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August 31, 2017

Darrell Nitschke
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 13.07,
Transmission Cost Recovery Rider**

Dear Mr. Nitschke:

Enclosed please find an original and seven (7) 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. The tariff sheet footer has been updated to reflect Bruce G. Gerhardson as Director of Regulatory Affairs and Compliance due to Thomas Brause's retirement.

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 you at dnitschk@nd.gov and to the North Dakota Public Service Commission at ndpsc@nd.gov.

If you have any questions regarding this filing, please contact me at 218-739-8275 or gice@otpc.com.

Sincerely,

/s/ *GINA S. ICE*
Gina S. Ice
Rates Analyst
Regulatory Administration

ljh
cc: Sara Cardwell
Jerry Lein

Enclosures
By electronic filing and U.S. mail

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

Case No. PU-17-

In the Matter of Otter Tail Power
Company's Application for Approval
of the Annual Rate Update to Rate
Schedule, Section 13.07,
Transmission Cost Recovery Rider

**APPLICATION FOR ANNUAL RATE UPDATE
FOR TRANSMISSION COST RECOVERY RIDER**

I. INTRODUCTION

Otter Tail Power Company (Otter Tail or Company) hereby applies to the North Dakota Public Service Commission (Commission) for approval of an annual rate update to its Transmission Cost Recovery Rider (TCRR) in compliance with N.D.C.C. § 49-05-04.3 and Ordering Paragraph 6 of the Commission's April 5, 2012 Order in Case Nos. PU-11-153 and PU-11-682 (the TCRR Order).

In this annual update, Otter Tail's TCRR rate is updated to reflect the TCRR revenue requirements for the next recovery period (calendar year 2018). 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 one new transmission project not currently in base rates and not previously included in the Rider, (2) forecast updates to the Big Stone South-Brookings and Big Stone South-Ellendale projects, and (3) details of the Midcontinent Independent System Operator Return on Equity complaints. Detailed information on these items is provided in this Application.

As explained in this Application, for a residential customer using 1,000 kWh per month the bill impact of this update is an increase of \$1.23 per month. For a large general service customer with 425 kW of demand, the bill impact of this update is an increase of \$172.55 per month.

GENERAL FILING INFORMATION

Pursuant to § 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

Gina S. Ice
Rates Analyst, Regulatory Administration
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8275

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

The date of this filing is August 31, 2017. The updated TCRR rate is calculated to take effect as of January 1, 2018.

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.

II. TRANSMISSION COST RECOVERY

A. Background

In this Application, Otter Tail requests an annual update to its rate schedule, Section 13.07, in compliance with the TCRR Order referenced above. Ordering Paragraph 6 of that Order requires as follows:

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

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

Attachments 5 – 23 provide the revenue requirement calculations for each of the transmission projects identified in this filing—both those previously included in Otter Tail's TCRR (Attachments 5 -22) and the new project for which Otter Tail is requesting TCRR recovery (Attachment 23).

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 the lines by wholesale customers.
- *Return on investment (cost of capital).* The cost of capital is as determined in Otter Tail's most recent general rate case (Commission Case No. PU-08-862).
- *Depreciation expense.* Depreciation expense is calculated using the Company's current composite depreciation rates.
- *Property taxes.* The property tax calculation is based on Otter Tail's composite tax rate for the jurisdiction in which the transmission facilities are located, and is calculated in accordance with the procedures specified by that state.

- *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 single pole 115 kV lines. 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. 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 32 to this filing to show the ADIT proration calculation impact on the revenue requirement for the recovery period. Actual ADIT balances will replace the federal prorated forecast ADIT amounts as they actually occur. The methodology used for proration of Federal ADIT in this Filing is consistent with Otter Tail's last Environmental Cost Recovery Rider update (Case No. PU-17-122) and Otter Tail's most recent Renewable Resource Adjustment Rider (Case No. PU-17-16).
- *Net Operating Loss (NOL) Carryforward.* Otter Tail included the NOL, related to TCRR projects, for the 2015 tax year in Case No. PU-16-624. This NOL is presented as a Deferred Tax Asset used to offset future taxable income. Otter Tail estimates all NOL carryforward for 2015 related to projects in its TCRR will be applied to its taxable income by the end of 2017 at which time, there is no further impact to rate base.
- *Midcontinent Independent System Operator (MISO) Schedule 26 and 26A expenses.* Schedule 26 and Schedule 26A costs for the recovery period appear on Lines 23 and 24 of the Tracker Account (Attachment 4), and are shown separately in Attachment 25. These are Otter Tail's retail share of the costs for projects that qualify for regional cost allocation through MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff.

Southwest Power Pool (SPP) Related Expenses (Attachment 26) and MISO Related Revenues (Attachment 27). In Case No. PU-15-661, the Commission approved the inclusion of SPP Schedule 7, 8, 9 and 11 expenses in the TCRR that were a result of Central Power Electric Cooperative (CPEC) joining SPP. Effective January 1, 2016, CPEC placed some of its eligible facilities under the SPP tariff. As a result, Otter Tail is subject to several charges under the SPP tariff, the majority of which are incurred through SPP Schedule 7, 8, 9 and 11 charges for transmission service.

SPP Schedules 7, 8, and 9 refer to different types of transmission service that Otter Tail may secure for serving Otter Tail load in SPP, which represent firm point-to-point, non-firm point-to-point, and network integration transmission service, respectively.

SPP Schedule 11 expenses are for projects approved through SPP's Integrated Transmission Planning process. The expenses included in this TCRR update are Otter Tail's forecasted share of the costs for transmission facilities approved by SPP, whose costs are shared on a regional and zonal basis. SPP Schedule 9 expenses appear on Line 25 and SPP Schedule 11 expense on Line 26 of the Tracker Account (Attachment 4). Both are shown separately in Attachment 26.

Concurrent with Otter Tail paying SPP charges for transmission service, CPEC started paying MISO charges for transmission service they have secured through MISO. A portion of these MISO charges paid by CPEC for transmission service are received by Otter Tail as Schedule 9 revenue. The inclusion of these MISO Schedule 9 revenues related to CPEC results in a reduction to the TCRR revenue requirement.

CPEC began collecting facility credits in MISO for CPEC owned transmission facilities that are eligible for inclusion in MISO in May 2017. These facility credits entitle CPEC to collect a revenue requirement for its transmission facilities in exchange for utilities within MISO taking transmission service over these facilities to serve their load. These facility credits are passed through to CPEC as a bill credit, which reduces MISO Schedule 9 charges that CPEC incurs in MISO, thereby reducing the amount of MISO Schedule 9 revenue Otter Tail receives from CPEC load in MISO. MISO Schedule 9 revenue from CPEC appears on Line 30 of the Tracker Account (Attachment 4) and is shown in detail in Attachment 27.

- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 31 and 34 of the Tracker Account Summary (Attachment 4) and are shown separately on Attachment 28 (Schedule 26) and Attachment 29 (Schedule 26A). These are Otter Tail's retail share of the revenues derived from Otter Tail's investment in projects that qualify for regional cost allocation through MISO's Tariff.
- *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, 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. As of January 5, 2015, Otter Tail and other MISO Transmission Owners were granted a 50-basis point adder for participation in a Regional Transmission Organization (RTO) to be applied to the base ROE. While the RTO adder was effective on January 6, 2015, collection of the RTO adder was deferred until a decision was issued in the first complaint.

FERC issued its decision on the first complaint on September 28, 2016, granting approval of a 10.32 percent base ROE effective prospectively from that date. The 15-month refund obligation for the first complaint required MISO to recalculate

bills issued from November 12, 2013 through February 11, 2015 using the 10.32 percent base ROE (and any appropriate adders, such as the RTO adder). The difference between that calculated value and what was collected or paid using the 12.38 percent ROE became Otter Tail's refund obligation.

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 based on actual operating results. MISO processed the refund for the first complaint period in two parts: the refund obligation associated with the forecasted rate was processed in February 2017 and the refund associated with the true-up was processed in June 2017. Otter Tail included the impacts of the refund within this filing, resulting in an \$83,000 reduction in the ND share of the revenue requirement as the expenses Otter Tail overpaid were greater than the amount that Otter Tail received once the total refund amounts were calculated using the load percentages that were in place for each month of the refund period.

The second complaint for the time period of February 12, 2015 through May 11, 2016 is still pending before FERC. The Administrative Law Judge issued an Initial Decision on June 30, 2016 recommending a 9.7 percent base ROE plus any applicable adders. The lack of a quorum for most of 2017 has delayed FERC's decision on the ALJ's Initial Decision. While FERC now has a quorum, the timing of the FERC decision on the second complaint is unknown. Otter Tail does not include any adjustments in this filing related to the second complaint due to the uncertainty of timing and ultimate decision outcome.

- *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 Schedule 26A expenses are allocated to MISO market participants for all MVP projects. The revenue is identified in Attachment 30 and is reflected as a credit in the rider (Attachment 4, line 35).
- *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 28 and Attachment 29 on the line

titled “Overhead Credit for Non-Retail Share” for each project. For this period, the percentage is 1.184 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 revenues represent Otter Tail’s share from MISO 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 31, there are no forecast amounts for Schedule 37 and 38 revenues. 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 is \$27,402 as can be seen in Attachment 4, line number 32. The Schedule 38 revenue credit reflected in this TCRR update is \$30,826, seen in Attachment 4 on line 33. These are actual amounts through July 2017 and are included as part of the 2017 true-up amount.

A detailed description of MISO schedules 37 and 38 can be found at:

<https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx>

C. Change in SPP Related Expenses - Attachments 25 & 26

Charges incurred by Otter Tail during 2017 are higher than originally forecasted in PU-16-624. Late in 2016, Otter Tail became aware that a correction was needed to the amount of Otter Tail load subject to the SPP tariff during 2016. Most of Otter Tail’s SPP transmission related expenses are based on an average of the prior year’s 12 monthly peak load values. When Otter Tail submitted its 2015 load data to SPP, it resulted in SPP charges being based on 32 MW of OTP load each month during 2016. The actual Otter Tail load data during 2016 was 54 MW leading to a billing adjustment of \$1.2M (Total System). This expense, related to 2016, is trued-up in 2017 resulting in higher SPP expenses in 2017.

Otter Tail was over billed by SPP in early 2017. SPP Schedule expenses were billed at approximately 47 MW whereas, Otter Tail should have been charged at approximately 29 MW. Otter Tail anticipates \$473,000 of over payments will be trued-up

late in 2017 and early 2018 and included these amounts in its SPP Schedule expense forecasts as a reduction to the revenue requirement. As seen in Attachment 26 of this filing, Schedule 7, 8 and 9 expenses are forecasted to be \$4.0 million [Total System], (\$1.7 million [ND]), and Schedule 11 expenses are forecasted to be \$147,000 [Total System], (\$61,000 [ND]) in 2017. The lower amounts forecasted for 2018 are due to the resettlement of the billing errors described above from early 2017, as well as a lower forecasted amount of Otter Tail load that is taking SPP transmission service. Any difference between the forecasted charges and the actual charges incurred as a result of SPP Schedules 7, 8, 9 and 11 will be trued up in next year's filing.

D. Projects previously approved for recovery in Otter Tail's TCRR

Seventeen projects previously approved for inclusion in Otter Tail's TCRR are included in this update. They were approved in Case Numbers PU-11-153, PU-11-682, PU-12-702, PU-13-755, PU-14-690, and PU-16-624.

The retail allocation of costs and revenues for these projects have been updated and carried out through 2017 and 2018 and are reflected in Attachments 5-22.

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|-----|--|---------------|
| 1. | CAPX 2020 – Fargo | Attachment 5 |
| 2. | CAPX 2020 – Bemidji | Attachment 6 |
| | a. Cass Lake-Nary-Helga-Bemidji | Attachment 7 |
| 3. | Rugby Wind Interconnection | Attachment 8 |
| 4. | Casselton – Buffalo 115 kV Project | Attachment 9 |
| 5. | CAPX 2020 - Brookings – Hampton | Attachment 10 |
| 6. | MVP - Big Stone Area Transmission to Brookings | Attachment 11 |
| 7. | MVP - Ellendale to Big Stone South | Attachment 12 |
| 8. | Ramsey 230/115 kW Transformer Upgrade | Attachment 13 |
| 9. | Karlstad, MN Capacitor Bank Project | Attachment 14 |
| 10. | Oakes Area Transmission Improvements | Attachment 15 |
| 11. | Hankinson Transformer Addition | Attachment 16 |
| 12. | NERC Compliance | Attachment 17 |
| 13. | Summit Transformer | Attachment 18 |
| 14. | Spiritwood Station Interconnection | Attachment 19 |
| 15. | Max-Ryder 41.6 kV Line Upgrade | Attachment 20 |
| 16. | Rugby Interconnect 41.6 kV Breaker | Attachment 21 |
| 17. | Granville Junction Breaker Station | Attachment 22 |

E. New transmission project included in this TCRR rate update

N.D.C.C. § 49-05-04.3 authorizes an approved TCRR rider 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.” Otter Tail has one new project that meets this criteria that it is requesting approval for inclusion in this TCRR update, which is described in detail below.

Description of New Project – Bagley 115 kV Switch Station – Attachment 23

Otter Tail owns and operates an extensive 115 kV network between Winger, MN and Bemidji, MN that serves several large customers at numerous substations. The existing 115 kV system is comprised of approximately 70 miles of line that has experienced some interruptions over the past five years. To mitigate these interruptions and improve reliability of the transmission system serving the customers in this area, Otter Tail will be constructing a new 115 kV switching station north of Bagley, MN, where three existing 115 kV lines currently intersect.

This project includes the installation of three new 115 kV circuit breakers that will replace the three existing 115 kV switches. The Bagley 115 kV Switch Station will improve reliability of the transmission system in this area by 1) reducing line exposure resulting in less customers being impacted by interruptions of the transmission system (2) improving restoration time to customers following interruptions of the transmission system by introducing additional automation and real-time visibility into the 115 kV system, and (3) increasing the operational flexibility of the transmission system to be able to perform routine maintenance on facilities in the local area without putting as many customers at risk for a service interruption.

The current estimate for the Bagley 115 kV Switch Station is approximately \$2.8 million (Total System) with an estimated in-service date of October 2018. North Dakota’s jurisdictional share of the total project based on the D2 allocation factor is approximately \$1.1 million.

Update of Project – Big Stone South – Brookings – Attachment 11

When Otter Tail was granted recovery of this project within its TCRR in Case No.

PU-12-702, it was anticipated that capital spend would be approximately \$133.6 million (Total System). In the current Petition, the total amount of capital spend for the Big Stone South-Brookings Project is \$74.9 million (Total System). Substantial cost savings were achieved during the course of this project due to a variety of factors, including effective project management, procuring material during favorable market conditions, and the availability of multiple contractors. North Dakota's jurisdictional share of Otter Tail's total capital costs by the end of construction based on the D2 allocation factor of 41.25727 percent and a composite retail load share of 1.7840 percent results in a cost savings of \$431,033 for North Dakota customers compared to the original approval for recovery in Case No. PU-12-702. This project is expected to be in service in late 2017.

Update of Project – Big Stone South – Ellendale – Attachment 12

When the Commission granted Otter Tail recovery of this project within its TCRR in Case No. PU-12-702, it was anticipated that capital investment would be approximately \$150.5 million (Total System). In the current Petition, the total amount of capital spend for the Big Stone South-Ellendale Project is updated to \$121.6 million (Total System). Similar to the Big Stone South-Brookings project, actual costs for materials, equipment, and contractors have been lower than previously forecasted. Furthermore, effective project management has also resulted in lower costs by executing a more efficient project timeline through coordination with contractors. North Dakota's jurisdictional share of Otter Tail's total capital costs by the end of construction based on the D2 allocation factor of 41.25727 percent and a retail load share of 1.940 percent results in a cost savings of \$231,487 for North Dakota customers compared to the original approval for recovery in Case No. PU-12-702. The Big Stone South-Ellendale project is expected to be in service in 2019.

III. 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 case (Case No. PU-08-862) to allocate total revenue requirements to jurisdictions (North Dakota, 41.25727 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 (¢ / kWh) for all other customers. The rate design detail is included in Attachment 3.

IV. RATE APPLICATION AND IMPACT

The total 2018 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2018; the true-up associated with an updated projection of the 2017 revenue requirement; and the carrying charge attributable to any projected over or under-collection that accumulates.

The revenue requirement attributable to calendar year 2018, as shown on line 38 of Attachment 4, page 2 of 2, is \$8,598,711.

The 2017 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, line 32 and as computed in Attachment 4, page 1 of 2, line 44, reflects an estimated under-collection amount of \$11,354 during the 2017 collection period. This amount is based on actual net revenues and expenses which have been included in the TCRR tracker through July 2017, and updated projections for August through December of 2017 as well as 2018. In Otter Tail's 2016 Initial Filing in Case No. PU-16-624, a \$2.6 million over-collection was estimated for 2016. Through conversations with Commission Staff, Otter Tail submitted a Supplemental Filing spreading that estimated over-collection over two years, 2017 and 2018. As a result of spreading the estimated \$2.6 million over-collection, Otter Tail projected the December 2017 tracker balance to be \$1.3 million. In this Petition, Otter Tail forecasts a tracker balance that is under-recovered at the end of the 2017 recovery period by \$11,354. This primarily stems from the SPP and MISO related items detailed above and a warmer than average winter leading to lower billing amounts than forecasted.

By design and structure of the TCRR, the related carrying credit of (\$17,412), as computed on Attachment 4, page 2 of 2, line 43, will be credited to customers as a reduction in the 2018 revenue requirements. The net revenue requirement for 2018 upon which rates are developed is \$8,592,654, as shown on line 40 of Attachment 4, page 2 of 2. The proposed rates for this net revenue requirement are calculated on lines 1-14 of Attachment 3.

The Transmission Rider is applicable to electric service under all of Otter Tail’s retail rate schedules. The charge is included as part of the Energy and Renewable Adjustment line on customers’ bills. The proposed rates, as calculated in Attachment 3 are as follows:

<u>Class</u>	<u>¢ / kWh</u>
Large General Service	\$2.095/kWh
Controlled Service	0.086¢
Lighting	0.332¢
All other service	0.599¢

These rates represent an increase to the rates currently in effect. The estimated increase for a residential customer using 1,000 kWh is \$1.23 per month. The following table shows the estimated rate change over the previous rate by individual rate classes:

	Average kWh/Month	kW	Customer (Meters)	Average kW/kWh's/ Meter	Current Rate	Proposed Rate	Change in Rate	Impact
Large General Service		105,708	281	377	\$ 1.689	\$ 2.095	\$ 0.406	\$ 152.86
Controlled Service	21,480,791		15,492	1,387	\$0.00065	\$ 0.00086	\$ 0.00021	\$ 0.29
Lighting	1,896,191		22,720	83	\$0.00270	\$ 0.00332	\$ 0.00062	\$ 0.05
All Other	79,655,789		60,590	1,315	\$0.00475	\$ 0.00599	\$ 0.00123	\$ 1.62

The proposed rates are based on an effective date of January 1, 2018 through December 31, 2018. If the implementation date is significantly later than January 1, 2018, Otter Tail requests the option to recalculate the Transmission Cost Recovery Rates in order to recover all approved costs in the remainder of the recommended recovery time period.

V. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE

Otter Tail’s redline and clean update to the Transmission Cost Recovery Rider (Section 13.07) is Attachment 33 to this Application.

VI. 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.

VII. NOTICE TO CUSTOMERS

Otter Tail will include on the September bills to its North Dakota customers, the following notice of the proposed change in rates for the transmission rider.

On August 31, 2017, Otter Tail Power Company filed a request with the North Dakota Public Service Commission to increase our Transmission Cost Recovery Rider, which is part of the Energy and Renewable adj. line on your bill. The proposed change is for bills rendered on and after January 1, 2018. This change is proposed only and, if suspended by the Commission, the new rates will not be effective until the Commission takes action.

See panel below for more information.

If approved, customers can expect the following average monthly bill impacts: Large General Service: \$172.55 (from \$1.689 per kW to \$2.095 per kW), Controlled Service: \$0.27 (from 0.065 cents per kWh to 0.086 cents), Lighting: \$0.06 (from 0.270 cents per kWh to 0.332 cents per kWh), all other service: \$1.23/1.67 (from 0.475 cents per kWh to 0.599 cents per kWh).

For more information contact customer service at 800-257-4044 or place an inquiry from our web site at otpc.com.

Attachment 34 is a draft of the proposed notice to customers upon implementation of the updated rates.

VIII. CONCLUSION

For the foregoing reasons, Otter Tail Power Company respectfully requests approval to implement this update to its Transmission Cost Recovery Rider, Section 13.07, effective as of January 1, 2018.

Date: August 31, 2017

Respectfully submitted:

OTTER TAIL POWER COMPANY

/s/ Gina S. Ice

Gina S. Ice

Rates Analyst

Regulatory Administration

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P.O. Box 496

Fergus Falls, MN 56538-0496

Phone (218) 739-8275

Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Summary
Attachment 5	CAPX Fargo-Monticello Revenue Requirements
Attachment 6	CAPX Bemidji-Grand Rapids Revenue Requirements
Attachment 7	Cass Lake-Nary-Helga-Bemidji Revenue Requirements
Attachment 8	Rugby Wind Interconnection Revenue Requirements
Attachment 9	Casselton-Buffalo 115 kV Project Revenue Requirements
Attachment 10	CAPX Brookings, SD-Hampton, MN Revenue Requirements
Attachment 11	MVP BSAT to BSS Brookings Revenue Requirements
Attachment 12	MVP Big Stone South to Ellendale Revenue Requirements
Attachment 13	Ramsey 230/115 kV Transformer Revenue Requirements
Attachment 14	Karlstad, MN Capacitor Bank Project Revenue Requirements
Attachment 15	Oakes Area Transmission Revenue Requirements
Attachment 16	Hankinson Transformer Addition Revenue Requirements
Attachment 17	NERC Compliance Revenue Requirements
Attachment 18	Summit Transformer Revenue Requirements
Attachment 19	Spiritwood Generator Interconnection Upgrades Revenue Requirements
Attachment 20	Max to Ryder 41.6 kV Line Upgrade
Attachment 21	Rugby 41.6 kV Breaker Station
Attachment 22	Granville Junction Breaker Station
Attachment 23	Bagley 115 kV Switch Station
Attachment 24	Attachment O Revenue Credit for Non-MISO Projects
Attachment 25	MISO Schedule 26 and 26A Expense
Attachment 26	SPP Expenses
Attachment 27	MISO Schedule 9 Revenue
Attachment 28	MISO Schedule 26 Revenue
Attachment 29	MISO Schedule 26A Revenue

Attachment 30	MISO Multi-Value Project Auction Revenue Rights Credit
Attachment 31	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 32	ADIT Pro-Rate
Attachment 33	Electric Rate Schedule Section 13.07 Redline and Clean
Attachment 34	Proposed Customer Notice

Projected Revenue for 2018

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,270,619 kW	\$2.095	\$2,661,414
2					
3	Controlled Service	(b)	243,255,777 kWh	0.086¢	\$209,395
4					
5	Lighting	(c)	23,001,296 kWh	0.332¢	\$76,406
6					
7	All other service		942,842,036 kWh	0.599¢	\$5,645,439
8					
9	Total revenue				<u>\$8,592,654</u>

- (a) Rate Schedules 10.03 Large General Service and 10.05 Large General Service - Time of Day
- (b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load (CT Metering), 14.05 Interruptible Load (Self-Contained Metering), 14.06 Deferred Load
- (c) Rate Schedules 11.03 Outdoor Lighting (energy only), 11.04 Outdoor Lighting

Summary of Revenue Requirements

Line No.	Revenue Requirements	2018
1	CAPX 2020 - Fargo	\$2,959,198
2	CAPX 2020 - Bemidji	\$728,409
3	Cass Lake-Nary-Helga-Bemidji	\$117,294
4	Rugby Wind Interconnection	\$2,513
5	Casselton – Buffalo 115 kV Project	\$318,661
6	CAPX 2020 - Brookings - Hampton	\$268,261
7	MVP - Big Stone Area Transmission	\$66,132
8	MVP - Ellendale to Big Stone South	\$105,206
9	Ramsey 230/115 kW Transformer Upgrade	\$15,908
10	Karlstad, MN Capacitor Bank Project	\$46,897
11	Oakes Area Transmission Improvements	\$277,550
12	Hankinson Transformer AEBition	\$31,873
13	NERC Compliance	\$617,810
14	Summit Transformer	\$31,715
15	Spiritwood Station Interconnection	\$33,340
17	Max - Ryder 41.6 kV Line Upgrades	\$74,858
18	Rugby Breaker Station	\$71,693
19	Granville Jct Breaker Station	\$39,698
20	Bagley 115kV Switch Station	\$75,900
21	Total Revenue Requirement	\$5,807,018
22	MISO Schedule 26 Expense	5,024,174
23	MISO Schedule 26A Expense	2,947,857
24	SPP Schedule 9 Expense	888,510
25	SPP Schedule 11 Expense	77,930
26	MISO Schedule 9 Revenue	(391,054)
27	MISO Schedule 26 Revenue	(5,171,593)
28	MISO Schedule 37 Revenue	(0)
29	MISO Schedule 38 Revenue	(0)
30	MISO Schedule 26A Revenue	(637,754)
31	MISO MVP ARR Revenue	(22,279)
32	Carrying Cost	(17,412)
33	True-Up	11,354
34	Net Revenue Requirement	\$8,592,654

Class Allocation and Rate Design

Line No.			2018
1	North Dakota Revenue Requirements		\$8,592,654 *
2	Large General Service Class	30.97%	\$2,661,414
3	Controlled Service	2.44%	209,395
4	Lighting	0.89%	76,406
5	All Other Service	65.70%	5,645,439
6	Total		\$8,592,654
7	Large General Service Class	kW	1,270,619
8	Controlled Service	kWh	243,255,777
9	Lighting	kWh	23,001,296
10	All Other Service	kWh	942,842,036
11	Large General Service Class	\$ / kW	2.095
12	Controlled Service	cents / kWh	0.086
13	Lighting	cents / kWh	0.332
14	All Other Service	cents / kWh	0.599

* Jurisdictional transmission allocation factor (D2 = 41.25727%) is from Otter Tail's last general rate case in North Dakota.

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2017												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	
1	Revenue Requirements													
1	CAPX 2020: Fargo	252,693	262,432	252,659	252,636	254,221	252,653	252,649	252,654	254,582	252,654	252,654	254,582	3,047,069
2	CAPX 2020: Bemidji	60,778	61,262	60,778	60,778	60,931	60,778	61,565	60,778	63,417	60,778	60,778	63,417	736,037
3	Cass Lake-Nary-Helga-Bemidji	10,034	10,034	10,034	10,033	10,033	10,033	10,033	10,033	10,033	10,033	10,033	10,033	120,402
4	Rugby Wind Interconnection	212	212	212	212	212	212	212	212	212	212	212	212	2,549
5	Casselton – Buffalo 115 kV Project	25,643	25,643	25,643	25,643	25,643	25,643	25,643	25,643	25,643	25,643	27,228	27,228	310,886
6	CAPX 2020: Brookings - Hampton	22,979	23,220	22,977	22,927	23,275	22,923	22,924	22,923	23,082	22,923	22,923	23,082	276,159
7	MVP: Big Stone Area Transmission	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	61,314
8	MVP: Ellendale to Big Stone South	5,418	5,418	5,418	5,418	5,418	5,418	5,418	5,418	5,418	5,418	5,418	5,418	65,021
9	Ramsey 230/115 kV Transformer Upgrade	1,392	1,540	1,392	1,392	1,355	1,392	1,392	1,392	1,392	1,392	1,392	1,392	16,811
10	Karlstad, MN Capacitor Bank Project	4,067	4,364	4,067	4,067	3,965	4,067	4,067	4,067	4,067	4,067	4,067	4,067	49,003
11	Oakes Area Transmission Improvements	27,059	27,720	27,059	27,059	26,362	27,059	27,059	27,059	27,059	27,059	27,059	27,059	324,671
12	Hankinson Transformer Addition	2,770	2,977	2,770	2,770	2,700	2,770	2,770	2,770	2,770	2,770	2,770	2,770	33,381
13	NERC Compliance	53,966	55,054	54,073	54,120	52,836	54,135	54,152	54,158	54,158	54,158	54,158	54,158	649,126
14	Summit Transformer	2,803	2,805	2,803	2,803	2,725	2,803	2,803	2,803	2,803	2,803	2,803	2,803	33,564
15	Spiritwood Station Interconnection	2,849	2,849	2,849	2,849	2,849	2,849	2,849	2,849	2,849	2,849	2,849	2,849	34,188
16	Max- Ryder 41 6 kV Line Upgrades	4,618	4,619	4,619	4,640	4,640	4,640	4,640	4,640	4,892	4,892	4,892	4,981	56,714
17	Rugby Breaker Station	6,217	6,217	6,217	6,217	6,187	6,217	6,217	7,097	7,106	7,106	7,106	7,106	79,009
18	Granville Jct Breaker Station	3,588	3,588	3,588	3,588	3,573	3,588	3,588	4,082	4,080	4,080	4,080	4,080	45,505
19	Bagley 115kV Switch Station	945	945	945	945	945	945	945	945	945	945	945	945	11,336
20	Total Revenue Requirements	493,141	506,010	493,213	493,208	492,980	493,236	494,037	494,634	499,619	494,894	496,478	501,292	5,952,744
21														
22	MISO & SPP Expenses													
23	MISO Schedule 26 Expense	545,262	3,760	529,284	398,586	283,647	365,282	415,172	452,960	390,678	441,636	452,960	566,200	4,845,426
24	MISO Schedule 26A Expense	460,067	120,393	219,519	181,053	167,874	178,830	186,373	217,389	207,961	219,089	244,163	273,611	2,676,321
25	SPP Schedule 9 Expense	38,140	226,703	223,517	132,551	122,754	105,841	164,019	152,760	152,760	152,760	115,946	78,155	1,665,906
26	SPP Schedule 11 Expense	2,666	7,375	7,911	6,249	4,976	4,010	6,194	5,242	5,242	3,584	1,951	60,643	60,643
27	Total MISO & SPP Expenses	1,046,135	358,232	980,230	718,440	579,251	653,964	771,758	828,351	756,640	818,726	816,653	919,917	9,248,296
28														
29	MISO Revenues													
30	MISO Schedule 9 Revenue	(112,342)	(88,541)	(563,234)	(122,039)	(37,034)	(41,122)	(55,793)	(19,815)	(12,946)	(27,101)	(31,840)	(51,716)	(1,163,523)
31	MISO Schedule 26 Revenue	(411,842)	184,873	(389,581)	(342,047)	(379,504)	(476,576)	(515,429)	(525,483)	(462,074)	(414,051)	(409,091)	(388,981)	(4,529,787)
32	MISO Schedule 37 Revenue	(4,765)	1,809	(4,799)	(4,800)	(5,409)	(4,721)	(4,717)	(0)	(0)	(0)	(0)	(0)	(27,402)
33	MISO Schedule 38 Revenue	(5,801)	4,703	(5,849)	(5,851)	(6,515)	(5,758)	(5,754)	(0)	(0)	(0)	(0)	(0)	(30,826)
34	MISO Schedule 26A Revenue	(53,126)	(5,307)	(40,489)	(39,182)	(41,376)	(47,845)	(52,505)	(57,822)	(58,389)	(47,888)	(44,068)	(44,956)	(532,951)
35	MISO MVP ARR Revenue	(1,682)	(1,636)	(1,568)	(706)	(642)	(581)	(1,276)	(2,269)	(2,269)	(2,269)	(2,269)	(2,269)	(19,437)
36	Total MISO Revenues	(589,557)	95,901	(1,005,520)	(514,625)	(470,480)	(576,602)	(635,475)	(605,389)	(535,678)	(491,310)	(487,268)	(487,922)	(6,303,926)
37														
38	Net Revenue Requirement	949,719	960,143	467,923	697,023	601,751	570,599	630,320	717,596	720,581	822,311	825,863	933,287	8,897,115
39														
40	Billed (forecast kWh x adj factor)	713,189	663,351	598,526	551,200	476,867	474,824	481,209	492,763	492,257	477,687	568,151	640,863	6,630,887
41														
42	Difference	236,530	296,792	(130,603)	145,823	124,884	95,774	149,111	224,833	228,324	344,624	257,712	292,423	2,266,227
43	Carrying Charge	(15,356)	(13,768)	(11,736)	(12,758)	(11,803)	(10,991)	(10,382)	(9,386)	(7,839)	(6,256)	(3,827)	(2,004)	(116,106)
44	Cummulative Difference	(1,917,594)	(1,634,570)	(1,776,909)	(1,643,844)	(1,530,763)	(1,445,979)	(1,307,250)	(1,091,803)	(871,319)	(532,951)	(279,065)	11,354	11,354
45														
46	Carrying Charge Calculation	(13,768)	(11,736)	(12,758)	(11,803)	(10,991)	(10,382)	(9,386)	(7,839)	(6,256)	(3,827)	(2,004)	82	82
47	Cumulative Carrying Charge	(23,018)	(34,754)	(47,512)	(59,315)	(70,305)	(80,687)	(90,074)	(97,913)	(104,169)	(107,995)	(109,999)	(109,917)	
48	Carrying cost	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%
49														
50														
51	Forecasted Sales (MWh)								130,358	130,224	126,370	150,301	169,537	
52														

Approved December 14, 2016 (PU-16-624)
Rate Effective January 1, 2017

SUMMARY	Jan 2017 - Dec 2017
Revenue requirements	\$8,396,895
Carrying Charge	(178,988)
True-Up	(1,302,333)
Total requirements	\$6,915,574
Jan 2017-Dec 2017 projected sales in MWh	1,829,481
Average Rate	\$0.00378

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2018												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	
1	Revenue Requirements													
1	CAPX 2020: Fargo	245,964	245,964	247,871	245,964	245,964	247,871	245,964	245,964	247,871	245,964	245,964	247,871	2,959,198
2	CAPX 2020: Bemidji	59,445	59,445	63,212	59,445	59,445	63,212	59,445	59,445	63,212	59,445	59,445	63,212	728,409
3	Cass Lake-Nary-Helga-Bemidji	9,831	9,831	9,831	9,756	9,756	9,756	9,756	9,756	9,756	9,756	9,756	9,756	117,294
4	Rugby Wind Interconnection	209	209	209	209	209	209	209	209	209	209	209	209	2,513
5	Casselton – Buffalo 115 kV Project	26,555	26,555	26,555	26,555	26,555	26,555	26,555	26,555	26,555	26,555	26,555	26,555	318,661
6	CAPX 2020: Brookings - Hampton	22,302	22,302	22,462	22,302	22,302	22,462	22,302	22,302	22,462	22,302	22,302	22,462	268,262
7	MVP: Big Stone Area Transmission	5,501	5,505	5,509	5,513	5,513	5,513	5,513	5,513	5,513	5,513	5,513	5,513	66,132
8	MVP: Ellendale to Big Stone South	8,767	8,767	8,767	8,767	8,767	8,767	8,767	8,767	8,767	8,767	8,767	8,767	105,206
9	Ramsey 230/115 kV Transformer Upgrade	1,326	1,326	1,326	1,326	1,326	1,326	1,326	1,326	1,326	1,326	1,326	1,326	15,908
10	Karlstad, MN Capacitor Bank Project	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908	3,908	46,897
11	Oakes Area Transmission Improvements	23,129	23,129	23,129	23,129	23,129	23,129	23,129	23,129	23,129	23,129	23,129	23,129	277,550
12	Hankinson Transformer Addition	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,656	2,656	31,873
13	NERC Compliance	51,484	51,484	51,484	51,484	51,484	51,484	51,484	51,484	51,484	51,484	51,484	51,484	617,810
14	Summit Transformer	2,643	2,643	2,643	2,643	2,643	2,643	2,643	2,643	2,643	2,643	2,643	2,643	31,715
15	Spiritwood Station Interconnection	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	2,778	33,340
16	Max- Ryder 41 6 kV Line Upgrades	6,064	6,095	6,127	6,159	6,191	6,222	6,254	6,286	6,317	6,349	6,381	6,413	74,858
17	Rugby Breaker Station	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	71,693
18	Granville Jct Breaker Station	3,308	3,308	3,308	3,308	3,308	3,308	3,308	3,308	3,308	3,308	3,308	3,308	39,698
19	Bagley 115kV Switch Station	6,126	6,126	6,126	6,126	6,126	6,126	6,126	6,126	6,126	6,126	7,319	7,319	75,900
20	Total Revenue Requirements	487,971	488,007	493,877	488,004	488,035	493,901	488,099	488,131	493,996	488,194	489,419	495,284	5,882,918
21														
22	MISO & SPP Expenses													
23	MISO Schedule 26 Expense	506,069	464,332	443,463	380,856	328,684	359,988	417,377	417,377	359,988	406,942	417,377	521,721	5,024,174
24	MISO Schedule 26A Expense	302,056	272,191	263,475	230,588	214,061	210,895	229,335	229,413	219,165	230,926	257,548	288,205	2,947,857
25	SPP Schedule 9 Expense	4,849	80,333	80,333	80,333	80,333	80,333	80,333	80,333	80,333	80,333	80,333	80,333	888,510
26	SPP Schedule 11 Expense	3,430	6,773	6,773	6,773	6,773	6,773	6,773	6,773	6,773	6,773	6,773	6,773	77,930
27	Total MISO & SPP Expenses	816,404	823,628	794,044	698,550	629,851	657,989	733,817	733,896	666,258	724,974	762,031	897,032	8,938,473
28														
29	MISO Revenues													
30	MISO Schedule 9 Revenue	(38,631)	(18,494)	(25,612)	(38,569)	(4,842)	(22,570)	(28,947)	(32,424)	(24,483)	(40,848)	(46,327)	(69,306)	(391,054)
31	MISO Schedule 26 Revenue	(430,966)	(430,966)	(430,966)	(430,966)	(430,966)	(430,966)	(430,966)	(430,966)	(430,966)	(430,966)	(430,966)	(430,966)	(5,171,593)
32	MISO Schedule 37 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
33	MISO Schedule 38 Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
34	MISO Schedule 26A Revenue	(53,132)	(53,119)	(53,127)	(53,121)	(53,132)	(53,133)	(53,147)	(53,149)	(53,165)	(53,173)	(53,176)	(53,178)	(637,754)
35	MISO MVP ARR Revenue	(1,857)	(1,857)	(1,857)	(1,857)	(1,857)	(1,857)	(1,857)	(1,857)	(1,857)	(1,857)	(1,857)	(1,857)	(22,279)
36	Total MISO Revenues	(524,587)	(504,437)	(511,562)	(524,513)	(490,796)	(508,526)	(514,917)	(518,396)	(510,471)	(526,844)	(532,326)	(555,306)	(6,222,679)
37														
38	Net Revenue Requirement	779,789	807,199	776,358	662,041	627,090	643,364	706,999	703,630	649,783	686,324	719,124	837,010	8,598,711
39														
40	Billed (forecast kWh x adj factor)	942,986	916,820	824,704	754,228	612,171	578,685	601,628	622,327	620,294	601,096	713,654	804,062	8,592,654
41														
42	Difference	(163,197)	(109,621)	(48,345)	(92,187)	14,919	64,679	105,372	81,304	29,489	85,228	5,470	32,948	6,057
43	Carrying Charge	82	(1,090)	(1,885)	(2,245)	(2,923)	(2,837)	(2,393)	(1,654)	(1,082)	(878)	(272)	(235)	(17,412)
44	Cummulative Difference	(151,761)	(262,472)	(312,702)	(407,134)	(395,138)	(333,297)	(230,318)	(150,668)	(122,261)	(37,911)	(32,713)	(0)	(0)
45														
46	Carrying Charge Calculation	(1,090)	(1,885)	(2,245)	(2,923)	(2,837)	(2,393)	(1,654)	(1,082)	(878)	(272)	(235)	(0)	
47	Cummulative Carrying Charge	(111,007)	(112,892)	(115,137)	(118,060)	(120,897)	(123,290)	(124,944)	(126,026)	(126,903)	(127,176)	(127,410)	(127,410)	
48	Carrying cost	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	8.62%	
49														
50														
51	Forecasted Sales (MWh)	198,821	193,304	173,882	159,023	129,071	122,011	126,848	131,213	130,784	126,736	150,468	169,530	1,811,694
52														

SUMMARY		Jan 2018 - Dec 2018
Revenue requirements		\$8,598,711
Carrying Charge		(17,412)
2017 True-Up		11,354
Total requirements		\$8,592,654
Jan 2018-Dec 2018 projected sales in MWh		1,811,694
Average Rate		\$0.00474

Line No.	Year>>	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	
		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	8,016,682	8,016,682	8,016,682	8,016,682	8,016,682	8,016,682	8,016,682	8,016,682	13,311,359	13,311,359	13,311,359	13,311,359	13,311,359	
2	Accumulated Depreciation	(395,809)	(407,287)	(418,766)	(430,244)	(441,723)	(453,201)	(464,679)	(476,158)	(487,636)	(499,115)	(510,594)	(522,073)	(533,552)	
3	Net Plant in Service	7,620,873	7,609,395	7,597,916	7,586,438	7,574,959	7,563,481	7,552,003	7,540,524	7,529,046	12,812,245	12,793,276	12,774,306	12,774,306	
4	CWIP	4,289,658	4,471,662	4,586,322	4,725,211	4,753,663	4,806,758	4,843,879	4,913,289	5,131,745	0	0	0	0	
5	ADIT - NOL DTA	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	(2,094)	
6	Reversal of ADIT - NOL DTA	1,569	1,617	1,664	1,712	1,760	1,808	1,855	1,903	1,951	1,999	2,046	2,094	2,094	
7	ADIT Federal Proration Factors	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	
8	Accumulated Deferred Income Taxes Federal & State	(1,818,444)	(1,823,091)	(1,827,737)	(1,832,384)	(1,837,030)	(1,841,677)	(1,846,323)	(1,850,970)	(1,855,616)	(2,210,520)	(2,562,591)	(2,914,663)	(2,914,663)	
9	Ending rate base	10,091,562	10,257,488	10,356,072	10,478,883	10,491,258	10,528,276	10,549,320	10,602,653	10,805,031	10,601,629	10,230,636	9,859,643	9,859,643	
10															
11	OTP Load Percentage	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	
12	Remove Non-OTP Load Portion	(4,916,912)	(4,997,756)	(5,045,789)	(5,105,626)	(5,111,656)	(5,129,692)	(5,139,945)	(5,165,930)	(5,264,535)	(5,165,432)	(4,984,673)	(4,803,914)	(4,803,914)	
12	Retail Ending Rate Base	5,174,650	5,259,732	5,310,283	5,373,257	5,379,603	5,398,584	5,409,375	5,436,722	5,540,496	5,436,198	5,245,963	5,055,729	5,055,729	
13															
14	Average rate base	443,016	443,016	443,016	443,016	443,016	443,016	443,016	443,016	443,016	443,016	443,016	443,016	5,316,193	
15															
16	Return on Rate Base	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	458,041	
17															
18	Available for return (equity portion of rate base)	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	304,587	
19															
20	EXPENSES														
21	O&M and Depreciation														
22	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	
23	Property Tax	5,211	5,211	5,211	5,211	5,211	5,211	5,211	5,211	5,211	5,211	5,211	5,211	62,530	
24	Book Depreciation	11,478	11,478	11,478	11,478	11,478	11,478	11,478	11,478	11,478	11,478	18,969	18,969	152,723	
25	Total O&M and Depreciation Expense	16,689	16,689	16,689	16,689	16,689	16,689	16,689	16,689	16,689	16,689	24,180	24,180	215,253	
26															
27	OTP Load Percentage	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	
28	Remove Non-OTP Load Portion	(8,132)	(8,132)	(8,132)	(8,132)	(8,132)	(8,132)	(8,132)	(8,132)	(8,132)	(8,132)	(11,781)	(11,781)	(104,878)	
29	Retail O&M and Depreciation Expenses	8,558	8,558	8,558	8,558	8,558	8,558	8,558	8,558	8,558	8,558	12,399	12,399	110,375	
30															
31	Income before Taxes														
32	Available for return (from above)	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	25,382	304,587	
33	Taxable Income (grossed up)	1.61146	40,809	40,809	40,809	40,809	40,809	40,809	40,809	40,809	40,809	40,809	40,809	489,702	
34															
35	Income Taxes														
36	Current and Def Income Taxes	37.94%	15,426	15,426	15,426	15,426	15,426	15,426	15,426	15,426	15,426	15,426	15,426	185,115	
37	Total Income Tax Expense		15,426	15,426	15,426	15,426	15,426	15,426	15,426	15,426	15,426	15,426	15,426	185,115	
38															
39															
40	REVENUE REQUIREMENTS														
41	Expenses	23,984	23,984	23,984	23,984	23,984	23,984	23,984	23,984	23,984	23,984	27,825	27,825	400,367	
42	Return on rate base	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	38,170	458,041	
43	Subtotal revenue requirements	62,154	62,154	62,154	62,154	62,154	62,154	62,154	62,154	62,154	62,154	65,995	65,995	858,409	
44	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	
45	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	
46	Total revenue requirements	62,154	62,154	62,154	62,154	62,154	62,154	62,154	62,154	62,154	62,154	65,995	65,995	858,409	
47															
48	North Dakota share - D2 factor	41.26%	25,643	25,643	25,643	25,643	25,643	25,643	25,643	25,643	25,643	27,228	27,228	310,886	

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3	Debt	Ratio	Cost	WA Cost											Property tax
4	Preferred equity	43.11%	6.30%	2.72%											2017 composite rate
5	Common equity	3.60%	4.75%	0.17%											0.78%
6	Total	53.30%	10.75%	5.73%											
7		100.00%		8.62%	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	37.80%	33.49%	4.31%											
15	Tax conversion factor	1.60776													
16	Wholesale Revenue Credit	0.00%													
17	ND share - D2 factor	41.2573%													
18	Deferred Tax														
19	Book depreciation	11,478	11,478	11,478	11,478	11,478	11,478	11,478	11,478	11,478	11,478	18,969	18,969	152,723	
20	Tax depreciation-Federal	23,770	23,770	23,770	23,770	23,770	23,770	23,770	23,770	23,770	23,770	950,339	950,339	3,064,950	
21	Tax depreciation-ND	23,770	23,770	23,770	23,770	23,770	23,770	23,770	23,770	23,770	23,770	950,339	950,339	3,064,950	
22	Federal deferred income taxes	(4,117)	(4,117)	(4,117)	(4,117)	(4,117)	(4,117)	(4,117)	(4,117)	(4,117)	(4,117)	(314,438)	(311,930)	(975,349)	
23	State deferred income taxes	(530)	(530)	(530)	(530)	(530)	(530)	(530)	(530)	(530)	(530)	(40,465)	(40,142)	(125,517)	

Line No.	Year>>	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017
		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	384,801	384,801	384,801	384,801	384,801	384,801	384,801	384,801	384,801	384,801	384,801	384,801	73,915,431	73,915,431
2	Accumulated Depreciation	(9,502)	(10,002)	(10,502)	(11,003)	(11,503)	(12,003)	(12,504)	(13,004)	(13,504)	(14,005)	(14,505)	(15,005)	(15,005)	(15,005)
3	Net Plant in Service	375,300	374,799	374,299	373,799	373,298	372,798	372,298	371,797	371,297	370,797	370,296	370,296	73,900,425	73,900,425
4	CWIP	63,012,372	62,585,849	63,639,990	63,508,671	65,106,643	65,942,184	68,108,188	68,525,015	71,257,165	72,186,378	73,121,875	0	0	0
5	ADIT Federal Proration Factors	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000	1,0000
6	Accumulated Deferred Income Taxes Federal & State	(69,293)	(69,622)	(69,951)	(70,280)	(70,609)	(70,938)	(71,268)	(71,597)	(71,926)	(72,255)	(72,584)	(14,665,645)	(14,665,645)	(14,665,645)
7	Ending rate base	63,318,378	62,891,026	63,944,338	63,812,190	65,409,332	66,244,044	68,409,218	68,825,216	71,556,537	72,484,920	73,419,588	59,234,780	59,234,780	59,234,780
8															
9	Composite OTP Rate Base Retail Load Percentage	1.774%	1.770%	1.772%	1.771%	1.774%	1.774%	1.778%	1.778%	1.782%	1.784%	1.785%	1.786%	1.786%	1.786%
10	Remove Non-OTP Load Portion	(62,195,223)	(61,777,585)	(62,810,929)	(62,682,198)	(64,249,207)	(65,068,919)	(67,193,136)	(67,601,370)	(70,281,114)	(71,191,513)	(72,108,846)	(58,177,028)	(58,177,028)	(58,177,028)
11	Retail Ending Rate Base	1,123,156	1,113,441	1,133,410	1,129,992	1,160,125	1,175,124	1,216,083	1,223,846	1,275,423	1,293,408	1,310,742	1,057,752	1,057,752	1,057,752
12	Average rate base	1,160,401	1,229,843	1,282,284	1,322,826	1,358,268	1,393,710	1,429,151	1,447,143	1,458,243	1,467,708	1,468,122	1,460,689	1,460,689	1,460,689
13		98,285	98,285	98,285	98,285	98,285	98,285	98,285	98,285	98,285	98,285	98,285	98,285	98,285	1,179,424
14	Return on Rate Base	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	101,619
15															
16	Available for return (equity portion of rate base)	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	67,574
17															
EXPENSES															
18	O&M and Depreciation														
19	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property Tax	27,380	27,380	27,380	27,380	27,380	27,380	27,380	27,380	27,380	27,380	27,380	27,380	27,380	328,560
21	Book Depreciation	500	500	500	500	500	500	500	500	500	500	500	500	500	6,004
22	Total O&M and Depreciation Expense	27,880	27,880	27,880	27,880	27,880	27,880	27,880	27,880	27,880	27,880	27,880	27,880	27,880	334,564
23															
24															
25	Composite OTP Expense Retail Load Percentage	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%	1.771%
26	Remove Non-OTP Load Portion	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(27,387)	(328,638)
27	Retail O&M and Depreciation Expenses	494	494	494	494	494	494	494	494	494	494	494	494	494	5,926
28	Income before Taxes	491	491	491	491	491	491	491	491	491	491	2,564	2,590	2,602	12,175
29	Available for return (from above)	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	5,631	67,574
30	Taxable Income (grossed up)	9,054	9,054	9,054	9,054	9,054	9,054	9,054	9,054	9,054	9,054	9,054	9,054	9,054	108,643
31															
32	Income Taxes														
33	Current and Def Income Taxes	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	41,069
34	Total Income Tax Expense	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	3,422	41,069
35															
36															
37															
REVENUE REQUIREMENTS															
38	Expenses	3,916	3,916	3,916	3,916	3,916	3,916	3,916	3,916	3,916	3,916	3,916	3,916	3,916	375,632
39	Return on rate base	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	8,468	101,619
40	Subtotal revenue requirements	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	477,251
41	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total revenue requirements	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	12,384	477,251
44															
45															
50	North Dakota share - D2 factor	41.26%	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	5,109	61,314

Line No.	SUPPORTING INFORMATION / DATA																
1	ND Cap Structure with allowed ROE per order.																
2	Capital Structure																
3	Debt	Ratio	Cost	WA Cost													Property tax
4	Preferred equity	43.11%	6.30%	2.72%													2017 composite rate
5	Common equity	3.60%	4.75%	0.17%													0.54%
6	Total	53.30%	10.75%	5.73%													
7		100.00%		8.62%	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	37.80%	33.49%	4.31%													
15	Tax conversion factor	1.60776															
16	Wholesale Revenue Credit	0.00%															
17	ND share - D2 factor	41.2573%															
18																	
19	Deferred Tax																
20	Book depreciation	500	500	500	500	500	500	500	500	500	500	500	500	500	6,004		
21	Tax depreciation-Federal	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	38,620,031		
22	Tax depreciation-ND	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	1,371	38,620,031		
23	Federal deferred income taxes	(292)	(292)	(292)	(292)	(292)	(292)	(292)	(292)	(292)	(292)	(292)	(292)	(12,929,210)	(12,932,417)		
24	State deferred income taxes	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(1,663,852)	(1,664,265)		

Line No.	Year>>	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017	2017
		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 December
RATE BASE														
1	Plant Balance	814,410	814,410	852,057	852,057	852,057	852,057	852,057	1,291,670	1,291,670	1,291,670	1,446,541	1,496,117	1,496,117
2	Accumulated Depreciation	(6,336)	(7,579)	(8,822)	(10,122)	(11,423)	(12,723)	(14,023)	(15,324)	(17,295)	(19,266)	(21,237)	(23,445)	(23,445)
3	Net Plant in Service	808,074	806,831	843,235	841,934	840,634	839,334	838,034	1,276,346	1,274,375	1,272,403	1,425,303	1,472,673	1,472,673
4	CW P (Project #127607 & #128423)	200,596	255,230	265,931	362,813	449,913	461,818	495,108	55,496	178,594	207,048	62,496	4,837	4,837
5	ADIT Federal Proration Factors	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
6	Accumulated Deferred Income Taxes Federal & State	(176,801)	(188,800)	(200,799)	(212,776)	(224,753)	(236,731)	(248,708)	(260,685)	(272,409)	(284,132)	(295,856)	(307,490)	(307,490)
7	Ending rate base	831,868	873,261	908,367	991,971	1,065,794	1,064,421	1,084,434	1,071,157	1,180,560	1,195,320	1,191,944	1,170,020	1,170,020
8														
9	Average rate base	86,947	86,947	86,947	86,947	86,947	86,947	86,947	86,947	86,947	86,947	86,947	86,947	1,043,362
10														
11	Return on Rate Base	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	89,896
12														
13	Available for return (equity portion of rate base)	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	59,779
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	529	529	529	529	529	529	529	529	529	529	529	529	6,349
19	Book Depreciation	1,242	1,243	1,243	1,300	1,300	1,300	1,300	1,300	1,971	1,971	1,971	2,208	18,351
20	Total O&M and Depreciation Expense	1,771	1,772	1,772	1,829	1,829	1,829	1,829	1,829	2,500	2,500	2,500	2,737	24,699
21														
22	Income before Taxes													
23	Available for return (from above)	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	4,982	59,779
24	Taxable Income (grossed up)	8,009	8,009	8,009	8,009	8,009	8,009	8,009	8,009	8,009	8,009	8,009	8,009	96,110
25														
26	Income Taxes													
27	Current and Def Income Taxes	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	36,331
28	Total Income Tax Expense	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	3,028	36,331
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	4,799	4,799	4,799	4,857	4,857	4,857	4,857	4,857	5,528	5,528	5,528	5,764	61,030
33	Return on rate base	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	7,491	89,896
34	Subtotal revenue requirements	12,290	12,291	12,291	12,348	12,348	12,348	12,348	12,348	13,019	13,019	13,019	13,255	150,926
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(1,096)	(1,096)	(1,096)	(1,101)	(1,103)	(1,101)	(1,101)	(1,101)	(1,161)	(1,161)	(1,161)	(1,182)	(13,462)
37	Total revenue requirements	11,194	11,195	11,195	11,247	11,246	11,247	11,247	11,247	11,858	11,858	11,858	12,073	137,464
38														
39	North Dakota share - D2 factor	4,618	4,619	4,619	4,640	4,640	4,640	4,640	4,640	4,892	4,892	4,892	4,981	56,714

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio	Cost	WA Cost										Property tax
4	Debt	43.11%	6.30%	2.72%										2017 composite rate
5	Preferred equity	3.60%	4.75%	0.17%										0.78%
6	Common equity	53.30%	10.75%	5.73%										
7	Total	100.00%		8.62%	Overall Return									
8														
9														
10	Project life (years)	Book	Tax											
11		50	15-year MACRS											
12				Fed Portion	State Portion									
13	Effective Tax Rate	37.80%	33.49%	4.31%										
14	Tax conversion factor	1.60776												
15	Wholesale Revenue Credit	8.92%												
16	ND share - D2 factor	41.25727%												
17														
18	Deferred Tax													
19	Book depreciation	1,242	1,243	1,243	1,300	1,300	1,300	1,300	1,300	1,971	1,971	1,971	2,208	18,351
20	Tax depreciation-Federal	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	395,817
21	Tax depreciation-ND	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	32,985	395,817
22	Federal deferred income taxes	(10,631)	(10,631)	(10,631)	(10,612)	(10,612)	(10,612)	(10,612)	(10,612)	(10,387)	(10,387)	(10,387)	(10,308)	(126,419)
23	State deferred income taxes	(1,368)	(1,368)	(1,368)	(1,366)	(1,366)	(1,366)	(1,366)	(1,366)	(1,337)	(1,337)	(1,337)	(1,326)	(16,269)

Line No.	Year>>	2018 Projected January	2018 Projected February	2018 Projected March	2018 Projected April	2018 Projected May	2018 Projected June	2018 Projected July	2018 Projected August	2018 Projected September	2018 Projected October	2018 Projected November	2018 Projected December	2018 Projected Total
RATE BASE														
1	Plant Balance	1,558,617	1,621,117	1,683,617	1,746,117	1,808,617	1,871,117	1,933,617	1,996,117	2,058,617	2,121,117	2,183,617	2,246,117	2,246,117
2	Accumulated Depreciation	(25,728)	(28,107)	(30,581)	(32,150)	(35,815)	(38,575)	(41,430)	(44,381)	(47,427)	(50,569)	(53,806)	(57,138)	(57,138)
3	Net Plant in Service	1,532,889	1,593,011	1,653,037	1,712,967	1,772,803	1,832,543	1,892,187	1,951,736	2,011,190	2,070,548	2,129,811	2,188,979	2,188,979
4	CW P (Project #127607 & #128423)	4,837	4,837	4,837	4,837	4,837	4,837	4,837	4,837	4,837	4,837	4,837	4,837	4,837
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	(318,046)	(327,797)	(336,666)	(344,686)	(351,852)	(358,198)	(363,646)	(368,239)	(372,010)	(374,935)	(377,049)	(378,328)	(378,328)
7	Ending rate base	1,219,681	1,270,051	1,321,208	1,373,119	1,425,788	1,479,182	1,533,378	1,588,334	1,644,018	1,700,450	1,757,600	1,815,488	1,815,488
8														
9	Average rate base	123,707	123,707	123,707	123,707	123,707	123,707	123,707	123,707	123,707	123,707	123,707	123,707	1,484,486
10														
11	Return on Rate Base	10.659	10.659	10.659	10.659	10.659	10.659	10.659	10.659	10.659	10.659	10.659	10.659	127.903
12														
13	Available for return (equity portion of rate base)	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	85.053
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	972	972	972	972	972	972	972	972	972	972	972	972	11,670
19	Book Depreciation	2,283	2,379	2,474	2,569	2,665	2,760	2,855	2,951	3,046	3,142	3,237	3,332	33,693
20	Total O&M and Depreciation Expense	3,256	3,351	3,446	3,542	3,637	3,733	3,828	3,923	4,019	4,114	4,209	4,305	45,363
21														
22	Income before Taxes													
23	Available for return (from above)	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	7.088	85.053
24	Taxable Income (grossed up)	11,395	11,395	11,395	11,395	11,395	11,395	11,395	11,395	11,395	11,395	11,395	11,395	136,744
25														
26	Income Taxes													
27	Current and Def Income Taxes	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	51,691
28	Total Income Tax Expense	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	4,308	51,691
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	7,563	7,659	7,754	7,849	7,945	8,040	8,136	8,231	8,326	8,422	8,517	8,612	97,054
33	Return on rate base	10,659	10,659	10,659	10,659	10,659	10,659	10,659	10,659	10,659	10,659	10,659	10,659	127,903
34	Subtotal revenue requirements	18,222	18,317	18,413	18,508	18,603	18,699	18,794	18,889	18,985	19,080	19,176	19,271	224,957
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(3,525)	(3,543)	(3,562)	(3,580)	(3,599)	(3,617)	(3,636)	(3,654)	(3,672)	(3,691)	(3,709)	(3,728)	(43,516)
37	Total revenue requirements	14,697	14,774	14,851	14,928	15,005	15,082	15,159	15,235	15,312	15,389	15,466	15,543	181,441
38														
39	North Dakota share - D2 factor	6,064	6,095	6,127	6,159	6,191	6,222	6,254	6,286	6,317	6,349	6,381	6,413	74,858

Line No.														
SUPPORTING INFORMATION / DATA														
1														
2														
3	ND Cap Structure with allowed ROE per order.													
4	Capital Structure		Ratio	Cost	WA Cost					Property tax				
5	Debt		43.11%	6.30%	2.72%					2018 composite rate			0.78%	
6	Preferred equity		3.60%	4.75%	0.17%									
7	Common equity		53.30%	10.75%	5.73%									
8	Total		100.00%		8.62%	Overall Return								
9														
10														
11	Project life (years)		Book	Tax										
12			50	15-year MACRS										
13					Fed Portion	State Portion								
14	Effective Tax Rate		37.80%	33.49%	4.31%									
15	Tax conversion factor		1.60776											
16	Wholesale Revenue Credit		19.34%											
17	ND share - D2 factor		41.2573%											
18	Deferred Tax													
19	Book depreciation	2,283	2,379	2,474	2,569	2,665	2,760	2,855	2,951	3,046	3,142	3,237	3,332	33,693
20	Tax depreciation-Federal	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	388,813
21	Tax depreciation-ND	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	32,401	388,813
22	Federal deferred income taxes	(10,087)	(10,055)	(10,023)	(9,991)	(9,991)	(9,991)	(9,895)	(9,863)	(9,831)	(9,799)	(9,767)	(9,736)	(119,031)
23	State deferred income taxes	(1,298)	(1,294)	(1,290)	(1,286)	(1,282)	(1,282)	(1,273)	(1,269)	(1,265)	(1,261)	(1,257)	(1,253)	(15,310)

Line No.	Year>>	2018 Projected Jan	2018 Projected Feb	2018 Projected Mar	2018 Projected Apr	2018 Projected May	2018 Projected Jun	2018 Projected Jul	2018 Projected Aug	2018 Projected Sep	2018 Projected Oct	2018 Projected Nov	2018 Projected Dec	2018 Projected Total
RATE BASE														
1	Plant Balance	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718	1,818,718
2	Accumulated Depreciation	(14,167)	(16,532)	(18,897)	(21,261)	(23,626)	(25,991)	(28,356)	(30,720)	(33,085)	(35,450)	(37,815)	(40,180)	(40,180)
3	Net Plant in Service	1,804,551	1,802,187	1,799,822	1,797,457	1,795,092	1,792,727	1,790,363	1,787,998	1,785,633	1,783,268	1,780,903	1,778,539	1,778,539
CWIP Calculation:														
	Beginning Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
	Additional CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0
	AFDUC	0	0	0	0	0	0	0	0	0	0	0	0	0
4	CWIP (Project #105866)	105866	0	0	0	0	0	0	0	0	0	0	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	0
6	Accumulated Deferred Income Taxes Federal & State	(358,172)	(359,742)	(361,175)	(362,474)	(363,636)	(364,665)	(365,557)	(366,311)	(366,932)	(367,415)	(367,765)	(367,978)	(367,978)
7	Ending rate base	1,446,379	1,442,444	1,438,647	1,434,983	1,431,456	1,428,062	1,424,806	1,421,687	1,418,701	1,415,853	1,413,138	1,410,560	1,410,560
8	Average rate base	119,084	119,084	119,084	119,084	119,084	119,084	119,084	119,084	119,084	119,084	119,084	119,084	1,429,012
9	Return on Rate Base	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	123,123
10														
11	Available for return (equity portion of rate base)	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	81,874
12														
13														
14														
EXPENSES														
O&M and Depreciation														
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	14,186
18	Book Depreciation	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	2,365	28,377
19	Total O&M and Depreciation Expense	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547	3,547	42,563
20														
21	Income before Taxes													
22	Available for return (from above)	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	6,823	81,874
23	Taxable Income (grossed up)	10,969	10,969	10,969	10,969	10,969	10,969	10,969	10,969	10,969	10,969	10,969	10,969	131,634
24														
25	Income Taxes													
26	Current and Def Income Taxes	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	49,760
27	Total Income Tax Expense	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	4,147	49,760
28														
29														
30														
31														
REVENUE REQUIREMENTS														
32	Expenses	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	92,323
33	Return on rate base	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	10,260	123,123
34	Subtotal revenue requirements	17,954	17,954	17,954	17,954	17,954	17,954	17,954	17,954	17,954	17,954	17,954	17,954	215,446
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(3,473)	(3,473)	(3,473)	(3,473)	(3,473)	(3,473)	(3,473)	(3,473)	(3,473)	(3,473)	(3,473)	(3,473)	(41,676)
37	Total revenue requirements	14,481	14,481	14,481	14,481	14,481	14,481	14,481	14,481	14,481	14,481	14,481	14,481	173,770
38														
39	North Dakota share - D2 factor	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	5,974	71,693

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	
14	
15	
16	
17	
18	Deferred Tax
19	Book depreciation
20	Tax depreciation-Federal
21	Tax depreciation-ND
22	Federal deferred income taxes
23	State deferred income taxes

Ratio	Cost	WA Cost
43.11%	6.30%	2.72%
3.60%	4.75%	0.17%
53.30%	10.75%	5.73%
100.00%		8.62% Overall Return

Property tax	2018 composite rate	0.78%
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Book	Tax
50	15-year MACRS

	Fed Portion	State Portion
Effective Tax Rate	37.80%	33.49%
Tax conversion factor	1.60776	4.31%
Wholesale Revenue Credit	19.34%	
ND share - D2 factor	41.2573%	

Line No.	Year>>	2018 Projected January	2018 Projected February	2018 Projected March	2018 Projected April	2018 Projected May	2018 Projected June	2018 Projected July	2018 Projected August	2018 Projected September	2018 Projected October	2018 Projected November	2018 Projected December	2018 Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	2,757,106	2,757,106	2,757,106	2,757,106
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	(3,585)	(7,170)	(7,170)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	2,757,106	2,753,522	2,749,937	2,749,937
CWIP Calculation:														
	Beginning Balance	857,106	857,106	857,106	857,106	857,106	1,757,106	2,057,106	2,307,106	2,557,106	2,707,106	0	0	0
	Additional CWIP	0	0	0	0	900,000	300,000	250,000	250,000	150,000	50,000	0	0	1,900,000
	Closings from CWIP										(2,757,106)	0	0	
	AFDUC											0	0	
4	CWIP (Project #106134)	106134	857,106	857,106	857,106	1,757,106	2,057,106	2,307,106	2,557,106	2,707,106	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	
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	(39,514)	(67,891)	(85,128)	(85,128)
7	Ending rate base	857,106	857,106	857,106	857,106	1,757,106	2,057,106	2,307,106	2,557,106	2,707,106	2,717,592	2,685,631	2,664,809	2,664,809
8	Average rate base	152,174	152,174	152,174	152,174	152,174	152,174	152,174	152,174	152,174	152,174	152,174	152,174	1,826,084
9	Return on Rate Base	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	157,335
10														
11	Available for return (equity portion of rate base)	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	104,624
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	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	3,585	3,585	7,170
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	3,585	3,585	7,170
21	Income before Taxes													
23	Available for return (from above)	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	8,719	104,624
24	Taxable Income (grossed up)	14,018	14,018	14,018	14,018	14,018	14,018	14,018	14,018	14,018	14,018	14,018	14,018	168,210
25														
26	Income Taxes													
27	Current and Def Income Taxes	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	63,586
28	Total Income Tax Expense	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	63,586
29														
30														
REVENUE REQUIREMENTS														
32	Expenses	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	5,299	8,884	8,884	70,756
33	Return on rate base	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	13,111	157,335
34	Subtotal revenue requirements	18,410	18,410	18,410	18,410	18,410	18,410	18,410	18,410	18,410	18,410	21,995	21,995	228,091
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(3,561)	(3,561)	(3,561)	(3,561)	(3,561)	(3,561)	(3,561)	(3,561)	(3,561)	(3,561)	(4,255)	(4,255)	(44,122)
37	Total revenue requirements	14,849	14,849	14,849	14,849	14,849	14,849	14,849	14,849	14,849	14,849	17,740	17,740	183,968
38														
39	North Dakota share - D2 factor	6,126	6,126	6,126	6,126	6,126	6,126	6,126	6,126	6,126	6,126	7,319	7,319	75,900

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
43.11%	6.30%	2.72%	2018 composite rate
3.60%	4.75%	0.17%	0.78%
53.30%	10.75%	5.73%	
100.00%		8.62% Overall Return	

Book	Tax
50	15-year MACRS

Fed Portion	State Portion
37.80%	33.49%
1.60776	4.31%
19.34%	
41.2573%	

0	0	0	0	0	0	0	0	0	0	0	3,585	3,585	7,170
0	0	0	0	0	0	0	0	0	0	0	395,185	395,185	1,185,556
0	0	0	0	0	0	0	0	0	0	0	395,185	395,185	1,185,556
0	0	0	0	0	0	0	0	0	0	0	(132,353)	(131,153)	(394,659)
0	0	0	0	0	0	0	0	0	0	0	(17,032)	(16,878)	(50,788)

2018 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$37,582,992
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
2	Account No. 454	(page 4, line 34)	109,188	TP 1.00000	109,188
3	Account No. 456.1	(page 4, line 37)	8,108,755	TP 1.00000	8,108,755
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)				8,217,943
7	To back out Schedule 9 Revenues received				(947,841)
8	Total Revenue Subject to the Wholesale Revenue Credit				7,270,101
				Wholesale Revenue Credit	19.34%

2017 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$36,836,735
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
2	Account No. 454	(page 4, line 34)	82,711	TP 1.00000	82,711
3	Account No. 456.1	(page 4, line 37)	5,926,663	TP 1.00000	5,926,663
4	Revenues from Grandfathered Interzonal Transactions		0	TP 1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP 1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)				6,009,374
7	To back out Schedule 9 Revenues received				(2,820,166)
8	MISO ROE1 Refund				96,177
9	Total Revenue Subject to the Wholesale Revenue Credit				3,285,386
10				Wholesale Revenue Credit	8.92%

		2017												
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	1,327,320	1,221,578	1,282,902	966,112	868,746	885,388	1,006,313	1,097,905	946,943	1,070,457	1,097,905	1,372,381	13,143,952
2	OTP owned portion of expenses not recoverable via rider 0 001%	(17)	(16)	(17)	(13)	(11)	(12)	(13)	(14)	(12)	(14)	(14)	(18)	(171)
3	MISO Schedule 26 Expense Recoverable	1,327,303	1,221,563	1,282,886	966,100	868,735	885,377	1,006,300	1,097,891	946,931	1,070,443	1,097,891	1,372,363	13,143,781
4														
5	MISO Settlements	(5,690)	(1,212,448)			(181,226)								(1,399,363)
6														
7	North Dakota share 41 257%	545,262	3,760	529,284	398,586	283,647	365,282	415,172	452,960	390,678	441,636	452,960	566,200	4,845,426
8														
9	MISO Schedule 26A Expense	1,115,117	556,039	532,073	438,839	448,769	433,451	451,733	526,911	504,058	531,031	591,806	663,183	6,793,011
10														
11	MISO Settlements		(264,229)			(41,874)								
12														
13	North Dakota share 41 257%	460,067	120,393	219,519	181,053	167,874	178,830	186,373	217,389	207,961	219,089	244,163	273,611	2,676,321

		2018												
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	1,226,635	1,125,469	1,074,886	923,138	796,680	872,555	1,011,658	1,011,658	872,555	986,366	1,011,658	1,264,572	12,177,829
2	OTP owned portion of expenses not recoverable via rider 0 001%	(16)	(15)	(14)	(12)	(10)	(11)	(13)	(13)	(11)	(13)	(13)	(16)	(158)
3	MISO Schedule 26 Expense Recoverable	1,226,619	1,125,455	1,074,872	923,126	796,670	872,543	1,011,645	1,011,645	872,543	986,353	1,011,645	1,264,556	12,177,671
4														
5	North Dakota share 41 257%	506,069	464,332	443,463	380,856	328,684	359,988	417,377	417,377	359,988	406,942	417,377	521,721	5,024,174
6														
7	MISO Schedule 26A Expense	732,127	659,740	638,615	558,902	518,843	511,172	555,865	556,055	531,215	559,722	624,249	698,557	7,145,062
8														
9	North Dakota share 41 257%	302,056	272,191	263,475	230,588	214,061	210,895	229,335	229,413	219,165	230,926	257,548	288,205	2,947,857

		2017													
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	
1	MISO Schedule 9 Revenues (CPEC Portion)	(302,352)	(238,297)	(1,530,406)	(328,453)	(282,943)	(274,728)	(314,212)	(217,381)	(198,894)	(236,990)	(249,745)	(303,237)	(4,477,637)	
2	CPEC Facility Credits in MISO	0	0	0	0	183,271	164,052	164,052	164,052	164,052	164,052	164,052	164,052	1,331,634	
3	Non-OTP Schedule 9 Revenues	30,057	23,689	165,230	32,652	9,909	11,005	14,928	5,301	3,463	7,250	8,518	13,835	325,837	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(272,295)	(214,608)	(1,365,176)	(295,801)	(89,763)	(99,671)	(135,232)	(48,028)	(31,378)	(65,688)	(77,175)	(125,350)	(2,820,166)	
5	North Dakota share	41.257%	(112,342)	(88,541)	(563,234)	(122,039)	(37,034)	(41,122)	(55,793)	(19,815)	(12,946)	(27,101)	(31,840)	(51,716)	(1,163,523)

		2018													
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	
1	MISO Schedule 9 Revenues (CPEC Portion)	(268,022)	(213,826)	(232,982)	(267,854)	(177,082)	(224,795)	(241,958)	(251,316)	(229,944)	(273,988)	(288,733)	(350,576)	(3,021,077)	
2	CPEC Facility Credits in MISO	164,052	164,052	164,052	164,052	164,052	164,052	164,052	164,052	164,052	164,052	164,052	164,052	1,968,621	
3	Non-OTP Schedule 9 Revenues	10,335	4,948	6,852	10,318	1,295	6,038	7,744	8,674	6,550	10,928	12,393	18,541	104,614	
4	OTP Share of MISO Schedule 9 Revenues (CPEC Portion)	(93,635)	(44,827)	(62,078)	(93,484)	(11,735)	(54,706)	(70,162)	(78,590)	(59,342)	(99,008)	(112,288)	(167,984)	(947,841)	
5	North Dakota share	41.257%	(38,631)	(18,494)	(25,612)	(38,569)	(4,842)	(22,570)	(28,947)	(32,424)	(24,483)	(40,848)	(46,327)	(69,306)	(391,054)

Line No.	2017	2017												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	(1,403,200)	(1,203,026)	(1,285,048)	(1,155,237)	(1,344,460)	(1,609,599)	(1,740,824)	(1,774,779)	(1,560,622)	(1,398,427)	(1,381,676)	(1,313,755)	(17,170,652)	
2	Overhead Credit for Non-Retail Share	1.106%	(15,525)	(13,310)	(14,218)	(12,781)	(14,875)	(17,808)	(19,260)	(19,636)	(17,267)	(15,472)	(15,287)	(14,535)	(189,974)
5	Fargo	67.043%	(940,747)	(806,545)	(861,534)	(774,506)	(901,366)	(1,079,123)	(1,167,101)	(1,189,865)	(1,046,288)	(937,548)	(926,317)	(880,781)	(11,511,720)
6	Retail Load Share		73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	
7	Retail Revenue		(696,031)	(596,738)	(637,423)	(573,034)	(666,894)	(798,411)	(863,503)	(880,345)	(774,117)	(693,663)	(685,354)	(651,663)	(8,517,176)
9	Overhead Credit for Non-Retail Share		(10,408)	(8,924)	(9,532)	(8,569)	(9,973)	(11,939)	(12,913)	(13,165)	(11,576)	(10,373)	(10,249)	(9,745)	(127,364)
10	Non-Retail Load Share		26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	
11	Non-Retail Overhead Credit		(2,708)	(2,321)	(2,480)	(2,229)	(2,594)	(3,106)	(3,359)	(3,424)	(3,011)	(2,698)	(2,666)	(2,535)	(33,131)
13	Total Revenue Credit for Fargo		(698,738)	(599,060)	(639,903)	(575,263)	(669,488)	(801,517)	(866,862)	(883,770)	(777,128)	(696,362)	(688,020)	(654,198)	(8,550,308)
16	Bemidji	14.635%	(205,358)	(176,063)	(188,067)	(169,069)	(196,762)	(235,565)	(254,770)	(259,739)	(228,397)	(204,660)	(202,208)	(192,268)	(2,512,925)
17	Retail Load Share		91.01%	91.01%	91.01%	91.01%	91.01%	91.01%	91.01%	91.01%	91.01%	91.01%	91.01%	91.01%	
18	Retail Revenue		(186,888)	(160,228)	(171,152)	(153,863)	(179,065)	(214,378)	(231,856)	(236,378)	(207,855)	(186,253)	(184,022)	(174,975)	(2,286,912)
20	Overhead Credit for Non-Retail Share		(2,272)	(1,948)	(2,081)	(1,871)	(2,177)	(2,606)	(2,819)	(2,874)	(2,527)	(2,264)	(2,237)	(2,127)	(27,803)
21	Non-Retail Load Share		8.99%	8.99%	8.99%	8.99%	8.99%	8.99%	8.99%	8.99%	8.99%	8.99%	8.99%	8.99%	
22	Non-Retail Overhead Credit		(204)	(175)	(187)	(168)	(196)	(234)	(254)	(258)	(227)	(204)	(201)	(191)	(2,501)
23	Total Revenue Credit for Bemidji		(187,093)	(160,403)	(171,339)	(154,031)	(179,261)	(214,612)	(232,109)	(236,636)	(208,082)	(186,456)	(184,223)	(175,167)	(2,289,413)
27	Cass Lake - Nary - Helga - Bemidji	6.243%	(87,602)	(75,105)	(80,226)	(72,121)	(83,935)	(100,487)	(108,680)	(110,799)	(97,430)	(87,304)	(86,258)	(82,018)	(1,071,964)
28	Retail Load Share		35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	35.00%	
29	Retail Revenue		(30,661)	(26,287)	(28,080)	(25,243)	(29,378)	(35,172)	(38,039)	(38,781)	(34,101)	(30,557)	(30,191)	(28,707)	(375,198)
31	Overhead Credit for Non-Retail Share		(969)	(831)	(888)	(798)	(929)	(1,112)	(1,202)	(1,226)	(1,078)	(966)	(954)	(907)	(11,860)
32	Non-Retail Load Share		65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	65.00%	
33	Non-Retail Overhead Credit		(630)	(540)	(577)	(519)	(604)	(723)	(782)	(797)	(701)	(628)	(620)	(590)	(7,709)
35	Total Revenue Credit for Bemidji		(31,291)	(26,828)	(28,657)	(25,762)	(29,982)	(35,894)	(38,821)	(39,578)	(34,802)	(31,185)	(30,811)	(29,297)	(382,907)
27	Rugby	0.348%	(4,883)	(4,187)	(4,472)	(4,020)	(4,679)	(5,601)	(6,058)	(6,176)	(5,431)	(4,867)	(4,808)	(4,572)	(59,754)
28	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%	
29	Retail Revenue		(4,883)	(4,187)	(4,472)	(4,020)	(4,679)	(5,601)	(6,058)	(6,176)	(5,431)	(4,867)	(4,808)	(4,572)	(59,754)
31	Total Revenue Credit for Rugby		(4,883)	(4,187)	(4,472)	(4,020)	(4,679)	(5,601)	(6,058)	(6,176)	(5,431)	(4,867)	(4,808)	(4,572)	(59,754)
34	Casselton	11.691%	(164,048)	(140,646)	(150,235)	(135,059)	(157,181)	(188,178)	(203,520)	(207,489)	(182,452)	(163,490)	(161,532)	(153,591)	(2,007,421)
35	Retail Load Share		51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	51.28%	
36	Retail Revenue		(84,119)	(72,119)	(77,036)	(69,254)	(80,598)	(96,492)	(104,359)	(106,394)	(93,556)	(83,833)	(82,829)	(78,757)	(1,029,345)
38	Overhead Credit for Non-Retail Share		(1,815)	(1,556)	(1,662)	(1,494)	(1,739)	(2,082)	(2,252)	(2,296)	(2,019)	(1,809)	(1,787)	(1,699)	(22,210)
39	Non-Retail Load Share		48.72%	48.72%	48.72%	48.72%	48.72%	48.72%	48.72%	48.72%	48.72%	48.72%	48.72%	48.72%	
40	Non-Retail Overhead Credit		(884)	(758)	(810)	(728)	(847)	(1,014)	(1,097)	(1,119)	(984)	(881)	(871)	(828)	(10,821)
42	Total Revenue Credit for Casselton		(85,003)	(72,877)	(77,846)	(69,982)	(81,445)	(97,507)	(105,456)	(107,513)	(94,540)	(84,714)	(83,699)	(79,585)	(1,040,167)
45	Retail Share of Schedule 26 Revenue		(1,007,009)	(863,354)	(922,217)	(829,058)	(964,854)	(1,155,131)	(1,249,305)	(1,273,673)	(1,119,983)	(1,003,584)	(991,562)	(942,819)	(12,322,548)
47	MISO Settlements		8,780	1,311,451	(22,055)		45,007								
49	North Dakota Share	41.257%	(411,842)	184,873	(389,581)	(342,047)	(379,504)	(476,576)	(515,429)	(525,483)	(462,074)	(414,051)	(409,091)	(388,981)	(4,529,787)

Line No.	2017	2017												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	(2,068,901)	(1,717,002)	(1,621,218)	(1,526,191)	(1,651,417)	(1,863,213)	(2,044,192)	(2,251,148)	(2,272,578)	(1,863,626)	(1,714,847)	(1,749,356)	(22,343,689)
2	Overhead Credit for Non-Retail Share	(22,890)	(18,997)	(17,937)	(16,886)	(18,271)	(20,614)	(22,617)	(24,906)	(25,144)	(20,619)	(18,973)	(19,355)	(247,208)
3														
4														
5	CAPX 2020 - Brookings	18.005%	(372,499)	(309,141)	(291,895)	(274,786)	(297,333)	(335,466)	(368,051)	(405,312)	(409,171)	(335,540)	(308,753)	(314,966)
6	Retail Load Share	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%
7	Retail Revenue	(75,573)	(62,719)	(59,220)	(55,749)	(60,323)	(68,059)	(74,670)	(82,230)	(83,013)	(68,074)	(62,640)	(63,900)	(816,169)
8														
9	Overhead Credit for Non-Retail Share	(4,121)	(3,420)	(3,229)	(3,040)	(3,290)	(3,712)	(4,072)	(4,484)	(4,527)	(3,712)	(3,416)	(3,485)	(44,509)
10	Non-Retail Load Share	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%
11	Non-Retail Overhead Credit	(3,285)	(2,726)	(2,574)	(2,423)	(2,622)	(2,959)	(3,246)	(3,575)	(3,609)	(2,959)	(2,723)	(2,778)	(35,479)
12	Total Revenue Credit for CAPX Brookings	(78,858)	(65,445)	(61,794)	(58,172)	(62,945)	(71,018)	(77,916)	(85,804)	(86,621)	(71,034)	(65,363)	(66,678)	(851,648)
13														
14														
15														
16	MVP BS South - Brookings	41.334%	(855,156)	(709,702)	(670,111)	(630,833)	(682,593)	(770,137)	(844,942)	(930,485)	(939,343)	(770,307)	(708,811)	(723,075)
17	Retail Load Share	1.774%	1.770%	1.772%	1.771%	1.774%	1.778%	1.778%	1.782%	1.782%	1.784%	1.785%	1.786%	1.786%
18	Retail Revenue	(15,169)	(12,565)	(11,878)	(11,171)	(12,107)	(13,662)	(15,020)	(16,546)	(16,743)	(13,745)	(12,654)	(12,912)	(164,171)
19														
20	Overhead Credit for Non-Retail Share	(9,461)	(7,852)	(7,414)	(6,979)	(7,552)	(8,521)	(9,348)	(10,295)	(10,393)	(8,523)	(7,842)	(8,000)	(102,181)
21	Non-Retail Load Share	98.226%	98.230%	98.228%	98.229%	98.226%	98.226%	98.222%	98.222%	98.218%	98.216%	98.215%	98.214%	98.214%
22	Non-Retail Overhead Credit	(9,294)	(7,713)	(7,283)	(6,856)	(7,418)	(8,370)	(9,182)	(10,112)	(10,208)	(8,371)	(7,702)	(7,857)	(100,364)
23														
24	Total Revenue Credit for MVP Brookings	(24,462)	(20,278)	(19,160)	(18,027)	(19,525)	(22,031)	(24,202)	(26,658)	(26,950)	(22,116)	(20,356)	(20,769)	(264,535)
25														
26														
27														
28														
29	MVP Ellendale - BS South	40.662%	(841,246)	(698,159)	(659,211)	(620,572)	(671,491)	(757,610)	(831,199)	(915,350)	(924,064)	(757,778)	(697,283)	(711,314)
30	Retail Load Share	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%
31	Retail Revenue	(16,320)	(13,544)	(12,789)	(12,039)	(13,027)	(14,698)	(16,125)	(17,758)	(17,927)	(14,701)	(13,527)	(13,799)	(176,254)
32														
33	Overhead Credit for Non-Retail Share	(9,307)	(7,724)	(7,293)	(6,866)	(7,429)	(8,382)	(9,196)	(10,127)	(10,224)	(8,384)	(7,715)	(7,870)	(100,519)
34	Non-Retail Load Share	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%
35	Non-Retail Overhead Credit	(9,127)	(7,574)	(7,152)	(6,733)	(7,285)	(8,220)	(9,018)	(9,931)	(10,025)	(8,221)	(7,565)	(7,717)	(98,568)
36														
37	Total Revenue Credit for MVP Ellendale	(25,447)	(21,119)	(19,941)	(18,772)	(20,312)	(22,917)	(25,143)	(27,689)	(27,952)	(22,922)	(21,092)	(21,517)	(274,823)
38														
39														
40	Retail Share of Schedule 26A Revenue	(128,767)	(106,842)	(100,895)	(94,971)	(102,782)	(115,966)	(127,262)	(140,151)	(141,524)	(116,072)	(106,812)	(108,964)	(1,391,006)
41														
42	MISO Settlements		93,979	2,758		2,494								99,231
43														
44	North Dakota share	41.257%	(53,126)	(53,307)	(40,489)	(39,182)	(41,376)	(47,845)	(52,505)	(57,822)	(58,389)	(47,888)	(44,068)	(44,956)
45														(532,951)

Line No.	2018	2018												Total 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	
1	Total Schedule 26 Revenue	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(2,300,977)	(27,611,727)
2	Overhead Credit for Non-Retail Share	(27,247)	(27,247)	(27,247)	(27,247)	(27,247)	(27,247)	(27,247)	(27,247)	(27,247)	(27,247)	(27,247)	(27,247)	(326,965)
3														
4														
5	CAPX 2020 - Brookings	14.135%	(325,236)	(325,236)	(325,236)	(325,236)	(325,236)	(325,236)	(325,236)	(325,236)	(325,236)	(325,236)	(325,236)	(3,902,835)
6	Retail Load Share	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%	20.288%
7	Retail Revenue	(65,984)	(65,984)	(65,984)	(65,984)	(65,984)	(65,984)	(65,984)	(65,984)	(65,984)	(65,984)	(65,984)	(65,984)	(791,807)
8														
9	Overhead Credit for Non-Retail Share	(3,851)	(3,851)	(3,851)	(3,851)	(3,851)	(3,851)	(3,851)	(3,851)	(3,851)	(3,851)	(3,851)	(3,851)	(46,215)
10	Non-Retail Load Share	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%	79.712%
11	Non-Retail Overhead Credit	(3,070)	(3,070)	(3,070)	(3,070)	(3,070)	(3,070)	(3,070)	(3,070)	(3,070)	(3,070)	(3,070)	(3,070)	(36,839)
12														
13	Total Revenue Credit for CAPX Brookings	(69,054)	(69,054)	(69,054)	(69,054)	(69,054)	(69,054)	(69,054)	(69,054)	(69,054)	(69,054)	(69,054)	(69,054)	(828,646)
14														
15														
16	MVP BS South - Brookings	40.807%	(938,957)	(938,957)	(938,957)	(938,957)	(938,957)	(938,957)	(938,957)	(938,957)	(938,957)	(938,957)	(938,957)	(11,267,490)
17	Retail Load Share	1.774%	1.770%	1.772%	1.771%	1.774%	1.774%	1.778%	1.778%	1.782%	1.784%	1.785%	1.786%	1.786%
18	Retail Revenue	(16,655)	(16,624)	(16,643)	(16,627)	(16,654)	(16,656)	(16,691)	(16,696)	(16,736)	(16,755)	(16,763)	(16,767)	(200,268)
19														
20	Overhead Credit for Non-Retail Share	(11,119)	(11,119)	(11,119)	(11,119)	(11,119)	(11,119)	(11,119)	(11,119)	(11,119)	(11,119)	(11,119)	(11,119)	(133,424)
21	Non-Retail Load Share	98.226%	98.230%	98.228%	98.229%	98.226%	98.226%	98.222%	98.222%	98.218%	98.216%	98.215%	98.214%	98.214%
22	Non-Retail Overhead Credit	(10,921)	(10,922)	(10,922)	(10,922)	(10,921)	(10,921)	(10,921)	(10,921)	(10,921)	(10,921)	(10,920)	(10,920)	(131,053)
23														
24	Total Revenue Credit for MVP Brookings	(27,577)	(27,545)	(27,565)	(27,549)	(27,575)	(27,578)	(27,612)	(27,617)	(27,656)	(27,675)	(27,683)	(27,687)	(331,320)
25														
26														
27	MVP Ellendale - BS South	45.058%	(1,036,784)	(1,036,784)	(1,036,784)	(1,036,784)	(1,036,784)	(1,036,784)	(1,036,784)	(1,036,784)	(1,036,784)	(1,036,784)	(1,036,784)	(12,441,402)
28	Retail Load Share	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%	1.940%
29	Retail Revenue	(20,114)	(20,114)	(20,114)	(20,114)	(20,114)	(20,114)	(20,114)	(20,114)	(20,114)	(20,114)	(20,114)	(20,114)	(241,363)
30														
31	Overhead Credit for Non-Retail Share	(12,277)	(12,277)	(12,277)	(12,277)	(12,277)	(12,277)	(12,277)	(12,277)	(12,277)	(12,277)	(12,277)	(12,277)	(147,325)
32	Non-Retail Load Share	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%	98.060%
33	Non-Retail Overhead Credit	(12,039)	(12,039)	(12,039)	(12,039)	(12,039)	(12,039)	(12,039)	(12,039)	(12,039)	(12,039)	(12,039)	(12,039)	(144,467)
34														
35	Total Revenue Credit for MVP Ellendale	(32,153)	(32,153)	(32,153)	(32,153)	(32,153)	(32,153)	(32,153)	(32,153)	(32,153)	(32,153)	(32,153)	(32,153)	(385,830)
36														
37														
38	Retail Share of Schedule 26A Revenue													

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

Line No.	2017	2017												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 37 Revenue	(15,661)	(15,660)	(15,660)	(15,664)	(15,664)	(15,405)	(15,394)	(0)	(0)	(0)	(0)	(0)	(109,109)
2	Overhead Credit for Non-Retail Share	1.106%	(173)	(173)	(173)	(173)	(173)	(170)	(170)	(0)	(0)	(0)	(0)	(1,207)
3														
4														
5	Fargo	100.00%	(15,661)	(15,660)	(15,660)	(15,664)	(15,664)	(15,405)	(15,394)	(0)	(0)	(0)	(0)	(109,109)
6	Retail Load Share		73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	
7	Retail Revenue		(11,587)	(11,587)	(11,587)	(11,589)	(11,589)	(11,398)	(11,390)	(0)	(0)	(0)	(0)	(80,727)
8														
9	Overhead Credit for Non-Retail Share		(173)	(173)	(173)	(173)	(173)	(170)	(170)	(0)	(0)	(0)	(0)	(1,207)
10	Non-Retail Load Share		26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	
11	Non-Retail Overhead Credit		(45)	(45)	(45)	(45)	(45)	(44)	(44)	(0)	(0)	(0)	(0)	(314)
12														
13	Total 37 Revenue Credit for Fargo		(11,632)	(11,632)	(11,632)	(11,634)	(11,634)	(11,442)	(11,434)	(0)	(0)	(0)	(0)	(81,041)
14														
15	MISO Settlements		84	16,016			(1,477)							
16														
17	North Dakota Share	41.257%	(4,765)	1,809	(4,799)	(4,800)	(5,409)	(4,721)	(4,717)	(0)	(0)	(0)	(0)	(27,402)
18														
19														
20														
21	Total Schedule 38 Revenue		(19,088)	(19,087)	(19,087)	(19,094)	(19,094)	(18,791)	(18,778)	(0)	(0)	(0)	(0)	(133,021)
22	Overhead Credit for Non-Retail Share	1.106%	(211)	(211)	(211)	(211)	(211)	(208)	(208)	(0)	(0)	(0)	(0)	(1,472)
23														
24														
25	Fargo	100.00%	(19,088)	(19,087)	(19,087)	(19,094)	(19,094)	(18,791)	(18,778)	(0)	(0)	(0)	(0)	(133,021)
26	Retail Load Share		73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	73.99%	
27	Retail Revenue		(14,123)	(14,122)	(14,122)	(14,127)	(14,127)	(13,903)	(13,893)	(0)	(0)	(0)	(0)	(98,418)
28														
29	Overhead Credit for Non-Retail Share		(211)	(211)	(211)	(211)	(211)	(208)	(208)	(0)	(0)	(0)	(0)	(1,472)
30	Non-Retail Load Share		26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	26.01%	
31	Non-Retail Overhead Credit		(55)	(55)	(55)	(55)	(55)	(54)	(54)	(0)	(0)	(0)	(0)	(383)
32														
33	Total 38 Revenue Credit for Fargo		(14,178)	(14,177)	(14,177)	(14,182)	(14,182)	(13,957)	(13,947)	(0)	(0)	(0)	(0)	(98,801)
34														
35														
36	MISO Settlements		117	25,577			(1,609)							
37														
38	North Dakota Share	41.257%	(5,801)	4,703	(5,849)	(5,851)	(6,515)	(5,758)	(5,754)	(0)	(0)	(0)	(0)	(30,826)

Federal ADIT Proration

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January 2018 - December 2018 Recovery Period			
Month	All Projects' Revenue Requirements	All Projects' Revenue Requirements with ADIT-Prorate	Difference due to Federal ADIT Proration (B - A)
Jan-18	\$487,194	\$487,971	\$778
Feb-18	\$487,229	\$488,007	\$778
Mar-18	\$493,099	\$493,877	\$778
Apr-18	\$487,226	\$488,004	\$778
May-18	\$487,258	\$488,035	\$778
Jun-18	\$493,123	\$493,901	\$778
Jul-18	\$487,321	\$488,099	\$778
Aug-18	\$487,353	\$488,131	\$778
Sep-18	\$493,219	\$493,996	\$778
Oct-18	\$487,416	\$488,194	\$778
Nov-18	\$488,641	\$489,419	\$778
Dec-18	\$494,507	\$495,284	\$778
	\$5,873,587	\$5,882,918	\$9,331

Revenue Requirement Adjustment Related to Federal ADIT Proration	\$9,331
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Attachment 33

Electric Rate Schedule Section 13.07

Redline and Clean

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service	50-510
Controlled Service	50-511
Lighting	50-512
All Other Service	50-513

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 any 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	\$1.6892.095
Controlled Service	(b)	0.065086 ¢/kWh	N/A
Lighting	(c)	0.270332 ¢/kWh	N/A
All Other Service		0.475599 ¢/kWh	N/A

(a) Rate schedules 10.03 Large General Service, 10.05 Large General Service – Time of Day, 14.02 Real Time Pricing Rider and 14.03 Large General Service 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

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NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota

Case No. PU-~~16-62417-~~

Approved by order dated: ~~December 14, 2016~~
Gerhardson

Regulatory Affairs & Compliance

EFFECTIVE with bills rendered on
and after January 1, ~~2017~~2018, in North

APPROVED: ~~Thomas R. Brause~~Bruce G.

~~Vice President, Administration~~Director,



NORTH DAKOTA PUBLIC
SERVICE COMMISSION
Dakota
Case No. PU-~~16-62417-~~
Approved by order dated: ~~December 14, 2016~~
Gerhardson
Regulatory Affairs & Compliance

EFFECTIVE with bills rendered on
and after January 1, ~~2017~~2018, in North
APPROVED: ~~Thomas R. Brause~~Bruce G.
~~Vice President, Administration~~Director,



DETERMINATION OF DEMAND CHARGE (LARGE GENERAL SERVICE CLASS ONLY): The demand charge shall be billed according to the demand charge as defined in the applicable rate schedule the Customer is taking service.

~~N~~
~~N~~
~~N~~

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

~~N~~
~~N~~
~~N~~
~~N~~

NORTH DAKOTA PUBLIC
SERVICE COMMISSION
North Dakota
Case No. ~~PU-11-153 and PU-11-68217-~~
Approved by order dated: ~~April 25, 2012~~
Gerhardson
~~Administration~~Director, Regulatory Affairs & Compliance

EFFECTIVE with bills rendered on
and after ~~May 1, 2012~~January 1, 2018, in

APPROVED: ~~Thomas R. Brause~~Bruce G.
~~Vice President,~~

TRANSMISSION COST RECOVERY RIDER

DESCRIPTION	RATE CODE
Large General Service	50-510
Controlled Service	50-511
Lighting	50-512
All Other Service	50-513

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 any electric service under all of the Company's retail rate schedules.

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

RATE:

TRANSMISSION COST RECOVERY			
Energy Charge per kWh:		kWh	kW
Large General Service	(a)	N/A ¢/kWh	\$2.095
Controlled Service	(b)	0.086 ¢/kWh	N/A
Lighting	(c)	0.332 ¢/kWh	N/A
All Other Service		0.599 ¢/kWh	N/A

(a) Rate schedules 10.03 Large General Service, 10.05 Large General Service – Time of Day, 14.02 Real Time Pricing Rider and 14.03 Large General Service 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

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DETERMINATION OF DEMAND CHARGE (LARGE GENERAL SERVICE CLASS ONLY): The demand charge shall be billed according to the demand charge as defined in the applicable rate schedule the Customer is taking service.

MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.

Changes to North Dakota's 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 reliable and economical service.

These changes below apply to bills rendered on and after January 1, 2018, and are included in the Energy and Renewable Adjustment line item.

	Old rates		New rates		Impact of new rates ⁽¹⁾
Large General Service	\$1.689	per kW	\$2.095	per kW	\$172.55/month
Controlled Service	\$0.00065	per kWh	\$0.00086	per kWh	\$0.27/month
Lighting	\$0.00270	per kWh	\$0.00332	per kWh	\$0.06/month
Residential	\$0.00475	per kWh	\$0.00599	per kWh	\$1.23/month
All other service	\$0.00475	per kWh	\$0.00599	per kWh	\$1.67/month

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

For more information contact Customer Service at 800-257-4044 or place an inquiry from our web site at otpc.com.