)	(55,716)	(289,995)
42	MISO Schedule 26 Revenue	(299,308)	(299,308)	(299,308)	(299,308)	(299,308)	(299,308)	(299,308)	(299,308)	(299,308)	(299,308)	(299,308)	(299,308)	(3,591,693)
43	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
44	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
45	MISO Schedule 26A Revenue	(55,531)	(55,531)	(55,531)	(55,531)	(55,531)	(55,531)	(55,531)	(55,531)	(55,531)	(55,531)	(55,531)	(55,531)	(666,378)
46	MISO MVP ARR Revenue	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(908)	(10,891)
47	Total MISO Revenues	(398,184)	(380,898)	(391,228)	(356,758)	(362,712)	(351,324)	(379,242)	(371,624)	(367,404)	(388,667)	(399,452)	(411,463)	(4,558,956)
48														
49	Net Revenue Requirement	750,158	722,334	669,091	606,238	544,603	611,112	611,041	623,409	564,269	612,070	626,076	729,624	7,670,024
50														
51	Billed (forecast kWh x adi factor)	838,701	817,706	732,914	656,995	535,854	497,527	523,652	542,789	533,638	508,694	627,363	719,839	7,535,673
52														
53	Big Stone II True-Up													
54	Difference	(88,544)	(95,372)	(63,823)	(50,758)	8,749	113,585	87,390	80,620	30,631	103,376	(1,287)	9,785	134,351
55	Carrying Charge	(749)	(1,318)	(1,933)	(2,352)	(2,690)	(2,652)	(1,945)	(1,401)	(897)	(707)	(53)	(62)	(16,759)
56	Cumulative Difference	(206,885)	(303,574)	(369,331)	(422,441)	(416,382)	(305,448)	(220,004)	(140,785)	(111,051)	(8,382)	(9,723)	(0)	(0)
57														
58	Carrying Charge Calculation	(1,318)	(1,933)	(2,352)	(2,690)	(2,652)	(1,945)	(1,401)	(897)	(707)	(53)	(62)	(0)	
59	Cumulative Carrying Charge	(310,658)	(312,591)	(314,943)	(317,634)	(320,285)	(322,230)	(323,632)	(324,528)	(325,235)	(325,289)	(325,351)	(325,351)	
60	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%	
61														
62														
63	Forecasted 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

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 M		1,700,653
Average Rate		\$0.00443

Line No.	Year>>	2023 Projected Jan	2023 Projected Feb	2023 Projected Mar	2023 Projected Apr	2023 Projected May	2023 Projected Jun	2023 Projected Jul	2023 Projected Aug	2023 Projected Sep	2023 Projected Oct	2023 Projected Nov	2023 Projected Dec	2023 Projected Total
RATE BASE														
1	Plant Balance	128,390	128,390	128,390	128,390	4,716,850	5,469,119	6,269,119	6,469,119	6,769,119	6,869,119	6,894,119	6,894,119	6,894,119
2	Accumulated Depreciation	(1,563)	(1,735)	(1,908)	(2,080)	(2,253)	(8,588)	(15,935)	(24,356)	(33,045)	(42,138)	(51,365)	(60,626)	(60,626)
3	Net Plant in Service	126,827	126,655	126,483	126,310	4,714,598	5,460,531	6,253,184	6,444,763	6,736,074	6,826,981	6,842,754	6,833,494	6,833,494
CWIP Calculation:														
	Beginning Balance	2,415,927	2,813,460	2,963,460	3,113,460	3,838,460	0	0	0	0	0	0	0	0
	Additional CWIP	397,533	150,000	150,000	725,000	750,000	752,269	800,000	200,000	300,000	100,000	25,000	0	4,349,802
	Closings from CWIP AFUDC					(4,588,460)	(752,269)	(800,000)	(200,000)	(300,000)	(100,000)	(25,000)	0	0
4	CWIP (Project #T02031.039) 106687	2,813,460	2,963,460	3,113,460	3,838,460	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
6	Accumulated Deferred Income Taxes Federal & State	(1,419)	(1,598)	(1,763)	(1,914)	(8,878)	(14,236)	(18,834)	(22,700)	(25,964)	(28,606)	(30,675)	(32,161)	(32,161)
7	Ending rate base	2,938,868	3,088,517	3,238,180	3,962,857	4,705,720	5,446,295	6,234,350	6,422,064	6,710,110	6,798,375	6,812,079	6,801,333	6,801,333
8	Average rate base	421,157	421,157	421,157	421,157	421,157	421,157	421,157	421,157	421,157	421,157	421,157	421,157	5,053,881
9	Return on Rate Base	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	386,218
10														
11	Available for return (equity portion of rate base)	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	259,226
12														
13														
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	3,785	3,785	3,785	3,785	3,785	3,785	3,785	3,785	3,785	3,785	3,785	3,785	45,419
19	Book Depreciation	172	172	172	172	172	6,336	7,346	8,421	8,690	9,093	9,227	9,261	59,235
20	Total O&M and Depreciation Expense	3,957	3,957	3,957	3,957	3,957	10,121	11,131	12,206	12,475	12,878	13,012	13,045	104,655
21	Income before Taxes													
23	Available for return (from above)	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	21,602	259,226
24	Taxable Income (grossed up)	28,576	28,576	28,576	28,576	28,576	28,576	28,576	28,576	28,576	28,576	28,576	28,576	342,914
25														
26	Income Taxes													
27	Current and Def Income Taxes	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	83,688
28	Total Income Tax Expense	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	6,974	83,688
29														
30														
REVENUE REQUIRMENTS														
32	Expenses	10,931	10,931	10,931	10,931	10,931	17,095	18,105	19,180	19,449	19,852	19,986	20,019	188,343
33	Return on rate base	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	32,185	386,218
34	Subtotal revenue requirements	43,116	43,116	43,116	43,116	43,116	49,280	50,290	51,365	51,633	52,036	52,171	52,204	574,560
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(6,654)	(6,654)	(6,654)	(6,654)	(6,654)	(7,605)	(7,761)	(7,927)	(7,968)	(8,030)	(8,051)	(8,056)	(88,666)
37	Total revenue requirements	36,462	36,462	36,462	36,462	36,462	41,675	42,529	43,438	43,665	44,006	44,120	44,148	485,894
38														
39	North Dakota share - D2 factor	14,439	14,439	14,439	14,439	14,439	16,503	16,841	17,201	17,291	17,426	17,471	17,482	192,409

Line No.	SUPPORTING INFORMATION / DATA
1	
2	ND Cap Structure with allowed ROE per order.
3	Capital Structure
4	Debt <u>Ratio</u> <u>Cost</u> <u>WA Cost</u>
5	Preferred equity 47.50% 5.29% 2.51%
6	Common equity 0.00% 0.00% 0.00%
7	Total 52.50% 9.77% 5.13%
8	7.64% Overall Return
9	
10	Project life (years) 50 15-year MACRS
11	
12	
13	<u>Fed Portion</u> <u>State Portion</u>
14	Effective Tax Rate 24.40% 20.09% 4.31%
15	Tax conversion factor 1.32284
16	Wholesale Revenue Credit 15.43%
17	ND share - D2 factor 39.5989%
18	Deferred Tax
19	Book depreciation 172 172 172 172 172 6,336 7,346 8,421 8,690 9,093 9,227 9,261 59,235
20	Tax depreciation-Federal 1,016 1,016 1,016 1,016 43,302 43,302 43,302 43,302 43,302 43,302 43,302 43,302 43,302 350,484
21	Tax depreciation-ND 1,016 1,016 1,016 1,016 43,302 43,302 43,302 43,302 43,302 43,302 43,302 43,302 43,302 350,484
22	Federal deferred income taxes (170) (170) (170) (170) (8,667) (7,428) (7,225) (7,009) (6,955) (6,874) (6,847) (6,841) (58,526)
23	State deferred income taxes (36) (36) (36) (36) (1,859) (1,593) (1,550) (1,503) (1,492) (1,474) (1,469) (1,467) (12,553)

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		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	197,057	197,111	197,111	462,677	463,557	4,646,915	4,646,915	4,646,915	4,646,915	4,646,915	4,646,915
2	Accumulated Depreciation	0	0	0	(265)	(529)	(794)	(1,416)	(2,038)	(8,280)	(14,522)	(20,764)	(27,006)	(27,006)
3	Net Plant in Service	0	0	197,057	196,846	196,581	461,882	462,141	4,644,877	4,638,635	4,632,393	4,626,151	4,619,909	4,619,909
CWIP Calculation:														
	Beginning Balance	4,135,431	4,172,735	4,260,631	4,084,949	4,084,760	4,082,931	3,829,186	3,895,278	0	0	0	0	0
	Additional CWIP	37,304	87,896	21,375	(135)	(1,829)	11,821	66,973	288,080	0	0	0	0	511,484
	Closings from CWIP			(197,057)	(54)	0	(265,566)	(880)	(4,183,358)	0	0	0	0	0
	AFDUC													
4	CWIP (Project #T02031.059)	106727	4,172,735	4,260,631	4,084,949	4,084,760	4,082,931	3,829,186	3,895,278	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 Taxes Federal & State	0	0	(240)	(416)	(592)	(8,628)	(16,577)	(24,526)	(31,103)	(37,680)	(44,257)	(50,834)	(50,834)
7	Ending rate base	4,172,735	4,260,631	4,281,765	4,281,190	4,278,920	4,282,440	4,340,843	4,620,351	4,607,532	4,594,713	4,581,894	4,569,075	4,569,075
8	Average rate base	365,433	365,433	365,433	365,433	365,433	365,433	365,433	365,433	365,433	365,433	365,433	365,433	4,385,194
9	Return on Rate Base	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	335,117
10	Available for return (equity portion of rate base)	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	224,928
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	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	0
19	Book Depreciation	0	0	0	265	265	265	621	623	6,242	6,242	6,242	6,242	27,006
20	Total O&M and Depreciation Expense	0	0	0	265	265	265	621	623	6,242	6,242	6,242	6,242	27,006
22	Income before Taxes	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	224,928
23	Available for return (from above)	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	18,744	224,928
24	Taxable Income (grossed up)	24,795	24,795	24,795	24,795	24,795	24,795	24,795	24,795	24,795	24,795	24,795	24,795	297,543
26	Income Taxes	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	72,615
27	Current and Def Income Taxes	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	72,615
28	Total Income Tax Expense	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	6,051	72,615
REVENUE REQUIREMENTS														
31	Expenses	6,051	6,051	6,051	6,316	6,316	6,316	6,673	6,674	12,293	12,293	12,293	12,293	99,621
33	Return on rate base	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	27,926	335,117
34	Subtotal revenue requirements	33,978	33,978	33,978	34,242	34,242	34,242	34,599	34,600	40,220	40,220	40,220	40,220	434,738
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(6,858)	(6,858)	(6,858)	(6,911)	(6,911)	(6,911)	(6,983)	(6,984)	(8,118)	(8,118)	(8,118)	(8,118)	(87,745)
37	Total revenue requirements	27,120	27,120	27,120	27,331	27,331	27,331	27,616	27,617	32,102	32,102	32,102	32,102	346,993
39	North Dakota share - D2 factor	10,739	10,739	10,739	10,823	10,823	10,823	10,936	10,936	12,712	12,712	12,712	12,712	137,405

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		Ratio	Cost	WA Cost											
4	Debt	47.50%	5.29%	2.51%											
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)														
11		Book	Tax												
12		50	15-year MACRS												
13															
14		Effective Tax Rate	Fed Portion	State Portion											
15		24.40%	20.09%	4.31%											
16		Tax conversion factor													
17		1.32284													
18		Wholesale Revenue Credit													
19		20.18%													
20		ND share - D2 factor													
21		39.5989%													
22	Deferred Tax														
23	Book depreciation	0	0	0	265	265	265	621	623	6,242	6,242	6,242	6,242	27,006	
24	Tax depreciation-Federal	0	0	985	985	985	33,192	33,192	33,192	33,192	33,192	33,192	33,192	235,302	
25	Tax depreciation-ND	0	0	985	985	985	33,192	33,192	33,192	33,192	33,192	33,192	33,192	235,302	
26	Federal deferred income taxes	0	0	(198)	(145)	(145)	(6,617)	(6,545)	(6,545)	(5,416)	(5,416)	(5,416)	(5,416)	(41,857)	
27	State deferred income taxes	0	0	(42)	(31)	(31)	(1,419)	(1,404)	(1,404)	(1,162)	(1,162)	(1,162)	(1,162)	(8,978)	

Line No.	Year>>	2023 Projected Jan	2023 Projected Feb	2023 Projected Mar	2023 Projected Apr	2023 Projected May	2023 Projected Jun	2023 Projected Jul	2023 Projected Aug	2023 Projected Sep	2023 Projected Oct	2023 Projected Nov	2023 Projected Dec	2023 Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	5,675,000	5,675,000	5,675,000
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(7,623)	(7,623)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	5,675,000	5,667,377	5,667,377
CWIP Calculation:														
	Beginning Balance	965,000	1,080,000	1,195,000	1,480,000	1,830,000	2,170,000	2,625,000	3,310,000	3,880,000	4,765,000	5,450,000	0	0
	Additional CWIP	115,000	115,000	285,000	350,000	340,000	455,000	685,000	570,000	885,000	685,000	225,000	0	4,710,000
	Closings from CWIP											(5,675,000)	0	
	AFDUC												0	
4	CWIP (Project #T05031.0122) 107643	1,080,000	1,195,000	1,480,000	1,830,000	2,170,000	2,625,000	3,310,000	3,880,000	4,765,000	5,450,000	0	0	0
5	ADIT Proration Factors 107643	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 Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	(8,614)	(14,474)	(14,474)
7	Ending rate base	1,080,000	1,195,000	1,480,000	1,830,000	2,170,000	2,625,000	3,310,000	3,880,000	4,765,000	5,450,000	5,666,386	5,652,903	5,652,903
9	Average rate base	256,854	256,854	256,854	256,854	256,854	256,854	256,854	256,854	256,854	256,854	256,854	256,854	3,082,253
11	Return on Rate Base	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	235,546
13	Available for return (equity portion of rate base)	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	158,096
EXPENSES														
<i>O&M and Depreciation</i>														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	18,142
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	7,623	7,623
20	Total O&M and Depreciation Expense	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	1,512	9,135	25,765
22	Income before Taxes													
23	Available for return (from above)	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	13,175	158,096
24	Taxable Income (grossed up)	17,428	17,428	17,428	17,428	17,428	17,428	17,428	17,428	17,428	17,428	17,428	17,428	209,136
26	Income Taxes													
27	Current and Def Income Taxes	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	51,039
28	Total Income Tax Expense	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	4,253	51,039
REVENUE REQUIREMENTS														
32	Expenses	5,765	5,765	5,765	5,765	5,765	5,765	5,765	5,765	5,765	5,765	5,765	13,388	76,804
33	Return on rate base	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	19,629	235,546
34	Subtotal revenue requirements	25,394	25,394	25,394	25,394	25,394	25,394	25,394	25,394	25,394	25,394	25,394	33,017	312,350
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(3,919)	(3,919)	(3,919)	(3,919)	(3,919)	(3,919)	(3,919)	(3,919)	(3,919)	(3,919)	(3,919)	(5,095)	(48,202)
37	Total revenue requirements	21,475	21,475	21,475	21,475	21,475	21,475	21,475	21,475	21,475	21,475	21,475	27,922	264,148
38														
39	North Dakota share - D2 factor	8,504	8,504	8,504	8,504	8,504	8,504	8,504	8,504	8,504	8,504	8,504	11,057	104,600

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%										
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	15.43%												
16	ND share - D2 factor	39.5989%												
17														
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	7,623	7,623
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	141,875	141,875	283,750
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	141,875	141,875	283,750
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	(28,510)	(26,978)	(55,487)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	(6,115)	(5,786)	(11,901)

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		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	180,786	180,786	181,670	181,670	181,670	3,334,186	3,960,293	4,032,750	4,041,737	4,005,187	4,005,187
2	Accumulated Depreciation	0	0	0	(232)	(463)	(696)	(929)	(1,161)	(5,433)	(10,507)	(15,674)	(20,852)	(20,852)
3	Net Plant in Service	0	0	180,786	180,554	181,207	180,974	180,741	3,333,025	3,954,860	4,022,243	4,026,064	3,984,335	3,984,335
CWIP Calculation:														
	Beginning Balance	695,403	752,229	760,462	794,118	1,165,841	1,759,515	2,042,835	2,175,931	0	0	0	0	0
	Additional CWIP	56,827	8,233	214,442	371,722	594,559	283,319	133,097	976,585	626,106	72,457	8,987	(36,551)	3,309,784
	Closings from CWIP			(180,786)		(884)		0	(3,152,516)	(626,106)	(72,457)	(8,987)	36,551	
	AFDUC													
4	CWIP (Project #T03032.038)	107332	752,229	760,462	794,118	1,165,841	1,759,515	2,042,835	2,175,931	0	0	0	0	0
5	ADIT Proration Factors	107332	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 Taxes Federal & S	107362	0	0	(221)	(385)	(549)	(713)	(876)	(10,594)	(19,326)	(27,863)	(36,376)	(44,887)
7	Ending rate base	107363	752,229	760,462	974,684	1,346,010	1,940,173	2,223,096	2,355,796	3,322,431	3,935,533	3,994,381	3,989,687	3,939,448
8														
9	Average rate base		193,778	193,778	193,778	193,778	193,778	193,778	193,778	193,778	193,778	193,778	193,778	2,325,333
10														
11	Return on Rate Base		14,808	14,808	14,808	14,808	14,808	14,808	14,808	14,808	14,808	14,808	14,808	177,702
12														
13	Available for return (equity portion of rate base)		9,939	9,939	9,939	9,939	9,939	9,939	9,939	9,939	9,939	9,939	9,939	119,272
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs		0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax		469	469	469	469	469	469	469	469	469	469	469	5,633
19	Book Depreciation		0	0	0	232	232	233	233	233	4,272	5,074	5,167	20,852
20	Total O&M and Depreciation Expense		469	469	469	701	701	702	702	702	4,741	5,543	5,636	26,484
21														
22	Income before Taxes													
23	Available for return (from above)		9,939	9,939	9,939	9,939	9,939	9,939	9,939	9,939	9,939	9,939	9,939	119,272
24	Taxable Income (grossed up)		13,148	13,148	13,148	13,148	13,148	13,148	13,148	13,148	13,148	13,148	13,148	157,778
25														
26	Income Taxes													
27	Current and Def Income Taxes		3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	38,505
28	Total Income Tax Expense		3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	3,209	38,505
29														
30														
REVENUE REQUIREMENTS														
31														
32	Expenses		3,678	3,678	3,678	3,910	3,910	3,911	3,911	3,911	7,950	8,752	8,845	64,990
33	Return on rate base		14,808	14,808	14,808	14,808	14,808	14,808	14,808	14,808	14,808	14,808	14,808	177,702
34	Subtotal revenue requirements		18,487	18,487	18,487	18,718	18,718	18,719	18,719	18,719	22,758	23,560	23,653	242,692
35	Adjustments		0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit		(3,731)	(3,731)	(3,731)	(3,778)	(3,778)	(3,778)	(3,778)	(3,778)	(4,593)	(4,755)	(4,774)	(48,984)
37	Total revenue requirements		14,755	14,755	14,755	14,940	14,940	14,941	14,941	14,941	18,165	18,805	18,879	193,708
38														
39	North Dakota share - D2 factor		5,843	5,843	5,843	5,916	5,916	5,917	5,917	5,917	7,193	7,447	7,476	76,706

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		Ratio	Cost	WA Cost											
4	Debt	47.50%	5.29%	2.51%											
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			Fed Portion	State Portion											
14	Effective Tax Rate	24.40%	20.09%	4.31%											
15	Tax conversion factor	1.32284													
16	Wholesale Revenue Credit	20.18%													
17	ND share - D2 factor	39.5989%													
18	Deferred Tax														
19	Book depreciation	0	0	0	232	232	233	233	233	4,272	5,074	5,167	5,178	20,852	
20	Tax depreciation-Federal	0	0	904	904	904	904	904	40,052	40,052	40,052	40,052	40,052	204,779	
21	Tax depreciation-ND	0	0	904	904	904	904	904	40,052	40,052	40,052	40,052	40,052	204,779	
22	Federal deferred income taxes	0	0	(182)	(135)	(135)	(135)	(135)	(8,002)	(7,190)	(7,029)	(7,010)	(7,008)	(36,960)	
23	State deferred income taxes	0	0	(39)	(29)	(29)	(29)	(29)	(1,716)	(1,542)	(1,508)	(1,504)	(1,503)	(7,927)	

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		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	103,152	103,152	1,230,346	1,230,346	1,230,346	1,230,346	1,230,346	1,230,346
2	Accumulated Depreciation	0	0	0	0	0	(139)	(139)	(277)	(1,930)	(3,582)	(5,235)	(6,888)	(6,888)
3	Net Plant in Service	0	0	0	0	0	103,152	103,014	1,230,069	1,228,416	1,226,764	1,225,111	1,223,458	1,223,458
CWIP Calculation:														
	Beginning Balance	1,254,127	1,285,907	1,232,321	1,232,321	1,236,807	1,230,346	1,127,194	1,127,194	0	0	0	0	0
	Additional CWIP	31,780	(53,588)	0	4,486	(6,461)	0	0	0	0	0	0	0	(23,781)
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0
	AFDUC						(103,152)		(1,127,194)	0	0	0	0	0
4	CWIP (Project #T05002.020)	136358	1,285,907	1,232,321	1,232,321	1,236,807	1,230,346	1,127,194	1,127,194	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	0.0027	0
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	(2,145)	(4,256)	(6,367)	(8,108)	(9,849)	(11,591)	(11,902)	(11,902)
7	Ending rate base	1,285,907	1,232,321	1,232,321	1,236,807	1,230,346	1,228,202	1,225,952	1,223,703	1,220,308	1,216,914	1,213,520	1,211,556	1,211,556
8	Average rate base	102,641	102,641	102,641	102,641	102,641	102,641	102,641	102,641	102,641	102,641	102,641	102,641	1,231,691
10	Return on Rate Base	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	94,126
11	Available for return (equity portion of rate base)	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	63,177
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	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	0
19	Book Depreciation	0	0	0	0	0	0	139	139	1,653	1,653	1,653	1,653	6,888
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	139	139	1,653	1,653	1,653	1,653	6,888
21	Income before Taxes													
22	Available for return (from above)	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	5,265	63,177
24	Taxable Income (grossed up)	6,964	6,964	6,964	6,964	6,964	6,964	6,964	6,964	6,964	6,964	6,964	6,964	83,572
25	Income Taxes													
27	Current and Def Income Taxes	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	20,396
28	Total Income Tax Expense	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	20,396
REVENUE REQUIRMENTS														
31	Expenses	1,700	1,700	1,700	1,700	1,700	1,700	1,838	1,838	3,352	3,352	3,352	3,352	27,283
33	Return on rate base	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	7,844	94,126
34	Subtotal revenue requirements	9,543	9,543	9,543	9,543	9,543	9,543	9,682	9,682	11,196	11,196	11,196	11,196	121,409
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(1,926)	(1,954)	(1,954)	(2,260)	(2,260)	(2,260)	(2,260)	(24,505)
37	Total revenue requirements	7,617	7,617	7,617	7,617	7,617	7,617	7,728	7,728	8,936	8,936	8,936	8,936	96,905
38	North Dakota share - D2 factor	3,016	3,016	3,016	3,016	3,016	3,016	3,060	3,060	3,539	3,539	3,539	3,539	38,373

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%											2022 composite rate
5	Preferred equity	0.00%	0.00%	0.00%											0.81%
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		Fed Portion	State Portion												
14	Effective Tax Rate	24.40%	20.09%	4.31%											
15	Tax conversion factor	1.32284													
16	Wholesale Revenue Credit	20.18%													
17	ND share - D2 factor	39.5989%													
18	Deferred Tax														
19	Book depreciation	0	0	0	0	0	0	139	139	1,653	1,653	1,653	1,653	6,888	
20	Tax depreciation-Federal	0	0	0	0	0	8,788	8,788	8,788	8,788	8,788	8,788	8,788	61,517	
21	Tax depreciation-ND	0	0	0	0	0	8,788	8,788	8,788	8,788	8,788	8,788	8,788	61,517	
22	Federal deferred income taxes	0	0	0	0	0	(1,766)	(1,738)	(1,738)	(1,434)	(1,434)	(1,434)	(1,434)	(10,978)	
23	State deferred income taxes	0	0	0	0	0	(379)	(373)	(373)	(308)	(308)	(308)	(308)	(2,355)	

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	
		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														
	Transmission Plant - Station Equipment (353)		348,804.73	348,804.73	348,804.73	348,804.73	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)		523,207.10	523,207.10	523,207.10	523,207.10	777,355.76	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77	777,355.77
1	Plant Balance	307,399	872,012	872,012	872,012	872,012	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	(15,214)	(15,626)	(16,798)	(17,969)	(19,140)	(20,312)	(22,052)	(23,792)	(25,533)	(27,273)	(29,013)	(30,754)	(30,754)
3	Net Plant In Service	292,185	856,385	855,214	854,043	852,871	1,275,281	1,273,541	1,271,801	1,270,060	1,268,320	1,266,580	1,264,839	1,264,839
CWIP Calculation:														
	Beginning Balance	988,194	988,194	423,581	423,581	423,581	423,581	0	0	0	0	0	0	0
	Additional CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0
	Closings from CWIP		(564,613)	0	0	0	(423,581)	(0)	0	0	0	0	0	0
	AFDUC													
4	CWIP (Project #T05008.027)	130717	988,194	423,581	423,581	423,581	0	0	0	0	0	0	0	0
5	ADIT Proration Factors		1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000
6	Accumulated Deferred Income Taxes Federal & State		(14,061)	(15,446)	(16,647)	(17,847)	(19,047)	(20,248)	(21,309)	(22,371)	(23,432)	(24,494)	(25,555)	(26,617)
7	Ending rate base		1,266,319	1,264,520	1,262,149	1,259,777	1,257,405	1,255,033	1,252,232	1,249,430	1,246,628	1,243,826	1,241,024	1,238,222
8														
9	Average rate base		104,511	104,511	104,511	104,511	104,511	104,511	104,511	104,511	104,511	104,511	104,511	1,254,129
10														
11	Return on Rate Base		7.987	7.987	7.987	7.987	7.987	7.987	7.987	7.987	7.987	7.987	7.987	95,841
12														
13	Available for return (equity portion of rate base)		5,361	5,361	5,361	5,361	5,361	5,361	5,361	5,361	5,361	5,361	5,361	64,327
14														
EXPENSES														
O&M and Depreciation														
16	Operating Costs		0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax		207	207	207	207	207	207	207	207	207	207	207	2,490
18														
Book depreciation - Summary														
	Transmission Plant - Station Equipment (353)			447	447	447	447	664	664	664	664	664	664	664
	Transmission Plant - Poles & Fixtures (355)			823	823	823	823	1,223	1,223	1,223	1,223	1,223	1,223	1,223
19	Book Depreciation		413	1,270	1,270	1,270	1,270	1,887	1,887	1,887	1,887	1,887	1,887	18,706
20	Total O&M and Depreciation Expense		620	2,748	2,748	2,748	2,748	3,982	3,982	3,982	3,982	3,982	3,982	21,196
21														
22	Income before Taxes													
23	Available for return (from above)		5,361	5,361	5,361	5,361	5,361	5,361	5,361	5,361	5,361	5,361	5,361	64,327
24	Taxable Income (grossed up)		7,091	7,091	7,091	7,091	7,091	7,091	7,091	7,091	7,091	7,091	7,091	85,095
25														
26	Income Taxes													
27	Current and Def Income Taxes		1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	20,767
28	Total Income Tax Expense		1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	1,731	20,767
29														
30														
REVENUE REQUIREMENTS														
32	Expenses		2,351	4,479	4,479	4,479	4,479	5,713	5,713	5,713	5,713	5,713	5,713	41,964
33	Return on rate base		7,987	7,987	7,987	7,987	7,987	7,987	7,987	7,987	7,987	7,987	7,987	95,841
34	Subtotal revenue requirements		10,338	12,466	12,466	12,466	12,466	13,700	13,700	13,700	13,700	13,700	13,700	137,804
35	Adjustments		0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit		(2,087)	(2,516)	(2,516)	(2,516)	(2,765)	(2,765)	(2,765)	(2,765)	(2,765)	(2,765)	(2,765)	(27,814)
37	Total revenue requirements		8,251	9,950	9,950	9,950	9,950	10,935	10,935	10,935	10,935	10,935	10,935	109,991
38														
39	North Dakota share - D2 factor		3,267	3,940	3,940	3,940	3,940	4,330	4,330	4,330	4,330	4,330	4,330	49,337

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		47.50%	5.29%	2.51%	2022 composite rate									
5		0.00%	0.00%	0.00%	0.81%									
6		52.50%	9.77%	5.13%										
7		100.00%		7.64%	Overall Return									
8														
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Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		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	95,275	97,972	50,298	53,508	54,233	823,692	823,692	874,496	874,496	874,496	874,496	874,496	874,496
2	Accumulated Depreciation	(39)	(167)	(299)	(366)	(438)	(511)	(1,618)	(2,724)	(3,899)	(5,073)	(6,248)	(7,423)	(7,423)
3	Net Plant in Service	95,236	97,804	49,999	53,142	53,795	823,180	822,074	871,772	870,597	869,422	868,248	867,073	867,073
CWIP Calculation:														
	Beginning Balance	899,085	850,550	850,587	826,441	822,854	820,263	50,804	50,804	0	0	0	0	0
	Additional CWIP	17,451	2,733	(71,819)	(377)	(1,867)	0	0	0	0	0	0	0	(53,879)
	Closings from CWIP	(65,986)	(2,696)	47,674	(3,211)	(724)	(769,459)		(50,804)	0	0	0	0	0
	AFDUC													
4	CWIP (Project #T05002.037)	132113	850,550	850,587	826,441	822,854	820,263	50,804	50,804	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 Taxes Federal & State	(1,264)	(2,149)	(3,033)	(3,932)	(4,831)	(5,729)	(6,375)	(7,021)	(7,650)	(8,280)	(8,909)	(9,539)	(9,539)
7	Ending rate base	944,522	946,242	873,407	872,064	869,227	868,256	866,503	864,751	862,947	861,143	859,338	857,534	857,534
8														
9	Average rate base	73,551	73,551	73,551	73,551	73,551	73,551	73,551	73,551	73,551	73,551	73,551	73,551	882,612
10														
11	Return on Rate Base	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	67,449
12														
13	Available for return (equity portion of rate base)	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	45,271
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	20	20	20	20	20	20	20	20	20	20	20	20	237
19	Book Depreciation	39	128	132	68	72	73	1,106	1,106	1,175	1,175	1,175	1,175	7,423
20	Total O&M and Depreciation Expense	59	148	151	87	92	93	1,126	1,126	1,194	1,194	1,194	1,194	7,660
21														
22	Income before Taxes													
23	Available for return (from above)	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	3,773	45,271
24	Taxable Income (grossed up)	4,991	4,991	4,991	4,991	4,991	4,991	4,991	4,991	4,991	4,991	4,991	4,991	59,887
25														
26	Income Taxes													
27	Current and Def Income Taxes	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	14,615
28	Total Income Tax Expense	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	1,218	14,615
29														
30														
REVENUE REQUIRMENTS														
32	Expenses	1,277	1,366	1,369	1,305	1,310	1,311	2,344	2,344	2,412	2,412	2,412	2,412	22,275
33	Return on rate base	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	5,621	67,449
34	Subtotal revenue requirements	6,898	6,986	6,990	6,926	6,930	6,931	7,965	7,965	8,033	8,033	8,033	8,033	89,724
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(1,392)	(1,410)	(1,411)	(1,398)	(1,399)	(1,399)	(1,608)	(1,608)	(1,621)	(1,621)	(1,621)	(1,621)	(18,109)
37	Total revenue requirements	5,506	5,576	5,579	5,528	5,532	5,532	6,357	6,357	6,412	6,412	6,412	6,412	71,615
38														
39	North Dakota share - D2 factor	2,180	2,208	2,209	2,189	2,190	2,191	2,517	2,517	2,539	2,539	2,539	2,539	28,359

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		Ratio	Cost	WA Cost											
4	Debt	47.50%	5.29%	2.51%											
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)	50	15-year MACRS												
11															
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	20.18%													
17	ND share - D2 factor	39.5989%													
18	Deferred Tax														
19	Book depreciation	39	128	132	68	72	73	1,106	1,106	1,175	1,175	1,175	1,175	7,423	
20	Tax depreciation-Federal	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	45,043	
21	Tax depreciation-ND	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	3,754	45,043	
22	Federal deferred income taxes	(746)	(729)	(728)	(741)	(740)	(740)	(532)	(532)	(518)	(518)	(518)	(518)	(7,560)	
23	State deferred income taxes	(160)	(156)	(156)	(159)	(159)	(159)	(114)	(114)	(111)	(111)	(111)	(111)	(1,621)	

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	
		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	0	0	0	0	0	1,252,252	1,252,252
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	1,252,252	1,252,252
CWIP Calculation:															
	Beginning Balance	2,554	113,417	114,179	114,623	226,142	231,140	231,359	240,137	287,872	616,238	1,119,285	1,151,342	1,151,342	1,249,698
	Additional CWIP	110,863	762	444	111,518	4,998	219	8,778	47,735	328,366	503,046	32,057	100,910	100,910	1,249,698
	Closings from CWIP	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	(1,252,252)	0
4	CWIP (Project #T03032.031)	113,417	114,179	114,623	226,142	231,140	231,359	240,137	287,872	616,238	1,119,285	1,151,342	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	1.0000
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	0	(15,281)	(15,281)
7	Ending rate base	113,417	114,179	114,623	226,142	231,140	231,359	240,137	287,872	616,238	1,119,285	1,151,342	1,236,971	1,236,971	1,236,971
8	Average rate base	36,444	36,444	36,444	36,444	36,444	36,444	36,444	36,444	36,444	36,444	36,444	36,444	36,444	437,328
9	Return on Rate Base	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	33,421
10															
11	Return on Rate Base	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	33,421
12															
13	Available for return (equity portion of rate base)	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	22,432
14															
EXPENSES															
O&M and Depreciation															
17	Operating Costs	0	0	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	0	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Income before Taxes														
23	Available for return (from above)	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	22,432
24	Taxable Income (grossed up)	2,473	2,473	2,473	2,473	2,473	2,473	2,473	2,473	2,473	2,473	2,473	2,473	2,473	29,673
25															
26	Income Taxes														
27	Current and Def Income Taxes	603	603	603	603	603	603	603	603	603	603	603	603	603	7,242
28	Total Income Tax Expense	603	603	603	603	603	603	603	603	603	603	603	603	603	7,242
29															
30															
REVENUE REQUIREMENTS															
32	Expenses	603	603	603	603	603	603	603	603	603	603	603	603	603	7,242
33	Return on rate base	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	2,785	33,421
34	Subtotal revenue requirements	3,389	3,389	3,389	3,389	3,389	3,389	3,389	3,389	3,389	3,389	3,389	3,389	3,389	40,662
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(684)	(8,207)
37	Total revenue requirements	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	2,705	32,455	32,455
38															
39	North Dakota share - D2 factor	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	12,852

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		<u>Ratio</u>	<u>Cost</u>	<u>WA Cost</u>											
4	Debt	47.50%	5.29%	2.51%											
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)	50	15-year	MACRS											
11															
12															
13		<u>Effective Tax Rate</u>	<u>Fed Portion</u>	<u>State Portion</u>											
14	Tax conversion factor	24.40%	20.09%	4.31%											
15	Wholesale Revenue Credit	1.32284													
16	ND share - D2 factor	20.18%													
17		39.5989%													
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	62,613	62,613
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	0	62,613	62,613
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	(12,582)	(12,582)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	(2,699)	(2,699)

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		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	448,641	609,200	607,683	610,502	607,090	607,090	607,090	607,090	607,090	607,090	803,700	3,213,168	3,213,168
2	Accumulated Depreciation	(1,130)	(1,785)	(2,674)	(3,561)	(4,453)	(5,339)	(6,225)	(7,112)	(7,998)	(8,884)	(9,771)	(10,944)	(10,944)
3	Net Plant in Service	447,511	607,415	605,008	606,940	602,637	601,751	600,865	599,978	599,092	598,206	793,930	3,202,224	3,202,224
4	CWIP (Project #)	828,119	960,313	1,289,999	1,554,319	1,930,091	2,678,812	3,272,720	4,667,797	5,764,428	6,832,010	7,019,655	4,722,432	4,722,432
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 Taxes Federal & State	(2,676)	(3,802)	(4,870)	(5,939)	(7,008)	(8,077)	(9,146)	(10,216)	(11,285)	(12,354)	(13,424)	(35,989)	(35,989)
6	Accumulated Deferred Income Taxes Federal & State - No Proration	(2,676)	(3,802)	(4,870)	(5,939)	(7,008)	(8,077)	(9,146)	(10,216)	(11,285)	(12,354)	(13,424)	(35,989)	(35,989)
7	Ending rate base	1,272,954	1,563,927	1,890,137	2,155,319	2,525,720	3,272,486	3,864,438	5,257,560	6,352,235	7,417,861	7,800,161	7,888,667	7,888,667
8														
9	Average rate base	335,018	335,018	335,018	335,018	335,018	335,018	335,018	335,018	335,018	335,018	335,018	335,018	4,020,215
10														
11	Return on Rate Base	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	307,225
12														
13	Available for return (equity portion of rate base)	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	206,207
14														
EXPENSES														
<i>O&M and Depreciation</i>														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	448	448	448	448	448	448	448	448	448	448	448	448	5,374
19	Book Depreciation	656	655	889	887	891	886	886	886	886	886	886	1,173	10,470
20	Total O&M and Depreciation Expense	1,104	1,103	1,337	1,335	1,339	1,334	1,334	1,334	1,334	1,334	1,334	1,621	15,844
21														
22	Income before Taxes													
23	Available for return (from above)	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	17,184	206,207
24	Taxable Income (grossed up)	22,732	22,732	22,732	22,732	22,732	22,732	22,732	22,732	22,732	22,732	22,732	22,732	272,778
25														
26	Income Taxes													
27	Current and Def Income Taxes	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	66,571
28	Total Income Tax Expense	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	5,548	66,571
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	6,651	6,650	6,885	6,883	6,887	6,882	6,882	6,882	6,882	6,882	6,882	6,882	7,169
33	Return on rate base	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	25,602	307,225
34	Subtotal revenue requirements	32,253	32,253	32,487	32,485	32,489	32,484	32,484	32,484	32,484	32,484	32,484	32,771	389,640
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(6,510)	(6,510)	(6,557)	(6,557)	(6,557)	(6,556)	(6,556)	(6,556)	(6,556)	(6,556)	(6,556)	(6,614)	(78,643)
37	Total revenue requirements	25,744	25,743	25,930	25,928	25,931	25,927	25,927	25,927	25,927	25,927	25,927	26,157	310,998
38														
39	North Dakota share - D2 factor	10,194	10,194	10,268	10,267	10,269	10,267	10,267	10,267	10,267	10,267	10,267	10,358	123,152

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%											2022 composite rate
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)														
11		Book	Tax												
12		50	15-year MACRS												
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	20.18%													
17	ND share - D2 factor	39.5989%													
18	Deferred Tax														
19	Book depreciation	656	655	889	887	891	886	886	886	886	886	886	1,173	10,470	
20	Tax depreciation-Federal	3,557	5,268	5,268	5,268	5,268	5,268	5,268	5,268	5,268	5,268	5,268	93,636	149,873	
21	Tax depreciation-ND	3,557	5,268	5,268	5,268	5,268	5,268	5,268	5,268	5,268	5,268	5,268	93,636	149,873	
22	Federal deferred income taxes	(583)	(927)	(880)	(880)	(879)	(880)	(880)	(880)	(880)	(880)	(880)	(18,580)	(28,013)	
23	State deferred income taxes	(125)	(199)	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(189)	(3,985)	(6,008)	

Line No.	Year>>	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
		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	712,198	712,198	798,189	796,529	797,604	950,017	950,764	1,580,360	1,696,436	1,806,852	2,219,619	2,496,815	2,496,815
2	Accumulated Depreciation	(849)	(1,889)	(2,929)	(4,094)	(5,257)	(6,421)	(7,808)	(9,196)	(11,504)	(13,980)	(16,618)	(19,859)	(19,859)
3	Net Plant in Service	711,348	710,309	795,260	792,434	792,347	943,596	942,956	1,571,164	1,684,933	1,792,872	2,203,001	2,476,957	2,476,957
4	CWIP (Project #)	59,956	335,278	475,645	750,567	812,876	802,447	834,660	411,090	528,631	681,060	498,396	365,429	365,429
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 Taxes Federal & State	(7,361)	(8,336)	(9,311)	(10,256)	(11,201)	(13,191)	(15,585)	(18,886)	(21,962)	(24,997)	(29,957)	(36,905)	(36,905)
7	Ending rate base	763,944	1,037,250	1,261,594	1,532,745	1,594,021	1,732,852	1,762,031	1,963,368	2,191,602	2,448,935	2,671,440	2,805,480	2,805,480
8														
9	Average rate base	144,159	144,159	144,159	144,159	144,159	144,159	144,159	144,159	144,159	144,159	144,159	144,159	1,729,905
10														
11	Return on Rate Base	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	132,199
12														
13	Available for return (equity portion of rate base)	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	88,731
14														
EXPENSES														
<i>O&M and Depreciation</i>														
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax	860	860	860	860	860	860	860	860	860	860	860	860	10,323
18	Book Depreciation	849	1,040	1,040	1,165	1,163	1,164	1,387	1,388	2,307	2,477	2,638	3,240	19,859
19	Total O&M and Depreciation Expense	1,710	1,900	1,900	2,026	2,023	2,025	2,247	2,248	3,167	3,337	3,498	4,101	30,182
20														
21	Income before Taxes													
22	Available for return (from above)	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	7,394	88,731
23	Taxable Income (grossed up)	9,781	9,781	9,781	9,781	9,781	9,781	9,781	9,781	9,781	9,781	9,781	9,781	117,377
24														
25	Income Taxes													
26	Current and Def Income Taxes	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	28,646
27	Total Income Tax Expense	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	2,387	28,646
28														
29														
30														
REVENUE REQUIRMENTS														
31	Expenses	4,097	4,287	4,287	4,413	4,410	4,412	4,634	4,635	5,555	5,724	5,885	6,488	58,828
32	Return on rate base	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	132,199
33	Subtotal revenue requirements	15,113	15,304	15,304	15,429	15,427	15,428	15,651	15,652	16,571	16,741	16,902	17,505	191,027
34	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Wholesale Revenue Credit	(3,050)	(3,089)	(3,089)	(3,114)	(3,114)	(3,114)	(3,159)	(3,159)	(3,345)	(3,379)	(3,411)	(3,533)	(38,556)
36	Total revenue requirements	12,063	12,215	12,215	12,314	12,313	12,314	12,492	12,493	13,227	13,362	13,491	13,971	152,471
37														
38	North Dakota share - D2 factor	4,777	4,837	4,837	4,877	4,876	4,876	4,947	4,947	5,238	5,291	5,342	5,533	60,377
39														

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		<u>Ratio</u>	<u>Cost</u>	<u>WA Cost</u>											
4	Debt	47.50%	5.29%	2.51%											
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)	<u>Book</u>	<u>Tax</u>												
11		50	15-year MACRS												
12															
13			<u>Fed Portion</u>	<u>State Portion</u>											
14	Effective Tax Rate	24.40%	20.09%	4.31%											
15	Tax conversion factor	1.32284													
16	Wholesale Revenue Credit	20.18%													
17	ND share - D2 factor	39.5989%													
18	Deferred Tax														
19	Book depreciation	849	1,040	1,040	1,165	1,163	1,164	1,387	1,388	2,307	2,477	2,638	3,240	19,859	
20	Tax depreciation-Federal	5,036	5,036	5,036	5,036	5,036	5,036	9,317	11,197	14,913	14,913	14,913	22,961	145,103	
21	Tax depreciation-ND	5,036	5,036	5,036	5,036	5,036	9,317	11,197	14,913	14,913	14,913	22,961	31,711	145,103	
22	Federal deferred income taxes	(841)	(803)	(803)	(778)	(778)	(1,638)	(1,971)	(2,718)	(2,533)	(2,499)	(4,084)	(5,721)	(25,168)	
23	State deferred income taxes	(180)	(172)	(172)	(167)	(167)	(351)	(423)	(583)	(543)	(536)	(876)	(1,227)	(5,398)	

Line No.	Year>>	2023 Projected January	2023 Projected February	2023 Projected March	2023 Projected April	2023 Projected May	2023 Projected June	2023 Projected July	2023 Projected August	2023 Projected September	2023 Projected October	2023 Projected November	2023 Projected December	2023 Projected Total
RATE BASE														
1	Plant Balance	2,542,232	2,587,649	2,633,065	2,678,482	2,723,899	2,769,315	2,814,732	2,860,149	2,905,565	2,950,982	2,996,399	3,407,244	3,407,244
2	Accumulated Depreciation	(23,504)	(27,215)	(30,993)	(34,837)	(38,747)	(42,724)	(46,767)	(50,876)	(55,052)	(59,294)	(63,602)	(67,976)	(67,976)
3	Net Plant in Service	2,518,728	2,560,433	2,602,072	2,643,645	2,685,151	2,726,591	2,767,965	2,809,272	2,850,513	2,891,688	2,932,797	3,339,268	3,339,268
4	CWIP (Project #)	365,429	365,429	365,429	365,429	365,429	365,429	365,429	365,429	365,429	365,429	365,429	0	0
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 Taxes Federal & State	(40,167)	(43,194)	(45,964)	(48,488)	(50,768)	(52,811)	(54,594)	(56,131)	(57,433)	(58,494)	(59,324)	(59,918)	(59,918)
7	Ending rate base	2,843,990	2,882,668	2,921,537	2,960,586	2,999,812	3,039,208	3,078,800	3,118,570	3,158,509	3,198,623	3,238,901	3,279,349	3,279,349
8														
9	Average rate base	253,372	253,372	253,372	253,372	253,372	253,372	253,372	253,372	253,372	253,372	253,372	253,372	3,040,464
10														
11	Return on Rate Base	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	232,352
12														
13	Available for return (equity portion of rate base)	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	155,953
14														
EXPENSES														
<i>O&M and Depreciation</i>														
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax	3,407	3,407	3,407	3,407	3,407	3,407	3,407	3,407	3,407	3,407	3,407	3,407	40,887
18	Book Depreciation	3,645	3,711	3,778	3,844	3,910	3,977	4,043	4,109	4,176	4,242	4,308	4,374	48,118
19	Total O&M and Depreciation Expense	7,052	7,119	7,185	7,251	7,318	7,384	7,450	7,517	7,583	7,649	7,715	7,782	89,005
20														
21	Income before Taxes													
22	Available for return (from above)	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	12,996	155,953
23	Taxable Income (grossed up)	17,192	17,192	17,192	17,192	17,192	17,192	17,192	17,192	17,192	17,192	17,192	17,192	206,300
24														
25	Income Taxes													
26	Current and Def Income Taxes	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	50,347
27	Total Income Tax Expense	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	4,196	50,347
28														
29														
30														
REVENUE REQUIREMENTS														
31	Expenses	11,248	11,314	11,381	11,447	11,513	11,580	11,646	11,712	11,778	11,845	11,911	11,977	139,352
32	Return on rate base	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	19,363	232,352
33	Subtotal revenue requirements	30,611	30,677	30,743	30,810	30,876	30,942	31,009	31,075	31,141	31,207	31,274	31,340	371,704
34	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Wholesale Revenue Credit	(4,724)	(4,734)	(4,744)	(4,755)	(4,765)	(4,775)	(4,785)	(4,795)	(4,806)	(4,816)	(4,826)	(4,836)	(57,362)
36	Total revenue requirements	25,887	25,943	25,999	26,055	26,111	26,167	26,223	26,279	26,335	26,391	26,448	26,504	314,343
37														
38	North Dakota share - D2 factor	10,251	10,273	10,295	10,318	10,340	10,362	10,384	10,406	10,429	10,451	10,473	10,495	124,476
39														

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%										
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				Fed Portion	State Portion									
13	Effective Tax Rate	24.40%	20.09%	4.31%										
14	Tax conversion factor	1.32284												
15	Wholesale Revenue Credit	15.43%												
16	ND share - D2 factor	39.5989%												
17														
18	Deferred Tax													
19	Book depreciation	3,645	3,711	3,778	3,844	3,910	3,977	4,043	4,109	4,176	4,242	4,308	4,374	48,118
20	Tax depreciation-Federal	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	215,776
21	Tax depreciation-ND	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	215,776
22	Federal deferred income taxes	(2,881)	(2,868)	(2,854)	(2,841)	(2,841)	(2,841)	(2,841)	(2,841)	(2,788)	(2,774)	(2,761)	(2,748)	(33,731)
23	State deferred income taxes	(618)	(615)	(612)	(609)	(606)	(604)	(601)	(598)	(595)	(592)	(589)	(586)	(7,226)

Line No.	Year>>	2023 Projected Jan	2023 Projected Feb	2023 Projected Mar	2023 Projected Apr	2023 Projected May	2023 Projected Jun	2023 Projected Jul	2023 Projected Aug	2023 Projected Sep	2023 Projected Oct	2023 Projected Nov	2023 Projected Dec	2023 Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	840,000	840,000
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	840,000	840,000
CWIP Calculation:														
	Beginning Balance	0	0	0	0	0	0	0	0	40,000	440,000	840,000	840,000	840,000
	Additional CWIP	0	0	0	0	0	0	0	40,000	400,000	400,000	0	0	840,000
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	(840,000)	0
	AFDUC	0	0	0	0	0	0	0	0	0	0	0	0	0
4	CWIP (Project #T03032.031) 7761	0	0	0	0	0	0	0	40,000	440,000	840,000	840,000	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
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	(1,833)	(1,833)
7	Ending rate base	0	0	0	0	0	0	0	40,000	440,000	840,000	840,000	838,167	838,167
8														
9	Average rate base	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,219	19,219	230,628
10														
11	Return on Rate Base	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	17,625
12														
13	Available for return (equity portion of rate base)	986	986	986	986	986	986	986	986	986	986	986	986	11,830
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	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	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
21														
22	Income before Taxes													
23	Available for return (from above)	986	986	986	986	986	986	986	986	986	986	986	986	11,830
24	Taxable Income (grossed up)	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	15,649
25														
26	Income Taxes													
27	Current and Def Income Taxes	318	318	318	318	318	318	318	318	318	318	318	318	3,819
28	Total Income Tax Expense	318	318	318	318	318	318	318	318	318	318	318	318	3,819
29														
30														
REVENUE REQUIRMENTS														
32	Expenses	318	318	318	318	318	318	318	318	318	318	318	318	3,819
33	Return on rate base	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	1,469	17,625
34	Subtotal revenue requirements	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	1,787	21,444
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(276)	(276)	(276)	(276)	(276)	(276)	(276)	(276)	(276)	(276)	(276)	(276)	(3,309)
37	Total revenue requirements	1,511	1,511	1,511	1,511	1,511	1,511	1,511	1,511	1,511	1,511	1,511	1,511	18,134
38														
39	North Dakota share - D2 factor	598	598	598	598	598	598	598	598	598	598	598	598	7,181

Line No.	SUPPORTING INFORMATION / DATA
1	
2	ND Cap Structure with allowed ROE per order.
3	Capital Structure
4	Debt
5	Preferred equity
6	Common equity
7	Total
8	
9	
10	Project life (years)
11	
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

Ratio	Cost	WA Cost	Property tax
47.50%	5.29%	2.51%	2023 composite rate
0.00%	0.00%	0.00%	1.88%
52.50%	9.77%	5.13%	
100.00%		7.64%	Overall Return

Book	Tax
50	15-year MACRS

Fed Portion	State Portion
24.40%	20.09%
1.32284	4.31%
15.43%	
39.5989%	

Line No.	Year>>	2023 Projected Jan	2023 Projected Feb	2023 Projected Mar	2023 Projected Apr	2023 Projected May	2023 Projected Jun	2023 Projected Jul	2023 Projected Aug	2023 Projected Sep	2023 Projected Oct	2023 Projected Nov	2023 Projected Dec	2023 Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	430,000	430,000
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	430,000	430,000
CWIP Calculation:														
	Beginning Balance	0	10,000	10,000	100,000	190,000	190,000	245,000	300,000	355,000	410,000	430,000	430,000	430,000
	Additional CWIP	10,000	0	90,000	90,000	0	55,000	55,000	55,000	55,000	20,000	0	0	0
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	(430,000)	0
	AFDUC	0	0	0	0	0	0	0	0	0	0	0	0	0
4	CWIP	6976	10,000	100,000	190,000	190,000	245,000	300,000	355,000	410,000	430,000	430,000	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
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	(938)	(938)
7	Ending rate base	10,000	10,000	100,000	190,000	190,000	245,000	300,000	355,000	410,000	430,000	430,000	429,062	429,062
8														
9	Average rate base	19,866	19,866	19,866	19,866	19,866	19,866	19,866	19,866	19,866	19,866	19,866	19,866	238,390
10														
11	Return on Rate Base	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	18,218
12														
13	Available for return (equity portion of rate base)	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	12,228
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	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	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
21														
22	Income before Taxes													
23	Available for return (from above)	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	12,228
24	Taxable Income (grossed up)	1,348	1,348	1,348	1,348	1,348	1,348	1,348	1,348	1,348	1,348	1,348	1,348	16,175
25														
26	Income Taxes													
27	Current and Def Income Taxes	329	329	329	329	329	329	329	329	329	329	329	329	3,948
28	Total Income Tax Expense	329	329	329	329	329	329	329	329	329	329	329	329	3,948
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	329	329	329	329	329	329	329	329	329	329	329	329	3,948
33	Return on rate base	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	1,518	18,218
34	Subtotal revenue requirements	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	22,165
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(285)	(285)	(285)	(285)	(285)	(285)	(285)	(285)	(285)	(285)	(285)	(285)	(3,421)
37	Total revenue requirements	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	1,562	18,745
38														
39	North Dakota share - D2 factor	619	619	619	619	619	619	619	619	619	619	619	619	7,423

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		<u>Ratio</u>	<u>Cost</u>	<u>WA Cost</u>										<u>Property tax</u>
4	Debt	47.50%	5.29%	2.51%										2023 composite rate
5	Preferred equity	0.00%	0.00%	0.00%										0.81%
6	Common equity	52.50%	9.77%	5.13%										
7	Total	100.00%		7.64% Overall Return										
8														
9														
10	Project life (years)	50	15-year MACRS											
11														
12														
13		<u>Fed Portion</u>	<u>State Portion</u>											
14	Effective Tax Rate	24.40%	20.09%	4.31%										
15	Tax conversion factor	1.32284												
16	Wholesale Revenue Credit	15.43%												
17	ND share - D2 factor	39.5989%												
18	Deferred Tax													
19	Book depreciation	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	21,500	21,500
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	21,500	21,500
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(4,320)	(4,320)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(927)	(927)

Line No.	Year>>	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023
		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														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	310,000
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	310,000
CWIP Calculation:														
	Beginning Balance	0	25,834	51,667	77,500	103,334	129,167	155,000	180,834	206,667	232,500	258,334	284,167	284,167
	Additional CWIP	25,833	25,833	25,833	25,833	25,833	25,833	25,833	25,833	25,833	25,833	25,833	25,833	25,833
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	0	(310,000)
	AFDUC													
4	CWIP (Project #T02032.0122)	T02032.0122	25,834	51,667	77,500	103,334	129,167	155,000	180,834	206,667	232,500	258,334	284,167	0
5	ADIT Proration Factors	107692	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 Taxes Federal & State		0	0	0	0	0	0	0	0	0	0	0	(677)
7	Ending rate base		25,834	51,667	77,500	103,334	129,167	155,000	180,834	206,667	232,500	258,334	284,167	309,324
8														
9	Average rate base		12,912	12,912	12,912	12,912	12,912	12,912	12,912	12,912	12,912	12,912	12,912	12,912
10														
11	Return on Rate Base		987	987	987	987	987	987	987	987	987	987	987	987
12														
13	Available for return (equity portion of rate base)		662	662	662	662	662	662	662	662	662	662	662	662
14														
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	0	0	0
20	Total O&M and Depreciation Expense		0	0	0	0	0	0	0	0	0	0	0	0
21														
22	Income before Taxes													
23	Available for return (from above)		662	662	662	662	662	662	662	662	662	662	662	662
24	Taxable Income (grossed up)		876	876	876	876	876	876	876	876	876	876	876	876
25														
26	Income Taxes													
27	Current and Def Income Taxes		214	214	214	214	214	214	214	214	214	214	214	214
28	Total Income Tax Expense		214	214	214	214	214	214	214	214	214	214	214	214
29														
30														
REVENUE REQUIREMENTS														
32	Expenses		214	214	214	214	214	214	214	214	214	214	214	214
33	Return on rate base		987	987	987	987	987	987	987	987	987	987	987	987
34	Subtotal revenue requirements		1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201	1,201
35	Adjustments		0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit		(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)	(185)
37	Total revenue requirements		1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015
38														
39	North Dakota share - D2 factor		402	402	402	402	402	402	402	402	402	402	402	402

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		<u>Ratio</u>	<u>Cost</u>	<u>WA Cost</u>											
4	Debt	47.50%	5.29%	2.51%											
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)	50	15-year	MACRS											
11															
12															
13		<u>Effective Tax Rate</u>	<u>Fed Portion</u>	<u>State Portion</u>											
14	Tax conversion factor	24.40%	20.09%	4.31%											
15	Wholesale Revenue Credit	1.32284													
16	ND share - D2 factor	15.43%													
17		39.5989%													
18	Deferred Tax														
19	Book depreciation	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	15,500	15,500	
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	15,500	15,500	
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(3,115)	(3,115)	
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(668)	(668)	

Line No.	Year>>	2023 Projected January	2023 Projected February	2023 Projected March	2023 Projected April	2023 Projected May	2023 Projected June	2023 Projected July	2023 Projected August	2023 Projected September	2023 Projected October	2023 Projected November	2023 Projected December	2023 Projected Total	
RATE BASE															
1	Plant Balance	0	0	0	410,000	485,000	735,000	776,667	818,333	860,000	901,667	1,310,000	2,055,000	2,055,000	
2	Accumulated Depreciation	(3,645)	(7,357)	(11,134)	(14,978)	(18,889)	(22,865)	(26,908)	(31,018)	(35,193)	(39,435)	(43,743)	(48,118)	(48,118)	
3	Net Plant in Service	(3,645)	(7,357)	(11,134)	395,022	466,111	712,135	749,758	787,316	824,807	862,232	1,266,257	2,006,882	2,006,882	
4	CWIP (Project #)	315,833	521,666	727,499	523,333	654,166	535,000	624,166	713,333	802,500	891,667	964,167	700,000	700,000	
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	0.0027	
6	Accumulated Deferred Income Taxes Federal & State	(3,262)	(6,289)	(9,059)	(11,583)	(13,863)	(15,907)	(17,689)	(19,226)	(20,528)	(21,589)	(22,420)	(23,013)	(23,013)	
7	Ending rate base	308,925	508,021	707,306	906,771	1,106,414	1,231,228	1,356,236	1,481,422	1,606,778	1,732,309	2,208,004	2,683,869	2,683,869	
8	Average rate base	101,521	101,521	101,521	101,521	101,521	101,521	101,521	101,521	101,521	101,521	101,521	101,521	1,218,253	
9	Return on Rate Base	7.758	7.758	7.758	7.758	7.758	7.758	7.758	7.758	7.758	7.758	7.758	7.758	93,099	
10	Available for return (equity portion of rate base)	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	62,487	
11															
12															
13															
14															
15	EXPENSES														
16	O&M and Depreciation														
17	Operating Costs	0	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	0	
19	Book Depreciation	3,645	3,711	3,778	3,844	3,910	3,977	4,043	4,109	4,176	4,242	4,308	4,374	48,118	
20	Total O&M and Depreciation Expense	3,645	3,711	3,778	3,844	3,910	3,977	4,043	4,109	4,176	4,242	4,308	4,374	48,118	
21															
22	Income before Taxes														
23	Available for return (from above)	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	62,487	
24	Taxable Income (grossed up)	6,888	6,888	6,888	6,888	6,888	6,888	6,888	6,888	6,888	6,888	6,888	6,888	82,660	
25															
26	Income Taxes														
27	Current and Def Income Taxes	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	20,173	
28	Total Income Tax Expense	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	1,681	20,173	
29															
30															
31	REVENUE REQUIRMENTS														
32	Expenses	5,326	5,393	5,459	5,525	5,591	5,658	5,724	5,790	5,857	5,923	5,989	6,056	68,291	
33	Return on rate base	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	7,758	93,099	
34	Subtotal revenue requirements	13,084	13,151	13,217	13,283	13,350	13,416	13,482	13,549	13,615	13,681	13,748	13,814	161,390	
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	
36	Wholesale Revenue Credit	(2,019)	(2,029)	(2,040)	(2,050)	(2,060)	(2,070)	(2,081)	(2,091)	(2,101)	(2,111)	(2,122)	(2,132)	(24,906)	
37	Total revenue requirements	11,065	11,121	11,177	11,233	11,290	11,346	11,402	11,458	11,514	11,570	11,626	11,682	136,484	
38															
39	North Dakota share - D2 factor	4,382	4,404	4,426	4,448	4,471	4,493	4,515	4,537	4,559	4,582	4,604	4,626	54,046	

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%											
6	Common equity	52.50%	9.77%	5.13%											
7	Total	100.00%		7.64%	Overall Return										
8															
9															
10															
11	Project life (years)	Book	Tax												
12		50	15-year MACRS												
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	15.43%													
17	ND share - D2 factor	39.5989%													
18	Deferred Tax														
19	Book depreciation	3,645	3,711	3,778	3,844	3,910	3,977	4,043	4,109	4,176	4,242	4,308	4,374	48,118	
20	Tax depreciation-Federal	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	215,776	
21	Tax depreciation-ND	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	17,981	215,776	
22	Federal deferred income taxes	(2,881)	(2,868)	(2,854)	(2,841)	(2,841)	(2,841)	(2,801)	(2,788)	(2,774)	(2,761)	(2,748)	(2,734)	(33,731)	
23	State deferred income taxes	(618)	(615)	(612)	(609)	(606)	(604)	(601)	(598)	(595)	(592)	(589)	(586)	(7,226)	

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				(732,331)
8	Total Revenue Subject to the Wholesale Revenue Credit				7,910,305
7				Wholesale Revenue Credit	15.43%

2022 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$40,512,693
	REVENUE CREDITS	(Note T)	Total	Allocator	
2	Account No. 454	(page 4, line 34)	196,605	TP 1.00000	196,605
3	Account No. 456.1	(page 4, line 37)	8,674,004	TP 1.00000	8,674,004
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)				8,870,609
7	To back out Schedule 9 Revenues received				(693,748)
8	Total Revenue Subject to the Wholesale Revenue Credit				8,176,861
7				Wholesale Revenue Credit	20.18%

		2022													
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)	(326,863)	(279,071)	(307,630)	(212,331)	(228,791)	(184,773)	(219,718)	(253,661)	(229,229)	(288,018)	(317,836)	(351,043)	(3,198,963)	
	CPEC Facility Credits in MISO	209,534	209,534	209,534	209,534	209,534	197,001	197,001	209,764	197,001	197,001	197,001	197,001	2,439,440	
2	Non-OTP Schedule 9 Revenues	10,161	6,022	8,495	242	1,668	(1,059)	1,967	3,801	2,791	7,882	10,464	13,340	65,775	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(107,168)	(63,515)	(89,601)	(2,555)	(17,590)	11,169	(20,749)	(40,096)	(29,437)	(83,135)	(110,370)	(140,702)	(693,748)	
5	MISO ROE	5,965													
6	North Dakota share	39.599%	(36,472)	(25,151)	(35,481)	(1,012)	(6,965)	4,423	(8,217)	(15,877)	(11,657)	(32,921)	(43,705)	(55,716)	(268,752)

		2023													
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)	(326,863)	(279,071)	(307,630)	(212,331)	(228,791)	(184,773)	(261,958)	(253,661)	(229,229)	(288,018)	(317,836)	(351,043)	(3,241,203)	
	CPEC Facility Credits in MISO	209,534	209,534	209,534	209,534	209,534	197,001	197,001	209,764	197,001	197,001	197,001	197,001	2,439,440	
2	Non-OTP Schedule 9 Revenues	10,161	6,022	8,495	242	1,668	(1,059)	5,625	3,801	2,791	7,882	10,464	13,340	69,433	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(107,168)	(63,515)	(89,601)	(2,555)	(17,590)	11,169	(59,332)	(40,096)	(29,437)	(83,135)	(110,370)	(140,702)	(732,331)	
5	North Dakota share	39.599%	(42,437)	(25,151)	(35,481)	(1,012)	(6,965)	4,423	(23,495)	(15,877)	(11,657)	(32,921)	(43,705)	(55,716)	(289,995)

		2022												
Line No.		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
	SCHEDULE 26													
1	MISO Schedule 26 Expense	1,151,356	989,586	948,009	885,389	739,831	925,737	981,220	979,245	846,261	1,003,424	1,003,424	1,208,944	11,662,425
2	OTP owned portion of expenses not recoverable via rider 0.000%	0	0	0	0	0	0	0	0	0	0	0	0	0
3	MISO Schedule 26 Expense Recoverable	1,151,356	989,586	948,009	885,389	739,831	925,737	981,220	979,245	846,261	1,003,424	1,003,424	1,208,944	11,662,425
4														
5	MISO Settlements	(7,395)												
6														
7	North Dakota share 39.599%	448,530	391,865	375,401	350,605	292,965	366,582	388,552	387,770	335,110	397,345	397,345	478,729	4,610,798
8														
9	MISO Schedule 26A Expense	954,250	832,139	755,185	703,080	658,320	665,856	711,869	666,516	633,758	668,687	817,562	913,502	8,980,725
10														
11	MISO Settlements	243												
12														
13	North Dakota share 39.599%	378,116	329,518	299,045	278,412	260,687	263,672	281,892	263,933	250,961	264,793	323,746	361,737	3,556,512

		2023												
Line No.		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
	SCHEDULE 26													
1	MISO Schedule 26 Expense	1,141,867	1,107,611	1,016,262	856,400	753,632	902,075	924,912	924,912	799,307	947,750	947,750	1,141,867	11,464,345
2	OTP owned portion of expenses not recoverable via rider 0.000%	0	0	0	0	0	0	0	0	0	0	0	0	0
3	MISO Schedule 26 Expense Recoverable	1,141,867	1,107,611	1,016,262	856,400	753,632	902,075	924,912	924,912	799,307	947,750	947,750	1,141,867	11,464,345
4														
5	North Dakota share 39.599%	452,167	438,602	402,429	339,125	298,430	357,212	366,255	366,255	316,517	375,299	375,299	452,167	4,539,755
6														
7	MISO Schedule 26A Expense	871,589	791,817	774,684	688,662	650,704	636,136	682,654	682,613	647,874	684,587	746,965	835,883	8,694,171
8														
9	North Dakota share 39.599%	345,140	313,551	306,766	272,703	257,672	251,903	270,324	270,307	256,551	271,089	295,790	331,001	3,442,797

Line No.	2022	2022												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	1.040%	(1,254,500)	(1,021,023)	(1,038,246)	(952,282)	(1,245,619)	(1,461,417)	(1,513,108)	(1,453,210)	(1,196,571)	(996,963)	(982,705)	(1,125,282)	(14,240,926)
2	Overhead Credit for Non-Retail Share		(13,047)	(10,619)	(10,798)	(9,904)	(12,954)	(15,199)	(15,736)	(15,113)	(12,444)	(10,368)	(10,220)	(11,703)	(148,106)
4	Fargo	66.568%	(835,095)	(679,675)	(691,140)	(633,915)	(829,184)	(972,836)	(1,007,246)	(967,373)	(796,533)	(663,658)	(654,167)	(749,078)	(9,479,900)
5	Retail Load Share		70.55%	70.55%	70.55%	70.55%	70.55%	70.55%	70.55%	70.55%	70.55%	70.55%	70.55%	70.55%	
6	Retail Revenue		(589,126)	(479,483)	(487,572)	(447,202)	(584,956)	(686,297)	(710,572)	(682,443)	(561,922)	(468,184)	(461,489)	(528,444)	(6,687,690)
7	Overhead Credit for Non-Retail Share		(8,685)	(7,069)	(7,188)	(6,593)	(8,624)	(10,117)	(10,475)	(10,061)	(8,284)	(6,902)	(6,803)	(7,790)	(98,591)
8	Non-Retail Load Share		29.45%	29.45%	29.45%	29.45%	29.45%	29.45%	29.45%	29.45%	29.45%	29.45%	29.45%	29.45%	
9	Non-Retail Overhead Credit		(2,558)	(2,082)	(2,117)	(1,942)	(2,540)	(2,980)	(3,085)	(2,963)	(2,440)	(2,033)	(2,004)	(2,295)	(29,039)
10	Total Revenue Credit for Fargo		(591,684)	(481,565)	(489,689)	(449,144)	(587,496)	(689,277)	(713,657)	(685,406)	(564,362)	(470,217)	(463,492)	(530,739)	(6,716,729)
15	Bemidji	13.750%	(172,494)	(140,391)	(142,759)	(130,939)	(171,273)	(200,945)	(208,052)	(199,816)	(164,528)	(137,082)	(135,122)	(154,728)	(1,958,127)
16	Retail Load Share		86.78%	86.78%	86.78%	86.78%	86.78%	86.78%	86.78%	86.78%	86.78%	86.78%	86.78%	86.78%	
17	Retail Revenue		(149,681)	(121,824)	(123,879)	(113,622)	(148,622)	(174,370)	(180,537)	(173,391)	(142,770)	(118,953)	(117,252)	(134,264)	(1,699,165)
18	Overhead Credit for Non-Retail Share		(1,794)	(1,460)	(1,485)	(1,362)	(1,781)	(2,090)	(2,164)	(2,078)	(1,711)	(1,426)	(1,405)	(1,609)	(20,365)
19	Non-Retail Load Share		13.23%	13.23%	13.23%	13.23%	13.23%	13.23%	13.23%	13.23%	13.23%	13.23%	13.23%	13.23%	
20	Non-Retail Overhead Credit		(237)	(193)	(196)	(180)	(236)	(276)	(286)	(275)	(226)	(189)	(186)	(213)	(2,693)
21	Total Revenue Credit for Bemidji		(149,919)	(122,017)	(124,075)	(113,802)	(148,857)	(174,646)	(180,824)	(173,665)	(142,996)	(119,142)	(117,438)	(134,477)	(1,701,858)
26	Cass Lake - Nary - Helga - Bemidji	5.933%	(74,429)	(60,577)	(61,599)	(56,499)	(73,903)	(86,706)	(89,773)	(86,219)	(70,993)	(59,150)	(58,304)	(66,763)	(844,914)
27	Retail Load Share		33.37%	33.37%	33.37%	33.37%	33.37%	33.37%	33.37%	33.37%	33.37%	33.37%	33.37%	33.37%	
28	Retail Revenue		(24,840)	(20,217)	(20,558)	(18,856)	(24,664)	(28,937)	(29,961)	(28,775)	(23,693)	(19,741)	(19,458)	(22,281)	(281,982)
29	Overhead Credit for Non-Retail Share		(774)	(630)	(641)	(588)	(769)	(902)	(934)	(897)	(738)	(615)	(606)	(694)	(8,787)
30	Non-Retail Load Share		66.63%	66.63%	66.63%	66.63%	66.63%	66.63%	66.63%	66.63%	66.63%	66.63%	66.63%	66.63%	
31	Non-Retail Overhead Credit		(516)	(420)	(427)	(391)	(512)	(601)	(622)	(597)	(492)	(410)	(404)	(463)	(5,854)
32	Total Revenue Credit for Bemidji		(25,356)	(20,637)	(20,985)	(19,247)	(25,176)	(29,538)	(30,583)	(29,372)	(24,185)	(20,151)	(19,862)	(22,744)	(287,836)
36	Rugby	0.044%	(552)	(449)	(457)	(419)	(548)	(643)	(666)	(639)	(526)	(439)	(432)	(495)	(6,266)
37	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%	
38	Retail Revenue		(552)	(449)	(457)	(419)	(548)	(643)	(666)	(639)	(526)	(439)	(432)	(495)	(6,266)
39	Total Revenue Credit for Rugby		(552)	(449)	(457)	(419)	(548)	(643)	(666)	(639)	(526)	(439)	(432)	(495)	(6,266)
43	Casselton	12.089%	(151,656)	(123,431)	(125,514)	(115,121)	(150,583)	(176,671)	(182,920)	(175,679)	(144,653)	(120,523)	(118,799)	(136,035)	(1,721,586)
44	Retail Load Share		48.89%	48.89%	48.89%	48.89%	48.89%	48.89%	48.89%	48.89%	48.89%	48.89%	48.89%	48.89%	
45	Retail Revenue		(74,148)	(60,348)	(61,366)	(56,285)	(73,623)	(86,378)	(89,433)	(85,893)	(70,724)	(58,926)	(58,083)	(66,510)	(841,718)
46	Overhead Credit for Non-Retail Share		(1,577)	(1,284)	(1,305)	(1,197)	(1,566)	(1,837)	(1,902)	(1,827)	(1,504)	(1,253)	(1,236)	(1,415)	(17,904)
47	Non-Retail Load Share		51.11%	51.11%	51.11%	51.11%	51.11%	51.11%	51.11%	51.11%	51.11%	51.11%	51.11%	51.11%	
48	Non-Retail Overhead Credit		(806)	(656)	(667)	(612)	(800)	(939)	(972)	(934)	(769)	(641)	(631)	(723)	(9,151)
49	Total Revenue Credit for Casselton		(74,954)	(61,004)	(62,033)	(56,897)	(74,423)	(87,317)	(90,405)	(86,827)	(71,493)	(59,567)	(58,715)	(67,233)	(850,868)
54	Spiritwood	0.630%	(7,903)	(6,432)	(6,541)	(5,999)	(7,847)	(9,207)	(9,533)	(9,155)	(7,538)	(6,281)	(6,191)	(7,089)	(89,718)
55	Retail Load Share		50.69%	50.69%	50.69%	50.69%	50.69%	50.69%	50.69%	50.69%	50.69%	50.69%	50.69%	50.69%	
56	Retail Revenue		(4,006)	(3,261)	(3,316)	(3,041)	(3,978)	(4,667)	(4,832)	(4,641)	(3,821)	(3,184)	(3,138)	(3,594)	(45,480)
57	Overhead Credit for Non-Retail Share		(82)	(67)	(68)	(62)	(82)	(96)	(99)	(95)	(78)	(65)	(64)	(74)	(933)
58	Non-Retail Load Share		49.31%	49.31%	49.31%	49.31%	49.31%	49.31%	49.31%	49.31%	49.31%	49.31%	49.31%	49.31%	
59	Non-Retail Overhead Credit		(41)	(33)	(34)	(31)	(40)	(47)	(49)	(47)	(39)	(32)	(32)	(36)	(460)
60	Total Revenue Credit for Spiritwood		(4,047)	(3,294)	(3,349)	(3,072)	(4,018)	(4,714)	(4,881)	(4,688)	(3,860)	(3,216)	(3,170)	(3,630)	(45,940)
65	Courtenay Wind	0.181%	(2,271)	(1,848)	(1,879)	(1,724)	(2,255)	(2,645)	(2,739)	(2,630)	(2,166)	(1,805)	(1,779)	(2,037)	(25,776)
66	Retail Load Share		0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	0.85%	
67	Retail Revenue		(19)	(16)	(16)	(15)	(19)	(22)	(23)	(22)	(18)	(15)	(15)	(17)	(218)
68	Overhead Credit for Non-Retail Share		(24)	(19)	(20)	(18)	(23)	(28)	(28)	(27)	(23)	(19)	(18)	(21)	(268)
69	Non-Retail Load Share		99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	99.15%	
70	Non-Retail Overhead Credit		(23)	(19)	(19)	(18)	(23)	(27)	(26)	(27)	(22)	(19)	(18)	(21)	(266)
71	Total Revenue Credit for Courtenay Wind		(43)	(35)	(35)	(32)	(42)	(50)	(51)	(49)	(41)	(34)	(33)	(38)	(484)
76	Astoria BSSB	0.806%	(10,111)	(8,229)	(8,368)	(7,675)	(10,040)	(11,779)	(12,196)	(11,713)	(9,644)	(8,036)	(7,921)	(9,070)	(114,782)
77	Retail Load Share		0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	0.82%	
78	Retail Revenue		(83)	(67)	(68)	(63)	(82)	(96)	(100)	(96)	(79)	(66)	(65)	(74)	(937)
79	Overhead Credit for Non-Retail Share		(105)	(86)	(87)	(80)	(104)	(123)	(127)	(122)	(100)	(84)	(82)	(94)	(1,194)
80	Non-Retail Load Share		99.18%	99.18%	99.18%	99.18%	99.18%	99.18%	99.18%	99.18%	99.18%	99.18%	99.18%	99.18%	
81	Non-Retail Overhead Credit		(104)	(85)	(86)	(79)	(104)	(122)	(126)	(121)	(99)	(83)	(82)	(94)	(1,184)
82	Total Revenue Credit for Astoria BSSB		(187)	(152)	(155)	(142)	(185)	(218)	(225)	(216)	(178)	(148)	(146)	(168)	(2,121)
83	Retail Share of Schedule 26 Revenue		(846,741)	(689,153)	(700,778)	(642,755)	(840,747)	(986,403)	(1,021,292)	(980,863)	(807,641)	(672,913)	(663,290)	(759,524)	(9,612,102)
84	MISO settlements		15,032												
85	North Dakota Share	39.599%	(320,268)	(272,897)	(277,501)	(254,524)	(332,927)	(390,605)	(404,421)	(388,411)	(319,817)	(266,466)	(262,655)	(300,763)	(3,791,255)

Line No.	2022	2022												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	(2,045,041)	(1,950,419)	(1,815,227)	(1,656,819)	(1,763,918)	(2,075,331)	(2,190,590)	(2,328,700)	(1,918,509)	(1,870,252)	(1,604,834)	(2,135,669)	(23,355,309)	
2	Overhead Credit for Non-Retail Share	1.040%	(21,268)	(20,284)	(18,878)	(17,231)	(18,345)	(21,583)	(22,782)	(24,218)	(19,952)	(19,451)	(16,690)	(22,211)	(242,895)
4															
5	CAPX 2020 - Brookings	12.540%	(256,446)	(244,581)	(227,628)	(207,763)	(221,194)	(260,244)	(274,698)	(292,017)	(240,579)	(234,528)	(201,245)	(267,811)	(2,928,732)
6	Retail Load Share		22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	22.798%	
7	Retail Revenue		(58,465)	(55,759)	(51,895)	(47,366)	(50,428)	(59,331)	(62,626)	(66,574)	(54,847)	(53,468)	(45,880)	(61,055)	(667,692)
8															
9	Overhead Credit for Non-Retail Share		(2,667)	(2,544)	(2,367)	(2,161)	(2,300)	(2,707)	(2,857)	(3,037)	(2,502)	(2,439)	(2,093)	(2,785)	(30,459)
10	Non-Retail Load Share		77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	77.202%	
11	Non-Retail Overhead Credit		(2,059)	(1,964)	(1,828)	(1,668)	(1,776)	(2,090)	(2,206)	(2,345)	(1,932)	(1,883)	(1,616)	(2,150)	(23,515)
12															
13	Total Revenue Credit for CAPX Brookings		(60,524)	(57,723)	(53,722)	(49,034)	(52,204)	(61,420)	(64,831)	(68,919)	(56,779)	(55,351)	(47,496)	(63,206)	(691,207)
14															
15															
16	MVP BS South - Brookings	35.708%	(730,237)	(696,450)	(648,176)	(591,612)	(629,855)	(741,053)	(782,209)	(831,525)	(685,056)	(667,824)	(573,049)	(762,598)	(8,339,644)
17	Retail Load Share		2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	2.048%	
18	Retail Revenue		(14,954)	(14,262)	(13,274)	(12,115)	(12,898)	(15,176)	(16,018)	(17,028)	(14,029)	(13,676)	(11,735)	(15,617)	(170,784)
19															
20	Overhead Credit for Non-Retail Share		(7,594)	(7,243)	(6,741)	(6,153)	(6,550)	(7,707)	(8,135)	(8,648)	(7,125)	(6,945)	(5,960)	(7,931)	(86,732)
21	Non-Retail Load Share		97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	97.952%	
22	Non-Retail Overhead Credit		(7,439)	(7,095)	(6,603)	(6,027)	(6,416)	(7,549)	(7,968)	(8,471)	(6,979)	(6,803)	(5,838)	(7,769)	(84,956)
23	Total Revenue Credit for MVP Brookings		(22,393)	(21,357)	(19,877)	(18,142)	(19,315)	(22,725)	(23,987)	(25,499)	(21,008)	(20,479)	(17,573)	(23,385)	(255,740)
24															
25	MVP Ellendale - BS South	51.752%	(1,058,358)	(1,009,389)	(939,423)	(857,444)	(912,870)	(1,074,034)	(1,133,683)	(1,205,158)	(992,875)	(967,900)	(830,540)	(1,105,260)	(12,086,933)
26	Retail Load Share		2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	2.000%	
27	Retail Revenue		(21,167)	(20,188)	(18,788)	(17,149)	(18,257)	(21,481)	(22,674)	(24,103)	(19,857)	(19,358)	(16,611)	(22,105)	(241,739)
28															
29	Overhead Credit for Non-Retail Share		(11,007)	(10,498)	(9,770)	(8,917)	(9,494)	(11,170)	(11,790)	(12,534)	(10,326)	(10,066)	(8,638)	(11,495)	(125,704)
30	Non-Retail Load Share		98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	98.000%	
31	Non-Retail Overhead Credit		(10,787)	(10,288)	(9,575)	(8,739)	(9,304)	(10,947)	(11,554)	(12,283)	(10,119)	(9,865)	(8,465)	(11,265)	(123,190)
32															
33	Total Revenue Credit for MVP Ellendale		(31,954)	(30,475)	(28,363)	(25,888)	(27,561)	(32,427)	(34,228)	(36,386)	(29,977)	(29,223)	(25,076)	(33,370)	(364,929)
34															
35															
36	Retail Share of Schedule 26A Revenue		(114,871)	(109,556)	(101,962)	(93,064)	(99,080)	(116,572)	(123,046)	(130,804)	(107,763)	(105,053)	(90,144)	(119,961)	(1,311,876)
37															
38	MISO Settlements		78												
39															
40	North Dakota share	39.599%	(45,410)	(43,383)	(40,376)	(36,852)	(39,235)	(46,161)	(48,725)	(51,797)	(42,673)	(41,600)	(35,696)	(47,503)	(519,410)

Federal ADIT Proration

	A	B	C	D
1		January 2023 - December 2023 Recovery Period		
		All Projects' Revenue Requirements without ADIT Prorated	All Projects' Revenue Requirements with ADIT- Prorated	Difference due to Federal ADIT Proration (B - A)
2	Month			
3	Jan-23	\$279,357	\$278,816	-\$541
4	Feb-23	\$279,401	\$278,860	-\$541
5	Mar-23	\$279,446	\$278,904	-\$541
6	Apr-23	\$279,490	\$278,949	-\$541
7	May-23	\$279,535	\$278,993	-\$541
8	Jun-23	\$281,643	\$281,102	-\$541
9	Jul-23	\$282,026	\$281,484	-\$541
10	Aug-23	\$282,430	\$281,889	-\$541
11	Sep-23	\$282,565	\$282,023	-\$541
12	Oct-23	\$282,744	\$282,202	-\$541
13	Nov-23	\$282,833	\$282,292	-\$541
14	Dec-23	\$286,314	\$285,772	-\$541
15		\$3,377,784	\$3,371,286	-\$6,498

16	Revenue Requirement Adjustment Related to Federal ADIT Proration	-\$6,498
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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%	0.21%
7	Preferred Equity %	0.00%	0.00%
8	Equity Return %	5.13%	0.43%
9	Rate of Return	7.64%	0.64%
10	Tax RR on Equity Return	1.66%	0.14%
11	Rate Base Rev Req Gross Up Factor	9.30%	0.77%

January 2022 - December 2022				
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-21	(\$6,475,742)	(\$6,429,486)	\$46,256
15	Jan-22	(\$6,634,308)	(\$6,582,030)	
16	Feb-22	(6,783,039)	(6,723,437)	
17	Mar-22	(6,916,296)	(6,850,167)	
18	Apr-22	(7,035,640)	(6,963,049)	
19	May-22	(7,139,945)	(7,061,766)	
20	Jun-22	(7,232,406)	(7,153,426)	
21	Jul-22	(7,309,268)	(7,230,531)	
22	Aug-22	(7,370,591)	(7,298,649)	
23	Sep-22	(7,416,912)	(7,350,063)	
24	Oct-22	(7,447,770)	(7,386,474)	
25	Nov-22	(7,464,244)	(7,407,469)	
26	Dec-22	(\$7,464,863)	(\$7,413,414)	\$51,449
27	ADIT Simple Average	(\$6,970,302)	(\$6,921,450)	\$48,852

28	Rate Base Rev Req Gross Up Factor	9.30%
29	Total Company Revenue Requirement	\$4,542

30	ND Revenue Requirement Related to Federal ADIT Proration-Preservation	\$1,799
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Attachment 42

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	NTCRE
Controlled Service	NTCRC
Lighting	NTCRL
All Other Service	NTCRO

C

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
Controlled Service (b)	0.0860 ⁰⁶⁷	¢/kWh	N/A
Lighting (c)	0.4960 ³⁰³	¢/kWh	N/A
All Other Service	0.5750 ⁴⁶²	¢/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

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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

C

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	\$1.841
Controlled Service (b)	0.086	¢/kWh	N/A
Lighting (c)	0.496	¢/kWh	N/A
All Other Service	0.575	¢/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

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Case No. PU-22-335
Attachment 43
ND TCR Filing Bill Message

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 affordable service.

The changes below apply to bill usage on and after January 1, 2023, 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	\$1.568	per kW	\$ 1.841	per kW	\$116.03/month
Controlled Service	\$0.00067	per kWh	\$ 0.00086	per kWh	\$0.24/month
Lighting	\$0.00303	per kWh	\$ 0.00496	per kWh	\$0.17/month
Residential	\$0.00462	per kWh	\$ 0.00575	per kWh	\$1.13/month
All other service	\$0.00462	per kWh	\$ 0.00575	per kWh	\$1.53/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.

Case No. PU-22-335
Attachment 44
Proposed Customer Notice

On September 15, 2022, 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, 2023. This change is proposed only, and if suspended by the Commission, the new rates will not be effective until the Commission takes action.

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

- Large General Service: \$116.03 (from \$1.568 to \$1.841 per kW)**
- Controlled Service: \$0.24 (from 0.067 cents to 0.086 cents per kWh)**
- Lighting: \$0.17 (from 0.303 cents to 0.496 cents per kWh)**
- Residential and all other service: \$1.13/ \$1.53 (from 0.462 cents to 0.575 cents per kWh)**

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