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August 31, 2012

Darrell Nitschke
Public Utilities Division
ND Public Service Commission
600 E. Boulevard, Dept. 408
Bismarck, ND 58505

**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 Application to the North Dakota Public Service Commission ("Commission") for approval of the annual update to its Transmission Cost Recovery Rider ("TCR") 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 agreed to with Commission Staff.

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 218-739-8607 or pbeithon@otpc.com.

Sincerely,

/s/ PETE J. BEITHON
Pete J. Beithon
Manager, Regulatory Recovery

dm
Enclosures
By electronic filing

An Equal Opportunity Employer

1 PU-12-702 Filed 08/31/2012 Pages: 80
2013 TCR rate update - electric rate schedule Section 13.07
Otter Tail Power Company
Pete Beithon

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

Docket No. _____

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 ("OTP or Company") hereby applies to the North Dakota Public Service Commission ("Commission") for approval of an annual rate update for its Transmission Cost Recovery Rider ("TCR") in compliance with NDCC § 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 TCR Order").

In this annual update filing, OTP's TCR rate has been adjusted to reflect the TCR revenue requirements for the next recovery period (calendar year 2013). The update includes the tracker balance estimated for the end of the current period so that no over- or under-recovery of TCR costs occurs (in compliance with Ordering paragraph 6 of the TCR Order). It also includes the costs of new transmission projects that are not currently in base rates and have not previously been included in the Rider. This annual update Application provides detailed information on each of these new projects.

As explained in this Application, for a residential customer using 750 kWh per month the bill impact of this update is an increase of 33 cents per month. For a large general service customer using 425 kW and 225,000 kWh the bill impact of this update is an increase of \$35.70 per month.

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

Bruce Gerhardson
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone (218) 739-8475

C. Title of utility employee responsible for filing

Peter J. Beithon
Manager, Regulatory Recovery
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8607

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

The date of this filing is August 31, 2012. The updated TCR rate has been calculated to take effect as of January 1, 2013.

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

Articles of Incorporation. A certified copy of OTP'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, OTP requests an annual update of its rate schedule, Section 13.07, in compliance with the TCR 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.

OTP's TCR Rider 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. TCR rate update revenue requirement calculations

Attachments 1-4 are, respectively, the Revenue, Revenue Requirements Summary, Rate Design, and Tracker Summary calculations used for OTP's proposed TCR rate update.

Attachments 5 – 16 provide the revenue requirement calculations for each of the transmission projects identified in this filing--both those previously included in OTP's TCR (Attachments 5 and 6) and the new projects for which OTP is requesting TCR recovery (Attachments 7-16).

These calculations have been made in compliance with the Commission's April 5, 2012 TCR Order and they are consistent with how OTP calculated its current TCR rate.

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, 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 OTP's most recent general rate case (Commission Case No. PU-08-862).
- *Depreciation expense.* Depreciation expense is calculated using the Company's latest transmission composite depreciation rate.
- *Property taxes.* The property tax calculation is based on OTP'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.
- *O&M expense.* Annual operation and maintenance (O&M) expense of the 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 once every other year on single pole 115 kV lines. Unscheduled patrols are completed for line sections where an unexplained interruption has occurred. To reduce costs of patrol after an interruption, data from protective relays is used to limit the patrol area. Vegetation management of new lines is typically limited for the first five years, since OTP's construction standard is to remove as many trees as possible and leave low growing brush. 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. OTP has set up transmission O&M accounting projects to track O&M costs specifically related to each line included in the Transmission Rider.
- *Schedule 26 and 26A expenses.* Schedule 26 and Schedule 26A costs for the recovery period appear on lines 16 and 18 of the Tracker Account (Attachment 4), and are shown separately in Attachment 18. These are OTP's retail share of the costs for projects that qualify for regional cost allocation through MISO's Tariff.

- *Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 17 and 19 of the Tracker Account Summary (Attachment 4) and are shown separately on Attachments 19 (Schedule 26) and Attachment 20 (Schedule 26A). These are OTP’s retail share of the revenues derived for OTP’s investments in projects that qualify for regional cost allocation through MISO’s tariff.
- *Revenue credit for administrative and general expenses recovered through MISO tariff for non-retail portion of projects qualifying for regional cost allocation.* OTP has included in these TCR rate update calculations an additional revenue credit (reduction to TCR revenue requirements) to account for reimbursements through MISO’s tariff for administrative and general O & M 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 as may already be recovered through OTP’s current retail rates. The revenue credit is reflected in Attachment 20 and Attachment 21 on the line titled “Overhead Credit for Non-Retail Share” for each project. For this period the percentage is 2.02 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 for MISO tariff Schedules 37 and 38* (Attachment 21). Included in this TCR rate update calculation are two revenue credits to reflect revenues received from MISO pursuant to Schedules 37 and 38 of the MISO tariff. The Schedule 37 revenues represent OTP’s allocation from MISO of contributions MISO required from American Transmission Systems Inc. (ASTI) for transmission investments of MISO transmission owners. ASTI withdrew from MISO on June 1, 2011, to integrate with PJM. The Schedule 38 revenues represent OTP’s allocation of payments from Duke-Ohio (“DEO”) and Duke-Kentucky (“DEK”) that departed MISO on December 31, 2011, yet have an ongoing obligation to pay for MISO projects due to their prior MISO membership. The Schedule 37 revenue credit to the TCR is forecast at \$32,068 for 2013. The Schedule 38 revenue credit to the TCR is forecast at \$46,074, for 2013. Detailed descriptions of these MISO schedules can be found at:

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

C. Projects previously approved for recovery in OTP’s TCR

The Fargo – Monticello and Bemidji – Grand Rapids CAPX 2020 projects were previously approved for inclusion in OTP’s TCR. The retail allocation of costs and revenues for these projects has been updated and carried out through 2013 and is reflected in Attachments 5 and 6.

D. New transmission projects included in the TCR rate update

N.D.C.C. § 49-05-04.3 authorizes an approved TCR 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.” OTP has ten such projects for inclusion in this TCR update, each of which is described in detail below.

Description of Project 1 - Rugby Substation – Attachment 7

A wind farm with a nameplate capacity of 150 MW has been constructed near Rugby, North Dakota. The project has been studied and interconnected through the provisions of the MISO Open Access Transmission Tariff. The project declared commercial operation on December 22, 2009. At the time of commercial operation, the interconnection customer had obtained an off-taker of the energy from the wind farm for only 40 MW of the project, thus allowing them a reduced level of reimbursement for the network upgrades that had been constructed for the project.

To accommodate the interconnection of this wind farm, OTP expanded the existing 230 kV bus at the Rugby substation by adding a new 230 kV breaker with associated equipment and relaying enhancements. The network upgrade cost that OTP has accumulated for upgrades at the Rugby substation is \$394,399. The interconnection customer is credited with an investment of \$394,399.

The network upgrades that were required as a part of this interconnection were funded under an earlier version of the MISO tariff that allowed for 50% reimbursement for network upgrade costs. However, the interconnection customer had only secured a power-purchase agreement for 40 MW of the total 150 MW at the time of commercial operation date (“COD”). Therefore, OTP is only obligated to reimburse the interconnection customer for 50% of the investment based on the portion of the wind farm output under contract to purchase the power at time of COD, which is half of 34.14% (51.1 MW/150 MW), or 17.04%. The end result is that the interconnection customer is paying 82.96% of the annual revenue requirements of OTP’s investment related to this wind farm, with the remaining 17.04% of the annual revenue requirements being requested from OTP ratepayers. The 17.04% OTP ratepayer portion represents supporting an annual revenue requirement of \$6,702, or approximately \$559 per month.

North Dakota’s jurisdictional share of OTP’s revenue requirement, based on the D2 allocation factor of 41.25727%, is \$42,765.

OTP is aware of another small portion of this wind farm (~5 MW) that has been secured under a purchase power agreement with a third party after the commercial operation date. At this time, OTP understands that the excess energy produced by this wind farm is available to the MISO market, with OTP having no contract to receive the energy for load serving purposes.

This project was identified in the 2006 MISO Transmission Expansion Plan (“MTEP06”), as referenced under project number 1462, for purposes of providing Network Upgrades and Interconnection Facilities on OTP’s transmission system in order to maintain transmission system stability and reliability for the interconnection and operation of the Rugby Wind, LLC generating facility.

Description of Project 2 – Casselton – Buffalo 115 kV Project – Attachment 8

The Casselton – Buffalo 115 kV project was approved as a Baseline Reliability Project (“BRP”) within Appendix A of the 2011 MISO Transmission Expansion Plan (“MTEP11”) by the MISO Board of Directors in December of 2011 under project 3481, facility numbers 6432, 6433, and 6434. The project involves the construction of 16 miles of 115 kV line and substation modifications at Buffalo. Transmission planning studies performed by OTP have identified this project as the preferred plan for serving the increased load in eastern North Dakota. MISO confirmed the results of the OTP studies through the MTEP11 process and designated this project as a BRP with regional cost sharing. Along with the Casselton – Buffalo 115 kV line, other underlying upgrades required on the transmission system include replacement of the Buffalo 345/115/41.6 kV transformer and reconductoring a portion of the Mapleton-Sheyenne 115 kV line. These underlying upgrades have been included in the MISO approval for this project.

This project was included in OTP’s most recent North Dakota Ten Year Plan.

Cost recovery for this project will come from the MISO tariff for Baseline Reliability Projects. In conformance with the MISO tariff for regional cost allocation of projects under 345 kV, 100% of this project was allocated based on the method of using Line Outage Distribution Factors (“LODF”). Through the MTEP11 process, the OTP pricing zone received 96.5% of the costs for this project. OTP load represents approximately 53% of the total load in the OTP pricing zone. Total project capital costs are \$12,754,169.

North Dakota’s jurisdictional share of OTP’s total capital costs (by the end of construction), based on the D2 allocation factor of 41.25727% and a retail share of 51.02%, is \$2,684,684.

Description of Project 3 – Brookings, SD – Hampton, MN 345 kV Line – Attachment 9

As part of the 2011 MISO Transmission Expansion Plan (“MTEP11”) approval, the MISO Board of Directors endorsed a portfolio of transmission projects across the MISO footprint called the Multi-Value Projects (“MVPs”). The MVPs have been identified and recommended to meet public policy requirements within the MISO states through 2026. The MVPs are “priority projects,” which stem from the Regional Generator Outlet Study (“RGOS”) in collaboration with the Upper Midwest Transmission Development Initiative (“UMTDI”).

The MVP portfolio approved by the MISO Board of Directors includes 18 distinct transmission projects across MISO, with OTP being involved in three of these projects, namely: Brookings – Hampton 345 kV line, Big Stone – Ellendale 345 kV line, and Big Stone – Brookings 345 kV line.

This is part of a project which was granted an Advanced Determination of Prudence on November 10, 2011, in Commission Case No. PU-09-676. OTP is planning to be a 4.1% owner of this project with an estimate total investment of \$27,968,054 over the construction period, which runs through 2015.

North Dakota's jurisdictional share of OTP's total capital costs (by the end of construction), based on the D2 allocation factor of 41.25727% and a retail load share of 21.25%, is \$2,452,007.

Description of Project 4 – Big Stone South to Brookings – Attachment 10

Attachment 10 includes two projects. One project is the Big Stone South to Brookings and the other project is the Big Stone South substation, which includes two 230 kV lines connecting Big Stone Plant to the new substation. Since the substation is closely related to the Big Stone South to Brookings project, we included the costs in a single attachment.

The first project included in Attachment 10 is one on which OTP is working closely with Xcel Energy ("XCEL") to develop the new 345 kV MVP transmission project that will be from Big Stone South to Brookings. This project is envisioned to be approximately 65 miles long and terminate at the existing Brookings County substation owned by Xcel Energy. OTP is planning to own 50% of the project. Major components of the project will involve the 345 kV line itself, as well as a new termination at the Big Stone South substation and the Brookings County substation. The schedule for this project is under development with the in-service date currently anticipated to be in 2017.

The Big Stone South – Brookings 345 kV project will help deliver low-cost generation resources from western MISO to other parts of the MISO footprint. Therefore, this project is scheduled to be completed after the Brookings – Hampton 345 kV project.

The second project included in Attachment 10 is as mentioned above, the new Big Stone 345 substation. Two 345 kV projects approved in the 2011 MISO Transmission Expansion Plan ("MTEP11") connect in the vicinity of Big Stone, South Dakota, namely Big Stone South – Ellendale 345 kV and Big Stone South – Brookings 345 kV. To facilitate the development of these two MVPs, it is necessary to develop a new 345 kV switchyard near Big Stone. After a review of the existing Big Stone 230/115 kV substation, it has become evident that physical limitations at the site will not allow for an adequate expansion for these future 345 kV terminations and transformers. Therefore, OTP is planning to build a new "Big Stone South" substation approximately 1.5 miles south of the existing Big Stone substation. The new Big Stone South substation and the existing Big Stone substation (i.e. "Big Stone Plant") are planning to be connected by two 230 kV lines to electrically connect the Big Stone Plant substation to the Big Stone South substation. The Big Stone South substation is planning to include two new 345/230 kV transformers and adequate space for the new 345 kV terminals into and out of the Big Stone area, with room for future expansion. The existing Big Stone Plant substation will also require minor modifications to accommodate the additional 230 kV terminations for the new 230 kV lines down to the Big Stone South substation. The new 345 kV lines into and out of the Big Stone area (Ellendale and Brookings) will terminate at the new Big Stone South substation. This configuration was included within the models that were used by MISO in studying the MVPs during MTEP11.

The MVPs being developed in the Big Stone area include three distinct projects, which are Big Stone Plant – Big Stone South 230 kV; Big Stone South – Ellendale 345 kV; and Big Stone South – Brookings 345 kV. The Big Stone Plant – Big Stone South 230 kV portion of the project is viewed as the first critical development in the Big Stone area in order to develop the

new 345 kV lines that emanate from Big Stone. OTP's total expected capital costs for the Big Stone Plant – Big Stone South 230 kV portion of the project are \$49,138,876 by the end of construction in 2017. OTP's total expected capital costs of the Big Stone South to Brookings 345 kV portion of the project are \$84,413,294 by the end of construction in 2017. OTP's total capital costs for the two related projects are \$133,552,171 by the end of construction in 2017.

These projects were discussed in OTP's most recent North Dakota Ten Year Plan.

This is part of a project which was granted an Advanced Determination of Prudence on November 10, 2011, in Case No. PU-09-676. The terms of the settlement section 4.b., approved in the final Order in that case, have been met.

North Dakota's jurisdictional share of OTP's total capital costs (by the end of construction), based on the D2 allocation factor of 41.25727% and a retail load share of 1.70%, is \$ \$936,700.

Description of Project 5 – Big Stone South – Ellendale, ND 345 kV Line – Attachment 11

OTP is working collaboratively with Montana-Dakota Utilities (“MDU”) to develop one of the new 345 kV MVP transmission projects that will extend from Big Stone South to Ellendale. This project is in the early stages of development, but is envisioned to be approximately 150 miles long and terminate at an expanded Ellendale substation in south central North Dakota. OTP is planning to own 50% of the project. Major components of the project will involve a new substation expansion at Ellendale, performed and owned by MDU, the 345 kV line itself, as well as a new termination at the Big Stone South substation. The schedule for this project is under development with the in-service date currently anticipated to be in 2019. The Big Stone South – Ellendale 345 kV project is viewed as the westernmost segment of 345 kV lines being developed through the MVP portfolio. Therefore, this segment of line is scheduled to be completed after other major west-east transmission lines are completed to allow the efficient delivery of low cost generation resources from the western portion of the MISO footprint. OTP's total expected capital costs for the Big Stone South to Ellendale, ND 345 kV portion of the project are \$150,486,418 by the end of construction in 2019.

This project was included in OTP's most recent North Dakota Ten Year Plan.

North Dakota's jurisdictional share of OTP's total capital costs (by the end of construction), based on the D2 allocation factor of 41.25727% and a retail load share of 1.70%, is \$1,055,472.

The 2011 MISO Transmission Expansion Plan includes details about this project under number 2220.

Description of Project 6 – Ramsey 230/115 kV Transformer Upgrade - Attachment 12

Interconnection studies performed by Minnkota Power Cooperative (“MPC”) for the Langdon wind farm identified the need to upgrade the Ramsey 230/115 kV transformer near Devils Lake, North Dakota. The Ramsey 230/115 kV transformer is owned by Great River Energy (“GRE”) and is currently rated at 84 MVA. To allow for an expedited interconnection of the Langdon wind farm in 2008, discussions between MPC, GRE, OTP, and the interconnection customers

resulted in the installation of a Special Protection Scheme (“SPS”) at the Ramsey substation to protect the Ramsey 230/115 kV transformer from overloading. This SPS consists of a relaying scheme that opens specific circuit breakers on the transmission system to eliminate excessive flows on the system, while still maintaining reliable service to customers.

GRE has informed OTP and the other interconnection customers that GRE’s guidelines for Special Protection Schemes on its system allow for a five-year timeframe in which such a protection scheme may operate. Therefore, GRE is planning to retire the SPS that is currently in place to protect the Ramsey 230/115 kV transformer in 2013. As a result, OTP and the other interconnection customers will be required to upgrade the existing 230/115 kV transformer at Ramsey.

Detailed engineering studies are underway within GRE at this time to estimate the costs of replacing this existing 230/115 kV transformer with either a 140 MVA transformer or a 187 MVA transformer. OTP and the other Langdon wind interconnection customers are obligated to pay for the transformer upgrade; however, if the final studies require a larger sized transformer (i.e. 187 MVA), there will be some additional load-serving benefits in the area. Therefore, a small increment of costs will be allocated to OTP and MPC, the utilities with load-serving obligations in the area, in proportion to their loads in the Devils Lake area. The transformer is expected to be ordered in 2012 and installed in 2013.

OTP’s allocation of the expected capital costs for this upgrade, based on the ownership percentage in the Langdon wind farm and the amount of OTP’s load in the Devils Lake area, is estimated to be \$608,421 in total, with a construction period running through 2013.

North Dakota’s jurisdictional share of OTP’s total capital costs (by the end of construction), based on the D2 allocation factor of 41.25727%, is \$251,018.

This project is currently within Appendix A of the 2012 MISO Transmission Expansion Plan (“MTEP”) as project 2738, facility 4761. This project is expected to be approved by the MISO Board of Directors as an Appendix A project in December of 2012. This project is not eligible for MISO regional cost allocation since the upgrade is being triggered through MPC’s Open Access Transmission Tariff (“OATT”).

Description of Project 7 – Sheyenne – Audubon 230 kV Line Upgrade – Attachment 13

Interconnection studies performed by Minnkota Power Cooperative (“MPC”) for the Luverne and Ashtabula wind farms have identified the need to upgrade the Sheyenne – Audubon 230 kV line. This transmission line is co-owned by Xcel Energy and OTP, with OTP owning approximately 96% of the line. Detailed engineering studies performed by OTP have identified that numerous structures along the existing 230 kV line will need to be modified in order to increase the line-to-ground clearance and, thus, the capacity of this line. In order to allow interconnection of the wind farms in an expedited manner, and to determine the status of other pending projects under development at the time of the interconnection studies, a temporary wind-adjusted rating methodology was implemented in mid-2009 to prevent this transmission line from overloading during real-time operating conditions. OTP’s guidelines for wind-adjusted ratings allows for a five-year timeframe. The sunset date of the five-year timeframe for the

wind-adjusted ratings of the Sheyenne – Audubon 230 kV line will expire in mid-2014. Due to the length of this line and the anticipated schedule to complete the necessary upgrades, investments for this 230 kV line upgrade are expected to begin in 2012 in order to meet a mid-2014 in-service date. This project is a result of the generation interconnection to the MPC transmission system and will be funded by OTP and the other interconnection customers.

This project was included in OTP's most recent North Dakota Ten Year Plan.

OTP's allocation of the expected capital costs for this upgrade, based on the ownership percentage in the wind farms interconnecting to the MPC system, is estimated at \$1,247,282 in total, with a construction period running through 2013.

North Dakota's jurisdictional share of OTP's total capital costs (by the end of construction), based on the D2 allocation factor of 41.25727%, is \$514,595.

This project currently resides within Appendix B of the MISO Transmission Expansion Plan ("MTEP") as project 3204, facility 5950. This project is expected to move into MTEP Appendix A during the 2013 MTEP planning cycle, which starts in September of 2012. This project is not eligible for MISO cost allocation since the upgrade is being triggered through the Open Access Transmission Tariff ("OATT") of MPC.

Description of Project 8 – Karlstad, MN Capacitor Bank Project – Attachment 14

Transmission planning studies performed by OTP and neighboring utilities have identified load serving concerns in the northern Red River Valley dating back to 2003. These load serving concerns were in part addressed by the CAPX Group 1 transmission projects currently under construction. However, information OTP has received about future load growth in the area has prompted additional studies. More recent transmission planning studies of this area reflecting possible load growth patterns have identified a long-term transmission plan for northwest Minnesota. The first phase of this transmission plan is to install two 10 MVAR capacitor banks on the 115 kV system at the Karlstad substation. This capacitor bank will help support voltages in northwest Minnesota for critical contingencies on the 115 kV system. This capacitor bank will need to be supplemented with a new Winger – Thief River Falls 230 kV line, which is envisioned to be the long-term transmission plan for this region. The capacitor banks project was originally targeted for installation in 2011, but was delayed after reviewing recent load patterns in northwest Minnesota. Recent operational studies have indicated the transmission system will need this voltage support prior to the winter of 2012/2013 based on historic loading patterns.

OTP's expected capital cost associated with this project is estimated to be \$1,043,219, all of which will be incurred in 2012.

North Dakota's jurisdictional share of OTP's total capital costs, based on the D2 allocation factor of 41.25727%, is \$430,404.

This project was approved by MISO as an Appendix A project during the 2010 MISO Transmission Expansion Plan ("MTEP10") as MTEP project 2826, facility 4956. This capacitor

bank project was not regionally cost allocated through MISO's tariff due to it not meeting the \$5 million cost threshold (a MISO tariff requirement for regional cost allocation). The investment will qualify towards investment credit in the MPC/OTP Integrated Transmission Agreement once it is in service.

Description of Project 9 – Oakes Area Transmission Improvements – Attachment 15

OTP has collaborated with Central Power Electric Cooperative ("CPEC") to develop the preferred transmission plan for serving the joint load in this area. The recommended plan involves the following key components:

- 230/41.6 kV Transformer
- 8 Miles of 41.6 kV Transmission Line
- 4 – 230 kV Circuit Breakers
- 4 – 41.6 kV Circuit Breakers
- 1 – 1800 KVAR Capacitor Bank

Load in this area has shown sustained growth over the past ten years leading to the existing transmission system becoming insufficient during certain times of the year. In addition to improving the adequacy of the transmission system, this project will also add sectionalizing capability along the existing Ellendale – Hankinson 230 kV line and will help minimize momentary and sustained interruptions to Oakes and Forman area customers. The Ellendale – Oakes – Forman – Hankinson 230 kV line is a portion of one of the few east-west 230 kV paths connecting low-cost generation resources from western North Dakota to Minnesota and South Dakota. OTP's estimated capital costs for this project by the end of the construction period in 2013 are expected to be \$5,998,219

This project was included in OTP's most recent North Dakota Ten Year Plan.

North Dakota's jurisdictional share of OTP's total capital costs (by the end of construction), based on the D2 allocation factor of 41.25727%, is \$2,474,700.

This project is expected to be approved as an Appendix A project by the MISO Board of Directors in December of 2012 through the MTEP12 efforts. The Oakes area transmission project is referenced in MTEP project 3658, facility numbers 6817, 6818, and 6819. This project is not eligible for regional cost allocation through MISO's tariff due to the 230 kV portion of the project not meeting the \$5 million threshold for regional allocation.

Description of Project 10 – Hankinson Transformer Addition – Attachment 16

OTP and Central Power Electric Cooperative ("CPEC") are working on a joint reliability project near Hankinson, North Dakota. This project involves the addition of a second 230/41.6 kV transformer, an expansion of the 230 kV and 41.6 kV buses at the Hankinson substation, and the replacement of a 230 kV circuit switcher with a 230 kV circuit breaker. This project is needed to enhance the reliability of the system by installing duplicate 230 kV deliveries to the 41.6 kV system and introducing new interrupting capabilities for 230 kV line faults. OTP's portion of

this project involves the 230 kV ring bus, while CPEC is focused on the installation of the second 230/41.6 kV transformer and the 41.6 kV bus expansion. OTP's capital costs for the 230 kV portion of the substation are \$877,358 with construction completed in 2012.

This project was included in OTP's most recent North Dakota Ten Year Plan.

North Dakota's jurisdictional share of OTP's total capital costs (by the end of construction), based on the D2 allocation factor of 41.25727%, is \$361,974.

This project is expected to be approved as an Appendix A project by the MISO Board of Directors in December of 2012 through the MTEP12 efforts. The Hankinson transformer addition is referenced in MTEP project 3431, facility 6327. This project is not eligible for regional cost allocation through MISO's tariff due to OTP's portion of the project not meeting the \$5 million cost threshold, but this investment will qualify towards investment credit in the CPEC /OTP Integrated Transmission Agreement once it is in service.

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, TCR Order. Specifically, the class allocations use the transmission demand allocation factor, D2, from OTP's most recent North Dakota general rate case (Case No. PU-08-862) to allocate total revenue requirements to jurisdictions (North Dakota, 41.25727%) 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 ($\text{\$/kWh}$) for all other customers. The rate design detail is included in Attachment 3.

V. RATE APPLICATION AND IMPACT

The total 2013 revenue requirements, as shown on line 1 in Attachment 3, are \$3,462,318. The proposed rates are then calculated on lines 2-14 of Attachment 3.

The Transmission Rider is applicable to electric service under all of OTP'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 are as follows:

<u>Class</u>	<u>\\$/kWh</u>
Large General Service	\$0.869/KW
Controlled Service	0.035¢
Lighting	0.136¢
All other service	0.249¢

The estimated increase for a residential customer using 750 kWh would be 750 times \$0.00044 or \$0.33 (33 cents) per month. The following table shows the estimated rate increase over the previous rate by individual rates:

	kWh	kW	Customers	Average kWh's	Current Rate	Proposed Rate	Change in Rate	Impact
Large General Service	610,545,142	425	226	225,000	\$0.78500	\$0.86900	\$0.08400	\$35.70
Controlled Service	251,779,515		15,691	1,300	\$0.00031	\$0.00035	\$0.00004	\$0.05
Lighting	22,386,895		21,109	90	\$0.00113	\$0.00136	\$0.00023	\$0.02
All Other	917,879,493		56,664	1,350	\$0.00205	\$0.00249	\$0.00044	\$0.59
	1,802,591,045							

The proposed rates are based on the assumption that they will be in effect beginning January 1, 2013 through December 31, 2013. Revenue requirement calculations are based on January 2012 through December 2013 costs. If the effective date is significantly later than January 1, 2013, OTP requests the option to recalculate the Transmission Cost Recovery Rates in order to recover all approved costs in the remainder of the suggested time period.

VI. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE

OTP's redline and clean update to the Transmission Cost Recovery Rider (Rate Designation 13.07) is Attachment 22 to this Application.

VII. FILING FEE

As allowed under N.D.C.C. § 49-05-04.3, Subd. 2.d, and based on discussions with Commission Staff, OTP has included a reduced 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

OTP has included on the September bills to its North Dakota customers, a notice of the proposed change in rates for the transmission rider.

IX. CONCLUSION

For the foregoing reasons, OTP respectfully requests approval to implement this update to its Transmission Cost Recovery Rider, Rate Designation 13.07, effective as of January 1, 2013.

Date: August 31, 2012

Respectfully submitted:

OTTER TAIL POWER COMPANY

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Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Summary
Attachment 5	CAPX Fargo-Monticello Revenue Requirements Calculation
Attachment 6	CAPX Bemidji-Grand Rapids Revenue Requirements Calculation
Attachment 7	Rugby Wind Interconnection Revenue Requirements Calculation
Attachment 8	Casselton-Buffalo 115 kV Project Revenue Requirements Calculation
Attachment 9	CAPX Brookings, SD-Hampton, MN Revenue Requirements Calculation
Attachment 10	MVP BSAT to BSS Brookings Revenue Requirements Calculation
Attachment 11	MVP Big Stone South to Ellendale Revenue Requirements Calculation
Attachment 12	Ramsey 230/115 kV Transformer Revenue Requirements Calculation
Attachment 13	Sheyenne-Audubon 230 kV Line Revenue Requirements Calculation
Attachment 14	Karlstad, MN Capacitor Bank Project Revenue Requirements Calculation
Attachment 15	Oakes Area Transmission Revenue Requirements Calculation
Attachment 16	Hankinson Transformer Addition Revenue Requirements Calculation
Attachment 17	Attachment O Revenue Credit Calculation for Non-MISO Projects
Attachment 18	MISO Schedule 26 and 26A Expense
Attachment 19	MISO Schedule 26 Revenue
Attachment 20	MISO Schedule 26A Revenue
Attachment 21	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 22	Electric Rate Schedule Section 13.07 Redline and Clean

Projected Revenue for 2013

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,234,227 kW	\$0.869	\$1,072,389
2					
3	Controlled Service	(b)	238,842,389 kWh	0.035¢	\$84,373
4					
5	Lighting	(c)	22,596,706 kWh	0.136¢	\$30,787
6					
7	All other service		914,768,227 kWh	0.249¢	\$2,274,769
8					
9	Total revenue				<u>\$3,462,318</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	2013
1	CAPX 2020 - Fargo	\$2,042,019
2	CAPX 2020 - Bemidji	\$831,125
3	CAPX 2020 - Brookings	\$2,765
4	Rugby Wind Interconnection	\$158,220
5	MVP - Big Stone South to Brookings	\$3,881
6	MVP - Ellendale to Big Stone South	\$2,672
7	Ramsey 230/115 kW Transformer Upgrade	\$22,927
8	Sheyenne – Audubon 230 kV Line Upgrade	\$24,986
9	Karlstad, MN Capacitor Bank Project	\$46,100
10	Oakes Area Transmission Improvements	\$174,940
11	Casselton – Buffalo 115 kV Project	\$141,988
12	Hankinson Transformer Addition	\$36,375
13	MISO Schedule 26 Expense	4,377,809
14	MISO Schedule 26 Revenue	(4,847,644)
15	MISO Schedule 37 Revenue	(32,068)
16	MISO Schedule 38 Revenue	(46,074)
17	MISO Schedule 26A Expense	49,509
18	MISO Schedule 26A Revenue	(236,207)
19	Carrying Cost	40,454
20	2011-2012 True-Up	668,540
21	Total	<u>\$3,462,318</u>

Class Allocation and Rate Design

Line No.			2013
1	Total North Dakota Revenue Requirements		\$3,462,318 *
2	Large General Service Class	30.97%	\$1,072,389
3	Controlled Service	2.44%	84,373
4	Lighting	0.89%	30,787
5	All Other Service	65.70%	<u>2,274,769</u>
6	Total		\$3,462,318
7	Large General Service Class	kW	1,234,227
8	Controlled Service	kWh	238,842,389
9	Lighting	kWh	22,596,706
10	All Other Service	kWh	914,768,227
11	Large General Service Class	\$ / kW	0.869
12	Controlled Service	cents / kWh	0.035
13	Lighting	cents / kWh	0.136
14	All Other Service	cents / kWh	0.249

* Jurisdictional transmission allocation factor (D2 = 47.89%) is from Otter Tail's last general rate case in North Dakota.

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2012												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	81,984	81,984	81,984	81,984	83,200	83,200	83,200	83,200	83,163	83,163	83,163	83,163	993,392
2	CAPX 2020 - Fargo	54,381	54,381	54,381	54,381	54,381	54,381	54,381	54,381	60,860	63,775	63,775	64,557	688,013
3	Rugby Wind Interconnection	233	233	233	233	233	233	233	233	233	233	233	233	2,799
4	CAPX 2020 - Brookings - Hampton	3,314	3,314	3,314	3,314	3,314	3,314	3,314	3,314	3,314	3,314	3,314	3,314	39,763
5	MVP - Big Stone South to Brookings	145	145	145	145	145	145	145	145	145	145	145	145	1,743
6	MVP - Ellendale to Big Stone South	25	25	25	25	25	25	25	25	25	25	25	25	295
7	Ramsey 230/115 kW Transformer Upgrade	619	619	619	619	619	619	619	619	619	619	619	619	7,434
8	Sheyenne - Audubon 230 kV Line Upgrade	475	475	475	475	475	475	475	475	475	475	475	475	5,697
9	Karlstad, MN Capacitor Bank Project	846	846	846	846	846	846	846	846	846	846	1,292	1,400	11,154
10	Oakes Area Transmission Improvements	725	725	725	725	725	725	725	725	822	822	822	822	9,082
11	Casselton - Buffalo 115 kV Project	809	809	809	809	809	809	809	809	809	809	809	809	9,709
12	Hankinson Transformer Addition	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,776	1,776	16,651
13	Total Revenue Requirements	144,866	144,866	144,866	144,866	146,082	146,082	146,082	146,082	152,621	155,536	156,448	157,337	1,785,732
14														
15	MISO Expenses & Revenues													
16	MISO Schedule 26 Expense	104,724	244,383	219,733	204,462	161,166	169,348	195,315	232,105	244,531	243,734	198,081	212,383	2,429,965
17	MISO Schedule 26 Revenue	(83,508)	(214,180)	(189,274)	(200,516)	(175,821)	(219,013)	(264,678)	(230,290)	(230,290)	(230,290)	(230,290)	(230,290)	(2,498,440)
18	MISO Schedule 37 Revenue	0	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(2,564)	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(29,282)
19	MISO Schedule 38 Revenue	0	(3,839)	(3,839)	(3,839)	(3,839)	(3,839)	(4,355)	(3,839)	(3,839)	(3,839)	(3,839)	(3,839)	(42,742)
20														
21	MISO Schedule 26A Expense	0	4,269	3,182	3,698	3,875	2,986	0	4,126	4,126	4,126	4,126	4,126	38,639
22	MISO Schedule 26A Revenue	0	(4,474)	(3,819)	(3,948)	(3,570)	(3,756)	(4,212)	(4,367)	(4,367)	(4,367)	(4,367)	(4,367)	(45,614)
23	Net MISO Expenses & Revenues	21,216	23,488	23,312	(2,814)	(20,861)	(56,945)	(80,495)	(4,937)	7,489	6,692	(38,961)	(24,659)	(147,475)
24														
25	Net Revenue Requirement	166,082	168,354	168,177	142,052	125,221	89,137	65,587	141,144	160,111	162,228	117,486	132,678	1,638,257
26														
27	Billed (forecast kWh x adj factor)	0	0	0	0	206,579	202,034	224,142	208,353	207,500	204,876	236,359	275,902	1,765,744
28														
29	Difference	166,082	168,354	168,177	142,052	(81,358)	(112,897)	(158,555)	(67,208)	(47,389)	(42,649)	(118,872)	(143,224)	(127,487)
30	Carrying Charge	5,072	6,301	7,555	8,817	9,900	9,387	8,644	7,567	7,139	6,850	6,593	5,787	5,787
31	Cummulative Difference	877,570	1,052,224	1,227,957	1,378,826	1,307,368	1,203,857	1,053,946	994,306	954,055	918,257	805,977	668,540	668,540
32														
33	Carrying Charge Calculation	6,301	7,555	8,817	9,900	9,387	8,644	7,567	7,139	6,850	6,593	5,787	4,800	89,340
34	Cumulative Carrying Charge	41,908	49,463	58,280	68,180	77,567	86,211	93,778	100,917	107,767	114,361	120,147	124,948	
35	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%	
36														
37														
38	Forecasted Sales (MWh)								129,350	128,821	127,192	146,737	171,286	1,788,497

Approved Rate Effective May 1, 2012

SUMMARY	Jan 2011 - Dec 2012
Revenue requirements	\$2,599,182
Carrying Charge	75,037
Total requirements	\$2,674,219
Feb 2012-Dec 2012 projected sales in MWh	1,660,215
Average Rate	\$0.00161

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2013												YE Projected
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	
Revenue Requirements														
1	CAPX 2020 - Fargo	170,168	170,168	170,168	170,168	170,168	170,168	170,168	170,168	170,168	170,168	170,168	170,168	2,042,019
2	CAPX 2020 - Bemidji	69,260	69,260	69,260	69,260	69,260	69,260	69,260	69,260	69,260	69,260	69,260	69,260	831,125
3	Rugby Wind Interconnection	230	230	230	230	230	230	230	230	230	230	230	230	2,765
4	CAPX 2020 - Brookings - Hampton	12,915	12,915	12,915	12,915	12,915	12,915	12,915	12,915	13,718	13,726	13,726	13,729	158,220
5	MVP - Big Stone South to Brookings	323	323	323	323	323	323	323	323	323	323	323	323	3,881
6	MVP - Ellendale to Big Stone South	223	223	223	223	223	223	223	223	223	223	223	223	2,672
7	Ramsey 230/115 kW Transformer Upgrade	1,789	1,789	1,789	1,789	1,789	1,789	1,789	2,034	2,034	2,112	2,112	2,112	22,927
8	Sheyenne - Audubon 230 kV Line Upgrade	2,082	2,082	2,082	2,082	2,082	2,082	2,082	2,082	2,082	2,082	2,082	2,082	24,986
9	Karlstad, MN Capacitor Bank Project	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	46,100
10	Oakes Area Transmission Improvements	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	174,940
11	Casselton - Buffalo 115 kV Project	11,832	11,832	11,832	11,832	11,832	11,832	11,832	11,832	11,832	11,832	11,832	11,832	141,988
12	Hankinson Transformer Addition	3,031	3,031	3,031	3,031	3,031	3,031	3,031	3,031	3,031	3,031	3,031	3,031	36,375
13	Total Revenue Requirements	290,017	290,017	290,017	290,017	290,017	290,017	290,017	290,263	291,066	291,152	291,152	294,244	3,487,999
MISO Expenses & Revenues														
15	MISO Schedule 26 Expense	401,530	406,934	436,570	386,415	379,184	295,341	342,334	354,982	373,987	372,768	302,945	324,819	4,377,809
17	MISO Schedule 26 Revenue	(230,226)	(419,765)	(419,765)	(419,765)	(419,765)	(419,765)	(419,765)	(419,765)	(419,765)	(419,765)	(419,765)	(419,765)	(4,847,644)
18	MISO Schedule 37 Revenue	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(2,672)	(32,068)
19	MISO Schedule 38 Revenue	(3,839)	(3,840)	(3,840)	(3,840)	(3,840)	(3,840)	(3,840)	(3,840)	(3,840)	(3,840)	(3,840)	(3,840)	(46,074)
21	MISO Schedule 26A Expense	4,126	4,126	4,126	4,126	4,126	4,126	4,126	4,126	4,126	4,126	4,126	4,126	49,509
22	MISO Schedule 26A Revenue	(4,375)	(21,076)	(21,076)	(21,076)	(21,076)	(21,076)	(21,076)	(21,076)	(21,076)	(21,076)	(21,076)	(21,076)	(236,207)
23	Net MISO Expenses & Revenues	164,543	(36,293)	(6,657)	(56,812)	(64,043)	(147,887)	(100,893)	(88,245)	(69,240)	(70,459)	(140,282)	(118,408)	(734,675)
24														
25	Net Revenue Requirement	454,561	253,725	283,361	233,205	225,975	142,131	189,125	202,017	221,826	220,692	150,870	175,836	2,753,324
26														
27	Billed (forecast kWh x adj factor)	371,432	368,254	333,259	297,953	249,364	236,460	243,454	250,630	249,441	246,533	284,203	331,336	3,462,318
28														
29	Difference	83,129	(114,529)	(49,898)	(64,748)	(23,389)	(94,329)	(54,329)	(48,613)	(27,615)	(25,840)	(133,333)	(155,500)	(708,995)
30	Carrying Charge	4,800	5,431	4,648	4,323	3,889	3,749	3,099	2,731	2,402	2,221	2,051	1,109	40,454
31	Cummulative Difference	756,470	647,372	602,122	541,697	522,197	431,618	380,388	334,506	309,292	285,672	154,391	0	0
32														
33	Carrying Charge Calculation	5,431	4,648	4,323	3,889	3,749	3,099	2,731	2,402	2,221	2,051	1,109	0	
34	Cumulative Carrying Charge	5,431	10,080	14,403	18,292	22,042	25,141	27,872	30,274	32,494	34,546	35,654	35,654	
35	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%	
36														
37														
38	Forecasted Sales (MWh)	193,004	191,353	173,169	154,823	129,575	122,870	126,504	130,233	129,615	128,104	147,678	172,169	1,799,097

SUMMARY		Jan 2013 - Dec 2013
Revenue requirements		\$2,753,324
Carrying Charge		40,454
2011-2012 True-Up		668,540
Total requirements		\$3,462,318
Jan 2013-Dec 2013 projected sales in MWh		1,799,097
Average Rate		\$0.00192

Otter Tail Power Company
Transmission Rider - Revenue Requirements
CAPX2020 Fargo-Monticello
Case No. PU-12

Line No.	Year>>	2011 Actual Total	2012 Actual January	2012 Actual February	2012 Actual March	2012 Actual April	2012 Actual May	2012 Actual June	2012 Actual July	2012 Projected August	2012 Projected September	2012 Projected October	2012 Projected November	2012 Projected December	2012 Projected Total
RATE BASE															
1		8,706,421	8,706,421	8,706,421	8,706,421	10,709,331	10,709,331	10,709,331	10,709,331	10,641,229	10,641,229	10,641,229	10,641,229	10,641,229	10,641,229
2		0	(15,937)	(31,874)	(47,811)	(63,747)	(83,350)	(102,954)	(122,557)	(142,160)	(161,651)	(181,143)	(200,634)	(220,126)	(220,126)
3		8,706,421	8,690,484	8,674,548	8,658,611	10,645,584	10,625,981	10,606,377	10,586,774	10,499,069	10,479,578	10,460,086	10,440,595	10,421,103	10,421,103
4		7,360,311	8,192,144	8,695,325	9,700,853	8,165,395	9,256,755	10,786,674	12,909,196	15,969,824	19,264,174	21,464,736	23,806,826	26,033,880	26,033,880
5		(3,338,695)	(3,365,044)	(3,391,393)	(3,417,742)	(3,444,091)	(3,469,034)	(3,493,977)	(3,518,920)	(3,543,863)	(3,568,849)	(3,593,834)	(3,618,820)	(3,643,806)	(3,643,806)
6		12,728,037	13,517,585	13,978,480	14,941,722	15,366,888	16,413,702	17,899,075	19,977,050	22,925,030	26,174,903	28,330,988	30,628,600	32,811,177	32,811,177
7															
8		80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%
9		(2,497,241)	(2,652,150)	(2,742,578)	(2,931,566)	(3,014,983)	(3,220,368)	(3,511,798)	(3,919,497)	(4,497,891)	(5,135,516)	(5,558,540)	(6,009,331)	(6,437,553)	(6,437,553)
10		10,230,796	10,865,434	11,235,902	12,010,156	12,351,905	13,193,334	14,387,276	16,057,553	18,427,139	21,039,387	22,772,448	24,619,269	26,373,624	26,373,624
11															
12		8,684,151	1,369,001	1,369,001	1,369,001	1,369,001	1,369,001	1,369,001	1,369,001	1,369,001	1,369,001	1,369,001	1,369,001	1,369,001	16,428,017
13															
14		748,221	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	1,415,428
15															
16		497,548	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	941,224
17															
EXPENSES															
O&M and Depreciation															
19		0	0	0	0	0	0	0	0	0	0	0	0	0	0
20		0	23,845	23,845	23,845	23,845	23,845	23,845	23,845	23,845	23,845	23,845	23,845	23,845	286,139
21		0	15,937	15,937	15,937	15,937	15,937	19,603	19,603	19,603	19,491	19,491	19,491	19,491	220,126
22		0	39,782	39,782	39,782	39,782	39,782	43,448	43,448	43,448	43,336	43,336	43,336	43,336	506,265
23		0	39,782	39,782	39,782	39,782	39,782	43,448	43,448	43,448	43,336	43,336	43,336	43,336	506,265
24															
25		80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%
26		0	(7,805)	(7,805)	(7,805)	(7,805)	(8,525)	(8,525)	(8,525)	(8,525)	(8,503)	(8,503)	(8,503)	(8,503)	(99,329)
27		0	31,977	31,977	31,977	31,977	34,924	34,924	34,924	34,924	34,834	34,834	34,834	34,834	406,936
28															
29															
30		497,548	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	78,435	941,224
31	1.62199	807,021	127,222	127,222	127,222	127,222	127,222	127,222	127,222	127,222	127,222	127,222	127,222	127,222	1,526,660
32															
33															
REVENUE REQUIREMENTS															
35		309,472	80,763	80,763	80,763	80,763	83,710	83,710	83,710	83,710	83,620	83,620	83,620	83,620	992,372
36		748,221	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	117,952	1,415,428
37		1,057,693	198,715	198,715	198,715	198,715	201,662	201,662	201,662	201,662	201,572	201,572	201,572	201,572	2,407,799
38															
39		0	0	0	0	0	0	0	0	0	0	0	0	0	0
40		1,057,693	198,715	198,715	198,715	198,715	201,662	201,662	201,662	201,662	201,572	201,572	201,572	201,572	2,407,799
41															
42	41.26%	436,375	81,984	81,984	81,984	81,984	83,200	83,200	83,200	83,200	83,163	83,163	83,163	83,163	993,392

Otter Tail Power Company
Transmission Rider - Revenue Requirements
CAPX2020 Fargo-Monticello
Case No. PU-12

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3				<u>Ratio</u>		<u>Cost</u>		<u>WA Cost</u>			<u>Property tax</u>			
4				Debt	43.11%	6.30%		2.72%			2012 composite rate	1.92%		
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	Project life (years)													
10				<u>Book</u>		<u>Tax</u>								
11				50		15-year MACRS								
12														
13						<u>Fed Portion</u>		<u>State Portion</u>						
14				Statutory Tax Rate	38.35%	33.20%	5.15%							
15				Tax conversion factor	1.62199									
16				Transmission Revenue	0.00%									
17				ND share - D2 factor	41.2573%									
18	Deferred Tax													
19	Book depreciation	0	15,937	15,937	15,937	15,937	19,603	19,603	19,603	19,603	19,491	19,491	19,491	220,126
20	Tax depreciation-Federal	8,706,421	84,648	84,648	84,648	84,648	84,648	84,648	84,648	84,648	84,648	84,648	84,648	1,015,774
21	Tax depreciation-ND	8,706,421	84,648	84,648	84,648	84,648	84,648	84,648	84,648	84,648	84,648	84,648	84,648	1,015,774
22	Federal deferred income taxes	33.20%	(2,890,314)	(22,810)	(22,810)	(22,810)	(22,810)	(21,593)	(21,593)	(21,593)	(21,630)	(21,630)	(21,630)	(264,135)
23	State deferred income taxes	5.15%	(448,381)	(3,539)	(3,539)	(3,539)	(3,539)	(3,350)	(3,350)	(3,350)	(3,356)	(3,356)	(3,356)	(40,976)

Otter Tail Power Company
Transmission Rider - Revenue Requirements
CAPX2020 Fargo-Monticello
Case No. PU-12

Line No.	SUPPORTING INFORMATION / DATA												
1	ND Cap Structure with allowed ROE per order.												
2	Capital Structure		<u>Ratio</u>		<u>Cost</u>		<u>WA Cost</u>		<u>Property tax</u>				
3	Debt		43.11%		6.30%		2.72%		2013 composite rate			1.92%	
4	Preferred equity		3.60%		4.75%		0.17%						
5	Common equity		53.30%		10.75%		5.73%						
6	Total		100.00%				8.62%	Overall Return					
7													
8													
9													
10	Project life (years)		<u>Book</u>		<u>Tax</u>								
11			50		15-year MACRS								
12													
13													
14													
15													
16													
17													
18	Deferred Tax												
19	Book depreciation		19,491	19,491	19,491	19,491	19,491	19,491	19,491	19,491	19,491	19,491	233,898
20	Tax depreciation-Federal		7,659	7,659	7,659	7,659	7,659	7,659	7,659	7,659	7,659	1,385,938	1,470,183
21	Tax depreciation-ND		7,659	7,659	7,659	7,659	7,659	7,659	7,659	7,659	7,659	1,385,938	1,470,183
22	Federal deferred income taxes	33.20%	3,928	3,928	3,928	3,928	3,928	3,928	3,928	3,928	3,928	(453,626)	(410,416)
23	State deferred income taxes	5.15%	609	609	609	609	609	609	609	609	609	(70,372)	(63,669)

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Bemidji-Grand Rapids
Case No. PU-12

Line No.	Year>>	2011 Actual Total	2012 Actual January	2012 Actual February	2012 Actual March	2012 Actual April	2012 Actual May	2012 Actual June	2012 Actual July	2012 Projected August	2012 Projected September	2012 Projected October	2012 Projected November	2012 Projected December	2012 Projected Total
RATE BASE															
1		0	0	0	0	0	0	0	0	15,644,526	22,680,848	22,680,848	24,568,780	24,568,780	24,568,780
2		0	0	0	0	0	0	0	0	0	(25,641)	(62,815)	(99,989)	(140,257)	(140,257)
3		0	0	0	0	0	0	0	0	15,644,526	22,655,206	22,618,032	24,468,791	24,428,523	24,428,523
4		13,187,587	14,093,227	16,640,856	18,084,755	19,099,910	20,371,560	20,758,486	21,345,330	6,368,999	1,133,216	1,278,696	0	0	0
5		0	0	0	0	0	0	0	0	(685,184)	(1,645,607)	(2,601,608)	(3,747,652)	(4,892,509)	(4,892,509)
6		13,187,587	14,093,227	16,640,856	18,084,755	19,099,910	20,371,560	20,758,486	21,345,330	21,328,341	22,142,816	21,295,121	20,721,139	19,536,014	19,536,014
7															
8		61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%
9		(5,110,190)	(5,461,125)	(6,448,332)	(7,007,843)	(7,401,215)	(7,893,980)	(8,043,913)	(8,271,315)	(8,264,732)	(8,580,341)	(8,251,859)	(8,029,441)	(7,570,205)	(7,570,205)
10		8,077,397	8,632,101	10,192,525	11,076,912	11,698,695	12,477,581	12,714,572	13,074,015	13,063,609	13,562,475	13,043,262	12,691,698	11,965,808	11,965,808
11															
12		4,337,721	976,094	976,094	976,094	976,094	976,094	976,094	976,094	976,094	976,094	976,094	976,094	976,094	11,713,127
13															
14		373,735	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	1,009,209
15															
16		248,525	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	671,090
17															
EXPENSES															
<i>O&M and Depreciation</i>															
19															
20		0	0	0	0	0	0	0	0	0	0	0	0	0	0
21		0	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	253,202
22		0	0	0	0	0	0	0	0	0	25,641	37,174	37,174	40,268	140,257
23		0	21,100	21,100	21,100	21,100	21,100	21,100	21,100	21,100	46,742	58,274	58,274	61,368	393,459
24															
25		61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%
26		0	(8,176)	(8,176)	(8,176)	(8,176)	(8,176)	(8,176)	(8,176)	(8,176)	(18,112)	(22,581)	(22,581)	(23,780)	(152,465)
27		0	12,924	12,924	12,924	12,924	12,924	12,924	12,924	12,924	28,629	35,693	35,693	37,588	240,994
28															
29															
30		248,525	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	55,924	671,090
31	1.62199	403,106	90,709	90,709	90,709	90,709	90,709	90,709	90,709	90,709	90,709	90,709	90,709	90,709	1,088,504
32															
33															
34															
35		154,581	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	417,414
36	38.35%	154,581	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	34,785	417,414
37															
REVENUE REQUIREMENTS															
38		154,581	47,708	47,708	47,708	47,708	47,708	47,708	47,708	47,708	63,414	70,477	70,477	72,373	658,408
39		373,735	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	84,101	1,009,209
40		528,316	131,809	131,809	131,809	131,809	131,809	131,809	131,809	131,809	147,514	154,578	154,578	156,473	1,667,617
41															
42		0	0	0	0	0	0	0	0	0	0	0	0	0	0
43		528,316	131,809	131,809	131,809	131,809	131,809	131,809	131,809	131,809	147,514	154,578	154,578	156,473	1,667,617
44															
45	41.2573%	217,969	54,381	54,381	54,381	54,381	54,381	54,381	54,381	54,381	60,860	63,775	63,775	64,557	688,013

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Bemidji-Grand Rapids
Case No. PU-12

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3				<u>Ratio</u>		<u>Cost</u>		<u>WA Cost</u>		<u>Property tax</u>					
4				Debt	43.11%	6.30%		2.72%		2012 composite rate			1.92%		
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				<u>Book</u>		<u>Tax</u>									
10				Project life (years)	50	15-year MACRS									
11															
12						<u>Fed Portion</u>		<u>State Portion</u>							
13				Statutory Tax Rate	38.35%	33.20%	5.15%								
14				Tax conversion factor	1.62199										
15				Transmission Revenue	0.00%										
16				ND share - D2 factor	41.2573%										
17															
18	Deferred Tax														
19	Book depreciation	0	0	0	0	0	0	0	0	0	25,641	37,174	37,174	40,268	140,257
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	1,786,776	2,530,167	2,530,167	3,025,750	3,025,750	12,898,610
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	1,786,776	2,530,167	2,530,167	3,025,750	3,025,750	12,898,610
22	Federal deferred income taxes	33.20%	0	0	0	0	0	0	0	(593,165)	(831,440)	(827,611)	(992,132)	(991,105)	(4,235,454)
23	State deferred income taxes	5.15%	0	0	0	0	0	0	0	(92,019)	(128,983)	(128,389)	(153,912)	(153,752)	(657,055)

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Casselton - Buffalo 115 kV Project (Project #104761)
Case No. PU-12

Line No.														
1	SUPPORTING INFORMATION / DATA													
2														
3														
4														
5														
6														
7														
8														
9														
10														
11														
12														
13														
14														
15														
16														
17														
18	Deferred Tax													
19	Book depreciation	1.96680%												
20	Tax depreciation-Federal													
21	Tax depreciation-ND													
22	Federal deferred income taxes													
23	State deferred income taxes													
22														
23	Book Depreciation Rate													

ND Cap Structure with allowed ROE per order.														
Capital Structure	Ratio	Cost	WA Cost	Property tax										
Debt	43.11%	6.30%	2.72%	2012 composite rate	1.50%									
Preferred equity	3.60%	4.75%	0.17%											
Common equity	53.30%	10.75%	5.73%											
Total	100.00%		8.62%	Overall Return										
Project life (years)														
	Book	Tax												
	50	15-year MACRS												
Statutory Tax Rate														
	38.35%	Fed Portion	33.20%	State Portion	5.15%									
Tax conversion factor														
	1.62199													
Transmission Revenue														
	0.00%													
ND share - D2 factor														
	41.2573%													

Otter Tail Power Company
Transmission Rider - Revenue Requirements
CAPX2020 Brookings, SD - Hampton, MN
Case No. PU-12

Line No.	Year>>	2013 Projected January	2013 Projected February	2013 Projected March	2013 Projected April	2013 Projected May	2013 Projected June	2013 Projected July	2013 Projected August	2013 Projected September	2013 Projected October	2013 Projected November	2013 Projected December	2013 Projected Total
RATE BASE														
1		0	0	0	0	0	0	0	5,588,956	5,643,555	5,645,617	5,666,720	10,247,379	10,247,379
2		0	0	0	0	0	0	0	0	(9,160)	(18,410)	(27,663)	(36,951)	(36,951)
3		0	0	0	0	0	0	0	5,588,956	5,634,395	5,627,207	5,639,057	10,210,428	10,210,428
4		8,529,400	9,420,592	10,564,835	11,615,431	12,654,394	13,724,589	14,670,839	9,976,202	10,524,459	10,481,022	12,367,199	8,879,766	8,879,766
5		0	0	0	0	0	0	0	(21,923)	(40,334)	(58,710)	(77,085)	(182,311)	(182,311)
6		8,529,400	9,420,592	10,564,835	11,615,431	12,654,394	13,724,589	14,670,839	15,543,235	16,118,520	16,049,519	17,929,171	18,907,883	18,907,883
7														
8		21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%
9		(6,716,903)	(7,418,716)	(8,319,808)	(9,147,152)	(9,965,336)	(10,808,114)	(11,553,286)	(12,240,298)	(12,693,335)	(12,638,996)	(14,119,222)	(14,889,958)	(14,889,958)
10		1,812,498	2,001,876	2,245,028	2,468,279	2,689,059	2,916,475	3,117,553	3,302,937	3,425,186	3,410,523	3,809,949	4,017,925	4,017,925
11														
12		236,023	236,023	236,023	236,023	236,023	236,023	236,023	236,023	236,023	236,023	236,023	236,023	2,832,270
13														
14		20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	244,027
15														
16		13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	162,272
17														
EXPENSES														
O&M and Depreciation														
19		0	0	0	0	0	0	0	0	0	0	0	0	0
20		12,033	12,033	12,033	12,033	12,033	12,033	12,033	12,033	12,033	12,033	12,033	12,033	144,399
21		0	0	0	0	0	0	0	0	9,160	9,250	9,253	9,288	36,951
22		12,033	12,033	12,033	12,033	12,033	12,033	12,033	12,033	21,194	21,283	21,286	21,321	181,350
23														
24														
25		21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%	21.25%
26		(9,476)	(9,476)	(9,476)	(9,476)	(9,476)	(9,476)	(9,476)	(9,476)	(16,690)	(16,760)	(16,763)	(16,790)	(142,813)
27		2,557	2,557	2,557	2,557	2,557	2,557	2,557	2,557	4,504	4,523	4,523	4,531	38,537
28														
29														
30		13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	13,523	162,272
31	1.6220	21,934	21,934	21,934	21,934	21,934	21,934	21,934	21,934	21,934	21,934	21,934	21,934	263,204
32														
33														
34	38.35%	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	100,932
35		8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	8,411	100,932
36														
37														
REVENUE REQUIRMENTS														
39		10,968	10,968	10,968	10,968	10,968	10,968	10,968	10,968	12,915	12,934	12,934	12,942	282,282
40		20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	20,336	244,027
41		31,304	31,304	31,304	31,304	31,304	31,304	31,304	31,304	33,250	33,269	33,270	33,277	526,309
42														
43		0	0	0	0	0	0	0	0	0	0	0	0	0
44		31,304	31,304	31,304	31,304	31,304	31,304	31,304	31,304	33,250	33,269	33,270	33,277	526,309
45														
50	41.26%	12,915	12,915	12,915	12,915	12,915	12,915	12,915	12,915	13,718	13,726	13,726	13,729	158,220

Otter Tail Power Company
Transmission Rider - Revenue Requirements
MVP BSAT to BSS Brookings
Case No. PU-12

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		<u>Ratio</u>		<u>Cost</u>		<u>WA Cost</u>								
4	Debt	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	Project life (years)													
10		<u>Book</u>		<u>Tax</u>										
11		50		15-year MACRS										
12														
13				<u>Fed Portion</u>	<u>State Portion</u>									
14	Statutory Tax Rate	38.35%		33.20%	5.15%									
15	Tax conversion factor	1.62199												
16	Transmission Revenue	0.00%												
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	0	0
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
21	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
22														
23	Book Depreciation Rate													

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Ramsey 230/115 kW Transformer Upgrade (Project #104766)
Case No. PU-12

Line No.	Year>>	2013 Projected January	2013 Projected February	2013 Projected March	2013 Projected April	2013 Projected May	2013 Projected June	2013 Projected July	2013 Projected August	2013 Projected September	2013 Projected October	2013 Projected November	2013 Projected December	2013 Projected Total
RATE BASE														
1		0	0	0	0	0	0	461,354	461,354	608,421	608,421	608,421	608,421	608,421
2		0	0	0	0	0	0	0	(756)	(1,512)	(2,510)	(3,507)	(4,504)	(4,504)
3		0	0	0	0	0	0	461,354	460,598	606,909	605,912	604,914	603,917	603,917
4		461,354	461,354	461,354	461,354	461,354	461,354	0	0	0	0	0	0	0
5		0	0	0	0	0	0	(1,944)	(3,599)	(5,253)	(6,815)	(8,377)	(9,939)	(9,939)
6		461,354	461,354	461,354	461,354	461,354	461,354	459,410	456,999	601,656	599,097	596,538	593,979	593,979
7														
8		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
9		0	0	0	0	0	0	0	0	0	0	0	0	0
10		461,354	461,354	461,354	461,354	461,354	461,354	459,410	456,999	601,656	599,097	596,538	593,979	593,979
11														
12		41,905	41,905	41,905	41,905	41,905	41,905	41,905	41,905	41,905	41,905	41,905	41,905	502,858
13														
14		3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	43,326
15														
16		2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	28,811
17														
EXPENSES														
<i>O&M and Depreciation</i>														
19		0	0	0	0	0	0	0	0	0	0	0	0	0
20		415	415	415	415	415	415	415	415	415	415	415	415	4,983
21		0	0	0	0	0	0	0	756	756	997	997	997	4,504
22		415	415	415	415	415	415	415	1,171	1,171	1,412	1,412	1,412	9,487
23														
24														
25		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
26		0	0	0	0	0	0	0	0	0	0	0	0	0
27		415	415	415	415	415	415	415	1,171	1,171	1,412	1,412	1,412	9,487
28														
29		2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	2,401	28,811
30		3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	3,894	46,731
31	1.6220													
32														
33		1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	17,920
34	38.35%													
35		1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	1,493	17,920
36														
37														
REVENUE REQUIRMENTS														
39		1,909	1,909	1,909	1,909	1,909	1,909	1,909	2,665	2,665	2,906	2,906	2,906	27,407
40		3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	43,326
41		5,519	5,519	5,519	5,519	5,519	5,519	5,519	6,275	6,275	6,516	6,516	6,516	70,733
42		0	0	0	0	0	0	0	0	0	0	0	0	0
43		(1,183)	(1,183)	(1,183)	(1,183)	(1,183)	(1,183)	(1,183)	(1,345)	(1,345)	(1,397)	(1,397)	(1,397)	(15,162)
44		4,336	4,336	4,336	4,336	4,336	4,336	4,336	4,930	4,930	5,119	5,119	5,119	55,570
45														
50	41.26%	1,789	1,789	1,789	1,789	1,789	1,789	1,789	2,034	2,034	2,112	2,112	2,112	22,927

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Karlstad, MN Capacitor Bank Project (Project #104763)
Case No. PU-12

Line No.	Year>>	2011 Actual Total	2012 Actual January	2012 Actual February	2012 Actual March	2012 Actual April	2012 Actual May	2012 Actual June	2012 Actual July	2012 Projected August	2012 Projected September	2012 Projected October	2012 Projected November	2012 Projected December	2012 Projected Total	
RATE BASE																
1		0	0	0	0	0	0	0	0	0	0	839,253	1,041,629	1,043,219	1,043,219	
2		0	0	0	0	0	0	0	0	0	0	0	(1,376)	(3,083)	(3,083)	
3		0	0	0	0	0	0	0	0	0	0	839,253	1,040,253	1,040,136	1,040,136	
4		0	0	0	0	0	3,540	11,812	29,395	209,090	545,892	0	0	0	0	
5		0	0	0	0	0	0	0	0	0	0	(62,845)	(125,163)	(187,353)	(187,353)	
6		0	0	0	0	0	3,540	11,812	29,395	209,090	545,892	776,408	915,091	852,783	852,783	
7																
8		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
9		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
10		0	0	0	0	0	3,540	11,812	29,395	209,090	545,892	776,408	915,091	852,783	852,783	
11																
12			21,436	21,436	21,436	21,436	21,436	21,436	21,436	21,436	21,436	21,436	21,436	21,436	257,232	
13																
14			1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	22,163	
15																
16			1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	14,738	
17																
EXPENSES																
<i>O&M and Depreciation</i>																
19																
20			0	0	0	0	0	0	0	0	0	0	0	0	0	
21			0	0	0	0	0	0	0	0	0	0	0	0	0	
22			0	0	0	0	0	0	0	0	0	0	1,376	1,707	3,083	
23			0	0	0	0	0	0	0	0	0	0	1,376	1,707	3,083	
24																
25		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
26		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
27		0	0	0	0	0	0	0	0	0	0	0	1,376	1,707	3,083	
28																
29																
30			1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	1,228	14,738	
31		1.6220	1,992	1,992	1,992	1,992	1,992	1,992	1,992	1,992	1,992	1,992	1,992	1,992	23,905	
32																
33																
34		38.35%	764	764	764	764	764	764	764	764	764	764	764	764	9,167	
35			764	764	764	764	764	764	764	764	764	764	764	764	9,167	
36																
37																
REVENUE REQUIREMENTS																
39			764	764	764	764	764	764	764	764	764	764	2,139	2,471	12,250	
40			1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	1,847	22,163	
41			2,611	2,611	2,611	2,611	2,611	2,611	2,611	2,611	2,611	2,611	3,986	4,318	34,413	
42			0	0	0	0	0	0	0	0	0	0	0	0	0	
43			(560)	(560)	(560)	(560)	(560)	(560)	(560)	(560)	(560)	(560)	(855)	(926)	(7,377)	
44			2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	2,051	3,132	3,392	27,036	
45																
50		41.26%	846	846	846	846	846	846	846	846	846	846	846	1,292	1,400	11,154

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Oakes Area Transmission (Project #104762 & #104614)
Case No. PU-12

Line No.	Year>>	2011 Actual Total	2012 Actual January	2012 Actual February	2012 Actual March	2012 Actual April	2012 Actual May	2012 Actual June	2012 Actual July	2012 Projected August	2012 Projected September	2012 Projected October	2012 Projected November	2012 Projected December	2012 Projected Total
RATE BASE															
1		0	0	0	0	0	0	0	0	182,688	182,688	182,688	182,688	182,688	182,688
2		0	0	0	0	0	0	0	0	0	(299)	(599)	(898)	(1,198)	(1,198)
3		0	0	0	0	0	0	0	0	182,688	182,388	182,089	181,789	181,490	181,490
4		180,411	180,675	180,902	181,390	181,624	182,639	182,671	182,688	0	0	0	28,215	361,215	361,215
5		0	0	0	0	0	0	0	0	(6,603)	(13,092)	(19,580)	(26,068)	(32,557)	(32,557)
6		180,411	180,675	180,902	181,390	181,624	182,639	182,671	182,688	176,084	169,297	162,509	183,936	510,148	510,148
7															
8		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
9		0	0	0	0	0	0	0	0	0	0	0	0	0	0
10		180,411	180,675	180,902	181,390	181,624	182,639	182,671	182,688	176,084	169,297	162,509	183,936	510,148	510,148
11															
12			17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	17,019	204,229
13															
14			1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	17,596
15															
16			975	975	975	975	975	975	975	975	975	975	975	975	11,701
17															
EXPENSES															
<i>O&M and Depreciation</i>															
19															
20			0	0	0	0	0	0	0	0	0	0	0	0	0
21			162	162	162	162	162	162	162	162	162	162	162	162	1,948
22			0	0	0	0	0	0	0	0	299	299	299	299	1,198
23			162	162	162	162	162	162	162	162	462	462	462	462	3,146
24															
25		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
26		0	0	0	0	0	0	0	0	0	0	0	0	0	0
27		0	162	162	162	162	162	162	162	162	462	462	462	462	3,146
28															
29															
30			975	975	975	975	975	975	975	975	975	975	975	975	11,701
31		1.6220	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	1,582	18,979
32															
33															
34		38.35%	606	606	606	606	606	606	606	606	606	606	606	606	7,278
35			606	606	606	606	606	606	606	606	606	606	606	606	7,278
36															
37															
REVENUE REQUIREMENTS															
39			769	769	769	769	769	769	769	769	1,068	1,068	1,068	1,068	10,424
40			1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	1,466	17,596
41			2,235	2,235	2,235	2,235	2,235	2,235	2,235	2,235	2,535	2,535	2,535	2,535	28,020
42			0	0	0	0	0	0	0	0	0	0	0	0	0
43			(479)	(479)	(479)	(479)	(479)	(479)	(479)	(479)	(543)	(543)	(543)	(543)	(6,006)
44			1,756	1,756	1,756	1,756	1,756	1,756	1,756	1,756	1,991	1,991	1,991	1,991	22,014
45															
50		41.26%	725	725	725	725	725	725	725	725	822	822	822	822	9,082

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Oakes Area Transmission (Project #104762 & #104614)
Case No. PU-12

Line No.	Year>>	2013 Projected January	2013 Projected February	2013 Projected March	2013 Projected April	2013 Projected May	2013 Projected June	2013 Projected July	2013 Projected August	2013 Projected September	2013 Projected October	2013 Projected November	2013 Projected December	2013 Projected Total
RATE BASE														
1		182,688	182,688	182,688	182,688	182,688	182,688	182,688	182,688	182,688	182,688	5,998,219	5,998,219	5,998,219
2		(1,497)	(1,797)	(2,096)	(2,395)	(2,695)	(2,994)	(3,294)	(3,593)	(3,893)	(4,192)	(4,491)	(14,322)	(14,322)
3		181,191	180,891	180,592	180,292	179,993	179,693	179,394	179,095	178,795	178,496	5,993,728	5,983,897	5,983,897
4		1,180,028	1,998,841	2,817,654	3,636,467	4,226,905	4,817,343	5,407,781	5,998,219	5,998,219	5,998,219	0	0	0
5		(32,782)	(33,007)	(33,232)	(33,458)	(33,683)	(33,908)	(34,133)	(34,358)	(34,584)	(34,809)	(92,198)	(145,932)	(145,932)
6		1,328,437	2,146,725	2,965,013	3,783,302	4,373,215	4,963,128	5,553,042	6,142,955	6,142,430	6,141,906	5,901,529	5,837,964	5,837,964
7														
8		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
9		0	0	0	0	0	0	0	0	0	0	0	0	0
10		1,328,437	2,146,725	2,965,013	3,783,302	4,373,215	4,963,128	5,553,042	6,142,955	6,142,430	6,141,906	5,901,529	5,837,964	5,837,964
11														
12		357,627	357,627	357,627	357,627	357,627	357,627	357,627	357,627	357,627	357,627	357,627	357,627	4,291,523
13														
14		30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	369,755
15														
16		20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	245,878
17														
18														
EXPENSES														
<i>O&M and Depreciation</i>														
19		0	0	0	0	0	0	0	0	0	0	0	0	0
20		325	325	325	325	325	325	325	325	325	325	325	325	3,901
21		299	299	299	299	299	299	299	299	299	299	299	9,831	13,125
22		625	625	625	625	625	625	625	625	625	625	625	10,156	17,026
23														
24														
25		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
26		0	0	0	0	0	0	0	0	0	0	0	0	0
27		625	625	625	625	625	625	625	625	625	625	625	10,156	17,026
28														
29		20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	20,490	245,878
30		33,234	33,234	33,234	33,234	33,234	33,234	33,234	33,234	33,234	33,234	33,234	33,234	398,812
31	1.6220													
32														
33		12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	152,935
34	38.35%													
35		12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	12,745	152,935
36														
37														
REVENUE REQUIRMENTS														
39		13,369	13,369	13,369	13,369	13,369	13,369	13,369	13,369	13,369	13,369	13,369	22,901	169,960
40		30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	30,813	369,755
41		44,182	44,182	44,182	44,182	44,182	44,182	44,182	44,182	44,182	44,182	44,182	53,714	539,715
42		0	0	0	0	0	0	0	0	0	0	0	0	0
43		(9,471)	(9,471)	(9,471)	(9,471)	(9,471)	(9,471)	(9,471)	(9,471)	(9,471)	(9,471)	(9,471)	(11,514)	(115,694)
44		34,711	34,711	34,711	34,711	34,711	34,711	34,711	34,711	34,711	34,711	34,711	42,200	424,022
45														
50	41.26%	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	14,321	17,410	174,940

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Hankinson Transformer Addition (Project #104776)
Case No. PU-12

Line No.	Year>>	2011 Actual Total	2012 Actual January	2012 Actual February	2012 Actual March	2012 Actual April	2012 Actual May	2012 Actual June	2012 Actual July	2012 Projected August	2012 Projected September	2012 Projected October	2012 Projected November	2012 Projected December	2012 Projected Total
RATE BASE															
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	877,358	877,358	877,358	877,358
2	Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	(1,438)	(2,876)	(2,876)
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	877,358	875,920	874,482	874,482
4	CWIP	0	4,016	22,585	41,997	76,070	112,327	501,684	604,971	660,909	839,162	0	0	0	0
5	Accumulated Deferred Income Taxes Fedederal & State	0	0	0	0	0	0	0	0	0	0	(52,853)	(105,155)	(157,457)	(157,457)
6	Ending rate base	0	4,016	22,585	41,997	76,070	112,327	501,684	604,971	660,909	839,162	824,505	770,765	717,025	717,025
7															
8	OTP Load Percentage	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
9	Remove Non-OTP Load Portion	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Retail Ending Rate Base	0	4,016	22,585	41,997	76,070	112,327	501,684	604,971	660,909	839,162	824,505	770,765	717,025	717,025
11															
12	Average rate base		33,180	33,180	33,180	33,180	33,180	33,180	33,180	33,180	33,180	33,180	33,180	33,180	398,155
13															
14	Return on Rate Base		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
15															
16	Available for return (equity portion of rate base)		1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	22,812
17															
EXPENSES															
<i>O&M and Depreciation</i>															
19	Operating Costs		0	0	0	0	0	0	0	0	0	0	0	0	0
20	Property Tax		0	0	0	0	0	0	0	0	0	0	0	0	0
21	Book Depreciation		0	0	0	0	0	0	0	0	0	0	1,438	1,438	2,876
22	Total O&M and Depreciation Expense		0	0	0	0	0	0	0	0	0	0	1,438	1,438	2,876
23															
24															
25	OTP Load Percentage	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
26	Remove Non-OTP Load Portion	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Retail O&M and Depreciation Expenses	0	0	0	0	0	0	0	0	0	0	0	1,438	1,438	2,876
28															
29	Income before Taxes														
30	Available for return (from above)		1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	1,901	22,812
31	Taxable Income (grossed up)	1.6220	3,083	3,083	3,083	3,083	3,083	3,083	3,083	3,083	3,083	3,083	3,083	3,083	37,001
32															
33	Income Taxes														
34	Current and Def Income Taxes	38.35%	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	14,189
35	Total Income Tax Expense		1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	14,189
36															
37															
REVENUE REQUIREMENTS															
39	Expenses		1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	1,182	2,620	2,620	17,065
40	Return on rate base		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
41	Subtotal revenue requirements		4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	4,041	5,479	5,479	51,370
42	Adjustments		0	0	0	0	0	0	0	0	0	0	0	0	0
43	Transmission Revenue		(866)	(866)	(866)	(866)	(866)	(866)	(866)	(866)	(866)	(866)	(1,175)	(1,175)	(11,012)
44	Total revenue requirements		3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	3,175	4,305	4,305	40,358
45															
46	North Dakota share - D2 factor	41.26%	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,310	1,776	16,651

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Hankinson Transformer Addition (Project #104776)
Case No. PU-12

Line No.	SUPPORTING INFORMATION / DATA													
1														
2	ND Cap Structure with allowed ROE per order.													
3	Capital Structure		<u>Ratio</u>		<u>Cost</u>		<u>WA Cost</u>			<u>Property tax</u>				
4	Debt		43.11%		6.30%		2.72%			2012 composite rate		0.00%		
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			<u>Book</u>		<u>Tax</u>									
10	Project life (years)		50		15-year MACRS									
11														
12					<u>Fed Portion</u>		<u>State Portion</u>							
13	Statutory Tax Rate		38.35%		33.20%		5.15%							
14	Tax conversion factor		1.62199											
15	Transmission Revenue		21.44%											
16	ND share - D2 factor		41.2573%											
17														
18	Deferred Tax													
19	Book depreciation	0	0	0	0	0	0	0	0	0	0	1,438	1,438	2,876
20	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	153,538	153,538	153,538	460,613
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	36,557	36,557	36,557	109,670
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	(50,971)	(50,493)	(50,493)	(151,957)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	(1,883)	(1,809)	(1,809)	(5,500)
22														
23	Book Depreciation Rate													

2013 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$ 29,746,325
	REVENUE CREDITS	(Note T)	Total	Allocator	
2	Account No. 454	(page 4, line 34)	87,404	TP 1.00000	87,404
3	Account No. 456.1	(page 4, line 37)	7,241,000	TP 1.00000	7,241,000
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)				7,328,404
7				Wholesale Revenue Credit	24.64%

2012 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$ 34,070,426
	REVENUE CREDITS	(Note T)	Total	Allocator	
2	Account No. 454	(page 4, line 34)	98,667	TP 1.00000	98,667
3	Account No. 456.1	(page 4, line 37)	7,204,688	TP 1.00000	7,204,688
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)				7,303,355
7				Wholesale Revenue Credit	21.44%

Line No.		2012												Total 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	Total Schedule 26 Revenue	(286,552)	(707,078)	(624,854)	(661,967)	(580,442)	(723,033)	(873,786)	(760,261)	(760,261)	(760,261)	(760,261)	(760,261)	(8,259,016)
2	Overhead Credit for Non-Retail Share	0	(13,609)	(12,026)	(12,740)	(11,171)	(13,916)	(16,817)	(14,632)	(14,632)	(14,632)	(14,632)	(14,632)	(153,439)
3														
4	Fargo	60.62%	(139,579)	(428,595)	(378,755)	(401,251)	(351,835)	(438,266)	(529,645)	(460,832)	(460,832)	(460,832)	(460,832)	(4,972,089)
5	Retail Load Share	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	80.38%	
6	Retail Revenue		(112,194)	(344,505)	(304,444)	(322,526)	(282,805)	(352,278)	(425,729)	(370,417)	(370,417)	(370,417)	(370,417)	(3,996,565)
7														
8	Overhead Credit for Non-Retail Share	0	(8,249)	(7,290)	(7,723)	(6,771)	(8,435)	(10,194)	(8,869)	(8,869)	(8,869)	(8,869)	(8,869)	(93,007)
9	Non-Retail Load Share	19.62%	19.62%	19.62%	19.62%	19.62%	19.62%	19.62%	19.62%	19.62%	19.62%	19.62%	19.62%	
10	Non-Retail Overhead Credit		0	(1,618)	(1,430)	(1,515)	(1,329)	(1,655)	(2,000)	(1,740)	(1,740)	(1,740)	(1,740)	(18,248)
11														
12	Total Revenue Credit for Fargo		(112,194)	(346,123)	(305,874)	(324,041)	(284,133)	(353,933)	(427,729)	(372,157)	(372,157)	(372,157)	(372,157)	(4,014,813)
13														
14														
15	Bemidji	39.25%	(146,657)	(277,528)	(245,255)	(259,822)	(227,823)	(283,790)	(342,961)	(298,402)	(298,402)	(298,402)	(298,402)	(3,275,850)
16	Retail Load Share	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	61.25%	
17	Retail Revenue		(89,827)	(169,986)	(150,219)	(159,141)	(139,542)	(173,822)	(210,064)	(182,771)	(182,771)	(182,771)	(182,771)	(2,006,458)
18														
19	Overhead Credit for Non-Retail Share	0	(5,341)	(4,720)	(5,001)	(4,385)	(5,462)	(6,601)	(5,743)	(5,743)	(5,743)	(5,743)	(5,743)	(60,225)
20	Non-Retail Load Share	38.75%	38.75%	38.75%	38.75%	38.75%	38.75%	38.75%	38.75%	38.75%	38.75%	38.75%	38.75%	
21	Non-Retail Overhead Credit		0	(2,070)	(1,829)	(1,938)	(1,699)	(2,116)	(2,558)	(2,225)	(2,225)	(2,225)	(2,225)	(23,337)
22														
23	Total Revenue Credit for Bemidji		(89,827)	(172,056)	(152,048)	(161,079)	(141,241)	(175,938)	(212,621)	(184,997)	(184,997)	(184,997)	(184,997)	(2,029,795)
24														
25														
26	Rugby	0.14%	(387)	(955)	(844)	(894)	(784)	(976)	(1,180)	(1,026)	(1,026)	(1,026)	(1,026)	(11,150)
27	Retail Load Share	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
28	Retail Revenue		(387)	(955)	(844)	(894)	(784)	(976)	(1,180)	(1,026)	(1,026)	(1,026)	(1,026)	(11,150)
29														
30	Total Revenue Credit for Rugby		(387)	(955)	(844)	(894)	(784)	(976)	(1,180)	(1,026)	(1,026)	(1,026)	(1,026)	(11,150)
31														
32	Retail Share of Schedule 26 Revenue		(202,408)	(519,134)	(458,765)	(486,013)	(426,158)	(530,848)	(641,530)	(558,180)	(558,180)	(558,180)	(558,180)	(6,055,758)
33														
33	North Dakota Share	41.26%	(83,508)	(214,180)	(189,274)	(200,516)	(175,821)	(219,013)	(264,678)	(230,290)	(230,290)	(230,290)	(230,290)	(2,498,440)

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 schedule.

APPLICATION OF SCHEDULE: This rate schedule 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	\$0.869785
Controlled Service (b)		0.0354 ¢/kWh	N/A
Lighting (c)		0.13613 ¢/kWh	N/A
All Other Service		0.24905 ¢/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

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 schedule.

APPLICATION OF SCHEDULE: This rate schedule 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	\$0.869
Controlled Service	(b)	0.035 ¢/kWh	N/A
Lighting	(c)	0.136 ¢/kWh	N/A
All Other Service		0.249 ¢/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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