STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Service in North Dakota	Case No. PU-08-862
And	
In the Matter of Otter Tail Power Company's Annual Filing for Renewable Resource Cost Recovery Factor	Case No. PU-08-742

AMENDED SETTLEMENT AGREEMENT

This Settlement Agreement is entered into by and between the North Dakota Public Service Commission Advocacy Staff ("Staff"), Otter Tail Corporation d/b/a Otter Tail Power Company ("OTP") and the Large Industrial Group ("LIG").[1] This Settlement Agreement resolves all outstanding issues in the above-captioned proceedings in a manner consistent with the public interest and will result in just and reasonable rates for OTP's retail electric operations in North Dakota.

BACKGROUND

These proceedings involve two different matters -- OTP's request to increase its retail rates to allow it to earn a reasonable return on equity and a request by OTP to recover through its Renewable Resources Rider costs associated with two wind projects -- one located near Lake Ashtabula and one located near Langdon, both in North Dakota.

The Rate Case

OTP sought to increase retail rates by $6,084,003 or 5.14 percent. An interim rate increase was approved to take effect on January 2, 2009 in the amount of $4,810,562 or 4.07 percent.

[1] The members of the LIG are Cargill, Incorporated, Tharaldson Ethanol Plant I, LLC, Goodrich Corporation, Bobcat Corporation, Prime Wood Inc., Cavendish Farms, Inc., Archer Daniels Midland Company, and ComDel Innovation Inc.

OTP's last North Dakota general rate case was in 1983. In 1987 OTP reduced its base rates by 4.27 percent as the result of the lower federal income tax rate in the Tax Reform Act of 1986 ("TRA 86"). This was a reduction of just over $3 million annually. The North Dakota Public Services Commission ("Commission") also monitors and reviews regulated utilities' earnings based on their annual reports to the Commission. As a result of such reviews, OTP has either reduced its base rates or made one-time refunds to customers in seven years since its last rate case. In addition, for the five years 2001 through 2005, OTP operated under a Commission-approved Performance Based Ratemaking ("PBR") Plan. This PBR Plan called for OTP to refund to customers a share of earnings if its return on equity ("ROE") exceeded a set level. This resulted in a refund in 2002 based on 2001 financial and performance results. The following table summarizes OTP's rate reductions/refunds in North Dakota.

Table 1

History of rate reductions/ refunds in ND			
Year	Amount	Percent (4)	Note
1987	$3,060,000	4.27%	(1)
1989	$1,000,000	1.50%	(2)
1990	$315,500	0.48%	(2)
1992	$1,000,000	1.50%	(3)
1994	$448,636	0.66%	(3)
1999	$685,000	0.91%	(3)
1999	$350,000	0.47%	(2)
2000	$42,442	0.05%	(3)
2002	$662,300	0.80%	(3)
(1) Reduction to base rates - TRA 86			
(2) Reduction to base rates			
(3) One-time refund			
(4) Percent of rates in effect at the time of the reduction			

In this current rate case, OTP identified three primary drivers for the need to request a rate increase. First, since the last rate case in 1983, operating costs, such as material, labor, pension, active medical and post-retirement medical have risen substantially. Second, OTP has experienced dramatic increases in fuel and purchased power costs, which currently are not being fully recovered through the fuel clause adjustment ("FCA") because certain customer classes are currently exempt from application of the FCA. Third, OTP has made substantial investments in infrastructure.

The Renewable Resources Rider Case

This is the first annual filing updating the costs to be recovered through the Renewable Resource Rider approved by Order dated May 21, 2008 in Case No. PU-06-466. That Order established the methodology for cost recovery for renewable energy generation projects, found OTP's investment in the 40.5 MW Langdon Wind Energy Center ("Langdon") to be prudent, and commenced recovery of costs associated with that project. In this current proceeding, OTP has requested a determination that its investment in the 48 MW Ashtabula Wind Energy Center ("Ashtabula") was prudent (pursuant to NDCC § 49-05-16), and that OTP's proposed 2009 Renewable Resource Adjustment factor in the Renewable Resource Rider is appropriate, based on the costs of Langdon and Ashtabula. OTP was granted a Certificate of Public Convenience and Necessity to construct and own Ashtabula (certificate number 5347, received by OTP on July 2, 2008) and the facility became operational in November 2008.

See Attachment A for a summary of the procedural history of these cases.

TERMS

The OTP, LIG and Staff (collectively "the Parties") agree to the provisions as defined below and supported by Attachments A through E to this Settlement Agreement.

I. Rate Base and Revenue Requirements in the Rate Case

The Parties agree that for purposes of recovery in base rates, the value of OTP's rate base, including property used and useful, for the service and convenience of the public in North Dakota is $187,360,150. Also, as a result of the adjustments agreed to herein and described below, the Parties agree to an increase in OTP's base electric rates for retail customers in North Dakota to ultimately yield an annual net retail sales and miscellaneous revenue increase of $3,597,887 or 3.04 percent. The Parties agree that such increase is necessary to provide OTP a just and reasonable rate of return on its property, used and useful, for the service and convenience of the public in North Dakota. As shown in Table 2 below and on Attachment B, the final rates will reflect an increase in base rates of $6,824,405 offset by projected fuel clause reductions as a result of customer credits from wholesale asset-based margins, estimated at $3,792,527. In addition, the Parties agree that OTP's proposal to recover $1,000,000 in DSM and Conservation program costs in base rates should instead be considered in a separate proceeding with any Commission approved costs being recovered through a separate rate rider.

Table 2

	Base Rates	Fuel Rates		Overall Revenues
	$6,824,405	Asset Based Margins	($3,792,527)	
		MISO Schedule 16 & 17 deferred costs	309,019	
		MISO Schedule 16 and 17 ongoing costs	256,990	
Total	$6,824,405		($3,226,518)	$3,597,887

An interim rate refund will be issued to customers for the difference between the interim rate increase placed into effect on January 2, 2009 and the Settlement Agreement amount, as reflected in Attachment C. (Attachment C reflects an estimated refund based on an assumed September 1, 2009 implementation of final rates—the actual refund amount will be calculated based on the implementation date set by the Commission). The interim rate refund will reflect the fact that wholesale asset-based margins were credited to the interim rate revenue requirement and will be credited to the fuel revenue requirement in final rates. The interim rate refund will also reflect the fact that MISO 16 and 17 costs were recovered in the interim rate revenue requirement and will be recovered through the fuel revenue requirement in final rates. See Attachment C for the calculation of the estimated interim rate refund and the estimated refund factor of 19.401 percent.

Following is a description of the specific test year adjustments agreed to in this Settlement Agreement (See also Attachment B).

A. Return on Equity

The Parties agree to a return on equity of 10.75 percent as outlined in the previous settlement with Staff and LIG. The adjustment reduces the original revenue request by $831,539, and OTP agrees to share any earnings above 10.75 percent with customers (see Other Terms and Conditions for a full discussion of this sharing mechanism).

The Parties also agree that a 10.75 percent ROE will be used for purposes of determining interim rates in OTP's next electric rate case.

B. Depreciation

The Parties agree that the change in depreciation allocation method proposed by OTP should occur at this time (See Direct Testimony of Ms. Bernadeen Brutlag at 2-6). OTP proposed allocating Accumulated Depreciation and Depreciation Expense using the same allocation factors as are used for allocating Electric Plant in Service. In the past, these costs had been directly assigned to each jurisdiction. This change in allocation method would increase North Dakota revenue requirements by $119,476. While parties agree that this allocation change should be accepted and used going forward, the increase in revenue requirements in this case will not be included, thus reducing the original revenue request by $119,476.[2]

C. Regulatory Liability

Staff requested that amounts previously recovered in rates as a future cost of removal and retirement be treated as a regulatory liability (See Majoros Direct at 11-13). The Parties agree that, unless directed otherwise by the Commission, rate recovery -- past, present, and future -- for the removal and retirement of OTP utility property will be used solely for the retirement of OTP's utility property and recognized as a regulatory liability.

[2] The basis for the revenue requirements amount is shown in footnote 1 on Attachment B to this Settlement Agreement.

D. Wholesale margins

For purposes of determining the overall revenue requirement, the Parties agree to credit to ratepayers through the FCA 85 percent of all asset-based margins achieved by OTP. Passing these credits directly through the FCA as they are realized ensures that neither customers nor OTP will be disadvantaged by a non-representative margin forecast in the test year. OTP will, starting with the month of September 2009,[3] include in its fuel clause adjustment calculation, the forecasted amount of wholesale margins for that month (i.e. September for the first month). A subsequent fuel clause adjustment calculation (estimated to occur two months after the forecasted month) will include any true-up needed to correct a prior forecast to reflect actual wholesale margins for the forecasted month. By sharing the gains on asset-based sales, the Parties recognize that OTP will have an incentive to maximize the benefit from these sales. With respect to non-asset based margins, the Parties agree to a fixed credit of $560,000 to the base rate revenue requirement. This amount is based on an OTP cost study and reflects an amount that the Parties agree is in excess of the incremental cost of this activity and provides a reasonable contribution to the costs of non-asset based trading, including common overheads.

E. Miscellaneous Expense Adjustments.

The Staff had proposed several miscellaneous adjustments in the Direct Testimony of Mr. Majoros. The Settlement Agreement does not reflect those individual adjustments, but rather, the Parties agree that a reduction of the revenue requirement in the amount of $158,000 is appropriate, $50,000 of which represents a reduction to OTP's requested economic development expenses as described below.

F. Economic Development Costs

OTP requested that it be allowed to recover $500,000 for economic development. The Parties agree that Economic Development is a prudent and reasonable expense that benefits OTP's ratepayers. However, the Parties also agree that the expense should be reduced to $450,000.

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[3] Or the month in which final rates are implemented, if a different month than September.

G. DSM and Energy Conservation.

OTP was ordered by the Commission in Case No. PU-06-481 to file proposed DSM programs as a condition of receiving an advance determination of prudence of the Big Stone II facility. As a result, OTP submitted a proposed North Dakota Energy Efficiency Plan (EEP) in Case No. PU-09-72 and included in the rate case, Case No. PU-08-862, to recover approximately an additional $1,000,000 in annual EEP costs in base rates. Rather than include this expense in base rates, the Parties agree that any new EEP costs that may be approved by the Commission in Case No. PU-09-72 should be recovered through a separate rider or other accounting treatment. The parties also agree that in the event the Commission approves the recovery of any such costs through a rider that class allocations of such costs should be handled as described in Section III, below.

H. MISO 16 and 17 Costs.

OTP requested recovery of deferred and current MISO Schedule 16 and 17 costs -- the deferred portion of those costs have accrued since April 2005 (the start of MISO Day 2) for recovery in this rate case in accordance with a settlement approved by the Commission in Case No. PU-05-131. In this current case, OTP proposed recovering these deferred and current costs in base rates. No party challenged the reasonableness of these costs. Staff, however, advocated for recovering these costs through the FCA, as was recently approved for Xcel Energy in Case No. PU-07-776, instead of recovering them in base rates. The Parties agree that recovering these costs through the FCA is reasonable, given that, like all other MISO Day 2 charge types which are also recovered through the FCA, they are non-discretionary charges billed out by the MISO for administration of the MISO energy market. This adjustment decreases OTP's base rate increase by $566,009, but it does not impact the overall revenue increase, since the recovery of these costs is just being moved from base rates to the FCA.

I. Other Necessary Adjustments

In addition to the agreed-upon reductions reflected above, making these adjustments to OTP's Cost of Service model also results in adjustments to the cash working capital (a reduction of $7,266) and to jurisdictional allocations (a reduction of $150,417).

II. Issues to be Addressed in OTP's Future Rate Cases

OTP will address the following issues in its next rate case and in future rate cases as indicated:

A. Benefits from Renewable Energy Credits

The Parties agree that in future rate cases OTP will credit the North Dakota jurisdiction with its proportionate share of the value from Renewable Energy Credits (RECs) based on the North Dakota allocated share of the costs of the assets used to produce the RECs.

B. Energy Costs Separate from Base Rates

The Parties agree that in its next rate case OTP will separate its energy costs from base rates. It is understood that this will give the appearance of much larger rate increases in future rate cases than is reflected in the overall change in customer bills.

C. Use of an E8760 Allocator.

The Parties agree that OTP should use an E8760 allocator in its next rate case for class cost of service study development purposes, and for the purposes of allocating fuel costs between classes.

D. Wind Farm Cost Recovery

The Parties Agree that in its next rate case OTP shall propose including the Ashtabula and Langdon wind farm costs in base rates.

III. Allocations and Rate Design for the Rate Case

The Parties agree that the class cost allocations for rate design purposes should be as reflected in Table 3, below: [4]

Table 3

	Allocations as result of proposed revenue requirements settlement							
1	Class	Current Revenues	Amount of Increase	Percent Increase	A/B margin credit	MISO 16 & 17	Net Increase	Net % Increase
2	Residential	$36,574,921	$2,194,495	6.00%	($979,303)	$146,154	$1,483,847	4.06%
3	Farms	$1,601,767	$96,106	6.00%	($50,761)	$7,576	$52,921	3.30%
4	General Service	$34,012,150	$1,435,982	4.22%	($899,736)	$134,280	$548,025	1.61%
5	Large General Service	$36,231,788	$1,140,540	3.15%	($1,340,629)	$200,080	($9)	0.00%
6	Irrigation	$45,963	$4,596	10.00%	($1,412)	$211	$3,395	7.39%
7	Lighting	$2,095,668	$419,134	20.00%	($49,011)	$7,314	$377,438	18.01%
8	OPA	$967,569	$135,460	14.00%	($36,492)	$5,446	$104,414	10.79%
9	Controlled Service Water Heating	$1,185,332	$118,533	10.00%	($42,447)	$6,335	$82,422	6.95%
10	Controlled Service Interruptible	$4,744,402	$1,186,100	25.00%	($351,046)	$52,391	$887,446	18.71%
11	Controlled Service Deferred	$849,617	$93,458	11.00%	($41,692)	$6,222	$57,988	6.83%
12	Total	$118,309,177	$6,824,405	5.77%	($3,792,527)	$566,009	$3,597,887	3.04%

These class allocations reflect the agreed-to adjustments to the base rate revenue requirement contained in this Agreement, and modification of OTP's originally proposed class allocations.

The Parties agree that it is appropriate that the LGS class not be allocated an overall increase in rates at this time, and that the impact of the current base rate allocation and asset based margin credit to the FCA would result in no increase for the LGS class (assuming historic levels of asset based margins). The Parties also agree that the LGS class would not have been allocated an overall increase in rates in this case even if EEP costs were recovered in this case (see Section I.G. of this Agreement). Therefore, if the Commission determines that it is appropriate for OTP to recover EEP costs through a rider in Case No. PU-09-72, or in any other case following this rate case and prior to OTP filing its next general rate case, then the Parties agree that those rider costs should be allocated to classes other than the LGS class, <u>even if some or all of the EEP programs are found to benefit the LGS class</u>.

[4] The amounts reflected in Table 3 for "A/B margin credit" and "MISO 16&17" are based on historical amounts earned for asset based margins and for MISO schedules 16 & 17 charges, each of which will be reflected in the FCA going forward based on actual future amounts.

The Parties agree that rate schedules reflecting the following rate designs will result in a basis of charge to OTP's customers that is just and reasonable and without discrimination.

The Residential Rate shall be as follows:

ND Residential Summary	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month		Energy Charge per kWh All Year	Summer	Winter	
	2007 Revenue $31,114,448	Proposed Rev $32,795,171	Increase 5.40%					
Current Rate								
Zone 1		$4.74		First 1,000 kWh:	$0.08240 *			
Zone 9 and Cottages		$5.65		Next 1,000 kWh:	$0.06737			
				Excess 1,000 kWh:	$0.05938			
				Water Heating Credit	-$2.00			
4 **Proposed Rate**	$8.00	$8.00		All kWh		$0.08444	$0.07863	First 1,000 Winter
Customer Charge, Seasonal Energy, Winter Declining Block		+Facilities					$0.07173	Excess
No Facilities Charge			$0.00					
				Water Heating Credit	-$4.00			
Marginal Costs	$10.11	Cust+Facilities		All kWh		$0.10545	$0.09619	
kWh > 1,800 in any month			$11.38					
kWh always < 1,800 per month			$44.92					

*Current Rates Include FCA

The Farm Service Rate shall be as follows:

ND Farm Summary	Customer Charge per month	Monthly Minimum Bill per month		Facilities Charge per kVA of Transformer	Energy per kWh Summer	Winter	All Year
				Current Rev $1,514,276		Proposed Rev $1,605,133	Increase 6.00%
		$7.51 + $0.71797 per kVA above 25 kVA				1st 150:	0.08702
Current Rates	$7.51			na		Next 1450:	0.06817
						Excess:	0.05730
2				3-Phase Surcharge per Mo.			Energy
Adjusted Rate	$12.00	Cust + Fac	Overhead		$0.07642	$0.06971	first 1,600
Declining Block			<25 kVA	$3.37	$0.06495	$0.05925	Excess
Seasonal Energy			25 kVA or more	$3.93			
Customer Charge			Underground				
Facilities for 3ph			<25 kVA	$9.39			
			25 kVA or more	$10.78			
Marginal Costs	$12.34				$0.10545	$0.09619	All
				Additional cost for 3-Phase per month			
			Overhead				
			<25 kVA	$9.61			
			25 kVA or more	$11.23			
			Underground				
			<25 kVA	$26.83			
			25 kVA or more	$43.11			

*Current Rates Include FCA

The Residential Demand Control (RDC) Rate shall be as follows:

ND Residential Controlled Demand Summary

Current Rev.	Proposed Rev.	Increase
$5,540,781	$6,059,372	9.36%

		Customer Charge per month	Minimum Bill per month		Facilities Charge per per KW month	Charge per kWh	Summer	Winter	Demand Charge per kW per mo. Summer	Winter
Current Rate									per 12-mo. max	
	No Seasonality - 12-month Demand Ratchet	$9.38	Customer Charge		$0.00		$0.04172	$0.04172	$3.69	$7.32
									Winter Ratchet	
Rate 4	Seasonal with Flat Facilities Charge, with 12-month Winter Ratchet	$18.38	Customer + Facilities Charge			All kWh:	$0.04627	$0.04671	$6.52	$2.63
				Fixed Facilities	$0.00					
					$0.00					
						Energy Only:	Summer	Winter	Capacity Only Summer	Winter
Marginal Costs		$16.77		<5000 kWh in all months:	$11.38		$0.06843	$0.06929	$12.45	$5.03
				>5000 kWh in any month:	$44.92					

*Current Rates Include FCA

The Large General Service Rate shall be as follows:

ND Large General Service- Sec, Prim, Trans. (Includes Pricing for LGS Off-Peak Rider)

Rev includes LGS + LGS Off Peak Rider + RTP Base

current Rev	Proposed Rev
$ 36,231,808	$ 37,372,348
3.15% Increase	

		Customer Charge per month	Minimum Bill per month		Facilities Charge per annual max. kW (minimum 80 kw) per month		Energy Charge per kWh			Demand Charge per kW	
SECONDARY							All Year			All Year	
	Current Rate										
		na	Demand Charge	All over 360 kWh per kW			$0.04245		1st 100 kW of billing demand:	$8.33	
				First 700,000 kWh			$0.05094		Excess kW of billing demand:	$6.80	
	Note: Billing demand is ratcheted			Excess kWh			$0.04289				
							Summer	Winter		Summer	Winter
Rate 3	Seasonal Energ, Load Factor Block, Facilities charge, Customer Charge, No Ratchet on Demand.	$40.00	Cust. Charge + facilities + demand charge							$7.29	$5.61
				< 1000 kW:	$0.30	All Other	$0.04715	$0.04761			
				> 1000 kW:	$0.15	First 700,000	$0.05115	$0.05165			
	Marginal Costs	$254.44		< 1000 kW:	$0.79		$0.06843	$0.06929		$12.45	$5.03
				> 1000 kW:	$0.40						
PRIMARY										All Year	
	Current Rate										
		na	Demand Charge	All over 360 kWh per kW			$0.04245		1st 100 kW of billing demand:	$8.04	
				First 700,000 kWh			$0.05094		Excess kW of billing demand:	$6.51	
	Note: Billing demand is ratcheted			Excess kWh			$0.04289				
							Summer	Winter		Summer	Winter
Rate 3	Seasonal Energ, Load Factor Block, Facilities charge, Customer Charge, No Ratchet on Demand.	$40.00	Cust. Charge + facilities + demand charge		$0.11					$7.24	$5.57
						All Other	$0.04695	$0.04737			
						First 700,000	$0.05095	$0.05141			
	Marginal Costs	$303.69			$0.28		$0.06809	$0.06867		$12.36	$5.00
TRANSMISSION										All Year	
	Current Rate										
		na	Demand Charge	All over 360 kWh per kW			$0.04245		1st 100 kW of billing demand:	$7.23	
				First 700,000 kWh			$0.05094		Excess kW of billing demand:	$5.65	
	Note: Billing demand is ratcheted			Excess kWh			$0.04289				
							Summer	Winter		Summer	Winter
Rate 3	Seasonal Energ, Load Factor Block, Facilities charge, Customer Charge, No Ratchet on Demand.	$40.00	Cust. Charge + facilities + demand charge		$0.00					$5.88	$4.73
						All Other	$0.04574	$0.04592			
						First 700,000	$0.04974	$0.04996			
	Marginal Costs	$384.36			$0.00		$0.06631	$0.06275		$7.02	$5.46

The Large General Service - Time of Day Rate shall be as follows:

North Dakota Large General Service - Time-of-Day 6-16-09

					SECONDARY		PRIMARY		SUBTRANSMISSION	
					LGS TOD with Customer and Facilities Charges	Marginal Costs	LGS TOD with Customer and Facilities Charges	Marginal Costs	LGS TOD with Customer and Facilities Charges	Marginal Costs
Cust. Charge	per	month			$ 60.00	$ 351.89	$ 60.00	$ 400.99	$ 60.00	$ 400.99
Monthly Min. Bill	per	month			$325 + Facilities + Cust. Chg.		$325 + Facilities + Cust. Chg.		$325 + Facilities + Cust. Chg.	
Facilities Charge	per annual max. kW (min. 80 kW)			< 1,000 kW	$ 0.30	$ 0.79	n/a	$ 0.29	n/a	$ -
				>=1,000 kW	$ 0.15		n/a		n/a	
				All kW	n/a		$ 0.11		$ 0.00	
Energy Charge	per kWh		Summer	PK	$ 0.08150	$0.13276	$ 0.08115	$0.13219	$ 0.07900	$0.12868
				SH	$ 0.06247	$0.10176	$ 0.06221	$0.10134	$ 0.06066	$0.09881
				OP	$ 0.03721	$0.06061	$ 0.03709	$0.06041	$ 0.03635	$0.05921
			Winter	PK	$ 0.07314	$0.11914	$ 0.07278	$0.11856	$ 0.07063	$0.11505
				SH	$ 0.05949	$0.09690	$ 0.05921	$0.09645	$ 0.05752	$0.09369
				OP	$ 0.04199	$0.06840	$ 0.04181	$0.06810	$ 0.04070	$0.06629
Demand Charge	per kW		Summer	PK	$ 5.75	$ 9.73	$ 5.71	$ 9.66	$ 4.86	$ 8.22
				SH	$ 1.59	$ 2.69	$ 1.57	$ 2.66	$ 1.06	$ 1.79
				OP	$ -	$ 0.04	$ -	$ 0.04	$ -	$ 0.03
			Winter	PK	$ 4.42	$ 3.77	$ 4.39	$ 3.74	$ 3.74	$ 3.39
				SH	$ 1.22	$ 0.88	$ 1.21	$ 0.88	$ 0.82	$ 0.76
				OP	$ -	$ 0.38	$ -	$ 0.38	$ -	$ 0.09

The Parties agree that the Large General Service – Time of Day Rate will be introduced on an experimental basis. This rate will be re-evaluated in OTP's next rate case.

Except as reflected above, the rate design shall be as OTP proposed in its request, modified to reflect adjustments to the revenue requirement and class allocations described in this Agreement.

- The Parties agree to the filed tariff changes proposed by OTP's initial filing, as amended to reflect the change in class allocations and the change in the revenue requirement. In addition, the Parties agree to the following two changes from OTP's original proposal for General Rules and regulations. Section 1.02 "Application for Service" shall be revised to add the following sentence to the end of the section: "The Company, if reasonable under the circumstances, may consent to a customer changing rates before taking service for the minimum one-year period described above, and provided the customer pays any charges that may be required under each rate, including for example, "ratchet" charges or other charges relating to discontinuance of service."

- A New Section shall be added to the General Rules and Regulations that reads as follows: "Upon signing a confidentiality agreement, a General Service customer shall be provided with the Company's most recent forecasts for fuel clause adjustments and rider adjustments."

- Several typographical errors and corrections necessary for clarity and correct application of the rates were discovered while reviewing the rate schedules during the course of this case. Changes to the rate schedules to correct these errors are reflected on Attachment D.

The parties agree that no other changes shall be made to OTP's General Rules and Regulations rate schedule.

OTP shall file compliance tariff pages setting forth the revised electric rates and tariffs provided by this Settlement Agreement at least thirty (30) days prior to the effective date of final rates.

IV. Interim Rates

The Parties agree the interim rates will remain in effect for bills rendered to all customer classes until final rates are implemented. Refunds will be issued to customers within ninety (90) days of the implementation of final rates for the difference between the interim revenue level and the final revenue level agreed to in this Settlement. Based on current information (and using September 1, 2009, as the assumed date for implementation of final rates), the Parties estimated that customers would receive $665,340 in base rate refunds and interest of $7,702 for a total estimated refund obligation of $673,042 (see Attachment C). The amount of refund will be determined by multiplying the interim rate refund factor by the interim retail revenues received from each customer.

V. Fuel Clause Adjustments

Currently, OTP uses a 12 percent line loss factor in calculating the retail sales used in calculating the FCA. The Parties agree that effective with the first month in which bills are rendered containing final rates OTP will use actual retail sales in calculating the FCA. The base cost of energy will also be determined using actual retail sales. This change has no effect on either the interim or final rate revenue requirement and is to be applied prospectively.

The Parties agree that effective January 6, 2009 when the MISO ASM became effective, OTP will include both revenues and expenses associated with the MISO ASM in the FCA calculation, and thereby all MISO ASM margins will be reflected in the FCA.

The Parties agree that Asset Based Margins (see the earlier discussion) will be credited to the FCA based on a forecast for the current time period, and trued up based on actual margins as soon as reasonably practical after the costs associated with the revenues are determined and in this manner the margins will be treated as credits offsetting fuel costs.

VI. The Renewable Resource Rider

A. Revenue Requirement

The Parties agree that the Commission should issue an Order finding OTP's investment in the Ashtabula Wind energy Center is prudent, and approving the 2009 Renewable Resource Cost Recovery Rider as filed. The Parties also agree that OTP shall file a new Renewable Resource rate to be effective for bills rendered on and after the date final rates are implemented.[5] This amended Renewable Resource rate will reflect the following changes in the revenue requirement used to determine the Renewable Resource rate, which changes shall be effective on and after the date final rates are implemented:

- The ROE will be reduced from 11.25 percent to 10.75 percent.
- OTP has been recovering previously unrecovered 2008 costs under the current 2009 rider rate adjustment. Effective with the implementation of final rates, OTP will remove the remaining unrecovered balance from the revenue requirement. The remaining unrecovered balance will be recovered over 48 months, beginning with the implementation of OTP's 2010 Annual Renewable Resource Cost Recovery Rate ("the 2010 Renewable Cost Recovery"). OTP will also be allowed to add a carrying cost of 8.62 percent to the unamortized balance starting on the date the above-referenced unrecovered balance is removed and continuing until

[5] The calculation of an estimated 2009 Renewable Resource rate using an assumed date of September 1, 2009, consistent with the terms of this Agreement is reflected on Attachment E.

the completion of the 48 month period, as it does for any unrecovered tracker balance.

- OTP had proposed partially levelizing the Production Tax Credit ("PTC") over a 25-year period to smooth the effect of losing the PTC after it expires in ten years. The Parties agree that the PTC should not be partially levelized as proposed. Instead, the PTC credits will be estimated and reflected in the renewable resource tracking accounts based on anticipated actual credits for each year and flowed through as a credit to the Renewable Resource Rider during the year in which the payments are received. To the extent the actual PTC credits are different from the amount anticipated, the difference will be trued-up in the Rider's tracker account.

B. Cost Allocation to Classes

OTP's 2010 Renewable Cost Recovery revenue requirement will be allocated between the customer classes with 20 percent allocated based on demand and 80 percent allocated based on energy. Within the LGS class, that classes' revenue allocation will be collected through both a demand and energy charge using the same 20 percent demand, 80 percent energy allocation. The 20 percent is based on using MISO's capacity accreditation percentage for wind. MISO is expected to amend this initial determination based on studies it is currently performing, and the Parties agree that the allocation factor used by OTP will be adjusted as necessary to correspond with the weighted average level of capacity approved by MISO for the projects being recovered through the Renewable Resource Rider.

C. Billing Treatment

The Parties agree that effective with final rates OTP's Renewable Cost Recovery rate will be combined with the fuel clause adjustment on customer bills to show a single Energy Adjustment.

D. State Allocation Factor

OTP agrees to monitor its E2 allocation factor and address in its annual Renewable Cost Recovery filings any material changes that may occur to that allocation factor.

VI. OTHER TERMS AND CONDITIONS

A. Customer Refunds for Earnings Above Authorized ROE

The Parties agree to an earnings-sharing mechanism that will result in customer refunds if OTP's net income exceeds a 10.75 percent ROE for its North Dakota electric operations.

If OTP earns in excess of 10.75 percent ROE during the 2009 or 2010 calendar years, OTP will refund to customers revenues corresponding to earnings as shown below:

- 50 percent of earnings in the calendar year above 10.75 percent up to and including 11.25 percent; and
- 75 percent of earnings in the calendar year above 11.25 percent.

Earnings sharing refunds would be applied to customer accounts as a one-time bill credit as soon as practical on or after July 1 of the following calendar year.

B. Rate Moratorium

The Parties agree to a moratorium on electric base rate increases until 2011 for OTP's North Dakota operations. This moratorium does not preclude OTP from submitting a rate application for electric rates prior to 2011, but no change in customer rates would be implemented before January 1, 2011.

C. Basis of Settlement Agreement

It is agreed this Settlement Agreement is a negotiated settlement agreement subject to approval by the Commission. Except for the purpose of setting interim rates and the establishment of a regulatory liability for amounts recovered in rates for removal and retirement, the Settlement Agreement does not establish any principle or precedent, nor adopt or recommend any specific type or amount of expense or rate base, for this or any future proceeding.

D. Effect of the Settlement Negotiations

It is understood and agreed that all offers of settlement and discussions related to this Settlement Agreement are privileged and may not be used in any manner in connection with proceedings in this case or otherwise, except as provided by law. In the event the Commission does not approve this Settlement Agreement, it shall not constitute part of the record in this proceeding and no part thereof may be used by any party for any purpose in this case or in any other.

E. Applicability and Scope

This Settlement Agreement shall be binding on the Parties, and their successors, assigns, agents, and representatives. Consistent with the Commission's settlement guidelines, this Settlement Agreement does not set policy or overturn precedent. This Settlement Agreement shall not in any respect constitute an agreement, admission or determination by any of the Parties as to the merits of any specific allegation or contention made by the Parties in this proceeding.

F. Effective Date

This Settlement Agreement shall be effective on the date of the Commission Order approving the Settlement Agreement. The revised rates and tariff provisions agreed to by this Settlement Agreement shall be effective for all bills rendered on and after a date that shall be set by the Commission Order approving the Settlement Agreement. The parties prefer that the effective date of final rates shall be the first day of a calendar month.

G. Modification

If the Commission Order modifies or conditions approval of this Settlement Agreement, it shall be deemed terminated if either Party files a letter with the Commission within three (3) business days of the date of such Order stating that a condition or modification to the Settlement Agreement is unacceptable to such Party.

CONCLUSION

The Parties have agreed to the forgoing terms to resolve the contested issues in the electric rate case proceeding and the Renewable Resource Rider proceeding. These terms are a result of negotiations between the Parties, are in the public interest and will result in reasonable electric rates. For these reasons, the Parties urge the Commission to approve the Settlement Agreement.

[Signature Pages Follow]

Otter Tail Corporation, d/b/a Otter Tail Power Company

By: Thomas R. Brause
Thomas R. Brause
Vice President Administration

Dated this 5th day of Oct 2009.

North Dakota Public Service Commission Staff

By: Annette Bendish

Annette Bendish
Counsel to Advocacy Staff

Dated this 2 day of October 2009.

Large Industrial Group

By: Ry Snl
Richard Savelkoul

Dated this 05 day of October 2009.

Procedural History

Case No. PU-08-862

On November 3, 2008, OTP filed a Notice of Change in Rates for Electric Service ("Notice") with the Commission, based on a historical 2007 test year, with rates to become effective December 3, 2008 unless they were suspended. The Notice proposed an increase in electric retail and miscellaneous base rates of $6,084,003, or approximately a 5.14 percent overall increase in revenues. Filed with the Notice were revised tariffs, direct testimony by nine witnesses, exhibits, and supporting statements.

Concurrent with the Notice, the Company submitted an Alternative Petition for Interim Rates. The proposed interim increase, which impacted only base rates, was for $4,810,562, or 4.07 percent, to be effective January 2, 2009 (60 days from filing) in the event the Commission suspended the proposed general increase. The proposed interim increase and rate design were submitted pursuant to the criteria set forth in N.D.C.C. § 49-05-06.

On November 20, 2008, the Commission issued an order suspending the Company's general rate increase application and set the matter for investigation and hearing.

On December 3, 2008, the Commission issued an order allowing an interim base rate increase of $4,810,562, or 4.07 percent, to be placed into effect January 2, 2009, subject to refund.

On December 17, 2008, the Commission issued a Notice of Public Input Sessions and Intervention Deadline announcing Public Input Sessions to be held via interactive television on February 10, 2009 and March 23, 2009 at 12:00 noon central time at various locations in Devils Lake, Jamestown, Washburn, Wahpeton, and Bismarck. Members of the public were invited to appear and participate in the informal discussion. The notice also set forth a deadline of February 27, 2009 for parties to indicate their interest in participating in the case.

On December 30, 2008, the Large Industrial Group, consisting of the Goodrich Corporation, Cargill Corporation, Cavendish Farms, Inc., Archer Daniels Midland Company, ComDel Innovation and Tharaldson Ethanol LLC, filed a Petition to Intervene with the Commission. The Large Industrial Group was the only party to intervene.

On January 14, 2009, the Commission ordered the hearing in Case No. PU-08-742, for the 2009 Renewable Resource Cost Recovery Rider and an advance determination of prudence for the Company's 48 MW ownership share in the Ashtabula Wind Energy Center, be combined with the hearing in the rate case, Case No. PU-08-862.

On February 20, 2009, the Company entered into a partial settlement agreement with the North Dakota Public Service Commission Advocacy Staff ("Staff"). The parties agreed to an overall rate of return ("ROR") of 8.62 percent, and a return on equity ("ROE") of 10.75 percent, for the Company. The Large Industrial Group did not oppose the partial settlement.

On March 11, 2009, the Commission issued a Notice of Hearing, Notice of Continued Hearing and Notice of Public Input Session which continued the hearing to May 11, 2009, and set forth the following issues to be considered in this case:

1. What is the value of Otter Tail's property, used and useful, for the service and convenience of the public in North Dakota?
2. What is Otter Tail's rate of return on its property, used and useful, for the service and convenience of the public in North Dakota?
3. What is a just and reasonable rate of return on Otter Tail's property, used and useful, for the service and convenience of the public in North Dakota?
4. What rates and charges are necessary to provide a just and reasonable rate of return on Otter Tail's property, used and useful, for the service and convenience of the public in North Dakota?
5. Are Otter Tail's proposed rate schedules designed in such a manner that they result in a basis of charge to its customers that is just and reasonable without discrimination?
6. Is Otter Tail's investment in the Ashtabula Wind Energy Center prudent?
7. Should the Commission approve the 2009 Renewable Resource Cost Recovery Rider as filed?
8. Should Otter Tail be permitted to recover any generation costs through a Rider?
9. Other relevant information or proposals concerning the proceedings.

The February 10, 2009 public input session was cancelled due to inclement weather. On March 23, 2009, the Commission conducted public input sessions. The sessions utilized interactive video-conferencing capabilities to include participants in Devils Lake, Jamestown, Washburn and Bismarck. The Wahpeton location was rescheduled for April 13, 2009 due to flooding conditions within the City of Wahpeton.

On April 1, 2009, the Large Industrial Group filed Direct Testimony prepared by two consultants, from KM Energy Consulting, LLC and LLS Resources, LLC.

On April 6, 2009, Staff filed Direct Testimony prepared by two consultants from Snavely King Majoros O'Connor & Bedell, Inc.

On April 23, Otter Tail filed a request to suspend the procedural schedule in order for the parties to finalize resolution of all disputed issues in this matter.

On April 29, 2009 the Commission issued its Order suspending the procedural schedule and continuing the hearing in this matter.

Otter Tail Power Company **Attachment B**
2007 Test Year; Case No. PU-08-862
PSC Staff Settlement Worksheet

Line No.	Description		Dollars	% of Revenue
1	Initial Filing		$6,084,003	5.14%
2	Cost of Capital Settlement Including Moratorium Until January 1, 2011		(831,539)	-0.70%
3				
4	Adjustments to original request:			
5	DSM and Energy Conservation (Separate Rider)		($1,000,000)	
6	Net Impact of change from directly assigned to allocated depreciation methods	(1)	(119,476)	
7	MISO Schedule 16 & 17 amortization of deferred amount (move to FCA)		(309,019)	
8	MISO Schedule 16 & 17 on-going costs (move to FCA)		(256,990)	
9	OTP package proposal for miscellaneous adjustments	(2)	(158,000)	
10	Remove expenses associated with Non-Asset Based Margins		(560,000)	
11	Move Asset-Based Margins to the FCA	(3)	4,133,109	
12	Cash working capital change		(7,266)	
13	Allocation impact of above adjustments		(150,417)	
14	Settlement position on Base Rates		$6,824,405	5.77%
15				
16	Adjustments for determining actual rate increase:			
17	Asset-Based Margins credit to the FCA	(4)	(3,792,527)	
18	MISO Schedule 16 & 17 - amortization of deferred costs moved to FCA		309,019	
19	MISO Schedule 16 & 17 - ongoing costs moved to FCA		256,990	
20	Adjustments through FCA		($3,226,518)	-2.73%
21				
22	Overall increase in rates		$3,597,887	3.04%

(1) Net revenue requirements impact of depreciation adjustments

Revenue requirements impact	
Rate base (ND)	($1,053,257)
ROR per settlement	8.62%
Return on rate base	($90,790.75)
Tax conversion factor	1.645413
Revenue requirements from rate base change	($149,388)
Depreciation expense (ND)	268,864
Net revenue requirements (increase)	$119,476

(2) Reflects a package adjustment for miscellaneous issues.

(3) Five-year average of margins.

(4) Assumes 85%/15% FCA crediting going forward. This amount is 85% of 2007 actual asset based margins of $4,461,797.

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY

Electric Utility - State of North Dakota

Case No. PU-08-862

Interim Refund Summary

Actuals through April 30, 2009 and projection for May, June, July and August 2009

Line No.	Test Year Basis	
1	Initial Ordered Interim Increase	$4,810,562
2	Final Ordered Increase	$6,824,405
3	Adjustments to make settlement compariable to interim	
4	Asset-based margins 85 percent moved to the FCA	($3,513,143)
5	MISO schedule 16 & 17 amortization deferred costs moved to FCA	309,019
6	MISO schedule 16 & 17 ongoing costs moved to FCA	256,990
7	Adjusted final Ordered Increase Line 2 + Line 4 + Line 5 + Line 6	$3,877,272
8	Test Year Refund Line 1 - Line 7	$933,290
9	Interim Refund Factor Line 8 / Line 1	19.401%

	Actual Basis	
10	Interim Increase Collected Attachment C, Page 2	$3,429,434
11	Actual Ordered Interim Increase Line 10 - Line 12	$2,764,094
12	Refund Obligation (without interest) Line 9 * Line 10	$665,340
13	Interest Attachment C, Page 3	$7,702
14	Total Refund Obligation Line 12 + Line 13	$673,042

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY **Attachment C**
Electric Utility - State of North Dakota **Page 2 of 3**
Case No. PU-08-862
Interim Refund Information by Customer Class and month
Actuals through April 30, 2009 and projection for May, June, July and August 2009

Customer Class	**Interim Revenue Collected**	**Refund Factor**	**Refund Obligation w/o interest**
Residential	$1,117,624	19.401%	$216,829
Farm	$47,664	19.401%	$9,247
General Service	$990,820	19.401%	$192,228
Large General Service	$939,960	19.401%	$182,360
Irrigation	$1,293	19.401%	$251
Area and Street Lighting	$57,433	19.401%	$11,143
OPA	$29,449	19.401%	$5,713
Water Heating	$31,357	19.401%	$6,084
Controlled Service Interruptible	$179,823	19.401%	$34,887
Controlled Service Deferred	$34,009	19.401%	$6,598
Total	$3,429,434	19.401%	$665,340

Month	**Interim Revenue Collected**	**Refund Factor**	**Refund Obligation w/o interest**
January-09	$530,469	19.401%	$102,915
February-09	$470,020	19.401%	$91,188
March-09	$447,008	19.401%	$86,723
April-09	$437,216	19.401%	$84,824
May-09	$375,192	19.401%	$72,791
June-09	$372,946	19.401%	$72,355
July-09	$396,891	19.401%	$77,000
August-09	$399,692	19.401%	$77,544
Total	$3,429,434		$665,340

Otter Tail Corporation d/b/a OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
Case No. PU-08-862
Interim Refund - Interest Calculation
Actuals through April 30, 2009 and projection for May, June, July and August 2009

A	B	C	D=B+C	E=(B+D)/2	F	G	H=(E*F*G)/365
Interim Rates	**Interest Calculation**						
Billing month	**Beginning balance**	**Difference**	**Ending balance**	**Average balance**	**Number of days**	**Annual interest[1]**	**Monthly interest**
January - 2009	$0	$102,915	$102,915	$51,458	31	3.25%	$142
February - 2009	$103,058	$91,188	$194,245	$148,651	28	3.25%	$371
March - 2009	$194,616	$86,723	$281,339	$237,978	31	3.25%	$657
April - 2009	$281,996	$84,824	$366,820	$324,408	30	3.25%	$867
Subtotal Actual		$365,650					$2,036
Projection for May, June, July and August 2009							
May - 2009	$367,686	$72,791	$440,477	$404,082	31	3.25%	$1,115
June - 2009	$441,592	$72,355	$513,947	$477,770	30	3.25%	$1,276
July - 2009	$515,223	$77,000	$592,224	$553,723	31	3.25%	$1,528
August - 2009	$593,752	$77,544	$671,296	$632,524	31	3.25%	$1,746
September - 2009	$673,042		$673,042	$673,042	30	3.25%	$1,798
Subtotal Projection		$299,689					$5,666
Total		$665,340					$7,702
Total Principal and Interest							**$673,042**

[1] Prime interest rates are from the Federal Reserve Statistical Release H15 - Bank Prime Loan - Monthly
http://www.federalreserve.gov/releases/h15/data/Monthly/H15_PRIME_NA.txt

<u>List of Changes to Rate Schedules to Correct Typographical Errors and to Accurately Describe Appropriate Application of the Rates.</u>

1. North Dakota Index – page 5 of 5, heading for Section 15.00, change the word "Minnesota" to "North Dakota".
2. Section 10.01 – General Service under 20 kW – In the Terms and Conditions section, strike the sentence "A Customer with a billing demand of less than 20 kW for 12 consecutive months will be given the option of returning to the Small General Service schedule (Section 10.01)." This change is necessary to clarify the requirements of taking service under this rate schedule.
3. Section 10.02 – General Service – 20 kW and Greater – The following changes provide clarity to the requirements of taking service under this rate schedule and how the facilities charge is determined and billed each month and is consistent with how this rate was designed.
    a. In the Application of Schedule, added the following phrase to the end of the first sentence in this section: ", with a measured demand of at least 20 kW within the most recent 12 months."
    b. In the Terms and Conditions section, strike the phrase "given the option of taking" and add the phrase "required to take" to the following sentence (as shown in strike-underline format): "A Customer with a billing demand of less than 20 kW for 12 consecutive months will be ~~given the option of taking~~ <u>required to take</u> service under the Small General Service schedule (Section 10.01).
    c. In the Determination of Facilities Charge section, add the following phrase to the end of the last sentence in this section: ", but in no event will the measured demand be considered less than 20 kW."
4. Section 10.03 – Large General Service – The following changes provide clarity to how the facilities and demand changes are determined and billed each month and are consistent with how this rate was designed.
    a. Monthly Minimum Charge – Replaced the $240 in the Monthly Minimum Charge with a demand charge based on a minimum of 80 kW. This is how this rate was historically billed and is consistent with how this rate was designed.
    b. Determination of Facilities Charge section, add the phrase "greater of 80 kW of the" to the following sentence (as shown in strike-underline format): "The monthly measured demand will be based on the <u>greater of 80 kW or the</u> maximum 15 consecutive minute period measured by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be based on the largest of the most recent 12 monthly measured demands."
    c. Determination of Demand Charge – Added the following section "DETERMINATION OF BILLING DEMAND: The billing demand shall be greater of 80 kW or the maximum kW as measured by a suitable demand meter for any period of 15 consecutive minutes during the month for which the bill is rendered adjusted for Excess Reactive Demand."

   d. Remove the Special Billing Demand section. This provision has not been used for many years and it was Otter Tail's intent to remove this provision in Otter Tail's initial filing.
5. Section 10.04 – Commercial Service – Time of Use – The following changes provide clarity to the requirements of taking service under this rate schedule and how the facilities charge is determined and billed each month and is consistent with how this rate was designed.
   a. Application of Schedule – Add the following phrase to the end of this section: ", with a measured demand of at least 20 kW within the most recent 12 months."
   b. Replaced the customer specific facilities charge with a Facilities Charge based on demand.
   c. Added a Terms and Conditions section to provide clarity to the requirements of taking service under this rate schedule.
   d. Removed the Contract Period and Agreement section. This change is the result of moving to a Facilities Charge based on demand. The contract period for this rate schedule is based on the contract period as required by Section 1.02 of the General Rules and Regulations.
   e. In the Determination of Demand Section, changed the word "during" with the word "for" to the following sentence (as shown in strike-underline format): "The billing demand shall be the maximum demand in kW registered over any period of one hour ~~during~~ for the month the bill is rendered."
   f. Added a Determination of Facilities Charge section. This change is necessary due to changing to a facilities charge based on demand. "DETERMINATION OF FACILITIES CHARGE: The monthly measured demand will be based on the maximum demand in kW registered over any one-hour period by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be the greater of 20 kW or the largest of the most recent 12 monthly measured demands."
6. Section 10.05 – Large General Service – Time of Day –
   a. On page 1 of 4, added back in the Description box, which includes the types of service and rate numbers. The Description box was inadvertently omitted from the rate schedule in Otter Tail's initial filing.
   b. In the Application of Schedule section changed the first sentence in this section as shown in strike-underline format: "This schedule is applicable to nonresidential Customers with ~~an existing load~~measured demand of at least 80 kW, within the most recent 12 months." This change provides clarity to the requirements of taking service under this rate schedule.
   c. Changed the Determination of Facilities Charge section as shown in strike-underline format: "The monthly measured demand will be based on the maximum ~~15 consecutive minute period measured~~demand in kW registered over any one-hour period by a suitable demand meter for the month for which the bill is rendered. The Facilities charge demand will be

~~based on~~the greater of 80 kW or the largest of the most recent 12 monthly measured demands."

~~c.~~d. Remove the Special Billing Demand section. This provision has not been used for many years and it was Otter Tail's intent to remove this provision in Otter Tail's initial filing.

7. Section 14.04 – Controlled Service Interruptible Load – CT Metering Rider –
   a. Under the Availability section in the second paragraph under Option 2, added the phrase "within the most recent 12 months." to the following sentence (as shown in strike-underline format): "During the control period the amount of ancillary load shall not exceed 5% of the metered maximum demand measured during any period, within the most recent 12 months." This change only affects the timing of when our Customer Information System ("CIS") would flag a meter for further investigation by our Customer Service Centers.
   b. Under the Determination of Control Period Demand – Option 2 only – we removed the demand ratchet to reflect how this rate was designed, so we removed the following phrases from this paragraph: "the greater of: 1)" and "or 2) the maximum metered kW during the control period established during the preceding 11 months." These changes are shown in the following sentence in strike-underline format: "The billing demand measured during the control period for which the bill is rendered shall be ~~the greater of: 1)~~ the maximum metered kW for any period of 15 consecutive minutes during the control period ~~or 2) the maximum metered kW during the control period established during the preceding 11 months~~."
8. Section 13.00 – Mandatory Riders – Applicability Matrix – On page 1 of 2 changed "Energy Efficiency Partnership (EEP) Cost Recovery Rider" to "Renewable Resource Cost Recovery Rider."
9. Section 14.04 – Controlled Service Interruptible Load – CT Metering Rider – In order to properly collect and bill for kWh and demand for Option 2, added control period and uncontrolled period rate codes for this option. Also added the phrase "(with short duration cycling)", which are for rate codes 169 and 269.

Revised and updated Renewable Resource Rider Cost Recovery Factor effective September 2009 based on the following:

1 Remove partial smoothing of PTC; instead credit PTC to tracker account as earned
See Attachment E, pages 2 and 3 of 6 for details

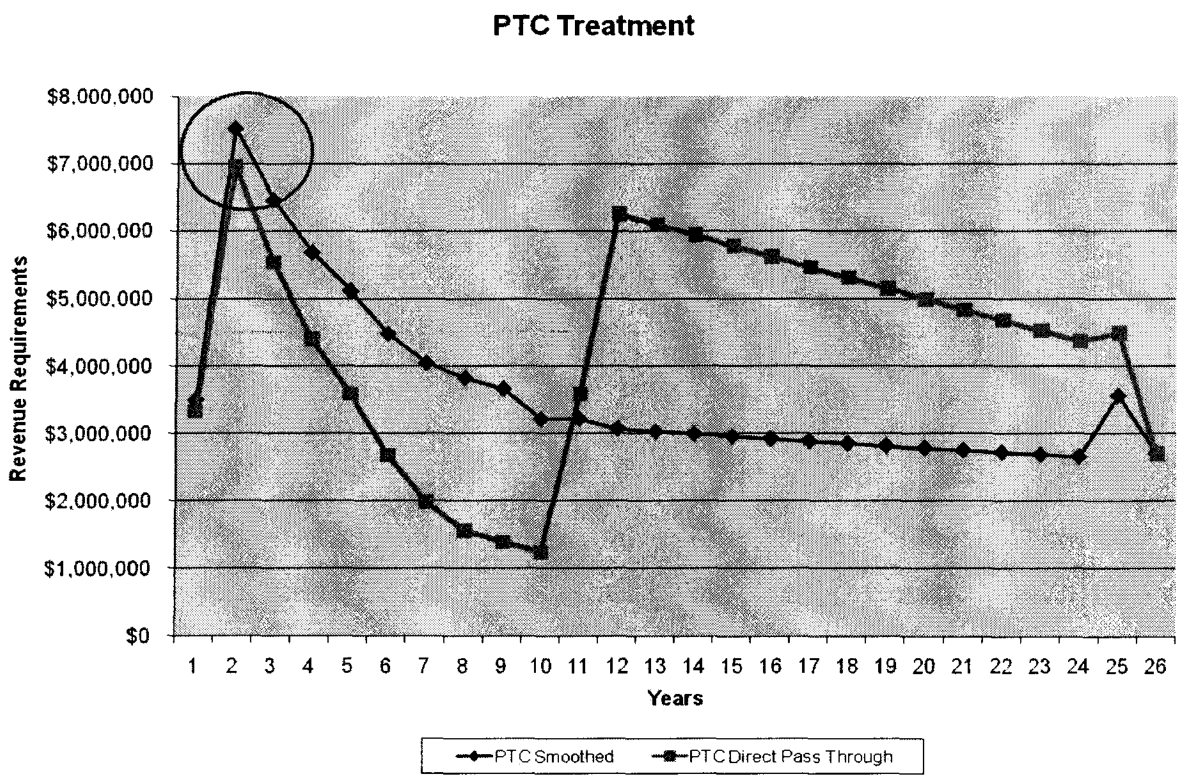
2 Remove uncollected portion of 2008 true-up amount and carrying charge from tracker for 2009 as shown in August 29, 2008, filing, and amortize the amount over 48 months beginning with next cost recovery period.
See Attachment E, pages 4 and 5 of 6 for details

Uncollected 2008 True-up revised to reflect PTC change	$622,888	
Divided by		
Monthly amortization	48	months
	$12,977	

3 Use ROE stipulated in general rate case (reduce ROE from 11.25% to 10.75% effective with final rates)
See Attachment E, page 6 of 6 for details

Impact of each change listed above:	cents/kWh
Rate requested in August 29, 2008, filing	0.510
Impact of removing PTC smoothing	(0.039)
Impact of removing uncollected 2008 true-up from tracker	(0.085)
Impact of reducing ROE to 10.75% on September 1, 2009	(0.014)
Revised Renewable Resource Rider Cost Recovery Factor	0.372

Otter Tail's annual filing proposed to smooth the PTC treatment by partially deferring the credit to eliminate the increase in revenue requirements that occurs after the PTC ends. That partial smoothing was used to calculate the Renewable Resource Adjustment rate currently in effect. Otter Tail now agrees, however, to credit the PTC directly to the Tracker Account as it is earned or forecast to be earned. The calculations shown on Attachment E, page 3 of 6, relate to the difference circled on the chart below.



Explanation of change due to change in PTC treatment

Revenue requirements
From Aug 29, 2008 filing
Partially smooths PTC

		A	B	C	D	E	F	G	H	I
Line #	Month	Langdon	Ashtabula	Total	Less Revenue Received	Difference	Cumulative Tracker Balance	Monthly Carrying Cost Rate	Carrying Cost	Total Revenue Requirements
1	January 2008	$299,857	$0	$299,857	$0	$299,857	$299,857	0.4167%	$1,249	$301,106
2	February	315,759	0	315,759	0	315,759	615,615	0.4167%	2,565	318,324
3	March	355,377	0	355,377	0	355,377	970,992	0.4167%	4,046	359,423
4	April	228,185	0	228,185	0	228,185	1,199,177	0.4167%	4,997	233,181
5	May	279,091	0	279,091	0	279,091	1,478,268	0.4167%	6,159	285,250
6	June	247,364	0	247,364	(193,660)	53,704	1,531,971	0.4167%	6,383	60,087
7	July	314,711	0	314,711	(204,008)	110,703	1,642,674	0.4167%	6,844	117,547
8	August	258,934	0	258,934	(231,789)	27,145	1,669,819	0.4167%	6,958	34,102
9	September	278,825	0	278,825	(229,288)	49,537	1,719,356	0.4167%	7,164	56,701
10	October	255,527	0	255,527	(236,137)	19,389	1,738,745	0.4167%	7,245	26,634
11	November	255,527	0	255,527	(275,177)	(19,651)	1,719,094	0.4167%	7,163	(12,488)
12	December	254,133	159,140	413,273	(313,787)	99,486	1,818,580	0.4167%	7,577	107,063
13	Subtotal	3,343,287	159,140	3,502,427	(1,683,847)	1,818,580			68,351	1,886,930
14										
15	January 2009	242,891	383,992	626,883	(980,068)	(353,185)	1,465,394	0.4167%	6,106	632,989
16	February	242,891	383,992	626,883	(957,360)	(330,477)	1,134,918	0.4167%	4,729	631,612
17	March	242,891	383,992	626,883	(872,773)	(245,890)	889,028	0.4167%	3,704	630,587
18	April	242,891	383,992	626,883	(799,237)	(172,354)	716,674	0.4167%	2,986	629,869
19	May	242,891	383,992	626,883	(686,363)	(59,480)	657,194	0.4167%	2,738	629,621
20	June	242,891	383,992	626,883	(667,015)	(40,132)	617,062	0.4167%	2,571	629,454
21	July	242,891	383,992	626,883	(702,182)	(75,299)	541,763	0.4167%	2,257	629,140
22	August	242,891	383,992	626,883	(705,390)	(78,506)	463,257	0.4167%	1,930	628,813
23	September	242,891	383,992	626,883	(698,612)	(71,729)	391,528	0.4167%	1,631	628,514
24	October	242,891	383,992	626,883	(691,677)	(64,794)	326,734	0.4167%	1,361	628,245
25	November	242,891	383,992	626,883	(786,315)	(159,432)	167,302	0.4167%	697	627,580
26	December	242,891	383,992	626,883	(893,248)	(266,365)	0	0.4167%	0	626,883
27	Subtotal	$2,914,696	$4,607,902	$7,522,598	($9,440,240)	($1,917,642)			$30,712	$7,553,309
28										
29	Total Revenue Requirements	$6,257,982	$4,767,042	$11,025,024	($11,124,087)	($99,062)			$99,062	$9,440,240
30										
31										

		A	B	C	D	E	F	G	H	I
32	Revenue requirements									
33	Directly credits PTC to Tracker									
34	Month	Langdon	Ashtabula	Total	Less Revenue Received	Difference	Cumulative Tracker Balance	Monthly Carrying Cost Rate	Carrying Cost	Total Revenue Requirements
35										
36	January 2008	$292,438	$0	$292,438	$0	$292,438	$292,438	0.4167%	$1,218	$293,656
37	February	307,511	0	307,511	0	307,511	599,949	0.4167%	2,500	310,011
38	March	342,843	0	342,843	0	342,843	942,791	0.4167%	3,928	346,771
39	April	209,534	0	209,534	0	209,534	1,152,326	0.4167%	4,801	214,336
40	May	263,821	0	263,821	0	263,821	1,416,146	0.4167%	5,901	269,721
41	June	232,749	0	232,749	(193,660)	39,089	1,455,235	0.4167%	6,063	45,152
42	July	304,006	0	304,006	(204,008)	99,998	1,555,233	0.4167%	6,480	106,478
43	August	243,452	0	243,452	(231,789)	11,663	1,566,896	0.4167%	6,529	18,192
44	September	263,343	0	263,343	(229,288)	34,055	1,600,951	0.4167%	6,671	40,726
45	October	240,045	0	240,045	(236,137)	3,907	1,604,859	0.4167%	6,687	10,594
46	November	240,045	0	240,045	(275,177)	(35,133)	1,569,726	0.4167%	6,541	(28,592)
47	December	238,651	159,140	397,791	(313,787)	84,004	1,653,730	0.4167%	6,891	90,894
48	Subtotal	$3,178,437	$159,140	$3,337,577	($1,683,847)	$1,653,730			$64,209	$1,717,939
49										
50	January 2009	$213,298	$366,234	$579,532	($370,919)	$208,613	$1,862,342	0.4167%	$7,760	$587,291
51	February	213,298	366,234	579,532	(957,438)	(377,907)	1,484,436	0.4167%	6,185	585,717
52	March	213,298	366,234	579,532	(872,845)	(293,313)	1,191,123	0.4167%	4,963	584,495
53	April	213,298	366,234	579,532	(799,303)	(219,771)	971,352	0.4167%	4,047	583,579
54	May	213,298	366,234	579,532	(686,419)	(106,888)	864,465	0.4167%	3,602	583,134
55	June	213,298	366,234	579,532	(667,070)	(87,538)	776,926	0.4167%	3,237	582,769
56	July	213,298	366,234	579,532	(702,239)	(122,708)	654,219	0.4167%	2,726	582,258
57	August	213,298	366,234	579,532	(705,447)	(125,916)	528,303	0.4167%	2,201	581,733
58	September	213,298	366,234	579,532	(506,878)	72,654	600,957	0.4167%	2,504	582,036
59	October	213,298	366,234	579,532	(501,846)	77,686	678,643	0.4167%	2,828	582,359
60	November	213,298	366,234	579,532	(570,510)	9,021	687,664	0.4167%	2,865	582,397
61	December	213,298	366,233	579,531	(648,096)	(68,565)	619,099	0.4167%	2,580	582,110
62	Subtotal	$2,559,575	$4,394,804	$6,954,379	($7,989,010)	($1,034,631)			$45,498	$6,999,877
63										
64	Total Revenue Requirements	$5,738,012	$4,553,944	$10,291,956	($9,672,857)	$619,099			$109,708	$8,717,816
65										
66	2009 projected sales (MWH)									1,851,179
67										
68	Renewable Resource Adjustment rate after removing smoothing of PTC (cents/kWh)									0.471
69										
70	Rate currently in effect									0.510
71										
72	Impact of removing smoothing of PTC									**(0.039)**

Otter Tail Power Company
North Dakota Case No. PU-08-742

Explanation of change due to change in PTC treatment

Revenue requirements
From Aug 29, 2008 filing
Partially smoothes PTC

		A	B	C	D	E	F	G	H	I
Line #	Month	Langdon	Ashtabula	Total	Less Revenue Received	Difference	Cumulative Tracker Balance	Monthly Carrying Cost Rate	Carrying Cost	Total Revenue Requirements
1	January 2008	$299,857	$0	$299,857	$0	$299,857	$299,857	0.4167%	$1,249	$301,106
2	February	315,759	0	315,759	0	315,759	615,615	0.4167%	2,565	318,324
3	March	355,377	0	355,377	0	355,377	970,992	0.4167%	4,046	359,423
4	April	228,185	0	228,185	0	228,185	1,199,177	0.4167%	4,997	233,181
5	May	279,091	0	279,091	0	279,091	1,478,268	0.4167%	6,159	285,250
6	June	247,364	0	247,364	(193,660)	53,704	1,531,971	0.4167%	6,383	60,087
7	July	314,711	0	314,711	(204,008)	110,703	1,642,674	0.4167%	6,844	117,547
8	August	258,934	0	258,934	(231,789)	27,145	1,669,819	0.4167%	6,958	34,102
9	September	278,825	0	278,825	(229,288)	49,537	1,719,356	0.4167%	7,164	56,701
10	October	255,527	0	255,527	(236,137)	19,389	1,738,745	0.4167%	7,245	26,634
11	November	255,527	0	255,527	(275,177)	(19,651)	1,719,094	0.4167%	7,163	(12,488)
12	December	254,133	159,140	413,273	(313,787)	99,486	1,818,580	0.4167%	7,577	107,063
13	Subtotal	3,343,287	159,140	3,502,427	(1,683,847)	1,818,580			68,351	1,886,930
14	Carrying cost 2009									30,712
15	2008 True-up including carrying cost									$1,917,642
16										
17	Total Revenue Requirements from August 29, 2008, filing									$9,440,240
18	Proportion represented by 2008 true-up amount									**20.3%**
19										
20										

21 Revenue requirements
22 Directly credits PTC to Tracker

		A	B	C	D	E	F	G	H	I
23	Month	Langdon	Ashtabula	Total	Less Revenue Received	Difference	Cumulative Tracker Balance	Monthly Carrying Cost Rate	Carrying Cost	Total Revenue Requirements
24										
25	January 2008	$292,438	$0	$292,438	$0	$292,438	$292,438	0.4167%	$1,218	$293,656
26	February	307,511	0	307,511	0	307,511	599,949	0.4167%	2,500	310,011
27	March	342,843	0	342,843	0	342,843	942,791	0.4167%	3,928	346,771
28	April	209,534	0	209,534	0	209,534	1,152,326	0.4167%	4,801	214,336
29	May	263,821	0	263,821	0	263,821	1,416,146	0.4167%	5,901	269,721
30	June	232,749	0	232,749	(193,660)	39,089	1,455,235	0.4167%	6,063	45,152
31	July	304,006	0	304,006	(204,008)	99,998	1,555,233	0.4167%	6,480	106,478
32	August	243,452	0	243,452	(231,789)	11,663	1,566,896	0.4167%	6,529	18,192
33	September	263,343	0	263,343	(229,288)	34,055	1,600,951	0.4167%	6,671	40,726
34	October	240,045	0	240,045	(236,137)	3,907	1,604,859	0.4167%	6,687	10,594
35	November	240,045	0	240,045	(275,177)	(35,133)	1,569,726	0.4167%	6,541	(28,592)
36	December	238,651	159,140	397,791	(313,787)	84,004	1,653,730	0.4167%	6,891	90,894
37		$3,178,437	$159,140	$3,337,577	($1,683,847)	$1,653,730			$64,209	
38	Total revised 2008 true-up									$1,717,939
39										
40	2009 Renewable Resource Adjustment revenue received, February-August 2009 (1,057,012 MWH x 0.51 cents)									$5,390,761
41										
42	Proportion of 2008 true-up collected February-August 2009, line 40 x line 18									1,095,052
43										
44	Uncollected amount to be credited to tracker and amortized over 48 months, line 38 minus line 4									$622,888

Impact of deferring 2008 True-Up

Revenue requirements
Directly credits PTC to Tracker

Line #	Month	A Langdon	B Ashtabula	C Total	D Less Revenue Received	E Difference	F Cumulative Tracker Balance	G Monthly Carrying Cost Rate	H Carrying Cost	I Total Revenue Requirements
1	January 2008	$292,438	$0	$292,438	$0	$292,438	$292,438	0.4167%	$1,218	$293,656
2	February	307,511	0	307,511	0	307,511	599,949	0.4167%	2,500	310,011
3	March	342,843	0	342,843	0	342,843	942,791	0.4167%	3,928	346,771
4	April	209,534	0	209,534	0	209,534	1,152,326	0.4167%	4,801	214,336
5	May	263,821	0	263,821	0	263,821	1,416,146	0.4167%	5,901	269,721
6	June	232,749	0	232,749	(193,660)	39,089	1,455,235	0.4167%	6,063	45,152
7	July	304,006	0	304,006	(204,008)	99,998	1,555,233	0.4167%	6,480	106,478
8	August	243,452	0	243,452	(231,789)	11,663	1,566,896	0.4167%	6,529	18,192
9	September	263,343	0	263,343	(229,288)	34,055	1,600,951	0.4167%	6,671	40,726
10	October	240,045	0	240,045	(236,137)	3,907	1,604,859	0.4167%	6,687	10,594
11	November	240,045	0	240,045	(275,177)	(35,133)	1,569,726	0.4167%	6,541	(28,592)
12	December	238,651	159,140	397,791	(313,787)	84,004	1,653,730	0.4167%	6,891	90,894
13	Subtotal	$3,178,437	$159,140	$3,337,577	($1,683,847)	$1,653,730			$64,209	$1,717,939
14										
15	January 2009	$213,298	$366,234	$579,532	($370,919)	$208,613	$1,862,342	0.4167%	$7,760	$216,372
16	February	213,298	366,234	579,532	(957,438)	(377,907)	1,484,436	0.4167%	6,185	(371,721)
17	March	213,298	366,234	579,532	(872,845)	(293,313)	1,191,123	0.4167%	4,963	(288,350)
18	April	213,298	366,234	579,532	(799,303)	(219,771)	971,352	0.4167%	4,047	(215,724)
19	May	213,298	366,234	579,532	(686,419)	(106,888)	864,465	0.4167%	3,602	(103,286)
20	June	213,298	366,234	579,532	(667,070)	(87,538)	776,926	0.4167%	3,237	(84,301)
21	July	213,298	366,234	579,532	(702,239)	(122,708)	654,219	0.4167%	2,726	(119,982)
22	August	213,298	366,234	579,532	(705,447)	(125,916)	528,303	0.4167%	2,201	(123,714)
23	Remove uncollected portion of 2008 true-up				**(622,888)**	(622,888)	(94,584)	0.4167%	(394)	(623,282)
24	September	213,298	366,234	579,532	(506,878)	72,654	(21,931)	0.4167%	(91)	579,440
25	October	213,298	366,234	579,532	(501,846)	77,686	55,755	0.4167%	232	579,764
26	November	213,298	366,234	579,532	(570,510)	9,021	64,777	0.4167%	270	579,802
27	December	213,298	366,233	579,531	(648,096)	(68,565)	(3,789)	0.4167%	(16)	579,515
28	Subtotal	$2,559,575	$4,394,804	$6,954,379	($8,611,897)	($1,657,518)			$34,722	$604,534
29										
30	Total Revenue Requirements	$5,738,012	$4,553,944	$10,291,956	($10,295,744)	($3,789)			$98,932	$2,322,473
31										
32	Remainder of 2009 (Sept-Dec) estimated sales (MWH)									601,981
33										
34	Revised 2009 Renewable Resource Adjustment rate (cents/kWh)									0.386
35										
36	Rate currently in effect									0.510
37										
38	Impact of deferring remaining 2008 true-up on rate									(0.124)
39										
40	Less impact of removing PTC smoothing									(0.039)
41										
42	Impact on rate of deferring remaining 2008 true-up									**(0.085)**

Impact of Reducing Return on Rate Base from 11.25% to 10.75%
Effective September 1, 2009

Line #	Month	Langdon Revenue Requirements @11.25%	Langdon Revenue Requirements @10.75%	Langdon Difference
1	September	$213,298	$205,008	($8,290)
2	October	213,298	205,008	(8,290)
3	November	213,298	205,008	(8,290)
4	December	213,298	205,008	(8,290)
5		$853,192	$820,032	($33,160)
6				
7				
8		Ashtabula		
9	Month	Revenue Requirements @11.25%	Revenue Requirements @10.75%	Difference
10				
11	September	$366,234	$353,913	($12,321)
12	October	366,234	353,913	(12,321)
13	November	366,234	353,913	(12,321)
14	December	366,234	353,913	(12,321)
15		$1,464,935	$1,415,652	($49,282)
16				
17	Total reduction in revenue requirements			($82,442)
18				
19	Estimated Sales Sept-Dec 2009 (MWH)			601,981
20				
21	Impact on Renewable Resource Adjustment rate (cents/kWh)			**(0.014)**