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November 5, 2010

Ms. Patricia Van Gerpen
Executive Director
South Dakota Public Utilities Commission
Capitol Building, 1st floor
500 East Capitol Avenue
Pierre, SD 57501-5070

Re: In the Matter of Otter Tail Power Company's Transmission Cost Recovery Rider Filing

Dear Ms. Van Gerpen:

Enclosed you will find the petition of Otter Tail Power Company, to the South Dakota Public Utilities Commission on implementation of a transmission cost recovery rider pursuant to Statutes §49-05-04.3 and §49-34A-25.1 through §49-34A-25.4.

If you have any questions regarding this filing, please contact me at 218-739-8269 or bmorlock@otpco.com.

Sincerely,

/s/ BRYAN D. MORLOCK
Bryan D. Morlock, P.E.
Consultant, Planning

wao
Enclosures
By electronic filing

STATE OF SOUTH DAKOTA
BEFORE THE
SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

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

Docket No. __________

PETITION OF OTTER TAIL POWER COMPANY

I. INTRODUCTION.

Otter Tail Power Company, ("Otter Tail or Company"), hereby petitions the South Dakota Public Utilities Commission ("Commission") for approval of a Transmission Cost Recovery Tariff, pursuant to SDCL Chapter 49-05 Section 4.3 and Chapter 49-34A Sections 25.1 through 25.4.

II. GENERAL FILING INFORMATION.

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.

Bruce Gerhardson
Associate General Counsel
Otter Tail Corporation
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.

Bryan D. Morlock, P.E.
Consultant, Planning
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496
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D. The date of filing and the date changes will take effect.

The date of this filing is November 5, 2010. Otter Tail 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 Otter Tail to increase regional transmission capacity or reliability, contained herein, go into effect as of March 1, 2011.

E. Statute controlling schedule for processing the filing.

ARSD Part 20:10:13:15 requires a 30-day notice to the Commission of a proposed change in a utility's tariff schedule, after which time the proposed changes take effect unless suspended. Because no determination of Otter Tail's general revenue requirement is necessary, the report called for under Part 20:10:13:26 and the general notice provisions applicable to changes in rates is not applicable in this filing. Otter Tail requests an expedited and informal proceeding, including any variances that may be necessary.

Pursuant to ARSD 20:10:13:18, Otter Tail will post a Notice of proposed changes contained in Attachment #10. This Notice will be placed in a conspicuous place in each business office in Otter Tail's affected electric service territory in South Dakota for at least 30 days before the change becomes effective. Otter Tail has also included Attachment #7 to comply with ARSD 20:10:13:26, which requires the Utility to report all rate schedule changes and customer impacts.

III. BACKGROUND OF ISSUE.

The South Dakota Legislature in 2006 passed HB 1091 which authorizes the Commission to approve a tariff mechanism for the automatic annual adjustment of charges for a public utility to recover the South Dakota jurisdictional portion of eligible investments in and expenses related to new or modified transmission resources. Eligible projects are defined as new or modified transmission facilities more than 5 miles in length and rated at 34.5 kilovolts or more. Associated facilities such as transformers and substations are included. Eligible expenses includes federally regulated costs charged to or incurred by the public utility to increase regional transmission capability or reliability.

HB 1091 is the Legislature's instrument to incentivize the investment in new transmission facilities to improve the capability and stability of the electric transmission system in South Dakota.

IV. PROPOSED CHANGES.

During the 2006 South Dakota Legislative Session, SD Stat. §49-05-04.3 was amended to read 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 petition, Otter Tail 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 Miwest Independent Transmission System Operator (MISO) through Schedule 26 under the federally regulated MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff.

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

Otter Tail 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 Open Access Transmission, Energy and Operating Reserve Markets Tariff ("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 Project ("BRP") required to ensure Transmission System reliability consistent with North American Electric Reliability Corporation ("NERC") standards, (2) Regionally Beneficial Project ("RBP") that provides economic benefit to the Midwest ISO Transmission System, (3) Generator Interconnection Project ("GIP") Network Upgrades required for the interconnection of generation to the Midwest ISO Transmission System, or (4) Multi Value Project ("MVP") that address regional public policy, reliability, and economic value to the Midwest ISO footprint.

Baseline Reliability Projects that are 345 kV and greater and that have a project cost greater than $5 million (or 5% 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] Baseline Reliability Projects that are between 100 kV and 345 kV and have a project cost greater than $5 million in project costs (or 5% 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.

Regionally Beneficial Projects 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

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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.

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.

Generator Interconnection Project Network Upgrades ("GIP NUs") are allocated pursuant to Attachment FF of the Midwest ISO Tariff, assigning up to 100% 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% to the Interconnection Customer.

Multi Value Projects 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).

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 which 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

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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.

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.

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

- For a project which 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, Otter Tail 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 which 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, Otter Tail 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 Otter Tail customers from revenue requirements of the project except for the revenue requirements specifically allocated to Otter Tail 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 Otter Tail will provide the project revenue requirements to pay for project costs.

Otter Tail has included Schedule 26 costs for recovery in this filing. The costs appear on line 4 of the Tracker Account (Attachment 4) and are shown separately in Attachment #9.

b. New or Modified Transmission Projects

Otter Tail presently has a general rate case filed with the Commission in Docket No. EL10-011. All transmission projects for which the Company is seeking cost recovery are included in the rate case and are anticipated to be included in base rates. Otter Tail 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.

Attachments #5 and #6 are examples of revenue requirement calculations for transmission projects 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.* SDCL §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 open access transmission tariff. It is a revenue credit that represents revenue that Otter Tail 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 Otter Tail's 2011 Attachment O, the revenue credit adjustment is 17.32%. This MISO revenue credit percentage is applied to in-service revenue requirements and updated each year thereafter. Therefore, the 17.32% is applied to the computed revenue requirement for the project. The calculation of the revenue credit adjustment is shown in Attachment #8.

- *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 Otter Tail'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 our 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. Otter Tail will set up transmission O&M accounting projects to track O&M costs specifically related to each line included in the Rider.

c. Tracker Balance

Otter Tail maintains a tracker account worksheet and accounting system 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 Otter Tail's costs and the amount recovered through South Dakota retail revenue. The tracker account balance (either positive or negative) will accrue monthly carrying charges at a rate of 1/12 of Otter Tail's cost of capital times the 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 Otter Tail.

Otter Tail anticipates continuing to make annual filings to revise the Transmission Cost Recovery Rates to reflect updated revenue requirements and additional new 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 4.

V. RATE DESIGN.

Otter Tail's proposed rate design uses the transmission demand allocation factor, D2, from Otter Tail's last South Dakota general rate case to allocate total revenue requirements to jurisdictions (South Dakota, 9.260463%) and rate classes. Otter Tail will update this allocator once Otter Tail's pending general rate case is completed and reflect any adjustment in the proposed tracker. The large general service (LGS) class's portion of retail revenue requirements based on D2 is 47.54%. The remaining portion (52.46%) of the retail revenue requirements will be collected from the non-LGS rate classes. This allocation method appropriately reflects the demand-driven nature of transmission costs. Otter Tail's proposed LGS rate design for the Transmission Rider incorporates demand ($/kW-month) and energy (¢/kWh) rates that recover the transmission project costs in a manner that follows existing LGS base rate design. Specifically, the LGS revenue requirements will be split between demand and energy based on the 2011 forecast base rate demand and energy revenue proportion of approximately 14% demand and 86% energy. As part of future filings, this split will be reviewed as necessary to reflect any material load changes. The LGS demand rate will be calculated as the LGS demand revenue requirements divided by the LGS class billing demand for the forecast year. The LGS energy rate will be calculated as the LGS energy revenue requirements divided by the LGS kilowatt-hour sales for the projected calendar year.

For the remaining retail rate classes (non-LGS) of controlled service, and lighting, and all other classes, Otter Tail proposes an energy rate only. 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 for controlled service, lighting, and all other classes is appropriate because it reflects the primarily energy-based rates for these classes and reduces the complexisty of administration.

VI. RATE APPLICATION AND IMPACT.

Otter Tail proposes that the Transmission Rider should be applicable to electric service under all of Otter Tail's retail rate schedules. The charge will be included as part of the Fuel Adjustment line on customers' bills. The proposed rates are as follows:

Class	¢ / kWh	$ / kW
Large General Service	0.045¢	$0.039
Controlled Service	0.061¢	N/A
Lighting	0.067¢	N/A
All other service	0.043¢	N/A

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

Approved SD Rates Based on 2007 Test Year			
Rate Class Impacts (1)		**Rate Class Impacts (1)**	
Residential		**Outdoor Lighting**	
Average Rate (¢/kWh)	8.416	Average Rate (¢/kWh)	13.137
Increase %	0.52%	Increase %	0.55%
Average Impact ($/month)	$0.35	Average Impact ($/month)	$0.05
Farm		**Municipal Pumping**	
Average Rate (¢/kWh)	7.797	Average Rate (¢/kWh)	5.892
Increase %	0.60%	Increase %	0.72%
Average Impact ($/month)	$0.81	Average Impact ($/month)	$1.49
General Service		**Water Heating, Controlled**	
Average Rate (¢/kWh)	7.857	Average Rate (¢/kWh)	6.465
Increase %	0.53%	Increase %	1.06%
Average Impact ($/month)	$1.13	Average Impact ($/month)	$0.13
Large General Service		**Interruptible Load**	
Average Rate (¢/kWh)	5.484	Average Rate (¢/kWh)	3.929
Average Rate ($/kW)	$4.30	Increase %	1.66%
Increase %	1.00%	Average Impact ($/month)	$1.10
Average Impact ($/month)	$117.96		
Irrigation		**Deferred Load**	
Average Rate (¢/kWh)	6.470	Average Rate (¢/kWh)	4.245
Increase %	0.67%	Increase %	1.37%
Average Impact ($/month)	$2.42	Average Impact ($/month)	$0.90

(1) Average rate calculation is from SD Docket No. EL08-030. Rate impacts are calculated from base rates.

The above rates are based on the assumption that they will be in effect beginning March 1, 2011. Revenue requirement calculations are based on the total 2011 costs, assuming revenue collection over the entire year. With revenue collection only over the March 1 – December 31, 2011 time period, some 2011 revenue requirements will be carried over to 2012 through the tracker true-up process. It is estimated that approximately $46,757 of revenue requirements plus $3,538 of carrying cost will be carried into 2012. If the effective date is significantly later than

March 1, 2011, Otter Tail requests the option to recalculate the Transmission Cost Recovery Rates in order to recover all approved costs in the remainder of 2011.

VII. TRANSMISSION COST RECOVERY RIDER RATE SCHEDULE.

Otter Tail's proposed Transmission Cost Recovery Rider is Attachment #7 to this Petition.

VIII. REVISIONS TO OTHER RATE SCHEDULES.

Attachment #7 to this Petition also includes redline and proposed final versions of Otter Tail's Rate Schedules Index and Rate Schedule 13.00, Mandatory Riders – Applicability Matrix, showing the addition of the Transmission Cost Recovery Rider.

IX. FIVE-YEAR TRANSMISSION RIDER ESTIMATE.

Otter Tail does not have any transmission projects in the five-year capital budget at this time that would be included in the Transmission Rider for ratebase recovery. It is possible that a project or projects could arise within the five-year period due to customer needs or unforeseen circumstances.

It is very difficult to forecast the Schedule 26 charges as MISO does not provide the information necessary to develop forward projections. Thus Otter Tail cannot forecast the Schedule 26 charges from RECB I projects being constructed in other parts of MISO. Based on the Company's expected investment levels in the Fargo to St. Cloud and Bemidji to Grand Rapids CAPX2020 projects, Otter Tail is forecasting the following *Company-wide* Schedule 26 charges:

2011	$1,218,960
2012	$4,840,000
2013	$6,828,000
2014	$8,223,000
2015	$9,045,000

X. CONCLUSION.

For the foregoing reasons, Otter Tail respectfully requests approval to implement the rate schedule with Rate Designation 13.05 effective as of March 1, 2009.

Date: November 5, 2010

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	Transmission Project #2 Example Revenue Requirements Calculation
Attachment #7	Redline and Clean Rate Schedules
Attachment #8	Wholesale Sales Revenue Credit Worksheet
Attachment #9	MISO Schedule 26 Expense Estimate
Attachment #10	Customer Notice

Projected Revenue for 2011

Class		Units		Rate per Unit		Amount
Large General Service	(a)	376,715	kW	$0.039		$14,791
		200,751,529	kWh	0.045	¢	90,858
Total LGS						$105,648
Controlled service	(b)	43,875,465	kWh	0.061	¢	$26,846
Lighting	(c)	4,509,929	kWh	0.067	¢	3,034
All other service		201,185,118	kWh	0.043	¢	86,722
Total revenue						$222,251

(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

Revenue Requirements	**2011**
Project 1	$ -
Project 2	-
Schedule 26	222,251
2010 Carrying cost	-
2010 True Up	-
Total	$ 222,251

Class Allocation and Rate Design

		2011	
Total South Dakota revenue requirements		$222,251	*
Large General Service class	47.54%	$105,648	
Controlled service	12.08%	26,846	
Lighting	1.37%	3,034	
All other service	39.02%	86,722	
Total		$222,251	
Large General Service class	kW	376,715	
Large General Service class	kWh	200,751,529	
Controlled service	kWh	43,875,465	
Lighting	kWh	4,509,929	
All other service	kWh	201,185,118	
Large General Service class	$ / kW month	0.039	**
Large General Service class	cents / kwh	0.045	
Controlled service	cents / kwh	0.061	
Lighting	cents / kwh	0.067	
All other service	cents / kwh	0.043	

* Jurisdictional transmission allocation factor (D2 = 9.260463%) is from Otter Tail's last general rate case in South Dakota.

** LGS revenue is 14% demand and 86% energy

Otter Tail Power Company
Transmission Rider Tracker
South Dakota

ATTACHMENT 4
PAGE 1 0F 1

TRACKER SUMMARY

Line								2011						
		January	February	March	April	May	June	July	August	September	October	November	December	YE
	Requirements Compared to Billed:	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
	Revenue Requirements													ck
1	Project 1	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Project 2	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Total	0	0	0	0	0	0	0	0	0	0	0	0	0
4	MISO Schedule 26 - expense/(revenue)	20,385	20,659	22,164	19,617	19,250	14,994	17,380	18,022	18,986	18,925	15,380	16,490	222,251
5	Net Revenue Requirement	20,385	20,659	22,164	19,617	19,250	14,994	17,380	18,022	18,986	18,925	15,380	16,490	222,251
6														
7	Billed (forecast kWh x adj factor)	0	0	19,894	18,481	16,519	16,564	17,035	17,347	17,533	16,552	18,481	20,256	222,251
8														
9	Difference	20,385	20,659	2,411	1,423	3,036	(1,253)	685	1,008	1,795	2,723	(2,736)	(3,379)	(3,379)
10	Carrying Charge	-	142	286	305	317	340	334	341	350	365	387	370	
11	Cummulative Difference	20,385	41,186	43,883	45,611	48,964	48,051	49,070	50,419	52,564	55,653	53,303	50,295	50,295
12														
13	Carrying Charge Calculation	0	142	286	305	317	340	334	341	350	365	387	370	
14	Cumulative Carrying Charge	0	142	428	733	1,050	1,390	1,724	2,065	2,416	2,781	3,168	3,538	3,538
15	Carrying cost	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%	8.34%
16	Monthly Rate	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	0.695000%	
17														
18														
19														
20														
21														
22	Forecasted Sales (MWh)	44,366	43,953	40,309	37,446	33,471	33,561	34,516	35,149	35,525	33,537	37,446	41,043	450,322
23													450,322	
24														
25														

SUMMARY	
Revenue requirements 2011	$222,251
2010 Carrying Charge and True up	0
Total requirements	$222,251
2011 projected sales in mWh	450,322
Average Rate	$0.00049

SUMMARY	
Year	**2011**
Revenue requirements	$222,251
True up & Carrying Charge	0
Total requirements	$222,251
2011 projected sales in mWh	450,322
Average Rate	$0.00049

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Project:

Line		*Year>>*		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	Total 2011
1	*RATE BASE*															
2	Plant Balance			0	0	0	0	0	0	0	0	0	0	0	0	0
3	Accumulated. Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0
4	Net Plant in Service			0	0	0	0	0	0	0	0	0	0	0	0	0
5	CWIP			0	0	0	0	0	0	0	0	0	0	0	0	0
6	Accum. Deferred Inc. Taxes Fed & State			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Ending rate base			0	0	0	0	0	0	0	0	0	0	0	0	0
8																
9	Average rate base (Informational only; no impact)		-	0	0	0	0	0	0	0	0	0	0	0	0	0
10																
11	Return on Rate Base			0	0	0	0	0	0	0	0	0	0	0	0	0
12																
13	Available for return (equity portion of rate base)			0	0	0	0	0	0	0	0	0	0	0	0	0
14																
15	*EXPENSES*															
16	*O&M and Depreciation*															
17	Operating Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax			0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
21																
22	Income before Taxes															
23	Available for return (from above)			0	0	0	0	0	0	0	0	0	0	0	0	0
24	Taxable Income (grossed up)	1.7056		0	0	0	0	0	0	0	0	0	0	0	0	0
25																
26	Income Taxes															
27	Current and Def Income Taxes		41.37%	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Income Tax Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
29																
30																
31	*REVENUE REQUIRMENTS*															
32	Expenses			0	0	0	0	0	0	0	0	0	0	0	0	0
33	Return on rate base			0	0	0	0	0	0	0	0	0	0	0	0	0
34	Subtotal revenue requirements			0	0	0	0	0	0	0	0	0	0	0	0	0
35	Adjustments															
36	Transmission Revenue		14.99%	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total revenue requirements			0	0	0	0	0	0	0	0	0	0	0	0	0
38																
39	SD share - D2 factor		9.26%	0	0	0	0	0	0	0	0	0	0	0	0	0

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Project:

Line		*Year>>*		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	Total 2011
	SUPPORTING INFORMATION / DATA															
Line																
1	SD Capstructure with allowed ROE per order.															
2	Capital Structure		Ratio													
3	Debt		46.50%													
4	Preferred equity		3.50%													
5	Common equity		50.00%													
6	Total		100.00%													
7																
8			Book													
9	Project life (years)		50													
10																
11	Statutory Tax Rate		41.37%													
12	Tax conversion factor		1.70561													
13																Transmission
14																
15	**Deferred Tax**															
16	Book depr. rate	1.9978%		0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	2.00%
17	Tax depr. rate (15-year MACRS) Yr 1	6.25%														6.25%
18	Tax depr. rate (15-year MACRS) Yr 2	9.38%														9.38%
19	Tax depr. rate (15-year MACRS) Yr 3	8.44%		0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	8.44%
20	Tax depr. rate (15-year MACRS) Yr 4	7.59%														7.59%
21	Tax depr. rate (15-year MACRS) Yr 5	6.83%														6.83%
22	Tax depr. rate (15-year MACRS) Yr 6	6.15%														6.15%
23	Tax depr. rate (15-year MACRS) Yr 7	5.91%														5.91%
24	Tax depr. rate (15-year MACRS) Yr 8	5.90%														5.90%
25	Tax depr. rate (15-year MACRS) Yr 9	5.91%														5.91%
26	Tax depr. rate (15-year MACRS) Yr 10	5.90%														5.90%
27	Tax depr. rate (15-year MACRS) Yr 11	5.91%														5.91%
28	Tax depr. rate (15-year MACRS) Yr 12	5.90%														5.90%
29	Tax depr. rate (15-year MACRS) Yr 13	5.91%														5.91%
30	Tax depr. rate (15-year MACRS) Yr 14	5.90%														5.90%
31	Tax depr. rate (15-year MACRS) Yr 15	5.91%														5.91%
32	Tax depr. rate (15-year MACRS) Yr 16	2.21%														2.21%
33																
34	Book depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Tax depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Book vs. tax depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Federal & State deferred income taxes	41.37%	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38																

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Langdon-Hensel Line

Line																
				lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:
		Year>>		**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	Total 3 Projected 2011
1	*RATE BASE*															
2	Plant Balance			0	0	0	0	0	0	0	0	0	0	0	0	0
3	Accumulated. Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0
4	Net Plant in Service			0	0	0	0	0	0	0	0	0	0	0	0	0
5	CWIP			0	0	0	0	0	0	0	0	0	0	0	0	0
6	Accum. Deferred Inc. Taxes Fed & State			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Ending rate base			0	0	0	0	0	0	0	0	0	0	0	0	0
8																
9	Average rate base		-	0	0	0	0	0	0	0	0	0	0	0	0	0
10																
11	Return on Rate Base			0	0	0	0	0	0	0	0	0	0	0	0	0
12																
13	Available for return (equity portion of rate base)			0	0	0	0	0	0	0	0	0	0	0	0	0
14																
15	*EXPENSES*															
16	*O&M and Depreciation*															
17	Operating Costs			0	0	0	0	0	0	0	0	0	0	0	0	0
18	Property Tax			0	0	0	0	0	0	0	0	0	0	0	0	0
19	Book Depreciation			0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total O&M and Depreciation Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
21																
22	Income before Taxes															
23	Available for return (from above)			0	0	0	0	0	0	0	0	0	0	0	0	0
24	Taxable Income (grossed up)	1.7056		0	0	0	0	0	0	0	0	0	0	0	0	0
25																
26	Income Taxes															
27	Current and Def Income Taxes		41.37%	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Total Income Tax Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
29																
30																
31	*REVENUE REQUIRMENTS*															
32	Expenses			0	0	0	0	0	0	0	0	0	0	0	0	0
33	Return on rate base			0	0	0	0	0	0	0	0	0	0	0	0	0
34	Subtotal revenue requirements			0	0	0	0	0	0	0	0	0	0	0	0	0
35	Adjustments															
36	Transmission Revenue		14.99%	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Total revenue requirements			0	0	0	0	0	0	0	0	0	0	0	0	0
38																
39	South Dakota share - D2 factor		9.260463%	0	0	0	0	0	0	0	0	0	0	0	0	0

Otter Tail Power Company
Transmission Rider - Revenue Requirements
Langdon-Hensel Line

				lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:	lease incr: Inflation:
		Year>>		**2011**	**2011**	**2011**	**2011**	**2011**	**2011**	**2011**	**2011**	**2011**	**2011**	**2011**	**2011**	Total 3
Line				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 2011
	SUPPORTING INFORMATION / DATA															
Line																
1	SD Capstructure with allowed ROE per order.															
2	Capital Structure		Ratio													
3	Debt		46.50%													
4	Preferred equity		3.50%													
5	Common equity		50.00%													
6	Total		100.00%													
7																
8			Book													
9	Project life (years)		50													
10																
11	Statutory Tax Rate		41.37%													
12	Tax conversion factor		1.70561													
13																Transmissio
14																D2 for pendin
15	**Deferred Tax**															
16	Book depr. rate	2.04%		0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	2.00%
17	Tax depr. rate (15-year MACRS) Yr 1	3.75%														3.75%
18	Tax depr. rate (15-year MACRS) Yr 2	9.63%														9.63%
19	Tax depr. rate (15-year MACRS) Yr 3	8.66%		0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	8.66%
20	Tax depr. rate (15-year MACRS) Yr 4	7.80%														7.80%
21	Tax depr. rate (15-year MACRS) Yr 5	7.02%														7.02%
22	Tax depr. rate (15-year MACRS) Yr 6	6.31%														6.31%
23	Tax depr. rate (15-year MACRS) Yr 7	5.90%														5.90%
24	Tax depr. rate (15-year MACRS) Yr 8	5.90%														5.90%
25	Tax depr. rate (15-year MACRS) Yr 9	5.91%														5.91%
26	Tax depr. rate (15-year MACRS) Yr 10	5.90%														5.90%
27	Tax depr. rate (15-year MACRS) Yr 11	5.91%														5.91%
28	Tax depr. rate (15-year MACRS) Yr 12	5.90%														5.90%
29	Tax depr. rate (15-year MACRS) Yr 13	5.91%														5.91%
30	Tax depr. rate (15-year MACRS) Yr 14	5.90%														5.90%
31	Tax depr. rate (15-year MACRS) Yr 15	5.91%														5.91%
32	Tax depr. rate (15-year MACRS) Yr 16	3.69%														3.69%
33																
34	Book depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Tax depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Book vs. tax depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Federal & State deferred income taxes	41.37%	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38																

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Section *Prior Sheet* *Item*

14.00 VOLUNTARY RIDERS & APPLICABILITY MATRIX

Section	Prior Sheet	Item
14.01	7	Water Heating – Controlled Service
14.02	N/A	Real Time Pricing Rider
14.03	30.9	Large General Service Rider
14.04	50	Controlled Service – Interruptible Load (CT Metering) Rider
14.05	50.1	Controlled Service – Interruptible Load (Self-Continaed Metering) Rider
14.06	50.2	Controlled Service – Deferred Load Rider
14.07	50.3 50.4 50.5	Fixed Time of Delivery Rider
14.08	94.5	Voluntary Air Conditioning Control Rider (**Cool***Savings*)
14.09	91.5	Voluntary Renewable Energy Rider (**Tail***Winds*)
14.10	N/A	N/A (section reserved for future use)
14.11	91	Released Energy Access Program (REAP) Rider
14.12	50.7	Bulk Interruptible Service Application and Pricing Guide

15.00 COMMUNITIES SERVED

Section	Prior Sheet	Item
15.00	N/A	South Dakota Communities Served

16.00 SUMMARY OF CONTRACTS WITH DEVIATIONS

Section	Prior Sheet	Item
16.00	Section 4, Sheets 1-4	Summary of Contracts with Deviations

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Section *Prior Sheet* *Item*

11.00 OTHER SERVICES

Section	Prior Sheet	Item
11.01	71.3	Standby Service
11.02	90	Irrigation Service
11.03	93	Outdoor Lighting – Energy Only
11.04	94	Outdoor Lighting
11.05	95	Municipal Pumping Service
11.06	96	Civil Defense – Fire Sirens

12.00 POWER PRODUCER RIDERS & APPLICABILITY MATRIX

Section	Prior Sheet	Item
12.01	70.8	Small Power Producer Rider – Occasional Delivery Energy Service
12.02	70.9	Small Power Producer Rider – Temperature-Time of Delivery Energy Service
12.03	71	Small Power Producer Rider – Dependable Service

13.00 MANDATORY RIDERS & APPLICABILITY MATRIX

Section	Prior Sheet	Item	
13.01	98	Fuel Adjustment Clause Rider • *Applicable to all services and riders unless otherwise stated in the mandatory riders matrix*	
13.02	N/A	N/A (reserved for future use)	
13.03	N/A	N/A (reserved for future use)	
13.04	98.3	Energy Efficiency Project (EEP) Rider	
13.05	N/A	Transmission Cost Recovery Rider	N

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Section *Prior Sheet* *Item*

14.00 VOLUNTARY RIDERS & APPLICABILITY MATRIX

Section	Prior Sheet	Item
14.01	7	Water Heating – Controlled Service
14.02	N/A	Real Time Pricing Rider
14.03	30.9	Large General Service Rider
14.04	50	Controlled Service – Interruptible Load (CT Metering) Rider
14.05	50.1	Controlled Service – Interruptible Load (Self-Continaed Metering) Rider
14.06	50.2	Controlled Service – Deferred Load Rider
14.07	50.3 50.4 50.5	Fixed Time of Delivery Rider
14.08	94.5	Voluntary Air Conditioning Control Rider (**Cool***Savings*)
14.09	91.5	Voluntary Renewable Energy Rider (**Tail***Winds*)
14.10	N/A	N/A (section reserved for future use)
14.11	91	Released Energy Access Program (REAP) Rider
14.12	50.7	Bulk Interruptible Service Application and Pricing Guide

15.00 COMMUNITIES SERVED

Section	Prior Sheet	Item
15.00	N/A	South Dakota Communities Served

16.00 SUMMARY OF CONTRACTS WITH DEVIATIONS

Section	Prior Sheet	Item
16.00	Section 4, Sheets 1-4	Summary of Contracts with Deviations

Fergus Falls, Minnesota

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.

Base Tariffs	Mandatory Riders	Fuel Adjustment Clause Rider	Energy Efficiency Partnership (EEP) Cost Recovery Rider	Transmission Cost Recovery Rider	
	Section Numbers	13.01	13.04	13.05	N
Residential Service	9.01				N
Residential Demand Control Service	9.02				N
Farm Service	9.03				N
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
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

✓ = May apply ■ = Mandatory ☐ = Not Applicable

(Continued)

	Mandatory Riders	Fuel Adjustment Clause Rider	Energy Efficiency Partnership (EEP) Cost Recovery Rider	Transmission Cost Recovery Rider	N
Base Tariffs	Section Numbers	13.01	13.04	13.05	N
Water Heating - Controlled Service	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
Released Energy Rider	14.11				N
Bulk Interruptible Application and Pricing Guidelines Rider	14.12				N

✓ = May apply ■ = Mandatory □ = Not Applicable

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.

	Mandatory Riders	Fuel Adjustment Clause Rider	Energy Efficiency Partnership (EEP) Cost Recovery Rider	Transmission Cost Recovery Rider	N
Base Tariffs	Section Numbers	13.01	13.04	13.05	N
Residential Service	9.01				N
Residential Demand Control Service	9.02				N
Farm Service	9.03				N
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
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

✓ = May apply ■ = Mandatory ☐ = Not Applicable

Fergus Falls, Minnesota

(Continued)

Base Tariffs	**Mandatory Riders**	Fuel Adjustment Clause Rider	Energy Efficiency Partnership (EEP) Cost Recovery Rider	Transmission Cost Recovery Rider	N
	Section Numbers	13.01	13.04	13.05	N
Water Heating - Controlled Service	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
Released Energy Rider	14.11				N
Bulk Interruptible Application and Pricing Guidelines Rider	14.12				N

✓ = May apply ■ = Mandatory □ = Not Applicable

TRANSMISSION COST RECOVERY RIDER N

DESCRIPTION	RATE CODE	
		N
Large General Service	30-510	N
Controlled Service	30-511	N
Lighting	30-512	N
All Other Service	30-513	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 South 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		kW	N
Large General Service	**(a)**	0.045	¢/kWh	$0.039	N
Controlled Service	**(b)**	0.061	¢/kWh	N/A	N
Lighting	**(c)**	0.067	¢/kWh	N/A	N
All Other Service		0.043	¢/kWh	N/A	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. N N
(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 N N
(c) Rate Schedules 11.03 Outdoor Lighting (energy only) and 11.04 Outdoor Lighting 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 Minnesota electric rates for the matrices of riders. N N N N

Attachment O

Line No.			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
				Wholesale Revenue Credit		17.32%

Line			2011												
18	*SCHEDULE 26*														
19			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YE
20			Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
21	MISO Schedule 26 Expense		220,126	223,089	239,336	211,840	207,876	161,911	187,674	194,608	205,027	204,358	166,080	178,072	2,400,000
22	MISO Schedule 26 Revenue		0	0	0	0	0	0	0	0	0	0	0	0	0
23	Net Schedule 26		220,126	223,089	239,336	211,840	207,876	161,911	187,674	194,608	205,027	204,358	166,080	178,072	2,400,000
24	South Dakota Share	9.26%	20,385	20,659	22,164	19,617	19,250	14,994	17,380	18,022	18,986	18,925	15,380	16,490	222,251

Notice to Otter Tail Power Company Customers

Otter Tail Power Company has upgraded transmission facilities to help ensure continued reliable service and to bring renewable energy to our South Dakota customers. The South Dakota Public Utilities Commission has approved an adjustment to the Transmission charge that is part of the Resource Adjustment on your monthly electric bill beginning March 1, 2011 to recover the cost of these transmission upgrades and expansions.

The current Transmission charge is:

Class	¢ / kWh	$ / kW
Large General Service	0.045¢	$0.039
Controlled Service	0.061¢	N/A
Lighting	0.067¢	N/A
All other service	0.043¢	N/A

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