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August 30, 2013



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.

An electronic copy of this filing is also being sent to you at [dnitschk@nd.gov](mailto:dnitschk@nd.gov) and to the North Dakota Public Service Commission at [ndpsc@nd.gov](mailto:ndpsc@nd.gov).

If you have any questions regarding this filing, please contact me at 218-739-8279 or [stommerdahl@otpc.com](mailto:stommerdahl@otpc.com).

Sincerely,

A handwritten signature in black ink, appearing to read "Stuart Tommerdahl".

Stuart Tommerdahl  
Manager, Regulatory Administration

dm  
Enclosures  
By electronic filing

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

Docket No. \_\_\_\_\_

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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

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**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 2014). 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). In addition, one project previously approved for recovery in the rider was canceled, and those costs have been removed in this update. The TCR update also includes the addition of one new transmission project that is not currently in base rates and has not previously been included in the Rider. This annual update Application provides detailed information on that project.

As explained in this Application, for a residential customer using 750 kWh per month the bill impact of this update is an increase of 72 cents per month. For a large general service customer with 425 kW of demand, the bill impact of this update is an increase of \$159.80 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**

Stuart Tommerdahl  
Manager, Regulatory Administration  
Otter Tail Power Company  
215 South Cascade Street  
P.O. Box 496  
Fergus Falls, MN 56538-0496  
(218) 739-8279

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

The date of this filing is August 30, 2013. The updated TCR rate has been calculated to take effect as of January 1, 2014.

**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 – 17 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 -16) and the new project for which OTP is requesting TCR recovery (Attachment 17).

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 17 and 22 of the Tracker Account (Attachment 4), and are shown separately in Attachment 19. These are OTP's retail share of the costs for projects that qualify for regional cost allocation through Midcontinent Independent System Operator, Inc. ("MISO's") Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

- *Schedule 26 and 26A revenues.* Schedule 26 and 26A revenues for the recovery period appear on lines 18 and 23 of the Tracker Account Summary (Attachment 4) and are shown separately on Attachment 20 (Schedule 26) and Attachment 21 (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.* These TCR rate update calculations include a 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 1.61 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 22).* The TCR rate update calculations also include 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 the schedule 26 cost allocation assigned to 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 Schedule 26 transmission projects due to their prior MISO membership. Note that in Attachment 22, there are no forecast amounts for Schedule 37 or 38 revenues. MISO does not provide a separate forecast for those revenues, but includes any Schedule 37 and 38 revenues within the Schedule 26 revenue forecasts that MISO develops. MISO does delineate Schedules 37 and 38 revenues when reporting actuals.

The Schedule 37 revenue credit reflected in this TCR update is \$24,834. The Schedule 38 revenue credit reflected in this TCR update is \$37,281. These are actual amounts through July 2013 and included as part of the 2013 true-up amount.

Detailed descriptions of these MISO schedules can be found at:

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

### C. Projects previously approved for recovery in OTP's TCR

Twelve projects were previously approved for inclusion in OTP's TCR in prior proceedings (Case Nos. PU-11-153 and PU-11-682, and Case No. PU-12-702). One of those projects, the Sheyenne-Audubon 230 kV Line Upgrade, has subsequently been canceled and has been removed from the TCR in this update. A detailed explanation is provided in the next section of this Application.

The retail allocation of costs and revenues for the remaining eleven projects have been updated and carried out through 2014 and are reflected in Attachments 5-16. Those projects are:

1.	CAPX 2020 – Fargo	Attachment 5
2.	CAPX 2020 – Bemidji	Attachment 6
	a. Cass Lake-Nary-Helga-Bemidji <sup>1</sup>	Attachment 7
3.	Rugby Wind Interconnection	Attachment 8
4.	Casselton – Buffalo 115 kV Project	Attachment 9
5.	CAPX 2020 - Brookings – Hampton	Attachment 10
6.	MVP - Big Stone Area Transmission to Brookings	Attachment 11
7.	MVP - Ellendale to Big Stone South	Attachment 12
8.	Ramsey 230/115 kW Transformer Upgrade	Attachment 13
9.	Karlstad, MN Capacitor Bank Project	Attachment 14
10.	Oakes Area Transmission Improvements	Attachment 15
11.	Hankinson Transformer Addition	Attachment 16

#### **Sheyenne – Audubon 230 kV Line Upgrade No Longer Needed**

In Q2 of 2013, the decision was made to cease further development of the Sheyenne – Audubon 230 kV upgrade project (“Sheyenne Project”). This project was added to the TCR rider in last year’s TCR Update (Case No. PU-12-702). The decision to cancel the project was based on additional transmission studies that indicated the Sheyenne Project was no longer needed to support the interconnection of the Luverne and Ashtabula wind farms due to a separate regional transmission project near the point of interconnection. The following provides further background leading up to this decision.

The need for the Sheyenne Project arose from the first phase of interconnection studies completed by Minnkota Power Cooperative (“MPC”) in 2008 for the interconnection of the Luverne and Ashtabula wind farms. These studies focused on projected near-term transmission system operating conditions during the 2010 timeframe. As a result of these studies, the Sheyenne Project was identified. In order to allow interconnection of the wind farms in an

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<sup>1</sup>MISO assigned a separate MTEP project number for the Cass-Lake-Nary-Helga-Bemidji portion of the CAPX 2020 – Bemidji project due to different ownership and load allocation percentages applicable to that component of the overall project. In prior TCR Updates, OTP had aggregated and presented all costs of the Bemidji project as one total project and reflected the weighted allocation percentages of the entire project. In order to present the projects at levels of detail consistent with how MISO reflects the breakdown of the projects in MISO Attachment GG, OTP has broken out that portion of the project in a separate attachment within this filing.

expedited manner, and to determine the status of other pending projects under development at the time of these interconnection studies, a temporary wind adjusted rating was implemented in mid-2009 to prevent the Sheyenne-Audubon transmission line (“Sheyenne Line”) from overloading during real-time operating conditions. One of the pending projects under development at the time of these interconnection studies was the CapX2020 Fargo – Monticello 345 kV line (“CAPX Fargo”).

The MAPP Design Review Subcommittee (“DRS”) required additional interconnection studies be conducted to evaluate out-year transmission system conditions as part of the project approval process. This study was completed in 2012 by MPC and focused on the 2017 time-frame. A key assumption in this out-year study was the operation of the CAPX Fargo line, which is scheduled to be energized in 2015. The out-year study showed that with the CAPX Fargo line in service, flows along the Sheyenne Line would be reduced to levels below the existing rating of the facility, therefore eliminating the need to upgrade the Sheyenne Line.

MISO reviewed the additional study material from MPC and confirmed in March 2013 that the addition of the CAPX Fargo line will reliably address the previously identified upgrades to the Sheyenne Line. OTP, as the transmission owner of the Sheyenne Line, similarly reviewed the additional study material from MPC and agreed with MISO’s conclusion and, in the March 2013 timeframe, began the process of cancelling the Sheyenne Project. Accordingly, the existing Facility Construction Agreement (“FCA”) has been amended to remove the requirement of the Sheyenne Project and instead, require wind adjusted ratings for the Sheyenne Line with an accompanying operating guide until the CAPX Fargo line is in-service. The amended FCA has been executed by MISO, OTP, and MPC and is currently pending approval by the Federal Energy Regulatory Commission (“FERC”) with an expected order to be issued in early October 2013. OTP anticipates it will have incurred less than \$15,000 (System) in project development costs associated with the Sheyenne Project. All costs have been removed from the TCR.

#### **D. New transmission projects included in this 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 one new project for inclusion in this TCR update, which is described in detail below.

#### **Description of New Project 1 – NERC Compliance Upgrades– Attachment 17**

In October of 2010 NERC issued a Recommendation (Rule 810 of NERC’s Rules of Procedure requires a response to NERC Recommendations) to the industry to identify discrepancies between design and actual field conditions of transmission lines. This Recommendation stemmed from an unnamed utility’s over-head line contacting vegetation due to insufficient clearance. The Recommendation included a requirement for transmission owners to prioritize their transmission facilities and complete an evaluation of their lines within a 3-year timeframe depending on their priority (which was to be identified as either “high”, “medium”, or “low” priority based on guidance from NERC) and to report such evaluation to the applicable Regional Entity, which in OTP’s case is the Midwest Reliability Organization (“MRO”). OTP prioritized its transmission lines into medium and low priority facilities generally aligned with medium

priority lines being operated at 230 kV and low priority lines being operated at 115 kV. This prioritization of lines was approved by the MRO in the second quarter of 2012. OTP's transmission system included seventeen medium priority lines, with all other lines falling into the "low" priority category (approximately ninety-five lines). The medium priority lines were divided into Phase I, comprised of six 230 kV lines, and Phase II, comprised of the remaining eleven 230 kV lines. Line surveys and evaluations were performed on Phase I medium priority lines in 2012. In 2013, OTP is completing necessary line improvements on the Phase I medium priority lines as well as line surveys and evaluations on the Phase II medium priority and low priority lines. Based on OTP's evaluation to date, it is expected that some mitigations (primarily structure modifications and/or replacements as well as modifying existing guy wires) will be required to increase clearances along various transmission facilities throughout the OTP service territory. Moreover, OTP has applied its analysis, to date, to estimate a total cost for all OTP facilities. In total, OTP estimates that expenditures for all NERC Recommendation related upgrades will cost approximately \$9.2 Million (system total). This cost is subject to change based on additional information that is being gathered for the low priority transmission lines.

#### **MISO Recovery Mechanism for NERC Upgrade Projects**

Effective February 12, 2013, FERC approved a MISO Tariff cost recovery schedule to allow recovery of NERC Recommendation related upgrades within each pricing zone through Attachment ZZ and Schedule 45. OTP expects to utilize Attachment ZZ for recovery of NERC Recommendation upgrades and will be seeking FERC approval of a revised Attachment O that will reflect the carve-out of Attachment ZZ revenues from Attachment O.

Through the MISO-defined recovery method, costs will be allocated within the OTP pricing zone based on a pro-rata share of MISO loads within the OTP pricing zone. Based on 2013 load information, it is estimated that OTP retail load customers will be allocated approximately 73% of the total cost of OTP related upgrades. OTP's current estimate for the total cost of the project is \$9.2 million (System). Based on North Dakota's D2 allocation factor of 41.25727%, it is expected that approximately 30% of the upgrade cost will be assigned to North Dakota retail customers, or approximately \$2.77 million ( $\$9.2 \text{ million} \times 73\% \times 41.25727\%$ ).

#### **Schedule 45 Expense from Other MISO Load**

Schedule 45 charges may also be assigned to OTP customers through other MISO transmission owners that also have transmission facilities within the OTP pricing zone. The cost of this assignment from other transmission owners or such transmission owners' desire to use Attachment ZZ is not known at the time of this filing. Any charges from other transmission owners in the OTP pricing zone will be in addition to the \$2.77 million assigned to ND retail customers. If OTP is able to quantify Schedule 45 charges prior to a ruling in this Docket, OTP will provide the updated information in a supplemental filing. Otherwise, OTP proposes incorporating those costs into future TCR updates for recovery.

### **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 ( $\text{¢} / \text{kWh}$ ) for all other customers. The rate design detail is included in Attachment 3.

## V. RATE APPLICATION AND IMPACT

The total 2014 revenue requirements, as shown on line 1 in Attachment 3, are \$4,753,703. This amount is before any true-up of 2013 revenue requirements or carrying charges/(credits).

The 2013 true-up portion of the revenue requirement calculation, as reflected on Attachment 2, line 24 and as computed in Attachment 4, page 1 of 2, line 32, reflects an estimated over-collection amount of (\$431,105) during the 2013 collection period. Over or under collections occur due to deviations in the amounts and timing of spending on projects, changes in MISO revenues and expenses, as well as deviations between projected sales and actual sales upon which the rates are applied. Actual and projected 2013 results reflect a lower capital spend during 2013 than originally anticipated, which results in a lower required revenue requirement for 2013. Although MISO expenses are expected to be higher in 2013, an increase in MISO revenues is also projected at a higher level than the increase in expenses. The larger net credit from these MISO components also contributed to a projected lower 2013 revenue requirement. By design and structure of the TCR, this over-collection and the carrying charge credits (\$31,192), as computed on Attachment 4, page 2 of 2, line 31, will be returned to customers as a reduction in the 2014 revenue requirements. The net revenue requirement for 2014 will be \$4,291,406. The proposed rates for this net revenue requirement are calculated on lines 2-22 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, as calculated in Attachment 3 are as follows:

<u>Class</u>	<u>¢ / kWh</u>
Large General Service	\$1.097/KW
Controlled Service	0.042¢
Lighting	0.166¢
All other service	0.302¢

These rates represent a slight increase in the rates currently in effect. The estimated increase for a residential customer using 750 kWh would be 750 times \$0.00096 or \$0.72 (72 cents) per month. The following table shows the estimated rate increase over the previous rate by individual rates:

	Ave. kWh /Month	kW	Customers (Meters)	Average kW/kWh's/ Meter	Current Rate	Proposed Rate	Change in Rate	Impact
Large General Service		100,966	267	378	\$0.72100	\$1.09700	\$0.37600	\$142.15
Controlled Service	20,553,397		15,266	1,346	\$0.00029	\$0.00042	\$0.00013	\$0.18
Lighting	1,915,402		22,896	84	\$0.00113	\$0.00166	\$0.00053	\$0.04
All Other	77,860,257		59,311	1,313	\$0.00206	\$0.00302	\$0.00096	\$1.26

The proposed rates are based on the assumption that they will be in effect beginning January 1, 2014 through December 31, 2014. Revenue requirement calculations are based on January 2014 through December 2014 costs as well as 2013 true-up amounts. If the effective date is significantly later than January 1, 2014, 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 (Section 13.07) is Attachment 23 to this Application.

#### **VII. FILING FEE**

As allowed under N.D.C.C. § 49-05-04.3, Subd. 2.d, OTP has included a filing fee of \$10,000 and will pay such additional fees as are reasonably necessary for completion of the application process as determined by the Commission.

#### **VIII. NOTICE TO CUSTOMERS**

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

**CONCLUSION**

For the foregoing reasons, OTP respectfully requests approval to implement this update to its Transmission Cost Recovery Rider, Section 13.07, effective as of January 1, 2014.

Date: August 30, 2013

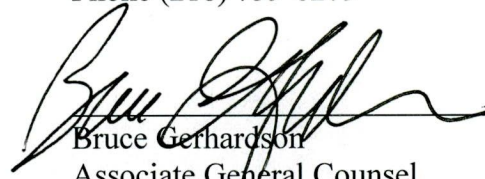
Respectfully submitted:

OTTER TAIL POWER COMPANY



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Bruce Gerhardson  
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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	Cass Lake-Nary-Helga-Bemidji Revenue Requirements Calculation
Attachment 8	Rugby Wind Interconnection Revenue Requirements Calculation
Attachment 9	Casselton-Buffalo 115 kV Project Revenue Requirements Calculation
Attachment 10	CAPX Brookings, SD-Hampton, MN Revenue Requirements Calculation
Attachment 11	MVP BSAT to BSS Brookings Revenue Requirements Calculation
Attachment 12	MVP Big Stone South to Ellendale Revenue Requirements Calculation
Attachment 13	Ramsey 230/115 kV Transformer 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	NERC Compliance Revenue Requirements Calculations
Attachment 18	Attachment O Revenue Credit Calculation for Non-MISO Projects
Attachment 19	MISO Schedule 26 and 26A Expense
Attachment 20	MISO Schedule 26 Revenue
Attachment 21	MISO Schedule 26A Revenue
Attachment 22	Revenue Credits for MISO Tariff Schedules 37 and 38
Attachment 23	Electric Rate Schedule Section 13.07 Redline and Clean

Projected Revenue for 2014

Line No.	Class		Units	Rate per Unit	Amount
1	Large General Service	(a)	1,211,586 kW	\$1.097	\$1,329,183
2					
3	Controlled Service	(b)	246,640,761 kWh	0.042¢	\$104,577
4					
5	Lighting	(c)	22,984,825 kWh	0.166¢	\$38,159
6					
7	All other service		934,323,079 kWh	0.302¢	\$2,819,486
8					
9	Total revenue				<u>\$4,291,406</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	2014
1	CAPX 2020 - Fargo	\$3,163,446
2	CAPX 2020 - Bemidji	\$774,829
3	Cass Lake-Nary-Helga-Bemidji	\$120,025
4	Rugby Wind Interconnection	\$2,359
5	Casselton - Buffalo 115 kV Project	\$291,794
6	CAPX 2020 - Brookings - Hampton	\$251,109
7	MVP - Big Stone Area Transmission	\$5,203
8	MVP - Ellendale to Big Stone South	\$5,025
9	Ramsey 230/115 kW Transformer Upgrade	\$23,685
10	Karlstad, MN Capacitor Bank Project	\$46,268
11	Oakes Area Transmission Improvements	\$90,450
12	Hankinson Transformer Addition	\$32,180
13	NERC Compliance	\$322,423
14		
15	MISO Schedule 26 Expense	4,061,650
16	MISO Schedule 26 Revenue	(4,668,834)
17	MISO Schedule 37 Revenue	0
18	MISO Schedule 38 Revenue	0
19		
20	MISO Schedule 26A Expense	610,402
21	MISO Schedule 26A Revenue	(378,309)
22		
23	Carrying Cost	(31,192)
24	True-Up - 2013	(431,105)
25		
26	Total	<u>\$4,291,406</u>

Class Allocation and Rate Design

Line No.		2014
1	North Dakota Revenue Requirements	\$4,753,703 *
2	2013 True-Up and Carrying Charge	(\$462,297)
3	Total North Dakota Revenue Requirements	\$4,291,406
4		
5	Large General Service Class	30.97% \$1,329,183
6	Controlled Service	2.44% 104,577
7	Lighting	0.89% 38,159
8	All Other Service	65.70% 2,819,486
9		
10	Total	\$4,291,406
11		
12		
13	Large General Service Class	kW 1,211,586
14	Controlled Service	kWh 246,640,761
15	Lighting	kWh 22,984,825
16	All Other Service	kWh 934,323,079
17		
18		
19	Large General Service Class	\$ / kW 1.097
20	Controlled Service	cents / kWh 0.042
21	Lighting	cents / kWh 0.166
22	All Other Service	cents / kWh 0.302

\* 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:	2013												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	142,565	142,565	142,565	142,565	142,565	142,565	142,565	142,565	143,041	142,545	142,561	143,156	1,711,826
2	CAPX 2020: Fargo	63,196	63,196	63,196	63,196	63,196	63,196	63,196	63,196	63,279	63,283	63,284	63,738	759,153
3	Cass Lake-Nary-Helga-Bemidji	10,249	10,249	10,627	10,634	10,634	10,634	10,634	10,630	10,629	10,629	10,629	10,629	126,805
4	Rugby Wind Interconnection	199	199	199	199	199	199	199	199	199	199	199	199	2,394
5	Casselton – Buffalo 115 kV Project	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	119,075
6	CAPX 2020: Brookings - Hampton	10,885	10,885	10,885	10,885	10,885	10,885	10,885	10,885	11,687	11,692	11,691	11,701	133,849
7	MVP: Big Stone Area Transmission	259	259	259	259	259	259	259	259	259	259	259	259	3,113
8	MVP: Ellendale to Big Stone South	140	140	140	140	140	140	140	140	140	140	140	140	1,678
9	Ramsey 230/115 kW Transformer Upgrade	2,035	2,035	2,035	2,035	2,035	2,035	2,035	1,859	2,166	2,166	2,166	2,166	24,772
10	Karlstad, MN Capacitor Bank Project	3,932	3,932	3,932	3,950	3,950	3,950	3,947	3,947	3,947	3,947	3,947	3,947	47,330
11	Oakes Area Transmission Improvements	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	1,246	14,946
12	Hankinson Transformer Addition	2,774	2,771	2,771	2,771	2,771	2,771	2,768	2,768	2,768	2,768	2,768	2,768	33,237
13	NERC Compliance													
14	<b>Total Revenue Requirements</b>	<b>247,403</b>	<b>247,400</b>	<b>247,779</b>	<b>247,804</b>	<b>247,804</b>	<b>247,804</b>	<b>247,798</b>	<b>247,617</b>	<b>249,285</b>	<b>248,798</b>	<b>248,814</b>	<b>249,872</b>	<b>2,978,179</b>
15														
16	<b>MISO Expenses &amp; Revenues</b>													
17	MISO Schedule 26 Expense	247,781	389,663	356,710	350,617	294,292	261,343	310,875	263,238	263,238	263,238	263,238	263,238	3,527,470
18	MISO Schedule 26 Revenue	(236,448)	(321,694)	(280,991)	(295,125)	(269,648)	(313,247)	(354,003)	(334,716)	(334,716)	(348,571)	(348,571)	(458,259)	(3,895,989)
19	MISO Schedule 37 Revenue	(2,417)	(3,741)	(3,741)	(3,741)	(3,741)	(3,741)	(3,713)	0	0	0	0	0	(24,834)
20	MISO Schedule 38 Revenue	(4,094)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,794)	0	0	0	0	0	(37,281)
21														
22	MISO Schedule 26A Expense	4,717	24,625	22,018	15,517	15,659	18,942	23,902	19,454	18,853	19,081	22,279	24,761	229,809
23	MISO Schedule 26A Revenue	(3,882)	(15,202)	(13,898)	(13,948)	(12,722)	(14,366)	(15,803)	(15,849)	(15,850)	(15,850)	(15,850)	(37,365)	(190,585)
24	<b>Net MISO Expenses &amp; Revenues</b>	<b>5,656</b>	<b>68,171</b>	<b>74,620</b>	<b>47,843</b>	<b>18,362</b>	<b>(56,547)</b>	<b>(44,536)</b>	<b>(67,873)</b>	<b>(68,475)</b>	<b>(82,102)</b>	<b>(78,904)</b>	<b>(207,626)</b>	<b>(391,410)</b>
25														
26	<b>Net Revenue Requirement</b>	<b>253,060</b>	<b>315,571</b>	<b>322,398</b>	<b>295,647</b>	<b>266,166</b>	<b>191,257</b>	<b>203,263</b>	<b>179,744</b>	<b>180,810</b>	<b>166,696</b>	<b>169,910</b>	<b>42,247</b>	<b>2,586,770</b>
27														
28	Billed (forecast kWh x adj factor)	<b>303,098</b>	<b>303,156</b>	<b>261,627</b>	<b>258,981</b>	<b>226,441</b>	<b>195,162</b>	<b>214,329</b>	214,036	213,045	204,803	240,671	274,390	2,909,741
29														
30	Difference	(50,039)	12,415	60,771	36,666	39,724	(3,905)	(11,066)	(34,292)	(32,235)	(38,107)	(70,761)	(232,144)	(322,971)
31	Carrying Charge	(724)	(1,088)	(1,007)	(578)	(319)	(36)	(64)	(144)	(391)	(626)	(904)	(1,418)	(7,300)
32	Cummulative Difference	(151,596)	(140,270)	(80,506)	(44,418)	(5,012)	(8,953)	(20,084)	(54,519)	(87,146)	(125,878)	(197,543)	(431,105)	(431,105)
33														
34	Carrying Charge Calculation	(1,088)	(1,007)	(578)	(319)	(36)	(64)	(144)	(391)	(626)	(904)	(1,418)	(3,095)	
35	Cumulative Carrying Charge	77,334	76,327	75,749	75,430	75,394	75,329	75,185	74,794	74,168	73,264	71,846	68,751	
36	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%	
37														
38														
39	Forecasted Sales (MWh)								134,073	133,452	128,289	150,757	171,879	718,451

Approved December 12, 2012;  
 Rate Effective January 1, 2013

	Jan 2013 - Dec 2013
<b>SUMMARY</b>	
Revenue requirements	\$2,923,294
Carrying Charge	(56)
2011-2012 True-Up	(51,131)
<b>Total requirements</b>	<b>\$2,872,106</b>
Jan 2013-Dec 2013 projected sales in MWh	1,799,097
Average Rate	\$0.00160

Line No.	TRACKER SUMMARY Requirements Compared to Billed:	2014												YE Projected
		January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	
1	Revenue Requirements	256,846	256,846	256,846	256,846	256,846	256,846	270,363	270,402	270,402	270,402	270,402	270,402	3,163,446
2	CAPX 2020: Fargo	64,569	64,569	64,569	64,569	64,569	64,569	64,569	64,569	64,569	64,569	64,569	64,569	774,829
3	Cass Lake-Nary-Helga-Bemidji	10,055	10,055	10,055	9,984	9,984	9,984	9,984	9,984	9,984	9,984	9,984	9,984	120,025
4	Rugby Wind Interconnection	197	197	197	197	197	197	197	197	197	197	197	197	2,359
5	Casselton – Buffalo 115 kV Project	23,676	23,676	23,676	23,676	23,676	23,676	24,956	24,956	24,956	24,956	24,956	24,956	291,794
6	CAPX 2020: Brookings - Hampton	20,661	20,701	20,716	20,738	20,754	21,053	21,060	21,069	21,078	21,086	21,093	21,100	251,109
7	MVP: Big Stone Area Transmission	434	434	434	434	434	434	434	434	434	434	434	434	5,203
8	MVP: Ellendale to Big Stone South	419	419	419	419	419	419	419	419	419	419	419	419	5,025
9	Ramsey 230/115 kW Transformer Upgrade	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	1,974	23,685
10	Karlstad, MN Capacitor Bank Project	3,856	3,856	3,856	3,856	3,856	3,856	3,856	3,856	3,856	3,856	3,856	3,856	46,268
11	Oakes Area Transmission Improvements	7,537	7,537	7,537	7,537	7,537	7,537	7,537	7,537	7,537	7,537	7,537	7,537	90,450
12	Hankinson Transformer Addition	2,682	2,682	2,682	2,682	2,682	2,682	2,682	2,682	2,682	2,682	2,682	2,682	32,180
13	NERC Compliance	26,906	26,906	26,906	26,906	26,906	26,906	26,906	26,906	26,906	26,906	26,906	26,906	322,423
14	<b>Total Revenue Requirements</b>	<b>419,811</b>	<b>419,851</b>	<b>419,865</b>	<b>419,817</b>	<b>419,833</b>	<b>420,132</b>	<b>434,936</b>	<b>434,985</b>	<b>434,993</b>	<b>435,001</b>	<b>435,008</b>	<b>434,562</b>	<b>5,128,794</b>
15														
16	<b>MISO Expenses &amp; Revenues</b>													
17	MISO Schedule 26 Expense	263,238	345,310	345,310	345,310	345,310	345,310	345,310	345,310	345,310	345,310	345,310	345,310	4,061,650
18	MISO Schedule 26 Revenue	(334,716)	(394,011)	(394,011)	(394,011)	(394,011)	(394,011)	(394,011)	(394,011)	(394,011)	(394,011)	(394,011)	(394,011)	(4,668,834)
19	MISO Schedule 37 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
20	MISO Schedule 38 Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
21														
22	MISO Schedule 26A Expense	62,926	59,500	52,742	47,912	42,880	44,059	46,910	46,575	45,076	46,780	54,538	60,504	610,402
23	MISO Schedule 26A Revenue	(15,850)	(32,951)	(32,951)	(32,951)	(32,951)	(32,951)	(32,951)	(32,951)	(32,951)	(32,951)	(32,951)	(32,951)	(378,309)
24	<b>Net MISO Expenses &amp; Revenues</b>	<b>(24,402)</b>	<b>(22,151)</b>	<b>(28,910)</b>	<b>(33,740)</b>	<b>(38,772)</b>	<b>(37,592)</b>	<b>(34,741)</b>	<b>(35,076)</b>	<b>(36,575)</b>	<b>(34,871)</b>	<b>(27,114)</b>	<b>(21,147)</b>	<b>(375,091)</b>
25														
26	<b>Net Revenue Requirement</b>	<b>395,409</b>	<b>397,700</b>	<b>390,956</b>	<b>386,077</b>	<b>381,061</b>	<b>382,540</b>	<b>400,195</b>	<b>399,909</b>	<b>398,418</b>	<b>400,130</b>	<b>407,894</b>	<b>413,415</b>	<b>4,753,703</b>
27														
28	Billed (forecast kWh x adj factor)	457,517	456,638	407,350	370,937	309,294	294,156	304,801	315,810	314,091	301,613	354,725	404,473	4,291,406
29														
30	Difference	(62,108)	(58,939)	(16,394)	15,140	71,768	88,383	95,394	84,099	84,327	98,517	53,169	8,942	462,297
31	Carrying Charge	(3,095)	(3,563)	(4,012)	(4,159)	(4,080)	(3,594)	(2,985)	(2,322)	(1,734)	(1,141)	(442)	(64)	(31,192)
32	Cummulative Difference	(496,308)	(558,810)	(579,216)	(568,235)	(500,547)	(415,758)	(323,349)	(241,572)	(158,979)	(61,604)	(8,878)	(0)	(0)
33														
34	Carrying Charge Calculation	(3,563)	(4,012)	(4,159)	(4,080)	(3,594)	(2,985)	(2,322)	(1,734)	(1,141)	(442)	(64)	(0)	
35	Cumulative Carrying Charge	65,187	61,175	57,016	52,936	49,342	46,357	44,035	42,301	41,160	40,717	40,653	40,653	
36	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%	
37														
38														
39	Forecasted Sales (MWh)	195,505	195,129	174,067	158,508	132,166	125,698	130,247	134,951	134,216	128,884	151,580	172,838	1,833,790

	Jan 2014 - Dec 2014
<b>SUMMARY</b>	
Revenue requirements	\$4,753,703
Carrying Charge	(31,192)
2013 True-Up	(431,105)
<b>Total requirements</b>	<b>\$4,291,406</b>
Jan 2014-Dec 2014 projected sales in MWh	1,833,790
Average Rate	\$0.00234



Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
CAPX2020 Fargo-Monticello Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3				<b>Ratio</b>	<b>Cost</b>	<b>WA Cost</b>									<b>Property tax</b>
4				43.11%	6.30%	2.72%									2013 composite rate
5				3.60%	4.75%	0.17%									1.86%
6				53.30%	10.75%	5.73%									
7				100.00%											
8															
9															
10															
11															
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15															
16															
17															
18															
19															
20															
21															
22															
23															

18	<b>Deferred Tax</b>														
19	Book depreciation	217,017	16,936	16,936	16,936	16,936	16,936	16,936	16,936	16,936	16,709	16,871	16,922	17,076	203,067
20	Tax depreciation-Federal	174,650	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	114,518
21	Tax depreciation-ND	174,650	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	9,543	114,518
22	Federal deferred income taxes	33.20% 14,065	2,454	2,454	2,454	2,454	2,454	2,454	2,454	2,454	2,379	2,433	2,450	2,501	29,396
23	State deferred income taxes	5.15% 2,182	381	381	381	381	381	381	381	381	369	377	380	388	4,560





Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Bemidji-Grand Rapids Revenue Requirements  
Case No. PU-13-

Line No.	Year>>	2012 Actual Total	2013 Actual January	2013 Actual February	2013 Actual March	2013 Actual April	2013 Actual May	2013 Actual June	2013 Actual July	2013 Projected August	2013 Projected September	2013 Projected October	2013 Projected November	2013 Projected December	2013 Projected Total	
<b>RATE BASE</b>																
1	Plant Balance - Unclassified									127,620	133,620	136,020	835,220	835,220	835,220	
2	Transmission Plant - Land and Land Rights (350)	565,699	565,699	565,699	565,699	565,699	565,699	565,699	565,699	565,699	565,699	565,699	565,699	565,699	565,699	
3	Transmission Plant - Poles & Fixtures (355)	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	12,666,382	
4	Transmission Plant - Overhead Conductors & Devices (356)	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	2,235,244	
5	Plant Balance	15,467,325	15,467,325	15,467,325	15,467,325	15,467,325	15,467,325	15,467,325	15,467,325	15,594,945	16,600,945	15,603,345	16,302,545	16,302,545	16,302,545	
6	Accumulated Depreciation	(102,090)	(130,232)	(158,375)	(186,517)	(214,659)	(242,801)	(270,943)	(299,085)	(327,227)	(355,585)	(383,953)	(412,325)	(441,878)	(441,878)	
7	Net Plant in Service	15,365,235	15,337,093	15,308,951	15,280,809	15,252,666	15,224,524	15,196,382	15,168,240	15,267,718	15,245,360	15,219,392	15,890,220	15,860,667	15,860,667	
8	CWIP (Project #103487)	0	19,944	28,860	102,712	83,328	90,991	89,415	115,820	0	0	0	0	0	0	
9	Accumulated Deferred Income Taxes Federal & State	(4,163,727)	(4,190,426)	(4,217,125)	(4,243,824)	(4,270,522)	(4,297,221)	(4,323,920)	(4,350,619)	(4,377,318)	(4,403,934)	(4,430,547)	(4,457,157)	(4,483,315)	(4,483,315)	
10	Ending rate base	11,201,508	11,166,611	11,120,685	11,139,697	11,065,472	11,018,294	10,971,877	10,933,441	10,890,400	10,841,426	10,788,846	11,433,063	11,377,352	11,377,352	
11																
12	OTP Load Percentage	90.56%	93.10%	93.10%	93.10%	93.10%	93.10%	93.10%	93.10%	93.10%	93.10%	93.10%	93.10%	93.10%	93.10%	
13	Remove Non-OTP Load Portion	(1,057,422)	(770,161)	(766,994)	(768,305)	(763,186)	(759,932)	(756,730)	(754,079)	(751,111)	(747,733)	(744,107)	(738,538)	(734,696)	(734,696)	
14	Retail Ending Rate Base	10,144,086	10,396,450	10,353,692	10,371,392	10,302,286	10,258,362	10,215,147	10,179,362	10,139,289	10,093,693	10,044,739	10,644,525	10,592,656	10,592,656	
15																
16	Average rate base	11,794,163	857,280	857,280	857,280	857,280	857,280	857,280	857,280	857,280	857,280	857,280	857,280	857,280	10,287,360	
17																
18	Return on Rate Base	1,016,181	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	886,355	
19																
20	Available for return (equity portion of rate base)	675,738	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	589,407	
21																
22	<b>EXPENSES</b>															
23	O&M and Depreciation															
24	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
25	Property Tax	178,710	24,232	24,232	24,232	24,232	24,232	24,232	24,232	24,232	24,232	24,232	24,232	24,232	290,786	
26	Book Depreciation	102,090	28,142	28,142	28,142	28,142	28,142	28,142	28,142	28,142	28,358	28,368	28,372	29,553	339,788	
27	Total O&M and Depreciation Expenses	280,800	52,374	52,374	52,374	52,374	52,374	52,374	52,374	52,374	52,590	52,600	52,604	53,786	630,573	
28																
29	OTP Load Percentage	90.560%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	
30	Remove Non-OTP Load Portion	(26,508)	(3,612)	(3,612)	(3,612)	(3,612)	(3,612)	(3,612)	(3,612)	(3,612)	(3,627)	(3,628)	(3,628)	(3,710)	(43,491)	
31	Retail O&M and Depreciation Expenses	254,293	48,762	48,762	48,762	48,762	48,762	48,762	48,762	48,762	48,963	48,972	48,976	50,076	587,083	
32																
33	Income before Taxes	675,738	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	589,407	
34	Available for return (from above)	675,738	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	49,117	589,407	
35	Taxable Income (grossed up)	1,621,919	1,096,043	79,668	79,668	79,668	79,668	79,668	79,668	79,668	79,668	79,668	79,668	79,668	956,014	
36																
37	Income Taxes	38.35%	420,305	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	366,608	
38	Current and Def Income Taxes	38.35%	420,305	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	366,608	
39	Total Income Tax Expense	38.35%	420,305	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	30,551	366,608	
40																
41																
42	<b>REVENUE REQUIRMENTS</b>															
43	Expenses	674,598	79,313	79,313	79,313	79,313	79,313	79,313	79,313	79,313	79,513	79,523	79,527	80,627	953,690	
44	Return on rate base	1,016,181	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	73,863	886,355	
45	Subtotal revenue requirements	1,690,779	153,176	153,176	153,176	153,176	153,176	153,176	153,176	153,176	153,376	153,386	153,390	154,490	1,840,046	
46	Adjustments															
47	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
48	Total revenue requirements	1,690,779	153,176	153,176	153,176	153,176	153,176	153,176	153,176	153,176	153,376	153,386	153,390	154,490	1,840,046	
49																
50	North Dakota share - D2 factor	41.2573%	697,569	63,196	63,196	63,196	63,196	63,196	63,196	63,196	63,279	63,283	63,284	63,738	759,153	

Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Bemidji-Grand Rapids Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3		<b>Ratio</b>	<b>Cost</b>	<b>WA Cost</b>											<b>Property tax</b>
4	Debt	43.11%	6.30%	2.72%											2013 composite rate
5	Preferred equity	3.60%	4.75%	0.17%											1.82%
6	Common equity	53.30%	10.75%	5.73%											
7	Total	100.00%		8.62%	Overall Return										
8															
9	Project life (years)														
10		<b>Book</b>	<b>Tax</b>												
11		50	15-year MACRS												
12															
13	Statutory Tax Rate														
14		36.35%	33.20%	3.15%											
15	Tax conversion factor														
16		1.62185													
17	Wholesale Revenue Credit														
18		0.00%													
18	ND share - D2 factor														
18		41.2573%													
18	<b>Deferred Tax</b>														
18	Book depreciation														
18	Transmission Plant - Land and Land Rights (350)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Transmission Plant - Poles & Fixtures (355)	87,770	24,300	24,300	24,300	24,300	24,300	24,300	24,300	24,300	24,300	24,300	24,300	24,300	24,300
18	Transmission Plant - Overhead Conductors & Devices (356)	14,320	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842	3,842
19	Book depreciation	102,090	28,142	28,142	28,142	28,142	28,142	28,142	28,142	28,142	28,358	28,358	28,372	29,553	339,788
20	Tax depreciation-Federal	10,959,974	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	1,173,188
21	Tax depreciation-ND	10,959,974	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	97,766	1,173,188
22	Federal deferred income taxes	33.20%	(3,604,546)	(23,113)	(23,113)	(23,113)	(23,113)	(23,113)	(23,113)	(23,113)	(23,042)	(23,038)	(23,037)	(22,645)	(276,668)
23	State deferred income taxes	5.15%	(559,181)	(3,586)	(3,586)	(3,586)	(3,586)	(3,586)	(3,586)	(3,586)	(3,575)	(3,574)	(3,574)	(3,513)	(42,920)





Offer Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Cass Lake-Nary-Helga-Bemidji Revenue Requirements  
Case No. PU-13-

Line No.	Year>>	2012 Actual Total	2013 Actual January	2013 Actual February	2013 Actual March	2013 Actual April	2013 Actual May	2013 Actual June	2013 Actual July	2013 Projected August	2013 Projected September	2013 Projected October	2013 Projected November	2013 Projected December	2013 Projected Total
<b>RATE BASE</b>															
1	Plant Balance	5,590,517	5,590,517	7,067,916	7,067,916	7,067,916	7,067,916	7,067,916	7,042,389	7,039,948	7,039,948	7,039,948	7,039,948	6,999,431	6,999,431
2	Accumulated Depreciation	(30,199)	(37,897)	(45,594)	(55,858)	(66,121)	(76,385)	(86,648)	(96,911)	(107,147)	(117,380)	(127,612)	(137,844)	(148,077)	(148,077)
3	Net Plant in Service	5,560,317	5,552,620	7,022,321	7,012,058	7,001,795	6,991,531	6,981,268	6,945,477	6,932,801	6,922,568	6,912,336	6,902,104	6,851,354	6,851,354
4	CWIP	1,440,886	1,488,980	3,582	(3,405)	(8,342)	(8,342)	(37,418)	(2,441)	0	0	0	0	0	0
5	Accumulated Deferred Income Taxes Federal & State	(1,827,929)	(1,833,035)	(1,864,384)	(1,894,770)	(1,925,145)	(1,955,520)	(1,985,896)	(2,016,271)	(2,046,657)	(2,077,044)	(2,107,432)	(2,137,819)	(2,168,206)	(2,168,206)
6	Ending rate base	5,173,274	5,208,565	5,161,509	5,113,884	5,068,308	5,027,669	4,957,954	4,926,765	4,886,144	4,845,524	4,804,904	4,764,285	4,683,148	4,683,148
7															
8	OTP Load Percentage	34.771%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%
9	Remove Non-OTP Load Portion	(3,374,475)	(3,346,607)	(3,316,373)	(3,285,773)	(3,256,489)	(3,230,378)	(3,185,585)	(3,165,545)	(3,139,445)	(3,113,346)	(3,087,247)	(3,061,148)	(3,009,016)	(3,009,016)
10	Retail Ending Rate Base	1,798,799	1,861,958	1,845,136	1,828,111	1,811,819	1,797,291	1,772,369	1,761,220	1,746,699	1,732,178	1,717,657	1,703,136	1,674,132	1,674,132
11															
12	Average rate base	1,830,717	147,760	147,760	147,760	147,760	147,760	147,760	147,760	147,760	147,760	147,760	147,760	147,760	1,773,116
13															
14	Return on Rate Base	157,734	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	152,771
15															
16	Available for return (equity portion of rate base)	104,890	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	101,589
17															
<b>EXPENSES</b>															
18															
19	O&M and Depreciation														
20	Operating Costs	3,886	432	432	432	478	478	478	478	478	478	478	478	478	5,594
21	Property Tax	74,492	11,016	11,016	11,016	11,016	11,016	11,016	11,016	11,016	11,016	11,016	11,016	11,016	132,190
22	Book Depreciation	30,199	7,698	7,698	10,263	10,263	10,263	10,263	10,263	10,236	10,232	10,232	10,232	10,232	117,878
23	Total O&M and Depreciation Expenses	108,576	19,145	19,145	21,711	21,757	21,757	21,757	21,757	21,729	21,726	21,726	21,726	21,726	255,662
24															
25	OTP Load Percentage	34.771%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%
26	Remove Non-OTP Load Portion	(70,823)	(12,301)	(12,301)	(13,950)	(13,979)	(13,979)	(13,979)	(13,979)	(13,961)	(13,959)	(13,959)	(13,959)	(13,959)	(164,265)
27	Retail O&M and Depreciation Expenses	37,753	6,844	6,844	7,761	7,778	7,778	7,778	7,778	7,768	7,767	7,767	7,767	7,767	91,394
28															
29	Income before Taxes	104,890	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	101,589
30	Available for return (from above)	104,890	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	8,466	101,589
31	Taxable Income (grossed up)	1,621,199	170,130	13,731	13,731	13,731	13,731	13,731	13,731	13,731	13,731	13,731	13,731	13,731	164,777
32															
33	Income Taxes														
34	Current and Def Income Taxes	38.35%	65,241	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	63,188
35	Total Income Tax Expense		65,241	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	5,266	63,188
36															
37															
<b>REVENUE REQUIREMENTS</b>															
38															
39	Expenses	102,994	12,110	12,110	13,027	13,043	13,043	13,043	13,043	13,033	13,032	13,032	13,032	13,032	154,582
40	Return on rate base	157,734	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	12,731	152,771
41	Subtotal revenue requirements	260,728	24,841	24,841	25,758	25,774	25,774	25,774	25,774	25,764	25,763	25,763	25,763	25,763	307,353
42	Adjustments														
43	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	Total revenue requirements	260,728	24,841	24,841	25,758	25,774	25,774	25,774	25,774	25,764	25,763	25,763	25,763	25,763	307,353
45															
46	North Dakota share - D2 factor	41.2573%	107,569	10,249	10,249	10,627	10,634	10,634	10,634	10,630	10,629	10,629	10,629	10,629	126,805

Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Cass Lake-Nary-Helga-Bemidji Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA														
1	ND Cap Structure with allowed ROE per order.														
2	Capital Structure														
3				Ratio	Cost	WA Cost								Property tax	
4				43.11%	6.30%	2.72%								2013 composite rate	1.86%
5				3.60%	4.75%	0.17%									
6				53.30%	10.75%	5.73%									
7				100.00%		Overall Return									
8	Project life (years)														
9				Book	Tax										
10				50	15-year MACRS										
11	Statutory Tax Rate														
12				36.35%	33.20%	8.15%									
13				1.62189											
14				0.00%											
15				41.2573%											
16															
17															
18	Deferred Tax														
19		30,199	7,698	7,698	10,263	10,263	10,263	10,263	10,236	10,232	10,232	10,232	10,232	117,878	
20		4,796,948	21,012	89,474	89,474	89,474	89,474	89,474	89,474	89,474	89,474	89,474	89,474	1,005,229	
21		4,796,948	21,012	89,474	89,474	89,474	89,474	89,474	89,474	89,474	89,474	89,474	89,474	1,005,229	
22	33.20%	(1,582,441)	(4,420)	(27,148)	(26,296)	(26,296)	(26,296)	(26,296)	(26,305)	(26,306)	(26,306)	(26,306)	(26,306)	(294,576)	
23	5.15%	(245,488)	(686)	(4,211)	(4,079)	(4,079)	(4,079)	(4,079)	(4,079)	(4,081)	(4,081)	(4,081)	(4,081)	(45,699)	















Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Casselton - Buffalo Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		Ratio	Cost	WA Cost										
4	Debt	43.11%	6.30%	2.72%	Property tax									
5	Preferred equity	3.60%	4.75%	0.17%	2013 composite rate									
6	Common equity	53.30%	10.75%	5.73%										
7	Total	100.00%		Overall Return										
8	Project life (years)													
9		Book	Tax											
10		50	15-year MACRS											
11	Statutory Tax Rate													
12			Fed Portion	State Portion										
13	Statutory Tax Rate	38.35%	33.20%	8.19%										
14	Tax conversion factor	1.52198												
15	Wholesale Revenue Credit	0.00%												
16	ND share - D2 factor	41.2573%												
17	Deferred Tax													
18	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	0	3,146,992	3,146,992
20	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	3,146,992	3,146,992
21	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(1,044,723)	(1,044,723)
22	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(162,070)	(162,070)



Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Casselton - Buffalo Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA												
1	ND Cap Structure with allowed ROE per order.												
2	Capital Structure	Ratio	Cost	WA Cost					Property tax				
3	Debt	43.11%	6.30%	2.72%				2014 composite rate	4.11%				
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	Project life (years)	Book	Tax										
10		50	15-year MACRS										
11													
12													
13													
14													
15													
16													
17													
18	Deferred Tax												
19	Book depreciation	10,129	10,129	10,129	10,129	10,129	16,043	16,043	16,043	16,043	16,043	16,043	157,031
20	Tax depreciation-Federal	23,727	23,727	23,727	23,727	23,727	48,727	48,727	48,727	48,727	48,727	233,727	644,728
21	Tax depreciation-ND	23,727	23,727	23,727	23,727	23,727	48,727	48,727	48,727	48,727	48,727	233,727	644,728
22	Federal deferred income taxes	(4,514)	(4,514)	(4,514)	(4,514)	(4,514)	(10,850)	(10,850)	(10,850)	(10,850)	(10,850)	(72,266)	(153,604)
23	State deferred income taxes	(700)	(700)	(700)	(700)	(700)	(1,683)	(1,683)	(1,683)	(1,683)	(1,683)	(11,211)	(23,829)



Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Brookings, SD - Hampton, MN Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA												
1													
2	ND Cap Structure with allowed ROE per order.												
3	Capital Structure	Ratio		Cost	WA Cost								
4	Debt	43.11%		6.30%	2.72%								
5	Preferred equity	3.60%		4.75%	0.17%								
6	Common equity	53.30%		10.75%	5.73%								
7	Total	100.00%			Overall Return								
8													
9	Project life (years)												
10		Book		Tax									
11		50		15-year MACRS									
12													
13		Statutory Tax Rate		Fed Portion	State Portion								
14		38.33%		33.20%	9.15%								
15		Tax conversion factor	1.62198										
16		Wholesale Revenue Credit	9.00%										
17		ND share - D2 factor	41.2573%										
18	<b>Deferred Tax</b>												
19	Book depreciation	0	0	0	0	0	0	0	9,377	9,434	9,420	9,537	37,767
20	Tax depreciation-Federal	0	0	0	0	0	0	606,530	606,530	606,530	606,530	2,481,341	4,907,462
21	Tax depreciation-ND	0	0	0	0	0	0	606,530	606,530	606,530	606,530	2,481,341	4,907,462
22	Federal deferred income taxes	0	0	0	0	0	0	(201,353)	(198,240)	(198,221)	(198,226)	(820,577)	(1,616,617)
23	State deferred income taxes	0	0	0	0	0	0	(31,236)	(30,753)	(30,750)	(30,751)	(127,298)	(250,789)

Offer Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Brookings, SD - Hampton, MN Revenue Requirements  
Case No. PU-13-

Line No.	Year>>	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014	2014
		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	Projected Total
<b>RATE BASE</b>														
1	Plant Balance	9,622,169	9,723,975	9,878,080	9,986,796	12,054,921	12,106,305	12,171,113	12,227,644	12,285,234	12,331,933	12,381,259	12,435,097	12,435,097
2	Accumulated Depreciation	(53,562)	(69,821)	(86,252)	(102,944)	(119,819)	(140,189)	(160,645)	(181,212)	(201,873)	(222,632)	(243,470)	(264,391)	(264,391)
3	Net Plant in Service	9,568,607	9,654,154	9,791,828	9,883,852	11,935,102	11,966,116	12,010,468	12,046,432	12,083,361	12,109,301	12,137,789	12,170,706	12,170,706
4	CWP	9,090,334	9,815,870	10,561,216	11,231,921	10,185,207	10,784,990	11,148,296	11,382,949	11,654,944	11,686,303	11,778,617	11,856,079	11,856,079
5	Accumulated Deferred Income Taxes Fedederal & State	(1,877,193)	(1,886,801)	(1,896,344)	(1,905,787)	(1,920,077)	(1,933,027)	(1,945,944)	(1,958,819)	(1,971,657)	(1,984,458)	(1,997,229)	(2,009,968)	(2,009,968)
6	Ending rate base	16,781,748	17,583,222	18,456,700	19,209,986	20,200,232	20,818,079	21,212,820	21,470,562	21,766,648	21,811,146	21,919,177	22,016,817	22,016,817
7														
8	OTP Load Percentage	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%
9	Remove Non-OTP Load Portion	(13,302,556)	(13,937,869)	(14,630,257)	(15,227,372)	(16,012,320)	(16,502,075)	(16,814,978)	(17,019,285)	(17,253,986)	(17,289,259)	(17,374,893)	(17,452,291)	(17,452,291)
10	Retail Ending Rate Base	3,479,192	3,645,354	3,826,443	3,982,614	4,187,912	4,316,004	4,397,842	4,451,277	4,512,661	4,521,887	4,544,284	4,564,527	4,564,527
11														
12	Average rate base	344,503	344,503	344,503	344,503	344,503	344,503	344,503	344,503	344,503	344,503	344,503	344,503	4,134,040
13														
14	Return on Rate Base	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	356,187
15														
16	Available for return (equity portion of rate base)	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	236,857
17														
<b>EXPENSES</b>														
18														
19	O&M and Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Operating Costs	23,372	23,372	23,372	23,372	23,372	23,372	23,372	23,372	23,372	23,372	23,372	23,372	280,467
21	Property Tax	15,795	16,259	16,431	16,691	16,875	20,370	20,457	20,566	20,662	20,759	20,838	20,921	226,624
22	Book Depreciation	39,167	39,631	39,803	40,064	40,247	43,742	43,829	43,938	44,034	44,131	44,210	44,294	507,092
23	Total O&M and Depreciation Expense													
24														
25	OTP Load Percentage	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%	20.73%
26	Remove Non-OTP Load Portion	(31,047)	(31,415)	(31,551)	(31,758)	(31,903)	(34,673)	(34,742)	(34,829)	(34,905)	(34,982)	(35,045)	(35,111)	(401,961)
27	Retail O&M and Depreciation Expenses	8,120	8,216	8,252	8,306	8,344	9,069	9,087	9,109	9,129	9,149	9,166	9,183	105,130
28														
29	Income before Taxes	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	19,738	236,857
30	Available for return (from above)	1,62199	32,015	32,015	32,015	32,015	32,015	32,015	32,015	32,015	32,015	32,015	32,015	384,180
31	Taxable Income (grossed up)													
32														
33	Income Taxes	38.35%	12,277	12,277	12,277	12,277	12,277	12,277	12,277	12,277	12,277	12,277	12,277	147,324
34	Current and Def Income Taxes		12,277	12,277	12,277	12,277	12,277	12,277	12,277	12,277	12,277	12,277	12,277	147,324
35	Total Income Tax Expense													
36														
37														
<b>REVENUE REQUIRMENTS</b>														
38														
39	Expenses	20,397	20,493	20,529	20,583	20,621	21,346	21,364	21,386	21,406	21,426	21,443	21,460	654,415
40	Return on rate base	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	29,682	356,187
41	Subtotal revenue requirements	50,079	50,176	50,211	50,265	50,303	51,028	51,046	51,069	51,088	51,109	51,125	51,142	1,010,602
42	Adjustments													
43	Wholesale Revenue Credit	0	0	0	0	0	0	0	0	0	0	0	0	0
44	Total revenue requirements	50,079	50,176	50,211	50,265	50,303	51,028	51,046	51,069	51,088	51,109	51,125	51,142	1,010,602
45														
46	North Dakota share - D2 factor	41.26%	20,661	20,701	20,716	20,738	20,754	21,053	21,060	21,069	21,078	21,086	21,093	251,109

Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Brookings, SD - Hampton, MN Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure													
3		Ratio	Cost	WA Cost										
4	Debt	43.11%	6.30%	2.72%										
5	Preferred equity	3.60%	4.75%	0.17%										
6	Common equity	53.30%	10.75%	5.73%										
7	Total	100.00%		8.62%	Overall Return									
8														
9	Project life (years)													
10		Book	Tax											
11		50	15-year MACRS											
12														
13		Statutory Tax Rate		Fed Portion	State Portion									
14		38.30%	33.20%	3.79%										
15		1.62189												
16		Wholesale Revenue Credit												
17		9.00%												
18		ND share - D2 factor												
19	Deferred Tax													
19	Book depreciation	15,795	16,259	16,431	16,691	16,875	20,370	20,457	20,566	20,662	20,759	20,838	20,921	226,624
20	Tax depreciation-Federal	41,316	41,316	41,316	41,316	54,140	54,140	54,140	54,140	54,140	54,140	54,140	54,140	598,386
21	Tax depreciation-ND	41,316	41,316	41,316	41,316	54,140	54,140	54,140	54,140	54,140	54,140	54,140	54,140	598,386
22	Federal deferred income taxes	(8,472)	(8,318)	(8,261)	(8,175)	(12,371)	(11,211)	(11,182)	(11,146)	(11,114)	(11,082)	(11,056)	(11,028)	(123,416)
23	State deferred income taxes	(1,314)	(1,290)	(1,282)	(1,268)	(1,919)	(1,739)	(1,735)	(1,729)	(1,724)	(1,719)	(1,715)	(1,711)	(19,146)

















Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Ramsey Transformer Upgrade Revenue Requirements  
Case No. PU-13-

Line No.	Year>>	2012 Actual Total	2013 Actual January	2013 Actual February	2013 Actual March	2013 Actual April	2013 Actual May	2013 Actual June	2013 Actual July	2013 Projected August	2013 Projected September	2013 Projected October	2013 Projected November	2013 Projected December	2013 Projected Total
<b>RATE BASE</b>															
1		0	0	0	0	0	0	0	0	561,633	561,633	561,633	561,633	578,608	578,608
2		0	0	0	0	0	0	0	0	(949)	(1,898)	(2,847)	(3,796)	(3,796)	(3,796)
3		0	0	0	0	0	0	0	0	561,633	560,684	559,735	558,786	574,812	574,812
4		432,865	432,865	432,865	432,865	432,865	561,633	561,633	561,633	0	0	0	0	0	0
5		0	0	0	0	0	0	0	0	(23,298)	(46,231)	(69,165)	(92,099)	(115,032)	(115,032)
6		432,865	432,865	432,865	432,865	432,865	561,633	561,633	561,633	538,335	514,453	490,570	466,687	459,780	459,780
7															
8			40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	40,507	486,081
9															
10			3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	41,881
11															
12			2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	27,850
13															
<b>EXPENSES</b>															
14															
15															
16			0	0	0	0	0	0	0	0	0	0	0	0	0
17			0	0	0	0	0	0	0	0	0	0	0	0	0
18			0	0	0	0	0	0	0	0	949	949	949	949	3,796
19			0	0	0	0	0	0	0	0	949	949	949	949	3,796
20															
21															
22			2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	27,850
23	1.62199		3,764	3,764	3,764	3,764	3,764	3,764	3,764	3,764	3,764	3,764	3,764	3,764	45,172
24															
25															
26	38.35%		1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	17,322
27			1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	17,322
28															
29															
<b>REVENUE REQUIREMENTS</b>															
30															
31			1,444	1,444	1,444	1,444	1,444	1,444	1,444	1,444	2,393	2,393	2,393	2,393	21,118
32			3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	3,490	41,881
33			4,934	4,934	4,934	4,934	4,934	4,934	4,934	4,934	5,883	5,883	5,883	5,883	62,999
34			0	0	0	0	0	0	0	0	0	0	0	0	0
35			0	0	0	0	0	0	0	(428)	(632)	(632)	(632)	(632)	(2,956)
36			4,934	4,934	4,934	4,934	4,934	4,934	4,934	4,505	5,251	5,251	5,251	5,251	60,043
37															
38	41.26%		2,035	2,035	2,035	2,035	2,035	2,035	2,035	1,859	2,166	2,166	2,166	2,166	24,772

Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Ramsey Transformer Upgrade Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA												
1	ND Cap Structure with allowed ROE per order.												
2	Capital Structure	Ratio	Cost	WA Cost	Property tax								
3	Debt	43.11%	6.30%	2.72%	2013 composite rate								
4	Preferred equity	3.60%	4.75%	0.17%									
5	Common equity	53.30%	10.75%	5.73%									
6	Total	100.00%		Overall Return									
7													
8													
9	Project life (years)	Book	Tax										
10		50	15-year MACRS										
11													
12				Fed Portion	State Portion								
13	Statutory Tax Rate	36.33%		33.26%	9.75%								
14	Tax conversion factor	1.02198											
15	Wholesale Revenue Credit	21.44%											
16	ND share - D2 factor	41.2573%											
17													
18	Deferred Tax												
19	Book depreciation	0	0	0	0	0	0	0	949	949	949	949	3,796
20	Tax depreciation-Federal	0	0	0	0	0	0	60,754	60,754	60,754	60,754	60,754	303,769
21	Tax depreciation-ND	0	0	0	0	0	0	60,754	60,754	60,754	60,754	60,754	303,769
22	Federal deferred income taxes	0	0	0	0	0	0	(20,169)	(19,854)	(19,854)	(19,854)	(19,854)	(99,584)
23	State deferred income taxes	0	0	0	0	0	0	(3,129)	(3,080)	(3,080)	(3,080)	(3,080)	(15,449)



















Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Oakes Area Transmission Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA													
1	ND Cap Structure with allowed ROE per order.													
2	Capital Structure	Ratio	Cost	WA Cost	Property tax									
3	Debt	43.11%	6.30%	2.72%	2014 composite rate									
4	Preferred equity	3.60%	4.75%	0.17%	1.41%									
5	Common equity	53.30%	10.75%	5.73%										
6	Total	100.00%		9.62%	Overall Return									
7														
8														
9	Project life (years)	Book	Tax											
10		50	15-year MACRS											
11				Fed Portion	State Portion									
12				38.35%	33.26%									
13	Statutory Tax Rate	38.35%		33.26%	3.75%									
14	Tax conversion factor	1.62196												
15	Wholesale Revenue Credit	22.31%												
16	ND share - D2 factor	41.2573%												
17														
18	<b>Deferred Tax</b>													
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	174,100	174,100
21	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	174,100	174,100
22	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(57,797)	(57,797)
23	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	(8,966)	(8,966)











Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
NERC Compliance Revenue Requirements  
Case No. PU-13-

Line No.	SUPPORTING INFORMATION / DATA													
1														
2	ND Cap Structure with allowed ROE per order.													
3	Capital Structure	Ratio	Cost	WA Cost										
4	Debt	43.11%	6.30%	2.72%	Property tax									
5	Preferred equity	3.60%	4.75%	0.17%	2014 composite rate									
6	Common equity	53.30%	10.75%	5.73%										
7	Total	100.00%		Overall Return										
8														
9														
10	Project life (years)	Book	Tax											
11		50	15-year MACRS											
12														
13		Statutory Tax Rate			Fed Portion	State Portion								
14		36.35%	33.20%	5.75%										
15		Tax conversion factor												
16		1.02189												
17		Wholesale Revenue Credit												
18		21.44%												
19		ND share - D2 factor												
20		41.2573%												
21	Deferred Tax													
22	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Tax depreciation-Federal	0	0	0	0	0	0	0	0	0	0	0	0	0
24	Tax depreciation-ND	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Federal deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
26	State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
27													0	0
28													460,345	460,345
29													460,345	460,345
30													(152,823)	(152,823)
31													(23,708)	(23,708)

2014 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$28,912,737
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
2	Account No. 454	(page 4, line 34)	75,803	TP 1.00000	75,803
3	Account No. 456.1	(page 4, line 37)	6,373,865	TP 1.00000	6,373,865
4	Revenues from Grandfathered Interzonal Transactions		0	TP 1.00000	0
5	Revenues from service provided by the ISO at a discount		0	TP 1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)				6,449,668
7				Wholesale Revenue Credit	22.31%

2013 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$33,932,824
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
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	21.60%

2012 Attachment O Filing

Line No.					Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)				\$ 34,070,426
	REVENUE CREDITS	(Note T)	<u>Total</u>	<u>Allocator</u>	
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%

		2012													
Line No.	SCHEDULE 26	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	YE Actual	
1	MISO Schedule 26 Expense	253,832	592,339	532,591	495,578	390,637	410,469	473,407	546,817	512,536	421,054	508,724	520,322	5,658,307	
2	North Dakota share	41.257%	104,724	244,383	219,733	204,462	161,166	169,348	195,315	225,602	211,458	173,715	209,886	214,671	2,334,463
5	MISO Schedule 26A Expense	0	10,348	7,713	8,964	9,391	7,237	7,420	5,663	6,437	6,478	6,877	8,963	85,491	
6	OTP owned portion of expenses	4.076%	0	(422)	(314)	(365)	(383)	(295)	(231)	(262)	(264)	(280)	(365)	(3,485)	
7	Net MISO Schedule 26A Expense	0	9,926	7,399	8,599	9,008	6,942	7,118	5,432	6,174	6,213	6,597	8,597	82,006	
9	North Dakota share	41.257%	0	4,095	3,052	3,548	3,717	2,864	2,937	2,241	2,547	2,564	2,722	3,547	33,833

		2013													
Line No.	SCHEDULE 26	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Projected	September Projected	October Projected	November Projected	December Projected	YE Projected	
1	MISO Schedule 26 Expense	600,575	944,470	864,599	849,832	713,310	633,447	753,503	638,040	638,040	638,040	638,040	638,040	8,549,935	
2	North Dakota share	41.257%	247,781	389,663	356,710	350,617	294,292	261,343	310,875	263,238	263,238	263,238	263,238	3,527,470	
3	MISO Schedule 26A Expense	11,433	59,685	53,366	37,611	37,954	45,912	57,935	47,154	45,697	46,250	54,001	60,016	557,015	
4	North Dakota share	41.257%	4,717	24,625	22,018	15,517	15,659	18,942	23,902	19,454	18,853	19,081	22,279	24,761	229,809

		2014												
Line No.	SCHEDULE 26	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	YE Projected
1	MISO Schedule 26 Expense	638,040	836,968	836,968	836,968	836,968	836,968	836,968	836,968	836,968	836,968	836,968	836,968	9,844,688
2	North Dakota share	41.257%	263,238	345,310	345,310	345,310	345,310	345,310	345,310	345,310	345,310	345,310	345,310	4,061,650
3	MISO Schedule 26A Expense	152,522	144,218	127,836	116,129	103,932	106,792	113,701	112,889	109,257	113,386	132,189	146,651	1,479,502
4	North Dakota share	41.257%	62,926	59,500	52,742	47,912	42,880	44,059	46,910	46,575	45,076	46,780	54,538	610,402

Line No.			2013												
			January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	July Actual	August Projected	September Projected	October Projected	November Projected	December Projected	Total Projected
1	Total Schedule 26 Revenue		(691,374)	(1,052,581)	(919,400)	(965,645)	(882,286)	(1,024,940)	(1,158,294)	(1,095,189)	(1,095,189)	(1,140,522)	(1,140,522)	(1,499,420)	(12,665,360)
2	Overhead Credit for Non-Retail Share	1.690%	(13,309)	(17,789)	(15,538)	(16,319)	(14,911)	(17,321)	(19,575)	(18,509)	(18,509)	(19,275)	(19,275)	(25,340)	(215,669)
5	Fargo	67.468%	(419,076)	(710,155)	(620,300)	(651,501)	(595,261)	(691,506)	(781,478)	(738,902)	(738,902)	(769,487)	(769,487)	(1,011,629)	(8,497,685)
6	Retail Load Share		75.691%	75.691%	75.691%	75.691%	75.691%	75.691%	75.691%	75.691%	75.691%	75.691%	75.691%	75.691%	
7	Retail Revenue		(317,203)	(537,524)	(469,512)	(493,128)	(450,559)	(523,408)	(591,508)	(559,282)	(559,282)	(582,433)	(582,433)	(765,712)	(6,431,983)
9	Overhead Credit for Non-Retail Share		(8,067)	(12,002)	(10,483)	(11,010)	(10,060)	(11,686)	(13,207)	(12,487)	(12,487)	(13,004)	(13,004)	(17,097)	(144,596)
10	Non-Retail Load Share		24.309%	24.309%	24.309%	24.309%	24.309%	24.309%	24.309%	24.309%	24.309%	24.309%	24.309%	24.309%	
11	Non-Retail Overhead Credit		(1,961)	(2,917)	(2,548)	(2,677)	(2,445)	(2,841)	(3,210)	(3,036)	(3,036)	(3,161)	(3,161)	(4,156)	(35,150)
13	Total Revenue Credit for Fargo		(319,164)	(540,441)	(472,060)	(495,804)	(453,004)	(526,249)	(594,719)	(562,318)	(562,318)	(585,594)	(585,594)	(769,868)	(6,467,133)
16	Bemidji	18.025%	(271,364)	(489,728)	(415,722)	(474,057)	(459,032)	(518,745)	(568,783)	(537,408)	(537,408)	(575,579)	(575,579)	(720,270)	(6,029,675)
17	Retail Load Share		93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	93.103%	
18	Retail Revenue		(252,648)	(476,642)	(402,292)	(462,053)	(448,064)	(512,004)	(561,383)	(529,793)	(529,793)	(570,400)	(570,400)	(721,630)	(6,029,675)
20	Overhead Credit for Non-Retail Share		(5,224)	(3,206)	(2,801)	(2,942)	(2,688)	(3,122)	(3,528)	(3,336)	(3,336)	(3,474)	(3,474)	(4,568)	(41,699)
21	Non-Retail Load Share		6.897%	6.897%	6.897%	6.897%	6.897%	6.897%	6.897%	6.897%	6.897%	6.897%	6.897%	6.897%	
22	Non-Retail Overhead Credit		(360)	(221)	(193)	(203)	(185)	(215)	(243)	(230)	(230)	(240)	(240)	(315)	(2,876)
24	Total Revenue Credit for Bemidji		(253,009)	(476,863)	(402,485)	(462,256)	(448,249)	(512,219)	(561,626)	(529,023)	(529,023)	(570,640)	(570,640)	(721,945)	(6,029,675)
27	Cass Lake - Nary - Helga - Bemidji	13.012%	0	(136,962)	(119,632)	(125,650)	(114,803)	(133,365)	(150,717)	(142,506)	(142,506)	(148,405)	(148,405)	(195,105)	(1,558,055)
28	Retail Load Share		35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	35.748%	
29	Retail Revenue		0	(48,961)	(42,766)	(44,917)	(41,040)	(47,675)	(53,878)	(50,943)	(50,943)	(53,052)	(53,052)	(69,746)	(556,974)
31	Overhead Credit for Non-Retail Share		0	(2,315)	(2,022)	(2,123)	(1,940)	(2,254)	(2,547)	(2,408)	(2,408)	(2,508)	(2,508)	(3,297)	(26,331)
32	Non-Retail Load Share		64.252%	64.252%	64.252%	64.252%	64.252%	64.252%	64.252%	64.252%	64.252%	64.252%	64.252%	64.252%	
33	Non-Retail Overhead Credit		0	(1,487)	(1,299)	(1,364)	(1,247)	(1,448)	(1,637)	(1,547)	(1,547)	(1,611)	(1,611)	(2,119)	(16,918)
35	Total Revenue Credit for Bemidji		0	(50,448)	(44,065)	(46,282)	(42,286)	(49,124)	(55,515)	(52,490)	(52,490)	(54,663)	(54,663)	(71,865)	(573,892)
27	Rugby	0.779%	(933)	(8,200)	(7,162)	(7,522)	(6,873)	(7,984)	(9,023)	(8,532)	(8,532)	(8,885)	(8,885)	(11,680)	(94,211)
28	Retail Load Share		100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	100.000%	
29	Retail Revenue		(933)	(8,200)	(7,162)	(7,522)	(6,873)	(7,984)	(9,023)	(8,532)	(8,532)	(8,885)	(8,885)	(11,680)	(94,211)
31	Total Revenue Credit for Rugby		(933)	(8,200)	(7,162)	(7,522)	(6,873)	(7,984)	(9,023)	(8,532)	(8,532)	(8,885)	(8,885)	(11,680)	(94,211)
34	Casselton	0.673%	0	(7,088)	(6,191)	(6,503)	(5,941)	(6,902)	(7,800)	(7,375)	(7,375)	(7,680)	(7,680)	(10,097)	(80,633)
35	Retail Load Share		52.458%	52.458%	52.458%	52.458%	52.458%	52.458%	52.458%	52.458%	52.458%	52.458%	52.458%	52.458%	
36	Retail Revenue		0	(3,718)	(3,248)	(3,411)	(3,117)	(3,621)	(4,092)	(3,869)	(3,869)	(4,029)	(4,029)	(5,297)	(42,298)
38	Overhead Credit for Non-Retail Share		0	(120)	(105)	(110)	(100)	(117)	(132)	(125)	(125)	(130)	(130)	(171)	(1,363)
39	Non-Retail Load Share		47.542%	47.542%	47.542%	47.542%	47.542%	47.542%	47.542%	47.542%	47.542%	47.542%	47.542%	47.542%	
40	Non-Retail Overhead Credit		0	(57)	(50)	(52)	(48)	(55)	(63)	(59)	(59)	(62)	(62)	(81)	(648)
41	Total Revenue Credit for Casselton		0	(3,775)	(3,298)	(3,463)	(3,164)	(3,676)	(4,154)	(3,928)	(3,928)	(4,091)	(4,091)	(5,378)	(42,946)
45	Retail Share of Schedule 26 Revenue		(573,106)	(779,728)	(681,070)	(715,327)	(653,577)	(759,252)	(858,038)	(811,290)	(811,290)	(844,872)	(844,872)	(1,110,736)	(9,443,158)
47	North Dakota Share	41.257%	(236,448)	(321,694)	(280,991)	(295,125)	(269,648)	(313,247)	(354,003)	(334,716)	(334,716)	(348,571)	(348,571)	(458,259)	(3,895,989)



Otter Tail Power Company  
North Dakota Transmission Cost Recovery Rider  
Schedule 26A Revenue  
Case No. PU-13-

Line No.		2013												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 26A Revenue	(55,156)	(240,417)	(219,784)	(220,568)	(201,184)	(227,186)	(249,904)	(250,629)	(250,629)	(250,629)	(250,629)	(590,837)	(3,007,552)
2	Overhead Credit for Non-Retail Share	1.690%	(1,062)	(4,063)	(3,714)	(3,728)	(3,400)	(3,839)	(4,223)	(4,236)	(4,236)	(4,236)	(9,985)	(50,957)
3														
4														
5	<b>CAPX 2020 - Brookings</b>	63.977%	(39,812)	(153,811)	(140,611)	(141,113)	(128,711)	(145,347)	(159,881)	(160,345)	(160,345)	(160,345)	(378,000)	(1,928,667)
6	Retail Load Share		20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	20.732%	
7	Retail Revenue		(8,254)	(31,888)	(29,151)	(29,255)	(26,684)	(30,133)	(33,147)	(33,243)	(33,243)	(33,243)	(78,367)	(399,851)
8														
9	Overhead Credit for Non-Retail Share		(766)	(2,599)	(2,376)	(2,385)	(2,175)	(2,456)	(2,702)	(2,710)	(2,710)	(2,710)	(6,388)	(32,688)
10	Non-Retail Load Share		79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	79.268%	
11	Non-Retail Overhead Credit		(608)	(2,061)	(1,884)	(1,890)	(1,724)	(1,947)	(2,142)	(2,148)	(2,148)	(2,148)	(5,064)	(25,911)
12														
13	<b>Total Revenue Credit for CAPX Brookings</b>		(8,861)	(33,949)	(31,035)	(31,146)	(28,409)	(32,080)	(35,288)	(35,391)	(35,391)	(35,391)	(83,431)	(425,762)
14														
15														
16	<b>MVP BS South - Brookings</b>	21.334%	(12,293)	(51,290)	(46,889)	(47,056)	(42,921)	(48,468)	(53,314)	(53,469)	(53,469)	(53,469)	(126,049)	(642,157)
17	Retail Load Share		1.669%	1.677%	1.678%	1.677%	1.678%	1.679%	1.681%	1.683%	1.684%	1.685%	1.685%	
18	Retail Revenue		(205)	(860)	(787)	(789)	(720)	(814)	(896)	(899)	(900)	(901)	(2,124)	(10,795)
19														
20	Overhead Credit for Non-Retail Share		(237)	(867)	(792)	(795)	(725)	(819)	(901)	(904)	(904)	(904)	(2,130)	(10,881)
21	Non-Retail Load Share		98.331%	98.323%	98.322%	98.323%	98.322%	98.319%	98.319%	98.317%	98.316%	98.315%	98.315%	
22	Non-Retail Overhead Credit		(233)	(852)	(779)	(782)	(713)	(805)	(886)	(888)	(888)	(888)	(2,094)	(10,698)
23														
24	<b>Total Revenue Credit for MVP Brookings</b>		(438)	(1,712)	(1,566)	(1,571)	(1,433)	(1,619)	(1,782)	(1,787)	(1,788)	(1,789)	(4,219)	(21,494)
25														
26														
27	<b>MVP Ellendale - BS South</b>	14.689%	(3,050)	(35,315)	(32,284)	(32,399)	(29,552)	(33,371)	(36,708)	(36,815)	(36,815)	(36,815)	(86,788)	(436,727)
28	Retail Load Share		1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	1.700%	
29	Retail Revenue		(52)	(600)	(549)	(551)	(502)	(567)	(624)	(626)	(626)	(626)	(1,475)	(7,424)
30														
31	Overhead Credit for Non-Retail Share		(59)	(597)	(546)	(548)	(499)	(564)	(620)	(622)	(622)	(622)	(1,467)	(7,388)
32	Non-Retail Load Share		98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	98.300%	
33	Non-Retail Overhead Credit		(58)	(587)	(536)	(538)	(491)	(554)	(610)	(612)	(612)	(612)	(1,442)	(7,262)
34														
35	<b>Total Revenue Credit for MVP Ellendale</b>		(110)	(1,187)	(1,085)	(1,089)	(993)	(1,122)	(1,234)	(1,237)	(1,237)	(1,237)	(2,917)	(14,687)
36														
37														
38	Retail Share of Schedule 26A Revenue		(9,409)	(36,848)	(33,686)	(33,806)	(30,835)	(34,821)	(38,304)	(38,416)	(38,416)	(38,417)	(90,567)	(461,943)
39														
40	<b>North Dakota share</b>	41.257%	(3,882)	(15,202)	(13,898)	(13,948)	(12,722)	(14,366)	(15,803)	(15,849)	(15,850)	(15,850)	(37,365)	(190,585)



Line No.		2013												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 37 Revenue	(7,693)	(11,914)	(11,914)	(11,914)	(11,914)	(11,914)	(11,826)	0	0	0	0	0	(79,089)
2	Overhead Credit for Non-Retail Share	1.690%	(148)	(201)	(201)	(201)	(201)	(200)	0	0	0	0	0	(1,355)
3														
4														
5	<b>Fargo</b>	100.00%	(7,693)	(11,914)	(11,914)	(11,914)	(11,914)	(11,914)	(11,826)	0	0	0	0	(79,089)
6	Retail Load Share		75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	
7	Retail Revenue		(5,823)	(9,018)	(9,018)	(9,018)	(9,018)	(9,018)	(8,951)	0	0	0	0	(59,864)
8														
9	Overhead Credit for Non-Retail Share		(148)	(201)	(201)	(201)	(201)	(200)	0	0	0	0	0	(1,355)
10	Non-Retail Load Share		24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	
11	Non-Retail Overhead Credit		(36)	(49)	(49)	(49)	(49)	(49)	0	0	0	0	0	(329)
12														
13	<b>Total Revenue Credit for Fargo</b>		(5,859)	(9,067)	(9,067)	(9,067)	(9,067)	(8,999)	0	0	0	0	0	(60,193)
14														
15														
16	<b>North Dakota Share</b>	41.257%	(2,417)	(3,741)	(3,741)	(3,741)	(3,741)	(3,713)	0	0	0	0	0	(24,834)
17														
18														
19	Total Schedule 38 Revenue		(13,030)	(17,449)	(17,449)	(17,449)	(17,449)	(17,449)	(18,453)	0	0	0	0	(118,728)
20	Overhead Credit for Non-Retail Share	1.690%	(251)	(295)	(295)	(295)	(295)	(295)	(312)	0	0	0	0	(2,037)
21														
22														
23	<b>Fargo</b>	100.00%	(13,030)	(17,449)	(17,449)	(17,449)	(17,449)	(17,449)	(18,453)	0	0	0	0	(118,728)
24	Retail Load Share		75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	75.69%	
25	Retail Revenue		(9,862)	(13,207)	(13,207)	(13,207)	(13,207)	(13,207)	(13,967)	0	0	0	0	(89,866)
26														
27	Overhead Credit for Non-Retail Share		(251)	(295)	(295)	(295)	(295)	(295)	(312)	0	0	0	0	(2,037)
28	Non-Retail Load Share		24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	24.31%	
29	Non-Retail Overhead Credit		(61)	(72)	(72)	(72)	(72)	(76)	0	0	0	0	0	(495)
30														
31	<b>Total Revenue Credit for Fargo</b>		(9,923)	(13,279)	(13,279)	(13,279)	(13,279)	(13,279)	(14,043)	0	0	0	0	(90,361)
32														
33														
34	<b>North Dakota Share</b>	41.257%	(4,094)	(5,479)	(5,479)	(5,479)	(5,479)	(5,794)	0	0	0	0	0	(37,281)





**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	<del>\$0.72</del> 1.097
Controlled Service	(b)	0.029042 ¢/kWh	N/A
Lighting	(c)	0.113166 ¢/kWh	N/A
All Other Service		0.206302 ¢/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

NORTH DAKOTA PUBLIC SERVICE COMMISSION  
 Dakota  
 Case No. PU-12-702 PU-13-  
 Approved by order dated December 12, 2012

EFFECTIVE with bills rendered on and after January 1, ~~2013~~2014, in North

APPROVED: Thomas R. Brause  
 Vice President, Administration



**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
<b>Large General Service (a)</b>	N/A	¢/kWh	\$1.097
<b>Controlled Service (b)</b>	0.042	¢/kWh	N/A
<b>Lighting (c)</b>	0.166	¢/kWh	N/A
<b>All Other Service</b>	0.302	¢/kWh	N/A

(a) Rate schedules 10.03 Large General Service, 10.05 Large General Service – Time of Day, 14.02 Real Time Pricing Rider and 14.03 Large General Service Rider.  
 (b) Rate Schedules 14.01 Water Heating, 14.04 Interruptible Load (CT Metering), 14.05 Interruptible Load (Self-Contained Metering), 14.06 Deferred Load, and 14.07 Fixed Time of Delivery  
 (c) Rate Schedules 11.03 Outdoor Lighting (energy only) and 11.04 Outdoor Lighting

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NORTH DAKOTA PUBLIC  
 SERVICE COMMISSION  
 Case No. PU-13-\_\_\_\_  
 Approved by order dated

EFFECTIVE with bills rendered on  
 and after January 1, 2014, in North Dakota

APPROVED: Thomas R. Brause  
 Vice President, Administration