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September 1, 2016

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.

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 218-739-8385 or bhaugen@otpc.com.

Sincerely,

/s/ BRYCE C. HAUGEN
Bryce C. Haugen
Senior Rates Analyst
Regulatory Administration

nlo

cc: Jerry Lien

Enclosures
By electronic filing and U.S. mail

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

Case No. PU-16-____

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 has been adjusted to reflect the TCRR revenue requirements for the next recovery period (calendar year 2017). 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 removal of one transmission project that was previously approved for recovery, (2) the addition of three new transmission projects that are not currently in base rates and have not previously been included in the Rider, (3) the impact of Federal bonus tax depreciation which was passed by Congress on December 18, 2015 and the resulting Deferred Tax Asset, and (4) 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 a decrease of \$2.91 per month. For a large general service customer with 425 kW of demand, the bill impact of this update is a decrease of \$434.48 per

month. Otter Tail notes that this TCRR rate reduction, for 2017 rates, is the result of an approximately \$2.6 million true-up and that it expects its 2017 annual update to include proposed 2018 rates that will return to current rate levels.

II. 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

Bryce C. Haugen
Senior Rates Analyst, Regulatory Administration
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8385

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

The date of this filing is September 1, 2016. The updated TCRR rate has been calculated to take effect as of January 1, 2017.

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.

III. 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 – 22 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 -19) and the three new projects for which Otter Tail is requesting TCRR recovery (Attachments 20-22).

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 typically 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 where an unexplained interruption has occurred. To reduce the cost of patrols after an interruption, data from protective relays is used to limit the patrol area. 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. Other O&M costs are dependent on the severity of storms and resulting damage, tree growth, items found on line patrols, the cost of NERC reporting requirements, and supervision. Otter Tail has set up transmission O&M accounting projects to track O&M costs specifically related to each line included in the Transmission Rider.
- *Proration of Accumulated Deferred Income Taxes (ADIT).* The proration of Federal ADIT was first introduced by Otter Tail in its TCRR Supplemental Filing in Case No. PU-15-661. Proration of Federal ADIT is necessary for compliance with Internal Revenue Service (IRS) normalization rules with regard to ADIT. Otter Tail became aware of the issue in 2015 following the release of several Private Letter Rulings (PLRs) issued by the IRS.

Otter Tail provides Attachment 31 to this filing to show the ADIT proration calculation impact on the revenue requirement for the recovery period. 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-16-148) and Otter Tail's most recent Renewable Resource Adjustment Rider (Case No. PU-16-14).

- *Midcontinent Independent System Operator (MISO) Schedule 26 and 26A expenses.* Schedule 26 and Schedule 26A costs for the recovery period appear on lines 22 and 23 of the Tracker Account (Attachment 4), and are shown separately in Attachment 24. 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 25) and Revenues (Attachment 26).* In Docket PU-15-661, the Commission approved the inclusion of SPP Schedule 7, 8, or 9 and 11 expenses as well as MISO Schedule 9 revenues resulting from Central Power Electric Cooperative's (CPEC) move in to SPP in the TCRR. Otter Tail and CPEC have a highly integrated transmission system as a result of joint planning and development spanning over 65 years. CPEC joined SPP as a transmission owner effective January 1, 2016, and placed some of its eligible facilities within the Otter Tail/CPEC integrated transmission system under the SPP tariff. As a result, a portion of Otter Tail load is now subject to the SPP tariff, and started to incur SPP Schedule 9 and 11 expenses for transmission

service on January 1, 2016. Otter Tail's load that is served along a transmission path that includes transmission facilities under the SPP tariff may be subject to SPP Schedule 7, 8, or 9 charges and SPP Schedule 11 charges.

Schedule 7, 8 or 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. To date, Otter Tail has only secured network integration transmission service for its load in SPP (SPP Schedule 9), but could opt to secure either type of point-to-point transmission service in the future for locations on the edge of the Otter Tail/CPEC integrated transmission system or in other locations where Otter Tail has the potential to utilize existing interconnections to neighboring non-CPEC utilities that own transmission facilities under the SPP tariff.

Schedule 11 is part of SPP's tariff and is similar to the MISO Schedule 26 and 26A expenses that Otter Tail incurs. These 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.

Concurrent with Otter Tail paying SPP charges for transmission service, CPEC started paying MISO charges for transmission service it receives through MISO on January 1, 2016. A portion of these MISO charges paid by CPEC for transmission service in MISO are received by Otter Tail as Schedule 9 revenue. In the TCRR, Otter Tail includes as a credit to the overall revenue requirement, its share of the MISO Schedule 9 revenues from CPEC to offset Otter Tail's new SPP transmission service charges. The inclusion of these revenues results in a reduction to the TCRR revenue requirement.

Starting in 2017, Otter Tail anticipates CPEC will begin collecting Facility Credits in MISO for CPEC owned transmission facilities that are eligible for inclusion in MISO. These Facility Credits will entitle CPEC to collect a revenue requirement for its transmission facilities which are highly integrated with other transmission facilities in MISO, in exchange for utilities within MISO taking transmission service over these facilities to serve their load. These CPEC Facility Credits result in a revenue stream to CPEC that will effectively reduce Schedule 9 charges that CPEC will incur in MISO, thereby reducing the amount of MISO Schedule 9 revenue Otter Tail receives from CPEC load in MISO. Therefore, Otter Tail includes any amount of CPEC Facility Credits that Otter Tail has to pay to CPEC as a reduction to the MISO Schedule 9 revenues from CPEC. SPP Schedule 9 expenses appear on Line 24 and SPP Schedule 11 expense on Line 25 of the Tracker Account (Attachment 4). Both are shown separately in Attachment 25. MISO Schedule 9 revenue from CPEC appears on Line 29 of the Tracker Account (Attachment 4) and is shown separately in Attachment 26.

- *MISO Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 30 and 33 of the Tracker Account Summary (Attachment 4) and are shown separately on Attachment 27 (Schedule 26) and Attachment 28 (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 the 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 are seeking to reduce the current ROE of 12.38 percent to 9.15 percent and 8.67 percent, respectively. The Administrative Law Judge's (ALJ) Initial Decision in the first complaint was issued on December 22, 2015 and recommended a 10.32 percent base ROE. The ALJ's Initial Decision is not binding and the proceeding is now awaiting a FERC Order that is expected in the fall of 2016. In the second complaint, the ALJ issued an Initial Decision on June 30, 2016 recommending a 9.7 percent base ROE. FERC is not expected to issue an order on the second proceeding until the spring of 2017. 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) that will be applied to the base ROE after that date. Collection of the RTO adder is deferred until the resolution of the first ROE complaint proceeding.

Otter Tail anticipates true-ups will be necessary for MISO expenses and revenues for the time periods included in the complaints, and possibly for future time periods. Otter Tail expects the MISO revenues Otter Tail received over the complaint time periods may result in a payment (refund of revenues) obligation to MISO. The MISO expenses Otter Tail paid over the complaint time periods could result in a credit (return of prior expenses paid) issued to Otter Tail from MISO for the complaint periods.

The implications of the outstanding ROE Complaints may also impact future periods. MISO continues to require Transmission Owners to make Attachment O, GG, and MM filings using the currently approved 12.38 percent ROE. Updates to these three attachments are due to MISO by Transmission Owners by September 1, 2016 for the 2017 calendar year. These updates are used to calculate both MISO revenues and expenses for the 2017 calendar year. Due to Otter Tail's challenge of properly estimating the impact to MISO expenses and the uncertainty of when and how settlement of this issue will be resolved, Otter Tail did not include an estimate for this adjustment in this Application.

- *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 29, and is included in the TCRR based on Otter Tail's load ratio share in MISO. This revenue is reflected as a credit in the rider (Attachment 4, line 34).

- *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 27 and Attachment 28 on the line titled "Overhead Credit for Non-Retail Share" for each project. For this period the percentage is 1.336 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 allocation from MISO of the Schedule 26 cost allocation assigned to American Transmission Systems Inc. (ATSI) for transmission investments of MISO transmission owners. ATSI withdrew from MISO on June 1, 2011, to integrate with PJM. The Schedule 38 revenues represent Otter Tail's allocation of payments from Duke-Ohio (DEO) and Duke-Kentucky (DEK) that departed MISO on December 31, 2011. ATSI, DEO, and DEK have an ongoing obligation to pay for MISO Schedule 26 transmission projects due to their prior MISO membership.

Note that in Attachment 30, 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 \$36,353 as can be seen in Attachment 4, line number 31. The Schedule 38 revenue credit reflected in this TCRR update is \$46,299, seen in Attachment 4 on line 32. These are actual amounts through July 2016 and are included as part of the 2016 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. Bonus Tax Depreciation

As noted earlier, in late 2015, Congress passed new Federal bonus tax depreciation legislation. The following table summarizes the time frames and bonus tax depreciation percentages approved by Congress on December 18, 2015. Equipment placed into service in these years is eligible for bonus tax depreciation.

Year	Bonus % Approved
2015	50%
2016	50%
2017	50%
2018	40%
2019	30%

Otter Tail placed several large projects into service in 2015, including transmission projects, the Big Stone AQCS project, and other investments to its rate base. Due to the size of these investments, the use of bonus tax depreciation on these investments created a Tax Net Operating Loss (NOL) position for Otter Tail's 2015 tax year. The impact of this NOL position is described later in this Application.

Accelerated Tax Depreciation increases ADIT and Reduces Rate Base

Bonus and other accelerated tax depreciation provisions reduce the amount of actual taxes paid when tax returns are filed. Ratepayers benefit when the payment of taxes can be deferred until future periods and the mechanics of traditional ratemaking processes take this benefit into account. Typically, when the amount of depreciation expense for tax purposes is greater than the depreciation amount computed for book purposes, the difference is accounted for as ADIT. In traditional ratemaking, including Otter Tail's riders, the ADIT balances resulting from the timing differences between book and tax depreciation are included as a credit in the determination of the overall rate base upon which a return is calculated. Accelerated depreciation grows the ADIT balance which results in rate base dropping.

NOL Carryforward Position Creates Tax Asset to Offset Future Taxable Income

Due to significant capital investment by Otter Tail in 2015, the impact of bonus depreciation created a Tax NOL for the 2015 Tax Year. As a result, the portion of the

unused tax depreciation which remains when taxable income is reduced to zero creates a Deferred Tax Asset (NOL carry forward) that can be used to offset future taxable income. Otter Tail has allocated the NOL to each project by dividing the project tax depreciation by the total Company tax depreciation and applying that percent to the total 2015 forecasted NOL. The 2015 allocated NOL applicable to transmission projects is accounted for as a Deferred Tax Asset in the TCRR, which increases rate base. As the NOLs are applied against future taxable income, the Deferred Tax Asset balance will be reduced, lowering rate base and the associated revenue requirement. The remaining Deferred Tax Asset balance for transmission projects at December 31, 2016 is approximately \$2.0 million (Total Company). The treatment of the NOL tax position in this Filing is consistent with how it was handled in Otter Tail's last Environmental Cost Recovery Rider update (Case No. PU-16-148) and in Otter Tail's Renewable Resource Adjustment Rider (Case No. PU-16-14).

Overall Impacts of Bonus Depreciation and Deferred Tax Asset to the 2017 Rider Revenue Requirement

The bonus tax depreciation taken on 2015, 2016, and 2017 investments has increased the ADIT balance in Otter Tail's TCRR, *and has reduced the rate base in the rider*. As a result, the rate is lower in this annual update than it would have been without the bonus tax depreciation. The incremental impact of including bonus depreciation results in a reduction of approximately \$1.07M, offset by the corresponding Deferred Tax Asset of \$285k for a net decrease of \$785k on the 2017 revenue requirement.

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

SPP originally provided rate estimates to Otter Tail around July 2015 for various charge types that could apply to Otter Tail's load in SPP starting January 1, 2016. Otter Tail used this information to estimate that Otter Tail could incur charges of approximately \$3.97 million (Total System – Schedule 7, 8 or 9) and \$92 thousand (Total System – Schedule 11) in 2016, as seen in Otter Tail's Supplemental Filing in its 2016 annual update in Case No. PU-15-661. North Dakota's jurisdictional share of Schedule 7, 8, or 9 and Schedule 11 expenses (using the D2 allocator of 41.25727 percent) for 2016 was estimated to be \$1,637,703 and \$38,153, respectively.

Charges incurred by Otter Tail so far during 2016 are coming in lower than originally forecasted. Otter Tail has updated the forecast for SPP Schedule 9 and Schedule 11 expenses through the rest of 2016 based on the monthly invoices that Otter Tail has received from SPP so far during 2016. As seen in Attachment 25 of this filing, Schedule 7, 8, or 9 expenses are now forecasted to be \$2.0 million [Total System], (\$808 thousand [ND]), and Schedule 11 expenses are forecasted to be \$36 thousand [Total System], (\$15 thousand [ND]) in 2016. Any difference between the forecasted charges and the actual charges incurred as a result of SPP Schedules 7, 8, or 9 and 11 will be trued up in next year's filing.

On-going efforts to resolve MISO/SPP Seams Issues associated with CPEC's move to SPP

Otter Tail is committed to on-going efforts with CPEC and SPP to find an equitable solution to minimize the impact of the SPP tariff expenses noted above due to CPEC placing some of its eligible transmission facilities within the Otter Tail/CPEC integrated transmission system under the SPP tariff on January 1, 2016. Should the outcome of these efforts materially alter or change the amounts associated with the SPP expenses noted above during the time this Docket is open, Otter Tail will provide updated information and revised rate calculations in a supplemental filing.

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

Fourteen projects that were 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, and PU-14-690.

The retail allocation of costs and revenues for these projects have been updated and carried out through 2016 and are reflected in Attachments 5-19.

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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

Removal of Rugby to Harvey 115 kV Line Rebuild

In Case No. PU-15-661, Otter Tail requested, and the Commission approved, Otter Tail’s recovery of proposed costs associated with the Rugby to Harvey Transmission Project. Otter Tail’s estimated capital (Total System) costs for the project were projected at \$1,500,000 with \$250,000 budgeted for each year starting in 2016. North Dakota’s jurisdictional share of Otter Tail’s total capital costs for the project based on the D2 allocation factor of 41.25727 percent is \$618,859.

In this annual update, Otter Tail has removed this project from the TCRR. Otter Tail continues to assess its system needs and prioritize projects on a regular basis. A portion of the overall Rugby to Harvey Transmission Project was completed in 2015 and 2016. The upgrades that were completed for this project targeted a section of line that had historic reliability challenges. During 2016, it was determined that Otter Tail would postpone further upgrades on this line indefinitely to determine if reliability is enhanced with the upgrades that have been done to date, thereby allowing other higher priority needs to be addressed on Otter Tail’s system. The revenue requirement of \$9,594 attributable to this project in last year’s TCRR update has been removed and is being returned to customers as part of the true-up portion of the overall revenue requirement included in this TCRR update. If this project is revived at a later date, Otter Tail will request the inclusion of this project in a future annual update before including it in future revenue requirements.

F. New transmission projects 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 three

new projects that meet this criterion that it is requesting approval for inclusion in this TCRR update, each of which is described in detail below.

Description of New Project 1 – Max to Ryder 41.6 kV Line Upgrade– Attachment 20

Each year, Otter Tail reviews the performance and reliability of transmission lines throughout its system and identifies lines that meet the criteria for improvements. As a result of this process, the existing Max – Ryder 41.6 kV line was identified as needing improvements as components of the line are beginning to fail and are causing reliability concerns. The Max-Ryder 41.6 kV line is approximately 60 miles in length and carries energy to seven communities served by Otter Tail. A multi-year plan has been identified that will rebuild portions of this line each year to mitigate these concerns. The improvements of this line will consist of pole and insulator replacements, moving structures out of deep water hazards, and re-conductoring the line with an anti-galloping conductor.

Starting in 2015, Otter Tail targeted improvements on portions of the Max to Ryder 41.6 kV line while concentrating on the areas with the most failures causing interruptions to customers. Otter Tail will continue this strategy until the planned improvements to the line are completed, which is expected by the end of 2018.

The total cost for the Max to Ryder 41.6 kV Line Upgrade is approximately \$2.5 million. North Dakota’s jurisdictional share of the total project based on the D2 allocation factor is approximately \$1.0 million.

Description of New Project 2 – Rugby 41.6 kV Breaker Station– Attachment 21

Otter Tail is expanding its existing 230/115 kV substation at Rugby to enhance reliability in the local area. Otter Tail is installing a new 41.6 kV switchyard at the existing Rugby 230/115 kV substation by utilizing the 41.6 kV winding on an existing 230/115 kV transformer. As part of this project, Otter Tail plans to install four new 41.6 kV circuit breakers, and re-terminate two existing Otter Tail-owned 41.6 kV circuits from the Central Power Electric Cooperative (CPEC)-owned Rugby 115/41.6 kV Substation into the Otter Tail-owned Rugby 230/115 kV substation. By connecting the 41.6 kV tertiary of this existing 230/115 kV transformer to the 41.6 kV transmission system in the Rugby area, a stronger high voltage source is introduced by a direct connection to the 230

kV system rather than the existing 115 kV connection into the CPEC-owned 115/41.6 kV substation. This project is also driven, in part, by concerns with the extended outage of CPEC's 115/41.6 kV transformer at CPEC's Rugby substation. CPEC recently took this transformer out of service due to transformer oil tests showing internal problems with the unit. There is no specified return-to-service date of CPEC's 115/41.6 kV transformer.

As part of this project, some distribution facilities for serving the town of Rugby itself, (served from the Rugby South Distribution Substation), will be moved to the existing 230/115 kV substation.¹ Otter Tail is only requesting inclusion of costs in the TCRR for transmission facilities. The distribution facilities are not recoverable in the TCRR. Relocating these distribution facilities to the existing 230/115 kV substation will reduce the line exposure to the customers currently served by the Rugby South distribution substation by 35 line miles, likely resulting in less interruptions to these customers due to no longer being exposed to faults along the extensive 41.6 kV system in this area. Relocating the Rugby South distribution facilities to Otter Tail's 230/115 kV substation disconnects this distribution substation delivery from existing 41.6 kV lines, helping other adjacent high voltage transmission sources provide backup service to the Rugby area during contingencies. Lastly, the distribution-related portion of this project also involves moving the existing Rugby South distribution transformer to the existing Rugby Northwest substation to increase the capacity of the Rugby Northwest substation, allowing for more capability to serve customers during certain contingencies.

Overall, the Rugby 41.6 kV Breaker Station Project, when considering both the transmission and distribution components, will effectively enhance both the 41.6 kV and 12.5 kV systems in the Rugby area.

The current estimate for the transmission-related portion of the Rugby 41.6 kV Breaker Station is approximately \$2 million with an estimated in-service date of December 2016. North Dakota's jurisdictional share of the total project based on the D2 allocation factor is approximately \$0.8 million.

¹ Pursuant to N.D.C.C. § 49-03-01, Otter Tail filed a Certificate of Public Convenience and Necessity for the Rugby 41.6 kV Breaker Station on September 1, 2016.

Description of New Project 3 – Granville Junction Breaker Station– Attachment 22

Otter Tail is constructing a new 41.6 kV breaker station at a location referred to as “Granville Junction”. Granville Junction is a junction point of three existing 41.6 kV transmission lines that come from the Dunning Substation, Rugby Substation, and the Voltaire Substation. This project includes the installation of three 41.6 kV breakers designed to protect the transmission system in all three directions out of this new Granville Junction breaker station. This project, along with the planned configuration of the 41.6 kV transmission system, results in a decrease in exposure for Velva, Simcoe, Norwich, Surrey and Deering by shortening the 41.6 kV line mileage between breakers and normally open switches. In addition to reducing exposure for certain communities, other benefits of the Granville Junction Breaker Station include enhanced reliability of the 41.6 kV system by adding sectionalizing capability, improving restoration times, and adding operational flexibility to a portion of Otter Tail’s extensive 41.6 kV transmission system in North Dakota.

The current estimate for the Granville Junction Breaker Station is approximately \$1.1 million with an estimated in-service date of December 2016. North Dakota’s jurisdictional share of the total project based on the D2 allocation factor is approximately \$0.45 million.

IV. ALLOCATIONS AND RATE DESIGN

The allocations and rate design for this annual rider 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.

V. RATE APPLICATION AND IMPACT

The total 2017 revenue requirement is made up of three components: the estimated revenue requirement for calendar year 2017; the true-up associated with an updated projection of

the 2016 revenue requirement; and the carrying charge attributable to any projected over or under-collection that accumulates.

The revenue requirement attributable to calendar year 2017, as shown on line 37 of Attachment 4, page 2 of 2, is \$8,396,895.

The 2016 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 45, reflects an estimated over-collection amount of (\$2,604,666) during the 2016 collection period. This amount is based on actual net revenues and expenses which have been included in the TCRR tracker through July 2016, and updated projections for August through December of 2016. The primary drivers of this over collection are the implementation of bonus depreciation, the lower than originally anticipated SPP expenses, and the MISO ROE complaint proceedings which Otter Tail estimated an adjustment to increase the revenue requirement for in the 2016 recovery period that was not realized. Otter Tail notes that this \$2.6 million true-up is a reduction to the proposed revenue requirement and creates a significant reduction in the TCRR rates in this Filing. Otter Tail expects that its 2017 annual update, to be filed August 31, 2017 for the 2018 recovery period, will include a revenue requirement and proposed rate update that is in line with those approved for the 2015 annual update.

By design and structure of the TCRR, the related carrying credit of (\$125,772), as computed on Attachment 4, page 2 of 2, line 44, will be credited to customers as a reduction in the 2017 revenue requirements. The net revenue requirement for 2017 upon which rates are developed is \$5,666,458, as shown on line 39 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, for administrative purposes, 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	\$1.384/kW
Controlled Service	0.054¢
Lighting	0.221¢
All other service	0.389¢

These rates represent a decrease to the rates currently in effect. The estimated decrease for a residential customer using 1,000 kWh would be \$2.91 per month. The following table shows the estimated rate change over the previous rate by individual rate classes:

	Average kWh/Month	kWh	Customer (Meters)	Average kW/kWh's/ Meter	Current Rate	Proposed Rate	Change in Rate	Impact
Large General Service		107,116	340	315	\$ 2.406	\$ 1.384	\$ (1.022)	\$ (321.65)
Controlled Service	22,931,720		15,752	1,456	\$0.00088	\$ 0.00054	\$ (0.00035)	\$ (0.51)
Lighting	1,853,230		22,774	81	\$0.00399	\$ 0.00221	\$ (0.00178)	\$ (0.14)
All Other	80,381,964		60,026	1,339	\$0.00680	\$ 0.00389	\$ (0.00291)	\$ (3.89)

The proposed rates are based on the assumption that they will be in effect beginning January 1, 2017 through December 31, 2017. If the effective date is significantly later than January 1, 2017, 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.

VI. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE

Otter Tail's redline and clean update to the Transmission Cost Recovery Rider (Section 13.07) is Attachment 32 to this Application.

VII. FILING FEE

As allowed under N.D.C.C. § 49-05-04.3, Subd. 2.d, Otter Tail has included 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.

VIII. 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 September 1, 2016, Otter Tail Power Company filed a request with the North Dakota Public Service Commission to decrease 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, 2017. 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: (\$434.48) (from \$2.406 per kW to \$1.384 per kW), Controlled Service: (\$0.45) (from 0.088 cents per kWh to 0.054 cents), Lighting: (\$0.16) (from 0.399 cents per kWh to 0.221 cents per kWh), all other service: (\$2.91) (from 0.680 cents per kWh to 0.389 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 33 is a draft of the proposed notice to customers upon implementation of the updated rates.

IX. 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, 2017.

Date: September 1, 2016

Respectfully submitted:

OTTER TAIL POWER COMPANY

/s/ BRYCE C. HAUGEN

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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	Attachment O Revenue Credit for Non-MISO Projects
Attachment 24	MISO Schedule 26 and 26A Expense
Attachment 25	SPP Expenses
Attachment 26	MISO Schedule 9 Revenue
Attachment 27	MISO Schedule 26 Revenue
Attachment 28	MISO Schedule 26A Revenue
Attachment 29	MISO Multi-Value Project Auction Revenue Rights Credit

Attachment 30	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 31	ADIT Pro-Rate
Attachment 32	Electric Rate Schedule Section 13.07 Redline and Clean
Attachment 33	Proposed Customer Notice

Projected Revenue for 2017

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,268,497 kW	\$1.384	\$1,755,080
2					
3	Controlled Service	(b)	257,769,496 kWh	0.054¢	\$138,086
4					
5	Lighting	(c)	22,754,297 kWh	0.221¢	\$50,386
6					
7	All other service		955,869,464 kWh	0.389¢	\$3,722,906
8					
9	Total revenue				<u>\$5,666,458</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	2017
1	CAPX 2020 - Fargo	\$2,953,001
2	CAPX 2020 - Bemidji	\$700,061
3	Cass Lake-Nary-Helga-Bemidji	\$114,876
4	Rugby Wind Interconnection	\$2,544
5	Casselton – Buffalo 115 kV Project	\$306,343
6	CAPX 2020 - Brookings - Hampton	\$293,717
7	MVP - Big Stone Area Transmission	\$63,056
8	MVP - Ellendale to Big Stone South	\$75,468
9	Ramsey 230/115 kW Transformer Upgrade	\$22,152
10	Karlstad, MN Capacitor Bank Project	\$45,655
11	Oakes Area Transmission Improvements	\$283,372
12	Hankinson Transformer AEBition	\$31,338
13	NERC Compliance	\$624,644
14	Summit Transformer	\$31,832
15	Spiritwood Station Interconnection	\$34,252
16	Rugby to Harvey 115 kV Line Rebuild	\$0
17	Max - Ryder 41.6 kV Line Upgrades	\$70,150
18	Rugby Breaker Station	\$86,456
19	Granville Jct Breaker Station	\$46,968
20	Total Revenue Requirement	\$5,785,887
21	MISO Schedule 26 Expense	5,547,007
22	MISO Schedule 26A Expense	2,853,372
23	SPP Schedule 9 Expense	975,470
24	SPP Schedule 11 Expense	23,070
25	MISO Schedule 9 Revenue	(595,313)
26	MISO Schedule 26 Revenue	(5,372,458)
27	MISO Schedule 37 Revenue	0
28	MISO Schedule 38 Revenue	0
29	MISO Schedule 26A Revenue	(794,911)
30	MISO MVP ARR Revenue	(25,230)
31	Carrying Cost	(125,772)
32	True-Up	(2,604,666)
33	Net Revenue Requirement	\$5,666,458

Class Allocation and Rate Design

Line No.			2017
1	North Dakota Revenue Requirements		\$5,666,458 *
2	Large General Service Class	30.97%	\$1,755,080
3	Controlled Service	2.44%	138,086
4	Lighting	0.89%	50,386
5	All Other Service	65.70%	3,722,906
6	Total		\$5,666,458
7	Large General Service Class	kW	1,268,497
8	Controlled Service	kWh	257,769,496
9	Lighting	kWh	22,754,297
10	All Other Service	kWh	955,869,464
11	Large General Service Class	\$ / kW	1.384
12	Controlled Service	cents / kWh	0.054
13	Lighting	cents / kWh	0.221
14	All Other Service	cents / kWh	0.389

* 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:	2016												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													
2	CAPX 2020: Fargo	271,488	263,762	261,541	261,540	261,418	261,462	262,518	265,319	265,321	265,293	265,295	265,300	3,170,257
3	CAPX 2020: Bemidji	65,039	85,389	61,049	61,049	60,848	61,049	67,585	61,049	61,049	61,049	61,049	61,049	767,256
4	Cass Lake-Nary-Helga-Bemidji	10,056	10,056	10,056	10,137	10,059	10,059	10,059	10,059	10,059	10,059	10,059	10,059	120,776
5	Rugby Wind Interconnection	215	215	215	215	215	215	215	215	215	215	215	215	2,579
6	Casselton – Buffalo 115 kV Project	19,165	19,168	19,173	19,183	19,193	19,220	19,578	19,625	20,148	20,365	20,455	20,502	235,775
7	CAPX 2020: Brookings - Hampton	25,161	24,630	24,500	24,446	24,518	24,441	24,560	25,814	25,814	25,800	25,800	25,800	301,285
8	MVP: Big Stone Area Transmission	2,859	2,859	2,859	2,859	2,859	2,859	2,859	2,859	2,859	2,859	2,859	2,859	34,305
9	MVP: Ellendale to Big Stone South	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	2,198	26,372
10	Ramsey 230/115 kV Transformer Upgrade	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	1,835	22,024
11	Karlstad, MN Capacitor Bank Project	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	45,228
12	Oakes Area Transmission Improvements	24,897	24,945	24,944	24,941	24,919	24,919	24,919	24,919	24,919	24,919	24,919	24,919	299,076
13	Hankinson Transformer Addition	2,592	2,592	2,592	2,592	2,592	2,592	2,592	2,592	2,592	2,592	2,592	2,592	31,108
14	NERC Compliance	47,704	48,792	49,032	49,217	49,329	49,505	49,630	49,706	49,987	51,032	51,143	51,260	596,336
15	Summit Transformer	2,772	2,772	2,772	2,772	2,772	3,114	3,114	3,114	3,114	3,114	3,114	3,114	35,658
16	Spiritwood Station Interconnection	2,931	2,931	2,931	2,931	2,931	2,931	2,931	2,931	2,931	2,931	2,931	2,931	35,171
17	Max- Ryder 41.6 kV Line Upgrades	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Rugby Breaker Station	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	18,831
19	Granville Jct Breaker Station	995	995	995	995	995	995	995	995	995	995	995	995	11,941
20	Total Revenue Requirements	485,245	498,477	472,030	472,248	472,019	472,733	480,926	478,568	479,375	480,595	480,797	480,966	5,753,978
21	MISO & SPP Expenses													
22	MISO Schedule 26 Expense	582,156	485,059	487,784	431,032	400,979	391,458	477,918	423,097	394,118	475,260	521,627	550,606	5,621,093
23	MISO Schedule 26A Expense	234,424	203,473	186,572	166,478	156,311	150,644	162,469	149,210	142,262	150,858	167,356	187,094	2,057,150
24	SPP Schedule 9 Expense	0	0	0	0	337,171	68,234	67,112	67,112	67,112	67,112	67,112	67,112	808,076
25	SPP Schedule 11 Expense	0	0	0	0	6,207	1,242	1,238	1,238	1,238	1,238	1,238	1,238	14,875
26	Total MISO & SPP Expenses	816,580	688,532	674,356	597,510	900,668	611,578	708,737	640,657	604,729	694,467	757,333	806,049	8,501,196
27	MISO Revenues													
28	MISO Schedule 9 Revenue	(116,640)	(104,623)	(96,778)	(89,090)	(62,920)	(75,783)	(77,879)	(97,370)	(97,370)	(97,370)	(97,370)	(97,370)	(1,110,562)
29	MISO Schedule 26 Revenue	(433,210)	(386,057)	(389,321)	(357,911)	(420,887)	(486,815)	(547,967)	(489,672)	(445,882)	(429,908)	(417,311)	(399,732)	(5,204,673)
30	MISO Schedule 37 Revenue	(5,189)	(5,189)	(5,187)	(5,187)	(5,183)	(5,209)	(5,209)	0	0	0	0	0	(36,353)
31	MISO Schedule 38 Revenue	(6,637)	(6,637)	(6,640)	(6,640)	(6,635)	(6,555)	(6,555)	0	0	0	0	0	(46,299)
32	MISO Schedule 26A Revenue	(41,838)	(39,519)	(38,041)	(33,459)	(35,481)	(38,589)	(43,391)	(44,737)	(40,972)	(42,130)	(41,626)	(40,926)	(480,709)
33	MISO MVP ARR Revenue	(2,602)	(2,837)	(2,561)	(1,818)	(1,841)	(1,592)	(590)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(24,353)
34	Total MISO Revenues	(606,116)	(544,863)	(538,528)	(494,105)	(532,948)	(614,543)	(681,591)	(633,881)	(586,326)	(571,510)	(558,409)	(540,130)	(6,902,949)
35	Net Revenue Requirement	695,709	642,145	607,858	575,653	839,740	469,768	508,072	485,344	497,778	603,552	679,721	746,885	7,352,225
36														
37	Billed (forecast kWh x adj factor)	973,403	912,173	845,906	769,063	674,565	678,025	706,896	754,267	752,377	740,128	865,814	980,444	9,653,063
38														
39	Big Stone II True-Up													
40														
41	Difference	(277,694)	(270,028)	(238,048)	(193,410)	165,174	(208,257)	(198,824)	(268,923)	(254,599)	(136,576)	(186,093)	(233,559)	(2,300,838)
42	Carrying Charge	(1,379)	(3,383)	(5,346)	(7,094)	(8,533)	(7,409)	(8,957)	(10,449)	(12,455)	(14,372)	(15,456)	(16,903)	(111,735)
43	Cumulative Difference	(471,166)	(744,577)	(987,971)	(1,188,475)	(1,031,834)	(1,247,500)	(1,455,280)	(1,734,652)	(2,001,706)	(2,152,654)	(2,354,204)	(2,604,666)	(2,604,666)
44														
45	Carrying Charge Calculation	(3,383)	(5,346)	(7,094)	(8,533)	(7,409)	(8,957)	(10,449)	(12,455)	(14,372)	(15,456)	(16,903)	(18,701)	
46	Cumulative Carrying Charge	106,980	101,634	94,540	86,007	78,599	69,642	59,193	46,738	32,366	16,910	7	(18,695)	
47	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%	
48														
49	Forecasted Sales (MWh)	197,116	194,744	173,741	150,344	122,392	112,726	127,296	131,132	130,803	128,673	150,524	170,453	1,789,944
50														
51														
52														
53														

Approved December 16, 2015 (PU-15-661);
 Rate Effective January 1, 2016

SUMMARY	Jan 2016 - Dec 2016
Revenue requirements	\$9,505,989
Carrying Charge	(899)
2015 True-Up	479,463
Total requirements	\$9,984,553
Jan 2016-Dec 2016 projected sales in MWh	1,735,844
Average Rate	\$0.00575

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2017												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													
2	CAPX 2020: Fargo	246,083	246,083	246,083	246,083	246,083	246,083	246,083	246,083	246,083	246,083	246,083	246,083	2,953,001
3	CAPX 2020: Bemidji	58,338	58,338	58,338	58,338	58,338	58,338	58,338	58,338	58,338	58,338	58,338	58,338	700,061
4	Cass Lake-Nary-Helga-Bemidji	9,628	9,628	9,628	9,555	9,555	9,555	9,555	9,555	9,555	9,555	9,555	9,555	114,876
5	Rugby Wind Interconnection	212	212	212	212	212	212	212	212	212	212	212	212	2,544
6	Casselton – Buffalo 115 kV Project	25,413	25,415	25,444	25,478	25,513	25,521	25,590	25,594	25,594	25,594	25,594	25,594	306,343
7	CAPX 2020: Brookings - Hampton	24,477	24,477	24,476	24,477	24,476	24,477	24,476	24,476	24,476	24,476	24,476	24,476	293,717
8	MVP: Big Stone Area Transmission	5,255	5,255	5,255	5,255	5,255	5,255	5,255	5,255	5,255	5,255	5,255	5,255	63,056
9	MVP: Ellendale to Big Stone South	6,289	6,289	6,289	6,289	6,289	6,289	6,289	6,289	6,289	6,289	6,289	6,289	75,468
10	Ramsey 230/115 kV Transformer Upgrade	1,846	1,846	1,846	1,846	1,846	1,846	1,846	1,846	1,846	1,846	1,846	1,846	22,152
11	Karlstad, MN Capacitor Bank Project	3,805	3,805	3,805	3,805	3,805	3,805	3,805	3,805	3,805	3,805	3,805	3,805	45,655
12	Oakes Area Transmission Improvements	23,614	23,614	23,614	23,614	23,614	23,614	23,614	23,614	23,614	23,614	23,614	23,614	283,372
13	Hankinson Transformer Addition	2,612	2,612	2,612	2,612	2,612	2,612	2,612	2,612	2,612	2,612	2,612	2,612	31,338
14	NERC Compliance	52,054	52,054	52,054	52,054	52,054	52,054	52,054	52,054	52,054	52,054	52,054	52,054	624,644
15	Summit Transformer	2,653	2,653	2,653	2,653	2,653	2,653	2,653	2,653	2,653	2,653	2,653	2,653	31,832
16	Spiritwood Station Interconnection	2,854	2,854	2,854	2,854	2,854	2,854	2,854	2,854	2,854	2,854	2,854	2,854	34,252
17	Max- Ryder 41.6 kV Line Upgrades	5,444	5,552	5,633	5,699	5,714	5,845	5,954	6,062	6,062	6,062	6,062	6,062	70,150
18	Rugby Breaker Station	7,115	7,188	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	7,215	86,456
19	Granville Jct Breaker Station	3,914	3,914	3,914	3,914	3,914	3,914	3,914	3,914	3,914	3,914	3,914	3,914	46,968
20	Total Revenue Requirements	481,605	481,789	481,925	481,952	482,002	482,141	482,319	482,431	482,431	482,431	482,431	482,431	5,785,887
21	MISO & SPP Expenses													
22	MISO Schedule 26 Expense	578,416	543,711	514,790	416,459	370,186	404,891	439,596	468,517	462,733	399,107	474,301	474,301	5,547,007
23	MISO Schedule 26A Expense	290,243	261,971	255,152	222,526	211,662	206,616	221,213	222,168	212,097	224,584	248,093	277,048	2,853,372
24	SPP Schedule 9 Expense	81,289	81,289	81,289	81,289	81,289	81,289	81,289	81,289	81,289	81,289	81,289	81,289	975,470
25	SPP Schedule 11 Expense	1,922	1,922	1,922	1,922	1,922	1,922	1,922	1,922	1,922	1,922	1,922	1,922	23,070
26	Total MISO & SPP Expenses	951,870	888,893	853,153	722,197	665,059	694,719	744,020	773,896	758,041	706,902	805,606	834,561	9,398,919
27	MISO Revenues													
28	MISO Schedule 9 Revenue	(49,609)	(49,609)	(49,609)	(49,609)	(49,609)	(49,609)	(49,609)	(49,609)	(49,609)	(49,609)	(49,609)	(49,609)	(595,313)
29	MISO Schedule 26 Revenue	(447,705)	(447,705)	(447,705)	(447,705)	(447,705)	(447,705)	(447,705)	(447,705)	(447,705)	(447,705)	(447,705)	(447,705)	(5,372,458)
30	MISO Schedule 37 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
31	MISO Schedule 38 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
32	MISO Schedule 26A Revenue	(66,243)	(66,243)	(66,243)	(66,243)	(66,243)	(66,243)	(66,243)	(66,242)	(66,242)	(66,242)	(66,242)	(66,242)	(794,911)
33	MISO MVP ARR Revenue	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(2,102)	(25,230)
34	Total MISO Revenues	(565,660)	(565,660)	(565,659)	(565,659)	(565,659)	(565,659)	(565,659)	(565,659)	(565,659)	(565,659)	(565,659)	(565,659)	(6,787,911)
35	Net Revenue Requirement	867,816	805,022	769,419	638,490	581,402	611,201	660,680	690,668	674,813	623,674	722,378	751,332	8,396,895
36	Billed (forecast kWh x adj factor)	606,053	594,018	537,605	492,650	415,700	384,839	398,614	413,675	413,600	405,923	470,949	532,832	5,666,458
37	Big Stone II True-Up													
38	Difference	261,763	211,004	231,814	145,839	165,703	226,362	262,066	276,993	261,213	217,751	251,429	218,501	2,730,437
39	Carrying Charge	(18,701)	(16,956)	(15,563)	(14,010)	(13,064)	(11,968)	(10,428)	(8,622)	(6,695)	(4,867)	(3,339)	(1,558)	(125,772)
40	Cummulative Difference	(2,361,604)	(2,167,556)	(1,951,305)	(1,819,476)	(1,666,837)	(1,452,443)	(1,200,805)	(932,435)	(677,917)	(465,033)	(216,943)	0	0
41	Carrying Charge Calculation	(16,956)	(15,563)	(14,010)	(13,064)	(11,968)	(10,428)	(8,622)	(6,695)	(4,867)	(3,339)	(1,558)	0	
42	Cumulative Carrying Charge	(35,651)	(51,214)	(65,224)	(78,288)	(90,256)	(100,684)	(109,306)	(116,001)	(120,868)	(124,207)	(125,765)	(125,765)	
43	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%	
44	Forecasted Sales (MWh)	195,671	191,786	173,572	159,058	134,213	124,250	128,697	133,560	133,536	131,057	152,051	172,031	1,829,481

SUMMARY	Jan 2017 - Dec 2017
Revenue requirements	\$8,396,895
Carrying Charge	(125,772)
True-Up	(2,604,666)
Total requirements	\$5,666,458
Jan 2017-Dec 2017 projected sales in MWh	1,829,481
Average Rate	\$0.00310

Otter Tail Power Company
North Dakota Transmission Cost Recovery Rider
CAPX2020 Fargo-Monticello Revenue Requirements
Case No. PU-16-

Line No.	Year>>	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	
		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	81,709,762	81,807,792	81,807,363	81,420,955	81,625,128	81,544,408	81,578,540	81,584,215	81,513,747	81,519,338	81,529,915	81,529,915	81,529,915	81,529,915	
2	Accumulated Depreciation	(2,299,598)	(2,407,991)	(2,516,514)	(2,625,037)	(2,733,020)	(2,841,282)	(2,949,422)	(3,057,617)	(3,165,820)	(3,273,930)	(3,382,047)	(3,490,179)	(3,490,179)	(3,490,179)	
3	Net Plant in Service	79,410,163	79,399,801	79,290,848	78,795,919	78,892,109	78,703,127	78,629,118	78,526,598	78,347,927	78,245,408	78,147,868	78,039,736	78,039,736	78,039,736	
4	CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	ADIT - NOL DTA	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	4,047,348	
6	Reversal of ADIT - NOL DTA	(235,550)	(471,099)	(706,649)	(942,199)	(1,177,748)	(1,413,298)	(1,648,847)	(1,884,397)	(2,119,947)	(2,355,496)	(2,591,046)	(2,826,595)	(2,826,595)	(2,826,595)	
7	ADIT Proration Factors	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	1,000.00	0.3370	0.2548	0.1699	0.0877	0.0027	0.0027	
8	Accumulated Deferred Income Taxes Federal & State	(17,642,155)	(17,698,937)	(17,754,991)	(17,785,963)	(17,842,160)	(17,898,652)	(17,955,190)	(17,978,508)	(17,997,710)	(18,012,668)	(18,023,507)	(18,030,091)	(18,030,091)	(18,030,091)	
9	Ending rate base	65,579,807	65,277,452	64,876,557	64,115,506	63,919,549	63,438,525	63,072,428	62,711,041	62,277,619	61,924,592	61,580,663	61,230,398	61,230,398	61,230,398	
11	OTP Load Percentage	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	
12	Remove Non-OTP Load Portion	(17,879,023)	(17,796,592)	(17,687,296)	(17,479,810)	(17,426,387)	(17,295,245)	(17,195,436)	(17,096,911)	(16,978,747)	(16,882,502)	(16,788,736)	(16,693,243)	(16,693,243)	(16,693,243)	
13	Retail Ending Rate Base	47,700,784	47,480,861	47,189,261	46,635,695	46,493,162	46,143,280	45,876,992	45,614,130	45,298,872	45,042,091	44,791,927	44,537,155	44,537,155	44,537,155	
14	Average rate base	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	3,865,221	
16	Return on Rate Base	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	
18	Available for return (equity portion of rate base)	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	
21	EXPENSES															
22	O&M and Depreciation															
23	Operating Costs	33,639	7,534	0	0	131	0	3,638	12,917	12,917	12,917	12,917	12,917	12,917	155,000	
24	Property Tax	120,122	(17,796,592)	120,122	120,122	120,122	120,122	120,122	120,122	120,122	120,122	120,122	120,122	120,122	1,441,468	
25	Book Depreciation	108,032	108,393	108,523	108,522	107,983	108,262	108,140	108,195	108,203	108,110	108,117	108,132	108,132	1,298,613	
26	Total O&M and Depreciation Expenses	261,793	236,049	228,646	228,644	228,236	228,384	231,901	241,234	241,242	241,149	241,156	241,171	241,171	2,895,081	
28	OTP Load Percentage	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	72.737%	
29	Remove Non-OTP Load Portion	(71,373)	(64,354)	(62,336)	(62,335)	(62,242)	(62,264)	(63,223)	(65,768)	(65,770)	(65,744)	(65,746)	(65,750)	(65,750)	(789,286)	
30	Retail O&M and Depreciation Expenses	190,420	171,695	166,310	166,309	166,012	166,120	168,678	175,467	175,472	175,404	175,410	175,420	175,420	2,105,795	
27	Income before Taxes	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	221,455	2,657,460	
29	Available for return (from above)	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	4,272,547	
30	Taxable Income (grossed up)	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	356,046	4,272,547	
31	Income Taxes	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	1,615,087	
33	Current and Def Income Taxes	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	1,615,087	
34	Total Income Tax Expense	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	134,591	1,615,087	
37	REVENUE REQUIREMENTS															
38	Expenses	325,011	306,286	300,901	300,900	300,603	300,710	303,268	310,057	310,063	309,995	310,000	310,011	310,011	3,720,882	
39	Return on rate base	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	333,026	3,996,312	
40	Subtotal revenue requirements	658,037	639,312	633,927	633,926	633,629	633,736	636,294	643,083	643,089	643,021	643,026	643,037	643,037	7,717,193	
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	658,037	639,312	633,927	633,926	633,629	633,736	636,294	643,083	643,089	643,021	643,026	643,037	643,037	7,717,193	
44	North Dakota share - D2 factor	41.26%	271,488	263,762	261,541	261,540	261,418	261,462	262,518	265,319	265,321	265,293	265,295	265,300	3,170,257	
SUPPORTING INFORMATION / DATA																
1	ND Cap Structure with allowed ROE per order.															
2	Capital Structure	Ratio			Cost			WA Cost			Property tax					
3	Debt	43.11%			6.30%			2.72%			2016 composite rate					
4	Preferred equity	3.60%			4.75%			0.17%			1.77%					
5	Common equity	53.30%			10.75%			5.73%								
6	Total	100.00%			8.62%			Overall Return								
7	Project life (years)	Book			Tax											
8		50			15-year MACRS											
9		Effective Tax Rate			Fed Portion			State Portion								
10		37.80%			33.49%			4.31%								
11		Tax conversion factor			Wholesale Revenue Credit											
12		1.60776			0.00%											
13		ND share - D2 factor			41.2573%											
14																
15	Deferred Tax															
16	Book depreciation	108,032	108,393	108,523	108,522	107,983	108,262	108,140	108,195	108,203	108,110	108,117	108,132	108,132	1,298,613	
17	Tax depreciation-Federal	257,706	257,706	257,706	180,607	257,706	257,706	257,706	257,706	257,706	257,706	257,706	257,706	257,706	3,015,372	
18	Tax depreciation-ND	257,706	257,706	257,706	257,706	257,706	257,706	257,706	257,706	257,706	257,706	257,706	257,706	257,706	3,092,471	
19	Federal deferred income taxes	(50,128)	(50,007)	(49,983)	(24,142)	(50,144)	(50,051)	(50,092)	(50,073)	(50,071)	(50,102)	(50,099)	(50,095)	(50,095)	(574,968)	
20	State deferred income taxes	(6,451)	(6,435)	(6,430)	(6,430)	(6,453)	(6,441)	(6,446)	(6,444)	(6,444)	(6,448)	(6,447)	(6,447)	(6,447)	(77,315)	

Line No.	Year>>	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
		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		8,100,737	8,119,614	8,153,969	8,185,700	8,275,646	9,478,060	9,634,795	11,386,525	12,115,567	12,417,249	12,574,719	12,619,860	12,619,860
2		(258,978)	(270,855)	(282,760)	(294,715)	(306,714)	(318,843)	(332,696)	(346,774)	(363,365)	(381,001)	(399,070)	(417,364)	(417,364)
3		7,841,759	7,848,758	7,871,209	7,890,986	7,968,932	9,159,217	9,302,099	11,039,751	11,752,203	12,036,248	12,175,650	12,202,496	12,202,496
4		0	0	0	0	0	0	0	0	0	0	0	0	0
5		(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)	(2,526)
6		147	294	441	588	735	882	1,029	1,176	1,323	1,470	1,617	1,764	1,764
7		1,000	1,000	1,000	1,000	1,000	1,000	1,000	0.3370	0.2548	0.1699	0.0877	0.0027	
8		(1,844,218)	(1,925,119)	(2,006,009)	(2,086,881)	(2,167,735)	(2,248,541)	(2,328,695)	(2,361,730)	(2,388,611)	(2,409,435)	(2,424,494)	(2,433,632)	(2,433,632)
9		5,995,162	5,921,408	5,863,115	5,802,167	5,799,405	6,909,032	6,971,907	8,676,671	9,362,388	9,625,758	9,750,246	9,768,102	9,768,102
OTM and Depreciation														
11		50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%
12		(2,972,941)	(2,936,367)	(2,907,460)	(2,877,237)	(2,875,867)	(3,426,120)	(3,457,299)	(4,302,675)	(4,642,715)	(4,773,317)	(4,835,050)	(4,843,904)	(4,843,904)
12		3,022,221	2,985,041	2,955,655	2,924,930	2,923,538	3,482,912	3,514,608	4,373,997	4,719,674	4,852,441	4,915,197	4,924,198	4,924,198
EXPENSES														
O&M and Depreciation														
22		0	0	0	0	0	0	0	0	0	0	0	0	0
23		5,192	5,192	5,192	5,192	5,192	5,192	5,192	5,192	5,192	5,192	5,192	5,192	62,303
24		11,864	11,878	11,905	11,954	12,000	12,129	13,853	14,078	16,590	17,636	18,069	18,295	170,251
25		17,056	17,070	17,097	17,146	17,192	17,321	19,045	19,270	22,828	23,261	23,487	23,487	232,554
27		50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%
28		(8,458)	(8,465)	(8,478)	(8,503)	(8,525)	(8,589)	(9,444)	(9,556)	(10,802)	(11,320)	(11,535)	(11,647)	(115,321)
29		8,598	8,605	8,619	8,644	8,666	8,731	9,601	9,714	10,981	11,508	11,726	11,840	117,233
Income before Taxes														
32		17,927	17,927	17,927	17,927	17,927	17,927	17,927	17,927	17,927	17,927	17,927	17,927	215,121
33	1.61146	28,822	28,822	28,822	28,822	28,822	28,822	28,822	28,822	28,822	28,822	28,822	28,822	345,863
Income Taxes														
36	37.94%	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	130,741
37		10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	130,741
REVENUE REQUIREMENTS														
41		19,493	19,500	19,514	19,539	19,562	19,627	20,496	20,609	21,876	22,403	22,621	22,735	363,295
42		26,958	26,958	26,958	26,958	26,958	26,958	26,958	26,958	26,958	26,958	26,958	26,958	323,502
43		46,452	46,459	46,472	46,497	46,520	46,585	47,454	47,568	48,834	49,361	49,580	49,693	686,797
44		0	0	0	0	0	0	0	0	0	0	0	0	0
45		0	0	0	0	0	0	0	0	0	0	0	0	0
46		46,452	46,459	46,472	46,497	46,520	46,585	47,454	47,568	48,834	49,361	49,580	49,693	686,797
48	41.26%	19,165	19,168	19,173	19,183	19,193	19,220	19,578	19,625	20,148	20,365	20,455	20,502	235,775

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		Ratio	Cost	WA Cost											Property tax
4		43.11%	6.30%	2.72%											2016 composite rate
5		3.60%	4.75%	0.17%											0.77%
6		53.30%	10.75%	5.73%											
7		100.00%		8.62% Overall Return											
8															
9															
10	Project life (years)														
11		Book	Tax												
12		50	15-year MACRS												
13				Fed Portion	State Portion										
14		Effective Tax Rate	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		11,864	11,878	11,905	11,954	12,000	12,129	13,853	14,078	16,590	17,636	18,069	18,295	170,251	
20		225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	2,710,706	
21		225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	225,892	2,710,706	
22		(71,681)	(71,677)	(71,668)	(71,651)	(71,636)	(71,593)	(71,015)	(70,940)	(70,098)	(69,748)	(69,603)	(69,528)	(850,836)	
23		(9,225)	(9,224)	(9,223)	(9,221)	(9,219)	(9,213)	(9,139)	(9,129)	(9,021)	(8,976)	(8,957)	(8,947)	(109,494)	

Line No.	Year>>	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
		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	26,503,889	26,578,508	26,649,446	26,634,224	26,610,228	26,658,955	26,593,839	26,595,376	26,473,802	26,468,677	26,468,093	26,463,606	26,463,606	
2	Accumulated Depreciation	(686,029)	(722,128)	(758,320)	(794,606)	(830,873)	(867,108)	(903,408)	(939,623)	(975,839)	(1,011,893)	(1,047,940)	(1,083,987)	(1,083,987)	
3	Net Plant in Service	25,817,860	25,856,380	25,891,126	25,839,617	25,779,355	25,791,847	25,690,430	25,655,753	25,497,963	25,456,784	25,420,152	25,379,619	25,379,619	
4	CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	ADIT - NOL DTA	972,831	972,831	972,831	972,831	972,831	972,831	972,831	972,831	972,831	972,831	972,831	972,831	972,831	
6	Reversal of ADIT - NOL DTA	(56,618)	(113,235)	(169,852)	(226,469)	(283,086)	(339,703)	(396,320)	(452,937)	(509,554)	(566,171)	(622,789)	(679,406)	(679,406)	
7	ADIT Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.3370	0.2548	0.1699	0.0877	0.0027	0.0027	
8	Accumulated Deferred Income Taxes Federal & State	(5,279,797)	(5,307,476)	(5,335,119)	(5,362,727)	(5,390,342)	(5,417,969)	(5,445,571)	(5,456,972)	(5,466,361)	(5,473,687)	(5,478,996)	(5,482,222)	(5,482,222)	
9	Ending rate base	21,454,276	21,408,500	21,358,986	21,223,253	21,078,758	21,007,006	20,821,370	20,718,674	20,494,878	20,389,756	20,291,198	20,190,823	20,190,822	
OTL															
11	OTP Load Percentage	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	
12	Remove Non-OTP Load Portion	(17,006,376)	(16,970,090)	(16,930,841)	(16,823,248)	(16,708,710)	(16,651,833)	(16,504,684)	(16,423,279)	(16,245,880)	(16,162,552)	(16,084,427)	(16,004,861)	(16,004,861)	
13	Retail Ending Rate Base	4,447,901	4,438,410	4,428,145	4,400,005	4,370,048	4,355,172	4,316,686	4,295,396	4,248,998	4,227,204	4,206,771	4,185,961	4,185,961	
Average Rate Base															
15	Average rate base	361,078	361,078	361,078	361,078	361,078	361,078	361,078	361,078	361,078	361,078	361,078	361,078	361,078	4,332,938
Return on Rate Base															
17	Return on Rate Base	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	373,324
Available for return (equity portion of rate base)															
19	Available for return (equity portion of rate base)	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	248,253
EXPENSES															
O&M and Depreciation															
23	Operating Costs	9,194	2,519	911	177	1,045	178	1,501	16,250	16,250	16,250	16,250	16,250	195,000	
24	Property Tax	38,629	38,629	38,629	38,629	38,629	38,629	38,629	38,629	38,629	38,629	38,629	38,629	463,543	
25	Book Depreciation	35,637	36,099	36,191	36,287	36,266	36,235	36,301	36,214	36,216	36,054	36,047	36,047	433,595	
26	Total O&M and Depreciation Expense	83,459	77,247	75,731	75,092	75,940	75,042	76,430	91,093	91,095	90,933	90,926	90,925	1,092,138	
OTL															
28	OTP Load Percentage	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	
29	Remove Non-OTP Load Portion	(66,157)	(61,232)	(60,030)	(59,524)	(60,196)	(59,484)	(60,585)	(72,208)	(72,209)	(72,080)	(72,075)	(72,075)	(865,716)	
30	Retail O&M and Depreciation Expenses	17,303	16,015	15,701	15,568	15,744	15,558	15,846	18,885	18,886	18,852	18,851	18,851	226,422	
Income before Taxes															
32	Available for return (from above)	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	20,688	248,253	
34	Taxable Income (grossed up)	33,261	33,261	33,261	33,261	33,261	33,261	33,261	33,261	33,261	33,261	33,261	33,261	399,129	
Income Taxes															
37	Current and Def Income Taxes	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	150,877	
38	Total Income Tax Expense	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	12,573	150,877	
REVENUE REQUIREMENTS															
42	Expenses	29,876	28,588	28,274	28,141	28,317	28,131	28,419	31,458	31,459	31,425	31,424	31,424	1,243,015	
43	Return on rate base	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	31,110	373,324	
44	Subtotal revenue requirements	60,986	59,698	59,384	59,252	59,427	59,241	59,529	62,569	62,569	62,536	62,534	62,534	1,616,339	
45	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0	
46	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	
47	Total revenue requirements	60,986	59,698	59,384	59,252	59,427	59,241	59,529	62,569	62,569	62,536	62,534	62,534	1,616,339	
48	North Dakota share - D2 factor	41.26%													
49		25,161	24,630	24,500	24,446	24,518	24,441	24,560	25,814	25,814	25,800	25,800	25,800	301,285	

Line No.	SUPPORTING INFORMATION / DATA															
1	ND Cap Structure with allowed ROE per order.															
2	Capital Structure															
3	Debt	Ratio	Cost	WA Cost												
4		43.11%	6.30%	2.72%												
5	Preferred equity	3.60%	4.75%	0.17%												
6	Common equity	53.30%	10.75%	5.73%												
7	Total	100.00%		8.62%	Overall Return											
8																
9																
10	Project life (years)															
11		Book	Tax													
12		50	15-year MACRS													
13																
14		Effective Tax Rate	Fed Portion	State Portion												
15		37.80%	33.49%	4.31%												
16		Tax conversion factor	1.60776													
17		Wholesale Revenue Credit	0.00%													
18		ND share - D2 factor	41.2573%													
Deferred Tax																
19	Book depreciation	35,637	36,099	36,191	36,287	36,266	36,235	36,301	36,214	36,216	36,054	36,047	36,047	433,595		
20	Tax depreciation-Federal	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	1,311,832		
21	Tax depreciation-ND	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	109,319	1,311,832		
22	Federal deferred income taxes	(24,677)	(24,522)	(24,492)	(24,460)	(24,466)	(24,477)	(24,455)	(24,484)	(24,483)	(24,538)	(24,540)	(24,540)	(294,135)		
23	State deferred income taxes	(3,176)	(3,156)	(3,152)	(3,148)	(3,149)	(3,150)	(3,147)	(3,151)	(3,151)	(3,158)	(3,158)	(3,158)	(37,852)		

Line No.	Year>>	2017 Projected January	2017 Projected February	2017 Projected March	2017 Projected April	2017 Projected May	2017 Projected June	2017 Projected July	2017 Projected August	2017 Projected September	2017 Projected October	2017 Projected November	2017 Projected December	2017 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	83,131,200	83,131,200
2	Accumulated Depreciation	(9,418)	(9,970)	(10,522)	(11,074)	(11,626)	(12,178)	(12,730)	(13,282)	(13,833)	(14,385)	(14,937)	(15,489)	(15,489)
3	Net Plant in Service	375,383	374,831	374,279	373,727	373,175	372,624	372,072	371,520	370,968	370,416	369,864	83,115,711	83,115,711
4	CWIP	71,270,445	73,410,946	75,509,114	76,700,680	77,849,145	78,821,726	79,643,933	80,261,238	80,816,553	82,437,009	82,627,663	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	(80,212)	(80,478)	(80,720)	(80,941)	(81,137)	(81,312)	(81,463)	(81,590)	(81,696)	(81,777)	(81,837)	(1,994,078)	(1,994,078)
7	Ending rate base	71,565,616	73,705,299	75,802,673	76,993,467	78,141,183	79,113,038	79,934,542	80,551,167	81,105,825	82,725,647	82,915,690	81,121,633	81,121,633
EXPENSES														
19	O&M and Depreciation													
20	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Property Tax	38,766	38,766	38,766	38,766	38,766	38,766	38,766	38,766	38,766	38,766	38,766	38,766	465,189
22	Book Depreciation	552	552	552	552	552	552	552	552	552	552	552	552	6,623
23	Total O&M and Depreciation Expense	39,318	39,318	39,318	39,318	39,318	39,318	39,318	39,318	39,318	39,318	39,318	39,318	471,812
25	Composite OTP Expense Retail Load Percentage	1.510%	1.510%	1.510%	1.510%	1.510%	1.510%	1.510%	1.510%	1.510%	1.510%	1.510%	1.510%	1.510%
26	Remove Non-OTP Load Portion	(38,724)	(38,724)	(38,724)	(38,724)	(38,724)	(38,724)	(38,724)	(38,724)	(38,724)	(38,724)	(38,724)	(38,724)	(464,686)
27	Retail O&M and Depreciation Expenses	594	594	594	594	594	594	594	594	594	594	594	594	7,126
11	Income before Taxes	627	627	627	627	627	627	627	627	627	627	2,729	2,755	13,899
12	Available for return (from above)	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	5,750	69,006
31	Taxable Income (grossed up)	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	110,944
33	Income Taxes													
34	Current and Def Income Taxes	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	41,939
35	Total Income Tax Expense	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	3,495	41,939
REVENUE REQUIREMENTS														
39	Expenses	4,089	4,089	4,089	4,089	4,089	4,089	4,089	4,089	4,089	4,089	4,089	4,089	513,751
40	Return on rate base	8,648	8,648	8,648	8,648	8,648	8,648	8,648	8,648	8,648	8,648	8,648	8,648	103,771
41	Subtotal revenue requirements	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	617,522
42	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
44	Total revenue requirements	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	12,736	617,522
50	North Dakota share - D2 factor	41.26%	41.26%	41.26%	41.26%	41.26%	41.26%	41.26%	41.26%	41.26%	41.26%	41.26%	41.26%	63,056

Line No.	SUPPORTING INFORMATION / DATA
1	ND Cap Structure with allowed ROE per order.
2	Capital Structure
3	Debt
4	Preferred equity
5	Common equity
6	Total
7	
8	
9	
10	Project life (years)
11	
12	
13	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%	2017 composite rate
3.60%	4.75%	0.17%	0.69%
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%	4.31%	
1.60776			
0.00%			
41.2573%			
552	552	552	552
1,371	1,371	1,371	1,371
1,371	1,371	1,371	1,371
(274)	(274)	(274)	(274)
(35)	(35)	(35)	(35)
552	552	552	552
43,443,230	43,443,230	43,443,230	43,443,230
43,443,230	43,443,230	43,443,230	43,443,230
(14,549,605)	(14,549,605)	(14,549,605)	(14,549,605)
(1,872,379)	(1,872,379)	(1,872,379)	(1,872,379)

Line No.	Year>>	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	
		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	10,162,522	10,649,398	11,025,159	11,257,031	11,614,276	11,867,447	12,022,032	12,594,437	14,718,042	14,943,427	15,181,312	15,306,697	15,306,697		
2	Accumulated Depreciation	(110,408)	(125,883)	(142,055)	(158,767)	(175,807)	(193,360)	(211,276)	(229,413)	(248,372)	(270,376)	(292,704)	(315,373)	(315,373)		
3	Net Plant in Service	10,052,114	10,523,516	10,883,104	11,098,264	11,438,469	11,674,087	11,810,756	12,365,023	14,469,670	14,673,051	14,888,608	14,991,324	14,991,324		
CWIP Calculation:																
	Beginning Balance	3,949,630	2,190,721	2,190,721	2,190,721	2,190,721	2,190,721	2,190,721	2,190,721	2,190,721	1	1	1	3,242,020		
	Additional CWIP (NERC Projects)	288,565	486,876	375,761	231,872	357,245	253,171	154,585	572,405	(67,115)	225,385	237,885	125,385			
	Closings from CWIP AFUDC	(2,047,474)	(486,876)	(375,761)	(231,872)	(357,245)	(253,171)	(154,585)	(572,405)	(2,123,605)	(225,385)	(237,885)	(125,385)			
4	CWIP (NERC Compliance Projects)	2,190,721	2,190,721	2,190,721	2,190,721	2,190,721	2,190,721	2,190,721	2,190,721	1	1	1	1	1		
5	ADIT - NOL DTA	924,322	924,322	924,322	924,322	924,322	924,322	924,322	924,322	924,322	924,322	924,322	924,322	924,322		
6	Reversal of ADIT - NOL DTA	(53,794)	(107,588)	(161,382)	(215,176)	(268,970)	(322,764)	(376,558)	(430,352)	(484,146)	(537,940)	(591,734)	(645,528)	(645,528)		
7	ADIT Proration Factors	1,000	1,000	1,000	1,000	1,000	1,000	1,000	0.3370	0.2548	0.1699	0.0877	0.0027			
8	Accumulated Deferred Income Taxes Federal & State	(1,736,976)	(1,861,851)	(1,986,462)	(2,110,870)	(2,235,153)	(2,359,243)	(2,483,195)	(2,534,301)	(2,576,281)	(2,608,659)	(2,632,100)	(2,646,325)	(2,646,325)		
9	Ending rate base	11,376,386	11,669,119	11,850,301	11,887,260	12,049,388	12,107,123	12,066,045	12,515,413	12,333,565	12,450,773	12,589,096	12,623,794	12,623,794		
10																
11	Average rate base	1,005,117	1,005,117	1,005,117	1,005,117	1,005,117	1,005,117	1,005,117	1,005,117	1,005,117	1,005,117	1,005,117	1,005,117	12,061,404		
12																
13	Return on Rate Base	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	1,039,206		
14																
15	Available for return (equity portion of rate base)	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	691,049		
16																
17	EXPENSES															
O&M and Depreciation																
19	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0		
20	Property Tax	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	5,207	62,486		
21	Book Depreciation	12,300	15,474	16,173	16,712	17,040	17,553	17,916	18,138	18,959	22,004	22,328	22,669	217,264		
22	Total O&M and Depreciation Expense	17,507	20,681	21,380	21,919	22,247	22,760	23,123	23,345	24,166	27,212	27,535	27,876	279,750		
23																
24	Income before Taxes															
25	Available for return (from above)	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	57,587	691,049		
26	Taxable Income (grossed up)	92,587	92,587	92,587	92,587	92,587	92,587	92,587	92,587	92,587	92,587	92,587	92,587	1,111,039		
27																
28	Income Taxes															
29	Current and Def Income Taxes	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	419,989		
30	Total Income Tax Expense	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	34,999	419,989		
31																
32																
33	REVENUE REQUIREMENTS															
34	Expenses	52,506	55,681	56,379	56,918	57,246	57,759	58,122	58,344	59,165	62,211	62,534	62,875	699,739		
35	Return on rate base	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	86,601	1,039,206		
36	Subtotal revenue requirements	139,107	142,281	142,979	143,518	143,847	144,360	144,723	144,944	145,765	148,811	149,134	149,476	1,738,946		
37	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0		
38	Wholesale Revenue Credit	(23,481)	(24,017)	(24,135)	(24,226)	(24,268)	(24,368)	(24,429)	(24,467)	(24,605)	(25,120)	(25,174)	(25,232)	(293,537)		
39	Total revenue requirements	115,625	118,264	118,844	119,292	119,565	119,991	120,293	120,478	121,160	123,692	123,960	124,244	1,445,408		
40																
41	North Dakota share - D2 factor	41.26%	47,704	48,792	49,032	49,217	49,329	49,505	49,630	49,706	49,987	51,032	51,143	51,260	596,336	

Line No.	SUPPORTING INFORMATION / DATA															
1	ND Cap Structure with allowed ROE per order.															
2	Capital Structure															
3	Debt	Ratio	Cost	WA Cost												
4	Preferred equity	43.11%	6.30%	2.72%	Property tax											
5	Common equity	3.60%	4.75%	0.17%	2016 composite rate											
6	Total	53.30%	10.75%	5.73%	0.77%											
7		100.00%		8.62%	Overall Return											
8																
9																
10	Project life (years)	Book	Tax													
11		50	15-year MACRS													
12																
13																
14																
15																
16																
17																
18	Deferred Tax															
19	Book depreciation	12,300	15,474	16,173	16,712	17,040	17,553	17,916	18,138	18,959	22,004	22,328	22,669	217,264		
20	Tax depreciation-Federal	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	4,149,829		
21	Tax depreciation-ND	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	345,819	4,149,829		
22	Federal deferred income taxes	(111,701)	(110,637)	(110,404)	(110,223)	(110,113)	(109,941)	(109,820)	(109,745)	(109,470)	(108,450)	(108,342)	(108,228)	(1,317,075)		
23	State deferred income taxes	(14,375)	(14,238)	(14,208)	(14,185)	(14,170)	(14,148)	(14,133)	(14,123)	(14,088)	(13,956)	(13,942)	(13,928)	(169,494)		

Line No.	Year>>	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
		Actual January	Actual February	Actual March	Actual Apr	Actual May	Actual June	Actual July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	1,820,224
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	1,820,224
CWIP Calculation:														
	Beginning Balance	0	0	0	0	0	0	792	156,254	840,185	1,407,782	1,717,423	1,717,423	0
	Additional CWIP	0	0	0	0	0	0	792	155,462	683,930	567,597	309,641	102,801	1,820,224
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	(1,820,224)	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	792	156,254	840,185	1,407,782	1,717,423	0	0
5	ADIT Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.3370	0.2548	0.1699	0.0877	0.0027	0
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	(42,064)	(42,064)
7	Ending rate base	0	0	0	0	0	0	792	156,254	840,185	1,407,782	1,717,423	1,778,160	1,778,160
8														
9	Average rate base	37,824	37,824	37,824	37,824	37,824	37,824	37,824	37,824	37,824	37,824	37,824	37,824	453,892
10														
11	Return on Rate Base	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	39,107
12														
13	Available for return (equity portion of rate base)	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	26,005
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
21														
22	Income before Taxes													
23	Available for return (from above)	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	2,167	26,005
24	Taxable Income (grossed up)	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	3,484	41,810
25														
26	Income Taxes													
27	Current and Def Income Taxes	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	15,805
28	Total Income Tax Expense	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	15,805
29														
30														
REVENUE REQUIRMENTS														
32	Expenses	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	1,317	15,805
33	Return on rate base	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	3,259	39,107
34	Subtotal revenue requirements	4,576	4,576	4,576	4,576	4,576	4,576	4,576	4,576	4,576	4,576	4,576	4,576	54,912
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(772)	(772)	(772)	(772)	(772)	(772)	(772)	(772)	(772)	(772)	(772)	(772)	(9,269)
37	Total revenue requirements	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	3,804	45,643
38														
39	North Dakota share - D2 factor	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	1,569	18,831

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		Ratio	Cost	WA Cost									Property tax	
4	Debt	43.11%	6.30%	2.72%									2016 composite rate	0.77%
5	Preferred equity	3.60%	4.75%	0.17%										
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														
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	16.88%												
17	ND share - D2 factor	41.2573%												
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	0	955,617	955,617
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	955,617	955,617
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(320,051)	(320,051)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(41,187)	(41,187)

Line No.	Year>>	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
		Actual January	Actual February	Actual March	Actual Apr	Actual May	Actual June	Actual July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total
RATE BASE														
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	1,101,004
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	1,101,004
CWIP Calculation:														
	Beginning Balance	0	0	0	0	0	0	1,345	239,345	498,504	871,004	1,056,004	1,056,004	0
	Additional CWIP	0	0	0	0	0	0	1,345	238,000	259,159	372,500	185,000	45,000	1,101,004
	Closings from CWIP	0	0	0	0	0	0	0	0	0	0	0	(1,101,004)	0
	AFDUC	0	0	0	0	0	0	0	0	0	0	0	0	0
4	CWIP (Project #105869)	105869	0	0	0	0	0	1,345	239,345	498,504	871,004	1,056,004	0	0
5	ADIT Proration Factors	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.3370	0.2548	0.1699	0.0877	0.0027	0
6	Accumulated Deferred Income Taxes Federal & State	0	0	0	0	0	0	0	0	0	0	0	(25,443)	(25,443)
7	Ending rate base	0	0	0	0	0	0	1,345	239,345	498,504	871,004	1,056,004	1,075,561	1,075,561
8														
9	Average rate base	23,986	23,986	23,986	23,986	23,986	23,986	23,986	23,986	23,986	23,986	23,986	23,986	287,828
10														
11	Return on Rate Base	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	24,799
12														
13	Available for return (equity portion of rate base)	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	16,491
14														
EXPENSES														
O&M and Depreciation														
17	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
21														
22	Income before Taxes													
23	Available for return (from above)	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	1,374	16,491
24	Taxable Income (grossed up)	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	2,209	26,513
25														
26	Income Taxes													
27	Current and Def Income Taxes	835	835	835	835	835	835	835	835	835	835	835	835	10,022
28	Total Income Tax Expense	835	835	835	835	835	835	835	835	835	835	835	835	10,022
29														
30														
REVENUE REQUIRMENTS														
32	Expenses	835	835	835	835	835	835	835	835	835	835	835	835	10,022
33	Return on rate base	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	2,067	24,799
34	Subtotal revenue requirements	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	2,902	34,822
35	Adjustments	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Wholesale Revenue Credit	(490)	(490)	(490)	(490)	(490)	(490)	(490)	(490)	(490)	(490)	(490)	(490)	(5,878)
37	Total revenue requirements	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	2,412	28,944
38														
39	North Dakota share - D2 factor	995	995	995	995	995	995	995	995	995	995	995	995	11,941

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		Ratio	Cost	WA Cost											
4	Debt	43.11%	6.30%	2.72%											
5	Preferred equity	3.60%	4.75%	0.17%											
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															
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	16.88%													
17	ND share - D2 factor	41.2573%													
18	Deferred Tax														
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	0	578,027	578,027	
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	578,027	578,027	
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(193,590)	(193,590)	
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(24,913)	(24,913)	

2017 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$42,237,169
	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				Wholesale Revenue Credit	14.23%

2016 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$38,565,581
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
2	Account No. 454	(page 4, line 34)	76,025	TP 1.00000	76,025
3	Account No. 456.1	(page 4, line 37)	6,433,914	TP 1.00000	6,433,914
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)				6,509,939
7				Wholesale Revenue Credit	16.88%

		2016													
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 26 Expense	1,411,038	1,175,693	1,182,299	1,044,741	971,900	948,822	1,158,385	1,025,509	955,269	1,151,942	1,264,327	1,334,567	13,624,492	
2	North Dakota share	41.257%	582,156	485,059	487,784	431,032	400,979	391,458	477,918	423,097	394,118	475,260	521,627	550,606	5,621,093
3	MISO Schedule 26A Expense	568,201	493,180	452,215	403,513	378,868	365,133	393,795	361,658	344,816	365,652	405,641	453,481	4,986,153	
4	North Dakota share	41.257%	234,424	203,473	186,572	166,478	156,311	150,644	162,469	149,210	142,262	150,858	167,356	187,094	2,057,150

		2017													
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 26 Expense	1,401,973	1,317,855	1,247,756	1,009,421	897,263	981,381	1,065,499	1,135,598	1,121,578	967,361	1,149,618	1,149,618	13,444,921	
2	North Dakota share	41.257%	578,416	543,711	514,790	416,459	370,186	404,891	439,596	468,517	462,733	399,107	474,301	5,547,007	
3	MISO Schedule 26A Expense	703,495	634,969	618,440	539,362	513,029	500,800	536,179	538,493	514,084	544,349	601,332	671,513	6,916,046	
4	North Dakota share	41.257%	290,243	261,971	255,152	222,526	211,662	206,616	221,213	222,168	212,097	224,584	248,093	277,048	2,853,372

Line No.	2016	2016												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	(1,474,971)	(1,314,428)	(1,325,540)	(1,218,597)	(1,433,016)	(1,657,484)	(1,865,692)	(1,667,212)	(1,518,116)	(1,463,730)	(1,420,841)	(1,360,988)	(17,720,616)
2	Overhead Credit for Non-Retail Share	1.336%	(19,708)	(17,563)	(17,711)	(16,282)	(19,147)	(22,147)	(24,928)	(22,276)	(20,284)	(19,558)	(18,185)	(236,774)
5	Fargo	69.107%	(1,019,308)	(908,362)	(916,041)	(842,136)	(990,314)	(1,145,437)	(1,289,324)	(1,152,160)	(1,049,125)	(1,011,540)	(981,901)	(12,246,186)
6	Retail Load Share		72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	
7	Retail Revenue		(741,414)	(660,715)	(666,301)	(612,545)	(720,325)	(833,157)	(937,816)	(838,047)	(763,102)	(735,764)	(714,205)	(8,907,508)
9	Overhead Credit for Non-Retail Share		(13,620)	(12,137)	(12,240)	(11,252)	(13,232)	(15,305)	(17,227)	(15,395)	(14,018)	(13,516)	(13,120)	(163,628)
10	Non-Retail Load Share		27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	
11	Non-Retail Overhead Credit		(3,713)	(3,309)	(3,337)	(3,068)	(3,607)	(4,173)	(4,697)	(4,197)	(3,822)	(3,685)	(3,577)	(44,610)
13	Total Revenue Credit for Fargo		(745,127)	(664,024)	(669,638)	(615,612)	(723,932)	(837,329)	(942,512)	(842,244)	(766,923)	(739,448)	(717,782)	(8,952,118)
16	Bemidji	15.784%	(232,809)	(207,469)	(209,223)	(192,343)	(226,187)	(261,617)	(294,481)	(263,153)	(239,619)	(231,035)	(224,266)	(2,797,022)
17	Retail Load Share		89.47%	89.47%	89.47%	89.47%	89.47%	89.47%	89.47%	89.47%	89.47%	89.47%	89.47%	
18	Retail Revenue		(208,292)	(185,621)	(187,190)	(172,088)	(202,367)	(234,066)	(263,469)	(235,440)	(214,385)	(206,705)	(200,648)	(2,502,468)
20	Overhead Credit for Non-Retail Share		(3,111)	(2,772)	(2,796)	(2,570)	(3,022)	(3,496)	(3,935)	(3,516)	(3,202)	(3,087)	(2,997)	(37,372)
21	Non-Retail Load Share		10.53%	10.53%	10.53%	10.53%	10.53%	10.53%	10.53%	10.53%	10.53%	10.53%	10.53%	
22	Non-Retail Overhead Credit		(328)	(292)	(294)	(271)	(318)	(368)	(414)	(370)	(337)	(325)	(316)	(3,936)
24	Total Revenue Credit for Bemidji		(208,620)	(185,913)	(187,484)	(172,358)	(202,686)	(234,434)	(263,883)	(235,810)	(214,722)	(207,030)	(200,964)	(2,506,403)
27	Cass Lake - Nary - Helga - Bemidji	6.117%	(90,224)	(80,404)	(81,083)	(74,542)	(87,658)	(101,388)	(114,124)	(101,983)	(92,863)	(89,536)	(86,913)	(1,083,970)
28	Retail Load Share		34.41%	34.41%	34.41%	34.41%	34.41%	34.41%	34.41%	34.41%	34.41%	34.41%	34.41%	
29	Retail Revenue		(31,046)	(27,667)	(27,901)	(25,650)	(30,163)	(34,888)	(39,270)	(35,092)	(31,954)	(30,809)	(29,907)	(372,994)
31	Overhead Credit for Non-Retail Share		(1,206)	(1,074)	(1,083)	(996)	(1,171)	(1,355)	(1,525)	(1,363)	(1,241)	(1,196)	(1,161)	(14,483)
32	Non-Retail Load Share		65.59%	65.59%	65.59%	65.59%	65.59%	65.59%	65.59%	65.59%	65.59%	65.59%	65.59%	
33	Non-Retail Overhead Credit		(791)	(705)	(711)	(653)	(768)	(889)	(1,000)	(894)	(814)	(785)	(762)	(9,500)
35	Total Revenue Credit for Bemidji		(31,837)	(28,372)	(28,611)	(26,303)	(30,931)	(35,776)	(40,270)	(35,986)	(32,768)	(31,594)	(30,668)	(382,494)
27	Rugby	0.342%	(5,044)	(4,495)	(4,533)	(4,168)	(4,901)	(5,669)	(6,381)	(5,702)	(5,192)	(5,006)	(4,859)	(60,605)
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%	
29	Retail Revenue		(5,044)	(4,495)	(4,533)	(4,168)	(4,901)	(5,669)	(6,381)	(5,702)	(5,192)	(5,006)	(4,859)	(60,605)
31	Total Revenue Credit for Rugby		(5,044)	(4,495)	(4,533)	(4,168)	(4,901)	(5,669)	(6,381)	(5,702)	(5,192)	(5,006)	(4,859)	(60,605)
34	Casselton	7.884%	(116,287)	(103,630)	(104,506)	(96,074)	(112,979)	(130,676)	(147,091)	(131,443)	(119,688)	(115,400)	(112,019)	(1,397,093)
35	Retail Load Share		50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	50.41%	
36	Retail Revenue		(58,621)	(52,241)	(52,682)	(48,432)	(56,954)	(65,875)	(74,150)	(66,262)	(60,336)	(58,175)	(56,470)	(704,289)
38	Overhead Credit for Non-Retail Share		(1,554)	(1,385)	(1,396)	(1,284)	(1,510)	(1,746)	(1,965)	(1,756)	(1,599)	(1,542)	(1,497)	(18,667)
39	Non-Retail Load Share		49.59%	49.59%	49.59%	49.59%	49.59%	49.59%	49.59%	49.59%	49.59%	49.59%	49.59%	
40	Non-Retail Overhead Credit		(770)	(687)	(692)	(637)	(749)	(866)	(975)	(871)	(793)	(765)	(742)	(9,257)
42	Total Revenue Credit for Casselton		(59,392)	(52,927)	(53,375)	(49,069)	(57,702)	(66,741)	(75,125)	(67,133)	(61,129)	(58,939)	(57,212)	(713,546)
45	Retail Share of Schedule 26 Revenue		(1,050,020)	(935,731)	(943,641)	(867,510)	(1,020,153)	(1,179,950)	(1,328,171)	(1,186,875)	(1,080,735)	(1,042,017)	(1,011,486)	(12,615,166)
47	North Dakota Share	41.257%	(433,210)	(386,057)	(389,321)	(357,911)	(420,887)	(486,815)	(547,967)	(489,672)	(445,882)	(429,908)	(417,311)	(5,204,673)

Line No.	2016	2016												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	(1,179,064)	(1,113,315)	(1,071,016)	(941,692)	(998,893)	(1,086,557)	(1,220,884)	(1,258,921)	(1,152,991)	(1,185,603)	(1,171,411)	(1,151,531)	(13,531,877)	
2	Overhead Credit for Non-Retail Share	1.336%	(15,754)	(14,876)	(14,310)	(12,582)	(13,347)	(14,518)	(16,313)	(16,821)	(15,406)	(15,841)	(15,652)	(15,386)	(180,807)
3															
4															
5	CAPX 2020 - Brookings	30.170%	(355,719)	(335,883)	(323,121)	(284,105)	(301,362)	(327,810)	(368,336)	(379,812)	(347,853)	(357,692)	(353,410)	(347,412)	(4,082,513)
6	Retail Load Share		20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	
7	Retail Revenue		(73,748)	(69,635)	(66,989)	(58,901)	(62,478)	(67,962)	(76,363)	(78,743)	(72,117)	(74,157)	(73,269)	(72,025)	(846,387)
8															
9	Overhead Credit for Non-Retail Share		(4,753)	(4,488)	(4,317)	(3,796)	(4,027)	(4,380)	(4,922)	(5,075)	(4,648)	(4,779)	(4,722)	(4,642)	(54,549)
10	Non-Retail Load Share		79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	
11	Non-Retail Overhead Credit		(3,768)	(3,557)	(3,422)	(3,009)	(3,192)	(3,472)	(3,901)	(4,023)	(3,684)	(3,788)	(3,743)	(3,680)	(43,240)
12															
13	Total Revenue Credit for CAPX Brookings		(77,515)	(73,193)	(70,412)	(61,910)	(65,670)	(71,434)	(80,265)	(82,765)	(75,801)	(77,945)	(77,012)	(75,705)	(889,626)
14															
15															
16	MVP BS South - Brookings	38.236%	(450,830)	(425,690)	(409,517)	(360,068)	(381,940)	(415,459)	(466,821)	(481,365)	(440,861)	(453,331)	(447,904)	(440,303)	(5,174,089)
17	Retail Load Share		1.494%	1.502%	1.516%	1.524%	1.517%	1.514%	1.530%	1.527%	1.526%	1.526%	1.526%	1.530%	
18	Retail Revenue		(6,733)	(6,393)	(6,206)	(5,486)	(5,793)	(6,288)	(7,141)	(7,348)	(6,729)	(6,918)	(6,835)	(6,735)	(78,607)
19															
20	Overhead Credit for Non-Retail Share		(6,024)	(5,688)	(5,472)	(4,811)	(5,103)	(5,551)	(6,237)	(6,432)	(5,891)	(6,057)	(5,985)	(5,883)	(69,134)
21	Non-Retail Load Share		98.506%	98.498%	98.484%	98.476%	98.483%	98.486%	98.470%	98.473%	98.474%	98.474%	98.474%	98.470%	
22	Non-Retail Overhead Credit		(5,934)	(5,602)	(5,389)	(4,738)	(5,026)	(5,467)	(6,142)	(6,334)	(5,801)	(5,965)	(5,893)	(5,793)	(68,083)
23															
24	Total Revenue Credit for MVP Brookings		(12,667)	(11,996)	(11,595)	(10,223)	(10,819)	(11,755)	(13,283)	(13,682)	(12,530)	(12,883)	(12,728)	(12,529)	(146,691)
25															
26															
27	MVP Ellendale - BS South	31.594%	(372,516)	(351,743)	(338,379)	(297,520)	(315,592)	(343,289)	(385,729)	(397,746)	(364,278)	(374,582)	(370,098)	(363,817)	(4,275,288)
28	Retail Load Share		1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	
29	Retail Revenue		(6,333)	(5,980)	(5,752)	(5,058)	(5,365)	(5,836)	(6,557)	(6,762)	(6,193)	(6,368)	(6,292)	(6,185)	(72,680)
30															
31	Overhead Credit for Non-Retail Share		(4,977)	(4,700)	(4,521)	(3,975)	(4,217)	(4,587)	(5,154)	(5,314)	(4,867)	(5,005)	(4,945)	(4,861)	(57,124)
32	Non-Retail Load Share		98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	
33	Non-Retail Overhead Credit		(4,893)	(4,620)	(4,444)	(3,908)	(4,145)	(4,509)	(5,066)	(5,224)	(4,785)	(4,920)	(4,861)	(4,779)	(56,153)
34															
35	Total Revenue Credit for MVP Ellendale		(11,226)	(10,600)	(10,197)	(8,966)	(9,510)	(10,345)	(11,624)	(11,986)	(10,977)	(11,288)	(11,153)	(10,963)	(128,833)
36															
37															
38	Retail Share of Schedule 26A Revenue		(101,408)	(95,788)	(92,204)	(81,099)	(86,000)	(93,534)	(105,172)	(108,433)	(99,308)	(102,116)	(100,893)	(99,197)	(1,165,150)
39															
40	North Dakota share	41.257%	(41,838)	(39,519)	(38,041)	(33,459)	(35,481)	(38,589)	(43,391)	(44,737)	(40,972)	(42,130)	(41,626)	(40,926)	(480,709)

Line No.	2016	2016												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	(17,206)	(17,206)	(17,198)	(17,198)	(17,186)	(17,270)	(17,270)	0	0	0	0	0	(120,535)
2	Overhead Credit for Non-Retail Share	(230)	(230)	(230)	(230)	(230)	(231)	(231)	0	0	0	0	0	(1,611)
3														
4														
5	Fargo	(17,206)	(17,206)	(17,198)	(17,198)	(17,186)	(17,270)	(17,270)	0	0	0	0	0	(120,535)
6	Retail Load Share	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	
7	Retail Revenue	(12,515)	(12,515)	(12,510)	(12,510)	(12,501)	(12,562)	(12,562)	0	0	0	0	0	(87,673)
8														
9	Overhead Credit for Non-Retail Share	(230)	(230)	(230)	(230)	(230)	(231)	(231)	0	0	0	0	0	(1,611)
10	Non-Retail Load Share	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	
11	Non-Retail Overhead Credit	(63)	(63)	(63)	(63)	(63)	(63)	(63)	0	0	0	0	0	(439)
12														
13	Total Revenue Credit for Fargo	(12,578)	(12,578)	(12,572)	(12,572)	(12,563)	(12,625)	(12,625)	0	0	0	0	0	(88,112)
14														
15														
16	North Dakota Share	(5,189)	(5,189)	(5,187)	(5,187)	(5,183)	(5,209)	(5,209)	0	0	0	0	0	(36,353)
17														
18														
19	Total Schedule 38 Revenue	(22,006)	(22,006)	(22,016)	(22,016)	(22,001)	(21,734)	(21,734)	0	0	0	0	0	(153,514)
20	Overhead Credit for Non-Retail Share	(294)	(294)	(294)	(294)	(294)	(290)	(290)	0	0	0	0	0	(2,051)
21														
22														
23	Fargo	(22,006)	(22,006)	(22,016)	(22,016)	(22,001)	(21,734)	(21,734)	0	0	0	0	0	(153,514)
24	Retail Load Share	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	72.74%	
25	Retail Revenue	(16,007)	(16,007)	(16,014)	(16,014)	(16,003)	(15,809)	(15,809)	0	0	0	0	0	(111,661)
26														
27	Overhead Credit for Non-Retail Share	(294)	(294)	(294)	(294)	(294)	(290)	(290)	0	0	0	0	0	(2,051)
28	Non-Retail Load Share	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	27.26%	
29	Non-Retail Overhead Credit	(80)	(80)	(80)	(80)	(80)	(79)	(79)	0	0	0	0	0	(559)
30														
31	Total Revenue Credit for Fargo	(16,087)	(16,087)	(16,094)	(16,094)	(16,083)	(15,888)	(15,888)	0	0	0	0	0	(112,221)
32														
33														
34	North Dakota Share	(6,637)	(6,637)	(6,640)	(6,640)	(6,635)	(6,555)	(6,555)	0	0	0	0	0	(46,299)

	A	B	C	D
1		Tax Conversion Factor	1.5385	
2		Gross Up of Equity %	8.81%	
3		Equity %	5.73%	
4		Gross Up Factor	3.09%	

		Annual	Monthly
7	Debt Return %	2.72%	0.23%
8	Preferred Equity %	0.17%	0.01%
9	Equity Return %	5.73%	0.48%
10	Rate of Return	8.62%	0.72%
11	Tax RR on Equity Return	3.09%	0.26%
12	Rate Base Rev Req Gross Up Factor	11.70%	0.98%
13	Monthly Gross Up Factor (D12) Multiplied by ND D2 Factor (41.257%)		0.40%

January 2017 - December 2017 Recovery Period					
Month	Original ADIT Balance - All Projects	ADIT Prorate Balance - All Projects	Difference due to ADIT Proration (B - A)	Revenue Requirement Impact C * D12	
18	Jan-17	(\$38,493,989)	(\$38,483,821)	\$10,168	\$41
19	Feb-17	(38,633,459)	(38,603,655)	29,804	120
20	Mar-17	(38,772,787)	(38,712,883)	59,903	241
21	Apr-17	(38,912,001)	(38,811,885)	100,116	403
22	May-17	(39,051,207)	(38,900,403)	150,804	607
23	Jun-17	(39,190,412)	(38,978,782)	211,630	851
24	Jul-17	(39,329,226)	(39,046,499)	282,727	1,137
25	Aug-17	(39,467,952)	(39,103,735)	364,217	1,465
26	Sep-17	(39,606,678)	(39,150,869)	455,810	1,834
27	Oct-17	(39,745,405)	(39,187,564)	557,841	2,244
28	Nov-17	(39,884,131)	(39,214,156)	669,975	2,695
29	Dec-17	(\$56,444,532)	(\$41,142,515)	\$15,302,016	61,559
Total Revenue Requirement Impact					\$73,197

ND Revenue Requirement Adjustment	\$73,197
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Attachment 32
Redline and Clean Versions of
Tariff Sheet ND. 13.07 – Transmission Cost Recovery Rider

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	\$2.406 1.384
Controlled Service	(b)	0.088054 ¢/kWh	N/A
Lighting	(c)	0.399221 ¢/kWh	N/A
All Other Service		0.680389 ¢/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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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	\$1.384
Controlled Service	(b)	0.054 ¢/kWh	N/A
Lighting	(c)	0.221 ¢/kWh	N/A
All Other Service		0.389 ¢/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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Changes to North Dakota's Transmission Cost Recovery Rider

The North Dakota Public Service Commission (PSC) 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, 2017, and are included in the Energy and Renewable Adjustment line item.

	Old rates		New rates		Impact of new rates ⁽¹⁾
Large General Service	\$2.406	per kW	\$1.384	per kW	(\$434.48)/month
Controlled Service	\$0.00088	per kwh	\$0.00054	per kwh	(\$0.45)/month
Lighting	\$0.00399	per kwh	\$0.00221	per kwh	(\$0.16)/month
Residential	\$0.00680	per kwh	\$0.00389	per kwh	(\$2.91)/month
All other service	\$0.00680	per kwh	\$0.00389	per kwh	(\$3.92)/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.