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PUBLIC SERVICE COMMISSION

OTTER TAIL POWER COMPANY

April 29, 2011

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 Transmission Cost Recovery Rider Filing

Dear Mr. Nitschke:

Enclosed you will find the petition of Otter Tail Power Company, to the North Dakota Public Service Commission on implementation of a transmission cost recovery rider pursuant to NDCC § 49-05-04.3.

If you have any questions regarding this filing, please contact me at 218-739-8607 or pbeithon@otpco.com.

Sincerely,

Pete J. Beithon
Manager, Regulatory Economics

wao
Enclosures
By electronic filing

PU-11-153 Filed: 5/12/2011 Pages: 39
Transmission facility cost recovery tariff and 2011 rate adjustment
Otter Tail Power Company
Pete Beithon

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

Docket No. __________

In the Matter of Otter Tail Power Company's Application to Establish a Transmission Cost Recovery Tariff

APPLICATION OF OTTER TAIL POWER COMPANY

I. INTRODUCTION

Otter Tail Power Company, ("OTP or Company"), hereby petitions the North Dakota Public Service Commission ("Commission") for approval of a Transmission Cost Recovery Tariff ("Transmission Rider"), pursuant to NDCC § 49-05-04.3.

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) 998-7108
Fax (218) 998-3165

C. Title of utility employee responsible for filing

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

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

The date of this filing is April 29, 2011. OTP proposes that the tariff mechanism for the recovery of charges for jurisdictional costs of new or modified transmission facilities and federally regulated costs charged to OTP to increase regional transmission capacity or reliability, contained herein, go into effect as of June 1, 2011.

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

NDCC §49-05-04.3 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.

In this Application, OTP is proposing to implement a rate schedule ("Transmission Rider") for the recovery of investments and expenses associated with new or modified transmission projects that are not included in base rates, and for the recovery of expenses or charges from the Midwest Independent Transmission System Operator ("Midwest ISO" or "MISO") through Schedule 26 under the federally regulated MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

B. Costs to be recovered

Generally, two types of costs are proposed to be included for recovery in OTP's Transmission Rider: First are the Midwest ISO Schedule 26 costs allocated to North Dakota retail customers. The basis for these costs is described in Section III.B.1. Second is the North Dakota retail share of revenue requirements for transmission facilities not currently included in base rates. These costs are described in Section III.B.2.

1. Midwest ISO Regional Expansion Criteria and Benefits ("RECB") charges ("MISO Schedule 26")

OTP incurs charges from the Midwest ISO to pay for a portion of transmission investments of other electric utilities pursuant to Attachment FF of the Midwest ISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"). Attachment FF specifies the cost allocation procedures for new transmission projects within the Midwest ISO. This cost allocation, oftentimes referred to as "RECB," (after the Regional Expansion Criteria and Benefits Task Force ("RECB") stakeholder committee) specifies the process in which the Midwest ISO identifies and evaluates new transmission expansion projects eligible for inclusion in the Midwest ISO Transmission Expansion Plan ("MTEP"). The MTEP issued by the Midwest ISO is a regional expansion plan with three primary objectives: 1) to perform a reliability assessment of the Midwest ISO integrated transmission system; 2) to review transmission owning members' transmission plans and make sure that appropriate projects are reviewed and recommended to Midwest ISO Board of Directors for approval; and 3) to develop transmission upgrades to improve market performance.

Through its MTEP process, the Midwest ISO determines whether a proposed transmission project is eligible for cost-sharing pursuant to Attachment FF of the Midwest ISO Tariff. There are a variety of project types under the Midwest ISO Tariff that are eligible for cost-sharing including the following: (1) Baseline Reliability Projects ("BRP") required to ensure transmission system reliability consistent with North American Electric Reliability Corporation ("NERC") standards, (2) Regionally Beneficial Projects ("RBP") that provide economic benefit to the Midwest ISO transmission system, (3) Generator Interconnection Project Network Upgrades ("GIP NU") required for the interconnection of generation to the Midwest ISO transmission system, or (4) Multi Value Projects ("MVP") that address regional public policy, reliability, and economic value to the Midwest ISO footprint.

BRPs that are 345 kV and greater and that have a project cost greater than $5 million (or 5 percent or more of the transmission owner's net transmission plant) will be allocated 20 percent on a system-wide (postage stamp) rate to all Midwest ISO transmission customers, with the remaining 80 percent allocated on a sub-regional basis, which is based on a system power flow analysis referred to as Line Outage Distribution Factor ("LODF").[1] BRPs that are between 100 kV and 345 kV and have a project cost greater than $5 million in project costs (or 5 percent or more of the transmission owner's net transmission plant) will be allocated 100 percent on a sub-regional LODF basis to all transmission customers in designated pricing zones.

RBPs that have a project cost greater than $5 million will be allocated 20 percent on a system-wide (postage stamp) rate to all Midwest ISO transmission customers and 80 percent will be allocated to each pricing zone within each of three Planning Sub Regions (West, Central, and East) based on the relative benefit determined for each Planning Sub Region that has a positive present value of annual benefits over the evaluation period using the methodology for project benefit determined pursuant to Section II.B.1 of Attachment FF to the Midwest ISO Tariff.

GIP NUs are allocated pursuant to Attachment FF of the Midwest ISO Tariff, assigning up to 100 percent of the cost responsibility for Network Upgrades associated with GIPs to be allocated to the interconnection customer. For Network Upgrades to facilities in voltage classes at or above 345 kV, the interconnection customer shall be repaid 10 percent of the costs of the Generation Interconnection Project funded by the interconnection customer once commercial operation is achieved. The 10 percent reimbursement is recovered from all transmission customers in the Midwest ISO on a postage stamp basis. Network Upgrades to facilities in voltage classes below 345 kV are assigned 100 percent to the interconnection customer.

MVPs are a new project classification generally planned as regional transmission that provides multiple benefits. This project classification and its cost allocation are currently pending before FERC in Docket No. ER10-1791. As proposed, the Multi Value Project is a transmission expansion project that (1) enables the transmission system to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement or (2) provides multiple types of economic value across multiple pricing zones with a total MVP benefit-to-cost ratio of 1.0 or higher, or (3) solves at least one projected violation of a NERC or Regional Entity standard and provides economic value across multiple pricing zones, which collectively generates total financially quantifiable benefits in excess of the total project costs. The costs of an approved MVP project shall be recovered from all load in, and exports from, the Midwest ISO footprint on a postage-stamp basis based on system usage (i.e. MWh).

1 LODF is an engineering calculation of the change of flows on the transmission system created by the addition of a new transmission facility. MISO uses computer software to measure and model the LODF of all facilities within the MISO Transmission System for each new facility added to the system. MISO then models the LODF for each pricing zone for each new transmission facility. LODF is used because it is considered by MISO planners as a way to determine the added benefit of a new transmission facility to each of the pricing zones. Generally, pricing zones in close proximity to the proposed transmission facility have the greatest LODF cost allocation and those furthest away have little to no cost allocation from the LODF method, thus this benefit assignment is defined as Sub-Regional.

If, through the MTEP eligibility screening process, a project does not meet the criteria for a BRP, RBP, GIP NU, or MVP but is determined to provide local benefits the assignment of costs for that facility is left to the local pricing zone of the transmission owner of the facility. For example, for a proposed transmission facility that primarily benefits a local load center, the Midwest ISO would not administer cost sharing provisions under Attachment FF and the local transmission owner would be solely bear those costs and recover its revenue requirement under Attachment O to the Midwest ISO Tariff.

The BRP, RBP, GIP NU, and MVP cost allocation criteria and recovery mechanisms are specified in detail in Attachment FF,[2] Attachment GG,[3] and Schedule 26[4] of the Midwest ISO Tariff. The Midwest ISO's annual MTEP review process identifies those transmission projects that will be included in "Appendix A" to the MTEP and the respective cost-sharing is identified for each project as applicable.

The allocation of some project costs to MISO participants on a broader scale than just the utilities or companies that invest in the transmission project means that project investment on an individual company basis is unlikely to match the level of allocation on a load share ratio. In fact, each project that has a system-wide cost allocation would need to have every MISO entity with a cost allocation also be an investment participant in the project at the same level or the project would be underfunded and not be constructed. The alternative is that some project investors must invest in projects at a level that exceeds their cost allocation.

OTP proposes to use the following methodology for cost recovery of transmission projects:

- For a project that does not meet the criteria for a BRP, RBP, GIP NU, or MVP designation but is determined to provide local benefits and thus the assignment of costs for that facility is left to the local pricing zone of the transmission owner of the facility, OTP will use the Transmission Rider for cost recovery until the project is included in base rates or has been fully recovered. Revenue credits associated with wholesale use of the project will be received for the project through the Attachment O process as discussed above.

- For a project that does meet the criteria for a BRP, RBP, GIP NU, or MVP designation with MISO-determined cost allocations on a regional or system-wide basis, OTP will allow those projects to remain in Attachment GG and to collect the revenue requirements through the Attachment GG and Schedule 26 process. This will shield OTP customers from revenue requirements of the project except for the revenue requirements specifically allocated to OTP retail customers through the MISO process. Retail customers will already have received the benefit of the wholesale level usage of the project by other entities that received a cost allocation and the Schedule 26 revenue received by OTP will provide the project revenue requirements to pay for project costs.

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2 Attachment FF specifies the Transmission Expansion Planning Protocols.
3 Attachment GG specifies the calculation of the Network Upgrade Charge.
4 Schedule 26 specifies the Network Upgrade Charge from Transmission Expansion Plan.

OTP has included Schedule 26 costs for recovery in this filing. The costs appear on line 3 of the Tracker Account (Attachment 4) and are shown separately in Attachment 8.

2. New or modified transmission projects not currently in base rates

OTP does not have any transmission projects in its current 5-year capital budget for which it plans to seek cost recovery through the Transmission Rider.

Attachment 5 is an example of revenue requirement calculation for a transmission project included in the Transmission Rider. The revenue requirement for a project included in the Transmission Rider will include several components as described below.

- *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 includes a 13-month average rate base calculation.

- *CWIP.* NDCC § 49-05-04.3 allows a current return on CWIP.

- *Expense section.* The expenses applicable to a project will be listed here and include operating costs, property taxes, depreciation, and, income taxes.

- *Revenue requirements section.* This section will show the components of the revenue requirements. Included are the items computed from the sections previously mentioned, including expenses and return on rate base. Adjustments (usually reductions) to the revenue requirement will be included for monies received or paid for non-retail use of the lines. This includes amounts of MISO revenues generated from the Midwest ISO tariff. It is a revenue credit that represents revenue that OTP receives for the wholesale use of its transmission system from MISO and other non-MISO users. The revenue credit is a percentage of the revenue requirement based on the prior year's actual revenue credits divided by the most recent non-levelized revenue requirements from the MISO formula rate shown in MISO Attachment O. Using the information from OTP's 2011 Attachment O, the revenue credit adjustment is 17.32 percent. This MISO revenue credit percentage is applied to in-service revenue requirements and updated each year thereafter. Therefore, the 17.32 percent is applied to the computed revenue requirement for the project. The calculation of the revenue credit adjustment is shown in Attachment 7.

- *Return on investment (cost of capital).* The return on investment will utilize the cost of capital determined in the most recent approved general rate case.

- *Depreciation expense.* Depreciation expense will be calculated using the company's latest transmission composite depreciation rate.

- *Property taxes.* The property tax calculation will be based on OTP's composite tax rate for the jurisdiction in which the transmission facilities are located, and will be 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 will include 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 are 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 will set up transmission O&M accounting projects to track O&M costs specifically related to each line included in the Transmission Rider.

C. CAPX2020

OTP has invested in the Fargo to St. Cloud and Bemidji to Grand Rapids CAPX2020 Projects and is not requesting recovery of those costs through the Transmission Rider. OTP believes that such an approach would result in reasonable rates and recoveries over the long term, but the MISO recovery mechanisms appear likely to result in year-to-year Schedule 26 revenue variations, and therefore this approach may result in significant annual variations in the Transmission Rider rate. Also, by increasing the amount of the investment included in the Transmission Rider, retail customers will have exposure to increased risks associated with these investments.

OTP's investments in these regional projects is larger than its retail load share of responsibility for the projects; therefore, OTP's Schedule 26 revenues from the projects (which are based on the level of investment) exceeds OTP's Schedule 26 charges from the projects (which are based on OTP's load levels in MISO—and the particular MISO cost allocation methodology applicable to each project). Under OTP's proposal, OTP captures the revenues to support its level of investment by keeping the investments, the revenues and any associated risks outside the Transmission Rider and retail rates.

D. Tracker Account

OTP maintains in its accounting system a tracker account for all transmission related costs and revenues described in this Application to track and account for retail revenue requirements until all costs have been fully recovered or reflected in base rates as the result of a general rate case. The tracker account information compares OTP's costs and the amount recovered through North Dakota retail revenue. The tracker account balance (either positive or negative) will accrue monthly carrying charges at a rate of 1/12 of OTP's last approved rate of return multiplied by the previous month's tracker balance. Carrying charges on a negative tracker balance will accrue to the benefit of retail customers and carrying charges on a positive tracker balance will accrue to OTP.

OTP anticipates making annual filings to revise the Transmission Rider to reflect updated revenue requirements and additional transmission projects. When submitting annual filings, the tracker account will be updated so that any over- or under-recovered amount at the end of the previous year will be reflected in the Transmission Rider adjustment for the upcoming year. The tracker account detail is included in Attachment 5.

IV. RATE DESIGN

OTP's proposed rate design uses 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. OTP proposes to continue to use these most recently approved allocation factors but will review them for reasonableness in each annual update.

OTP is proposing an energy-only billing rate (¢ / kWh) for all customers. In order to most closely reflect transmission cost responsibility by customer class, OTP is proposing to use four classes and corresponding rates in this Rider. A rate for each class is a separate energy-based (kWh) change calculated as the revenue requirements divided by the kilowatt-hour sales for the projected period. This rate design is appropriate because it reflects the primarily energy-based rates for the classes and reduces the complexity of administration. The rate design detail is included in Attachment 3.

V. RATE APPLICATION AND IMPACT

OTP proposes that the Transmission Rider should be applicable to electric service under all of OTP's retail rate schedules. For administrative purposes, OTP proposes to include the charge as part of the Energy and Renewable Adjustment line on customers' bills. The proposed rates are as follows:

Class	¢ / kWh
Large General Service	0.093¢
Controlled Service	0.019¢
Lighting	0.072¢
All other service	0.130¢

The following table shows the estimated rate impact by retail customer class.

Approved ND Rates Based on 2007 Test Year			
Rate Class Impacts (1)		**Rate Class Impacts** (1)	
Residential		**Outdoor Lighting**	
Average Rate (¢/kWh)	8.495	Average Rate (¢/kWh)	10.937
Increase %	1.52%	Increase %	0.66%
Average Impact ($/month)	$1.09	Average Impact ($/month)	$0.07
Farm		**Municipal Pumping**	
Average Rate (¢/kWh)	7.283	Average Rate (¢/kWh)	6.467
Increase %	1.78%	Increase %	2.00%
Average Impact ($/month)	$2.34	Average Impact ($/month)	$3.29
General Service		**Water Heating, Controlled**	
Average Rate (¢/kWh)	8.462	Average Rate (¢/kWh)	6.598
Increase %	1.53%	Increase %	0.29%
Average Impact ($/month)	$3.94	Average Impact ($/month)	$0.04
Large General Service		**Interruptible Load**	
Average Rate (¢/kWh)	5.989	Average Rate (¢/kWh)	3.628
Increase %	1.56%	Increase %	0.53%
Average Impact ($/month)	$358.60	Average Impact ($/month)	$0.45
Irrigation		**Deferred Load**	
Average Rate (¢/kWh)	7.691	Average Rate (¢/kWh)	4.861
Increase %	1.69%	Increase %	0.40%
Average Impact ($/month)	$4.22	Average Impact ($/month)	$0.44

(1) Average rate calculation is from ND Docket No. PU-08-862. Rate impacts are calculated from base rates.

The proposed rates are based on the assumption that they will be in effect beginning June 1, 2011 through May 31, 2012. Revenue requirement calculations are based on January 2011 through May 2012 costs. If the effective date is significantly later than June 1, 2011, 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 proposed Transmission Cost Recovery Rider (Rate Designation 13.07) is Attachment 6 to this Application.

VII. REVISIONS TO OTHER RATE SCHEDULES

Attachment 6 to this Application also includes redline and proposed final versions of OTP's Rate Schedules Index and Rate Schedule 13.00, Mandatory Riders – Applicability Matrix, showing the addition of the Transmission Cost Recovery Rider.

VIII. CONCLUSION

For the foregoing reasons, OTP respectfully requests approval to implement the Transmission Cost Recovery Rider, Rate Designation 13.07, effective as of June 1, 2011.

Date: April 29, 2011

Respectfully submitted:

OTTER TAIL POWER COMPANY

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Attachments

Attachment 1	Revenue
Attachment 2	Revenue Requirements Summary
Attachment 3	Rate Design
Attachment 4	Tracker Summary
Attachment 5	Transmission Project #1 Example Revenue Requirements Calculation
Attachment 6	Redline and Clean Rate Schedules
Attachment 7	Wholesale Sales Revenue Credit Worksheet
Attachment 8	MISO Schedule 26 Expense Estimate

Otter Tail Power Company
Transmission Cost Recovery Rider
Docket No. PU-11-___

Projected Revenue for 2011

Line No.	Class		Units		Rate per Unit	Amount
1	Large General Service	(a)	625,434,660	kWh	0.094¢	$586,110
2						
3	Controlled Service	(b)	237,020,541	kWh	0.019¢	$46,114
4						
5	Lighting	(c)	23,227,738	kWh	0.072¢	$16,826
6						
7	All other service		957,837,354	kWh	0.130¢	$1,243,266
8						
9	Total revenue					$1,892,316

(a) Rate Schedules 10.03 Large General Service and 10.05 Large General Service - Time
(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

Otter Tail Power Company
Transmission Cost Recovery Rider
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Summary of Revenue Requirements

Line No.	Revenue Requirements	2011
1	Project #1	$0
2	Schedule 26	1,875,775
3	Carrying Cost	16,541
4	Total	$1,892,316

Otter Tail Power Company
Transmission Cost Recovery Rider
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Attachment 3
Page 1 of 1

Class Allocation and Rate Design

Line No.			2011	
1	Total North Dakota Revenue Requirements		$1,892,316	*
2	Large General Service Class	30.97%	$586,110	
3	Controlled Service	2.44%	46,114	
4	Lighting	0.89%	16,826	
5	All Other Service	65.70%	1,243,266	
6	Total		$1,892,316	
7	Large General Service Class	kWh	625,434,660	
8	Controlled Service	kWh	237,020,541	
9	Lighting	kWh	23,227,738	
10	All Other Service	kWh	957,837,354	
11	Large General Service Class	cents / kwh	0.094	
12	Controlled Service	cents / kwh	0.019	
13	Lighting	cents / kwh	0.072	
14	All Other Service	cents / kwh	0.130	

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

Otter Tail Power Company
Transmission Rider Tracker
North Dakota

Line No.	TRACKER SUMMARY *Requirements Compared to Billed:*	2011 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
	Revenue Requirements													
1	Project	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total	0	0	0	0	0	0	0	0	0	0	0	0	0
3	MISO Schedule 26 - expense/(revenue)	40,471	108,600	101,068	87,399	85,764	66,800	77,429	80,290	84,589	84,313	68,520	73,468	958,712
4	Net Revenue Requirement	40,471	108,600	101,068	87,399	85,764	66,800	77,429	80,290	84,589	84,313	68,520	73,468	958,712
5														
6	Billed (forecast kWh x adj factor)	0	0	0	0	0	131,001	130,296	133,905	138,264	133,901	157,688	182,041	958,712
7														
8	Difference	40,471	108,600	101,068	87,399	85,764	(64,201)	(52,867)	(53,615)	(53,676)	(49,588)	(89,168)	(108,573)	0
9	Carrying Charge													
10	Cummulative Difference	40,471	149,072	250,140	337,539	423,303	359,103	306,236	252,621	198,946	149,358	60,189	(48,383)	(48,383)
11														
12	Carrying Charge Calculation	291	1,070	1,796	2,424	3,039	2,578	2,199	1,814	1,428	1,072	432	(347)	
13	Cumulative Carrying Charge	291	1,361	3,157	5,580	8,620	11,198	13,397	15,211	16,639	17,711	18,144	17,796	17,796
14	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%	
15														
16														
17														
18	Forecasted Sales (MWh)	192,781	192,074	172,826	155,188	129,775	127,623	126,936	130,452	134,699	130,448	153,622	177,346	1,823,770

Otter Tail Power Company
Transmission Rider Tracker
North Dakota

Line No.	*TRACKER SUMMARY* *Requirements Compared to Billed:*	2012 January Projected	February Projected	March Projected	April Projected	May Projected	Jan 2011 thru May 2012
	Revenue Requirements						
1	Project	0	0	0	0	0	0
2	Total	0	0	0	0	0	0
3	MISO Schedule 26 - expense/(revenue)	183,140	185,605	199,122	176,246	172,948	1,875,775
4	Net Revenue Requirement	183,140	185,605	199,122	176,246	172,948	1,875,775
5							
6	Billed (forecast kWh x adj factor)	199,567	201,201	184,836	158,944	140,673	
7							
8	Difference	(16,427)	(15,596)	14,287	17,303	32,276	
9	Carrying Charge					16,541	
10	Cummulative Difference	(64,810)	(80,406)	(66,119)	(48,817)	(0)	
11							
12	Carrying Charge Calculation	(338)	(452)	(353)	(231)	118	
13	Cumulative Carrying Charge	17,459	17,007	16,654	16,423	16,541	
14	Carrying cost	8.62%	8.62%	8.62%	8.62%	8.62%	
15							
16							
17							
18	Forecasted Sales (MWh)	194,421	196,013	180,069	154,845	137,045	

SUMMARY	Jan 2011 - May 2012
Revenue requirements	$1,875,775
Carrying Charge	16,541
Total requirements	$1,892,316
June 2011-May 2012 projected sales in mWh	1,843,520
Average Rate	$0.00103

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Project

Line No.		2011 Projected January	2011 Projected February	2011 Projected March	2011 Projected April	2011 Projected May	2011 Projected June	2011 Projected July	2011 Projected August	2011 Projected September	2011 Projected October	2011 Projected November	2011 Projected December	2011 Projected Total
	RATE BASE													
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Accumulated. Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	0
4	CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Accum. Deferred Inc. Taxes Fed & State	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Ending rate base	0	0	0	0	0	0	0	0	0	0	0	0	0
7														
8	Average rate base	0	0	0	0	0	0	0	0	0	0	0	0	0
9														
10	Return on Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0
11														
12	Available for return (equity portion of rate base)	0	0	0	0	0	0	0	0	0	0	0	0	0
13														
14	*EXPENSES*													
15	*O&M and Depreciation*													
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
20														
21	Income before Taxes													
22	Available for return (from above)	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Taxable Income (grossed up)	0	0	0	0	0	0	0	0	0	0	0	0	0
24														
25	Income Taxes													
26	Current and Def Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Total Income Tax Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
28														
29														
30	*REVENUE REQUIRMENTS*													
31	Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Return on rate base	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Subtotal revenue requirements	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Adjustments													
35	Transmission Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total revenue requirements	0	0	0	0	0	0	0	0	0	0	0	0	0
37														
38	North Dakota share - D2 factor	0	0	0	0	0	0	0	0	0	0	0	0	0

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Project

Line No.														
	SUPPORTING INFORMATION / DATA													
1														
2		ND Capstructure with allowed ROE per order.												
3		Capital Structure		**Ratio**		**Cost**		**WA Cost**			Property tax			
4		Debt		43.11%		6.30%		2.72%			2011 composite rate		0.94%	
5		Preferred equity		3.60%		4.75%		0.17%						
6		Common equity		53.30%		10.75%		5.73%			Book Depreciation			
7		Total		100.00%				8.62%	Overall Return		2011 composite rate		1.9338%	
8														
9				Book	Tax									
10		Project life (years)		50	15-year MACRS									
11														
12			Statutory Tax Rate	39.16%										
13			Tax conversion factor	1.64366										
14			Transmission Revenue	17.32%										
15			ND share - D2 factor	41.257%										
16	**Deferred Tax**													
17	Book depr. rate	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	1.93%
18	Tax depr. rate (15-year MACRS) Yr 1													3.75%
19	Tax depr. rate (15-year MACRS) Yr 2													9.63%
20	Tax depr. rate (15-year MACRS) Yr 3													8.66%
21	Tax depr. rate (15-year MACRS) Yr 4	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	7.80%
22	Tax depr. rate (15-year MACRS) Yr 5													7.02%
23	Tax depr. rate (15-year MACRS) Yr 6													6.31%
24	Tax depr. rate (15-year MACRS) Yr 7													5.90%
25	Tax depr. rate (15-year MACRS) Yr 8													5.90%
26	Tax depr. rate (15-year MACRS) Yr 9													5.91%
27	Tax depr. rate (15-year MACRS) Yr 10													5.90%
28	Tax depr. rate (15-year MACRS) Yr 11													5.91%
29	Tax depr. rate (15-year MACRS) Yr 12													5.90%
30	Tax depr. rate (15-year MACRS) Yr 13													5.91%
31	Tax depr. rate (15-year MACRS) Yr 14													5.90%
32	Tax depr. rate (15-year MACRS) Yr 15													5.91%
33	Tax depr. rate (15-year MACRS) Yr 16													3.69%
34														
35	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Tax depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Book vs. tax depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Federal & State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
39														

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Project

Line No.		2012 Projected January	2012 Projected February	2012 Projected March	2012 Projected April	2012 Projected May	2012 Projected June	2012 Projected July	2012 Projected August	2012 Projected September	2012 Projected October	2012 Projected November	2012 Projected December	2012 Projected Total
	RATE BASE													
1	Plant Balance	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Accumulated. Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Plant in Service	0	0	0	0	0	0	0	0	0	0	0	0	0
4	CWIP	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Accum. Deferred Inc. Taxes Fed & State	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Ending rate base	0	0	0	0	0	0	0	0	0	0	0	0	0
7														
8	Average rate base	0	0	0	0	0	0	0	0	0	0	0	0	0
9														
10	Return on Rate Base	0	0	0	0	0	0	0	0	0	0	0	0	0
11														
12	Available for return (equity portion of rate base)	0	0	0	0	0	0	0	0	0	0	0	0	0
13														
14	*EXPENSES*													
15	*O&M and Depreciation*													
16	Operating Costs	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Property Tax	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Book Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Total O&M and Depreciation Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
20														
21	Income before Taxes													
22	Available for return (from above)	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Taxable Income (grossed up)	0	0	0	0	0	0	0	0	0	0	0	0	0
24														
25	Income Taxes													
26	Current and Def Income Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Total Income Tax Expense	0	0	0	0	0	0	0	0	0	0	0	0	0
28														
29														
30	*REVENUE REQUIRMENTS*													
31	Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Return on rate base	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Subtotal revenue requirements	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Adjustments													
35	Transmission Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Total revenue requirements	0	0	0	0	0	0	0	0	0	0	0	0	0
37														
38	North Dakota share - D2 factor	0	0	0	0	0	0	0	0	0	0	0	0	0

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Project

Line No.														
	SUPPORTING INFORMATION / DATA													
1														
2		ND Capstructure with allowed ROE per order.												
3		Capital Structure		**Ratio**		**Cost**		**WA Cost**			Property tax			
4		Debt		43.11%		6.30%		2.72%			2011 composite rate		0.94%	
5		Preferred equity		3.60%		4.75%		0.17%						
6		Common equity		53.30%		10.75%		5.73%			Book Depreciation			
7		Total		100.00%				8.62%	Overall Return		2011 composite rate		1.9338%	
8														
9				Book	Tax									
10		Project life (years)		50	15-year MACRS									
11														
12			Statutory Tax Rate	39.16%										
13			Tax conversion factor	1.64366										
14			Transmission Revenue	17.32%										
15			ND share - D2 factor	41.257%										
16	**Deferred Tax**													
17	Book depr. rate	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	1.93%
18	Tax depr. rate (15-year MACRS) Yr 1													3.75%
19	Tax depr. rate (15-year MACRS) Yr 2													9.63%
20	Tax depr. rate (15-year MACRS) Yr 3													8.66%
21	Tax depr. rate (15-year MACRS) Yr 4	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	7.80%
22	Tax depr. rate (15-year MACRS) Yr 5													7.02%
23	Tax depr. rate (15-year MACRS) Yr 6													6.31%
24	Tax depr. rate (15-year MACRS) Yr 7													5.90%
25	Tax depr. rate (15-year MACRS) Yr 8													5.90%
26	Tax depr. rate (15-year MACRS) Yr 9													5.91%
27	Tax depr. rate (15-year MACRS) Yr 10													5.90%
28	Tax depr. rate (15-year MACRS) Yr 11													5.91%
29	Tax depr. rate (15-year MACRS) Yr 12													5.90%
30	Tax depr. rate (15-year MACRS) Yr 13													5.91%
31	Tax depr. rate (15-year MACRS) Yr 14													5.90%
32	Tax depr. rate (15-year MACRS) Yr 15													5.91%
33	Tax depr. rate (15-year MACRS) Yr 16													3.69%
34														
35	Book depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Tax depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Book vs. tax depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0
38	Federal & State deferred income taxes	0	0	0	0	0	0	0	0	0	0	0	0	0
39														

Electric Service – North Dakota - Index

OTTER TAIL POWER COMPANY
Fergus Falls, Minnesota

OTTER TAIL POWER COMPANY
Fergus Falls, Minnesota

Rate Schedules & Riders

Section	*Prior Sheet*	*Item*
11.00	**OTHER SERVICES**	
11.01	71.1 71.2	Standby Service
11.02	90	Irrigation Service
11.03	93	Outdoor Lighting – Energy Only Dusk to Dawn
11.04	94	Outdoor Lighting Dusk to Dawn
11.05	95	Municipal Pumping Service
11.06	96	Civil Defense - Fire Sirens
12.00	**PURCHASE POWER RIDERS & APPLICABILITY MATRIX**	
12.01	70.8	Small Power Producer Rider Occasional Delivery Energy Service (Net Energy Billing Rate)
12.02	70.9	Small Power Producer Rider Time of Delivery Energy Service
12.03	71	Small Power Producer Rider Dependable Service
13.00	**MANDATORY RIDERS & APPLICABILITY MATRIX**	
13.01	98	Energy Adjustment Rider • *Applicable to all services and riders unless otherwise stated in the mandatory riders matrix*
13.04	98.8	Renewable Resource Cost Recovery Rider
13.05	N/A	Economic Development Cost Removal Rider ~~C~~
13.06	N/A	Big Stone II Cost Recovery Rider
13.07	N/A	Transmission Cost Recovery Rider N

Section	*Prior Sheet*	*Item*
14.00		**VOLUNTARY RIDERS & APPLICABILITY MATRIX**
14.01	7	Water Heating Control Rider
14.02	30.1	Real Time Pricing Rider
14.03	N/A	Large General Service Rider
14.04	50	Controlled Service – Interruptible Load CT Metering Rider (Large Dual Fuel)
14.05	50.1	Controlled Service – Interruptible Load Self-Contained Metering Rider (Small Dual Fuel)
14.06	50.2	Controlled Service Deferred Load Rider (Thermal Storage)
14.07	50.3 50.4 50.5	Fixed Time of Delivery Rider (Fixed TOD)
14.08	N/A	Air Conditioning Control Rider (**Cool***Savings*)
14.09	91.5	Voluntary Renewable Energy Rider (**Tail***Winds*)
14.10	92	WAPA Bill Crediting Program Rider
14.11	91	Released Energy Access Program (REAP) Rider
14.12	50.7	Bulk Interruptible Service Application and Pricing Guidelines
15.00		**NORTH DAKOTA ELECTRIC SERVICE AREA**
15.00		Retail Electric Service to Communities

MANDATORY RIDERS - APPLICABILITY MATRIX

The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply, Voluntary Rate Riders selected by the Customer, and charges listed in the General Rules and Regulations.

OTTER TAIL POWER COMPANY Applicability Matrix	Mandatory Riders	Energy Adjustment Rider	Renewable Resource Cost Recovery Rider	Economic Development Cost Removal Rider	Big Stone II Cost Recovery Rider	Transmission Cost Recovery Rider	N
Base Tariffs	Section Numbers	13.01	13.04	13.05	13.06	13.07	N
RESIDENTIAL & FARM SERVICES							
Residential Service	9.01						N
Residential Demand Control Service	9.02						N
Farm Service	9.03						N
GENERAL SERVICES							
Small General Service (Less than 20 kW)	10.01						N
General Service (20 kW or Greater)	10.02						N
Large General Service	10.03						N
Commercial Service - Time of Use	10.04						N
Large General Service - Time of Day	10.05						N
OTHER SERVICES							
Standby Service	11.01						N
Irrigation Service	11.02						N
Outdoor Lighting - Energy Only	11.03						N
Outdoor Lighting	11.04						N
Municipal Pumping Service	11.05						N
Fire Sirens - Civil Defense	11.06						N
Key:	✓ = May apply	■ = Mandatory	□ = Not Applicable				

OTTER TAIL POWER COMPANY Applicability Matrix	Mandatory Riders	Energy Adjustment Rider	Renewable Resource Cost Recovery Rider	Economic Development Cost Removal Rider	Big Stone II Cost Recovery Rider	Transmission Cost Recovery Rider	N
Base Tariffs	Section Numbers	13.01	13.04	13.05	13.06	13.07	N
VOLUNTARY RIDERS							
Water Heating Control Rider	14.01						N
Real Time Pricing Rider	14.02						N
Large General Service Rider	14.03	✓					N
Controlled Service - Interruptible Load CT Metering Rider	14.04						N
Controlled Service - Interruptible Load Self-Contained Metering Rider	14.05						N
Controlled Service Deferred Load Rider	14.06						N
Fixed Time of Delivery Rider	14.07						N
Air Conditioning Control Rider	14.08						N
Voluntary Renewable Energy Rider	14.09						N
WAPA Bill Crediting Program Rider	14.10						N
Released Energy Access Program Rider	14.11						N
Bulk Interruptible Service Application and Pricing Guidelines	14.12						N
Key:	✓ = May apply	▪ = Mandatory	☐ = Not Applicable				

OTTER TAIL POWER COMPANY
Fergus Falls, Minnesota

Electric Service – North Dakota - Index

Section	*Prior Sheet*	*Item*
4.00		**METERING & BILLING**
4.01	N/A	Meter and Service Installations
4.02	N/A	Meter Readings
4.03	99.9	Estimated Readings
4.04	N/A	Meter Testing
4.05	99.9	Access to Customers' Premises
4.06	99.9	Establishing Demands
4.07	99.9	Monthly Billing Period and Prorated Bills
4.08	99.9	Electric Service Statement – Identification of Amounts and Meter Reading
4.09	N/A	Billing Adjustments
4.10	98.2	Payment Policy
4.11	N/A	Even Monthly Payment (EMP)
4.12	N/A	Summary Billing Services
4.13	N/A	Account History Charge
4.14	N/A	Combined Metering
5.00		**STANDARD INSTALLATION AND EXTENSION RULES**
5.01	99.9	Extension Rules and Minimum Revenue Guarantee
5.02	N/A	Special Facilities
5.03	99.9	Temporary Services
5.04	N/A	Standard Installation
5.05	N/A	Service Connection

Section	*Prior Sheet*	*Item*
6.00		**USE OF SERVICE RULES**
6.01	99.9	Customer Equipment
6.02	99.9	Use of Service; Prohibition on Resale
7.00		**COMPANY'S RIGHTS**
7.01	99.9	Waiver of Rights or Default
7.02	N/A	Modification of Rates, Rules and Regulations
8.00		**GLOSSARY AND SYMBOLS**
8.01	N/A	Glossary
8.02	N/A	Definition of Symbols

Rate Schedules & Riders

9.00		**RESIDENTIAL AND FARM SERVICES**
9.01	1	Residential Service
9.02	5	Residential Demand Control Service
9.03	16	Farm Service
10.00		**GENERAL SERVICES**
10.01	N/A	Small General Service (Under 20 kW)
10.02	20	General Service (20 kW or Greater)
10.03	30	Large General Service
10.04	N/A	Commercial Service – Time of Use
10.05	30.3	Large General Service – Time of Day - Experimental

Section	*Prior Sheet*	*Item*
11.00		**OTHER SERVICES**
11.01	71.1 71.2	Standby Service
11.02	90	Irrigation Service
11.03	93	Outdoor Lighting – Energy Only Dusk to Dawn
11.04	94	Outdoor Lighting Dusk to Dawn
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11.06	96	Civil Defense - Fire Sirens
12.00		**PURCHASE POWER RIDERS & APPLICABILITY MATRIX**
12.01	70.8	Small Power Producer Rider Occasional Delivery Energy Service (Net Energy Billing Rate)
12.02	70.9	Small Power Producer Rider Time of Delivery Energy Service
12.03	71	Small Power Producer Rider Dependable Service
13.00		**MANDATORY RIDERS & APPLICABILITY MATRIX**
13.01	98	Energy Adjustment Rider • *Applicable to all services and riders unless otherwise stated in the mandatory riders matrix*
13.04	98.8	Renewable Resource Cost Recovery Rider
13.05	N/A	Economic Development Cost Removal Rider
13.06	N/A	Big Stone II Cost Recovery Rider
13.07	N/A	Transmission Cost Recovery Rider **N**

MANDATORY RIDERS - APPLICABILITY MATRIX

The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply, Voluntary Rate Riders selected by the Customer, and charges listed in the General Rules and Regulations.

OTTER TAIL POWER COMPANY Applicability Matrix	Mandatory Riders	Energy Adjustment Rider	Renewable Resource Cost Recovery Rider	Economic Development Cost Removal Rider	Big Stone II Cost Recovery Rider	Transmission Cost Recovery Rider	N
Base Tariffs	Section Numbers	13.01	13.04	13.05	13.06	13.07	N
RESIDENTIAL & FARM SERVICES							
Residential Service	9.01						N
Residential Demand Control Service	9.02						N
Farm Service	9.03						N
GENERAL SERVICES							
Small General Service (Less than 20 kW)	10.01						N
General Service (20 kW or Greater)	10.02						N
Large General Service	10.03						N
Commercial Service - Time of Use	10.04						N
Large General Service - Time of Day	10.05						N
OTHER SERVICES							
Standby Service	11.01						N
Irrigation Service	11.02						N
Outdoor Lighting - Energy Only	11.03						N
Outdoor Lighting	11.04						N
Municipal Pumping Service	11.05						N
Fire Sirens - Civil Defense	11.06						N
Key:	✓ = May apply	■ = Mandatory	□ = Not Applicable				

OTTER TAIL POWER COMPANY Applicability Matrix	Mandatory Riders	Energy Adjustment Rider	Renewable Resource Cost Recovery Rider	Economic Development Cost Removal Rider	Big Stone II Cost Recovery Rider	Transmission Cost Recovery Rider	N
Base Tariffs	Section Numbers	13.01	13.04	13.05	13.06	13.07	N
VOLUNTARY RIDERS							
Water Heating Control Rider	14.01	■	■	■	■	■	N
Real Time Pricing Rider	14.02	■	■	■	■	■	N
Large General Service Rider	14.03	✓	■	■	■	■	N
Controlled Service - Interruptible Load CT Metering Rider	14.04	■	■	■	■	■	N
Controlled Service - Interruptible Load Self-Contained Metering Rider	14.05	■	■	■	■	■	N
Controlled Service Deferred Load Rider	14.06	■	■	■	■	■	N
Fixed Time of Delivery Rider	14.07	■	■	■	■	■	N
Air Conditioning Control Rider	14.08						N
Voluntary Renewable Energy Rider	14.09						N
WAPA Bill Crediting Program Rider	14.10						N
Released Energy Access Program Rider	14.11	■					N
Bulk Interruptible Service Application and Pricing Guidelines	14.12	■	■	■	■	■	N
Key:	✓ = May apply	■ = Mandatory	□ = Not Applicable				

TRANSMISSION COST RECOVERY RIDER N

DESCRIPTION	RATE CODE
Large General Service	30-510
Controlled Service	30-511
Lighting	30-512
All Other Service	30-513

N N N N N N

REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this schedule. N N

APPLICATION OF SCHEDULE: This rate schedule is applicable to any electric service under all of the Company's retail rate schedules. N N

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. N N N N N

RATE: N

TRANSMISSION COST RECOVERY N

Energy Charge per kWh:	kWh		
Large General Service (a)	0.093	¢/kWh	
Controlled Service (b)	0.019	¢/kWh	
Lighting (c)	0.072	¢/kWh	
All Other Service	0.129	¢/kWh	

N N N N N

(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

N N N N N

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

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

Line No.	Attachment O		Total	Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT (page 3, line 31)					$ 34,298,860
	REVENUE CREDITS	(Note T)				
2	Account No. 454	(page 4, line 34)	115,163	TP	1.00000	115,163
3	Account No. 456.1	(page 4, line 37)	5,805,049	TP	1.00000	5,805,049
4	Revenues from Grandfathered Interzonal Transactions		20,400	TP	1.00000	20,400
5	Revenues from service provided by the ISO at a discount		0	TP	1.00000	0
6	TOTAL REVENUE CREDITS (sum lines 2-5)					5,940,612
7				Wholesale Revenue Credit		17.32%

Line No.	SCHEDULE 26		2011 Jan Actual	Feb Actual	Mar Actual	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	MISO Schedule 26 Expense		98,095	263,227	244,971	211,840	207,876	161,911	187,674	194,608	205,027	204,358	166,080	178,072	2,323,741
2	MISO Schedule 26 Revenue		0	0	0	0	0	0	0	0	0	0	0	0	0
3	Net Schedule 26		98,095	263,227	244,971	211,840	207,876	161,911	187,674	194,608	205,027	204,358	166,080	178,072	2,323,741
4	North Dakota share	41.25727%	40,471	108,600	101,068	87,399	85,764	66,800	77,429	80,290	84,589	84,313	68,520	73,468	958,712

Line No.	SCHEDULE 26		2012 Jan Projected	Feb Projected	Mar Projected	Apr Projected	May Projected	Jun Projected	Jul Projected	Aug Projected	Sep Projected	Oct Projected	Nov Projected	Dec Projected	YE Projected
1	MISO Schedule 26 Expense		443,898	449,873	482,636	427,188	419,195	326,504	378,457	392,438	413,450	412,101	334,911	359,093	4,839,745
2	MISO Schedule 26 Revenue														0
3	Net Schedule 26		443,898	449,873	482,636	427,188	419,195	326,504	378,457	392,438	413,450	412,101	334,911	359,093	4,839,745
4	North Dakota share	41.25727%	183,140	185,605	199,122	176,246	172,948	134,707	156,141	161,909	170,578	170,022	138,175	148,152	1,996,747