STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Otter Tail Corporation Electric Rate Increase Application	**Case No. PU-08-862**
Otter Tail Corporation Renewable Resource Cost Recovery Rider 2009 Application	**Case No. PU-08-742**

MEMORANDUM IN SUPPORT OF SETTLEMENT AGREEMENT

Advocacy Staff (Staff) submits this Memorandum in support of the Settlement Agreement filed with the North Dakota Public Service Commission on July 1, 2009, between Staff, the Large Industrial Group (LIG), and Otter Tail Power Company (OTP) in the above-captioned matters. OTP and the LIG assisted in the preparation of this memorandum and join Staff in supporting the Settlement Agreement.

BACKGROUND

On September 2, 2008, OTP made its first annual filing updating the costs to be recovered through its Renewable Resource Rider (Rider). (Case No. PU-08-742). The Rider was originally approved by the Commission in its May 21, 2008 Order in Case No. PU-06-466. The background on OTP's request to update the Rider rate and on its new Ashtabula Wind Energy Center facility is described in the Settlement Agreement on page 3.

On November 3 2008, OTP filed an application with the North Dakota Public Service Commission (Commission) seeking a $6,084, 003, or 5.14 percent, increase in base rates for electric service to customers in its North Dakota retail service territory.

112 PU-08-862 Filed 09/28/2009 Pages: 22
Sept. 28 Hearing - Exhibit 5 - Memorandum in Support of Settlement Agreement
Public Service Commission

The background of OTP's request, its last rate increase in 1983, its implementation of interim rates, and the primary drivers of the need for the increase are described in the Settlement Agreement at pages 1 to 3.

A procedural history for the rate case and renewable rider case is provided as Attachment A to the Settlement Agreement. As described therein, on March 11, 2009, the Commission issued a Notice of Hearing, Notice of Continued Hearing and Notice of Public Input Session for the two cases, which set forth the following issues to be considered:

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.

As is described in the procedural history (Attachment A of Settlement Agreement), LIG and Staff filed Direct Testimony on April 1 and April 6, 2009 respectively. Thereafter, the parties commenced discussions for the purposes of determining whether the comprehensive settlement might be reached. On April 29, 2009, the Commission issued an Order suspending the procedural schedule in order to allow the parties additional time and opportunity to pursue a comprehensive settlement. Ultimately, the parties reached a comprehensive settlement agreement on all issues presented in the cases, including, but not limited to, OTP's overall revenue deficiency, the prudence of OTP's investment in the Ashtabula Wind Energy Center, the method and amounts of Renewable Rider recoveries, base rate class revenue responsibilities, rate design, and tariff language. The terms of that settlement are contained in detail in the Settlement Agreement and summarized in this Memorandum. This Memorandum is not intended to alter the terms of that Settlement Agreement; instead, this Memorandum is offered only to summarize the terms of the Settlement Agreement and explain considerations taken by the parties in reaching the agreement

OVERVIEW OF SETTLEMENT

OTP's originally proposed increase to base rates was based on an historical test year ended December 31, 2007, adjusted for known and measurable changes, an 11.25 percent return on common equity, and an 8.89 percent overall rate of return on rate base.

Staff and LIG based their revenue requirement class allocation, rate design, and other determinations on their own comprehensive analyses of OTP's filing and on additional information obtained through discovery. OTP responded to a total of 499 discovery requests from Staff and LIG, many of which had several subparts. Based upon their reviews of OTP's filing and these discovery responses, Staff and LIG accepted some company adjustments, made corrections where necessary, modified other adjustments using more recent actual data, and rejected those that did not qualify as known and reasonably measurable. Lastly, Staff and LIG each introduced in their testimonies new adjustments not reflected in OTP's filed case.

Differences between the company, Staff, and LIG positions were discussed thoroughly at numerous settlement conferences that occurred between mid-April and late June, 2009. As a result of these discussions, each party modified certain positions that it had previously taken and each party accepted certain positions of the others where common ground was found. Ultimately, the parties were able to agree on a comprehensive resolution of all issues that Staff, LIG, and OTP believe is based on sound regulatory principles and which avoids costly and unnecessary litigation.

In the Settlement Agreement, Staff, LIG, and OTP agreed that OTP's revenue deficiency is $3,597,887, justifying an approximately 3.04 percent increase in base rates (3.04 percent reflects the net rate increase to customers, including estimated impact of including Midwest ISO Schedule 16 and 17 costs and Asset Based Margins in the Fuel Adjustment Clause as described below). The parties also agreed that OTP should continue to recover the cost of renewable generation facilities through the Renewable Rider, with adjustments as described in the Settlement Agreement. The settlement

provides OTP with an annual level of revenues relative to its current service costs that is fair and reasonable. These settlement rates allow OTP a reasonable opportunity to earn a return that is adequate to enable it to continue providing safe, adequate, and reliable service to its North Dakota retail customers.

RATE BASE, RETURN ON EQUITY, RATE OF RETURN, DEPRECIATION, AND TREATMENT OF REGULATORY LIABILITIES

The Settlement Agreement reflects that the parties have agreed that for 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 $187,173,203.

In the Settlement Agreement, the parties reaffirmed their settlement on overall rate of return (ROR) and return on equity (ROE), which were originally reached on February 20, 2009. The parties agreed to a ROR of 8.62 percent and ROE of 10.75 percent. That agreement results in an adjustment that reduces OTP's original revenue request by $831,539. The parties also agreed that OTP will share with customers any earnings above 10.75 percent, as described later in this Memorandum, and that the 10.75 percent ROE will be used for purposes of determining interim rates in OTP's next general rate case.

The parties also agreed that a change in depreciation allocation method that was proposed by OTP should occur at this time. See direct testimony of Ms. Bernadeen Brutlag at pages 2-6. In the past, these costs had been directly assigned to each of the jurisdictions OTP serves. OTP proposed, and the parties agreed, that OTP should allocate accumulated depreciation and depreciation expense using the same allocation factors as are used for allocating electric plant in service. This change in allocation

method would have increased North Dakota revenue requirements by $119,476, however, the parties have agreed that this allocation change should be accepted and used on a going-forward basis, but the increase in revenue requirements in this case will not be included, thus reducing OTP's original revenue request by $119,476.

Also, as part of the Settlement Agreement, the parties agreed that rate recovery – past, present, and future – for the removal or retirement of OTP utility property will be used solely for the retirement of OTP's utility property and recognized as a regulatory liability.

OPERATING INCOME

Wholesale Margins

The Settlement Agreement describes the parties' agreement with respect to asset based and non-asset based wholesale margin crediting. OTP's proposal for crediting asset based wholesale margins to the retail revenue requirement was to use a five-year average (2003-2007) margin rather than actual margins achieved during the test year. Staff recommended that OTP's proposal be modified to credit customers through the fuel clause adjustment (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 nonrepresentative margin forecast in the test year. By sharing the gains on asset based sales, the parties recognize in their settlement that OTP will have an incentive to optimize power plant operations in order to maximize the benefit from these sales. Such an incentive will benefit OTP's customers through increased availability of OTP's low-cost generation and reduced purchased power costs. Also, because both the purchased power costs

and asset based margins rise and fall with changes to market prices, the settlement's approach to margin crediting has the added benefit of providing higher margin credits to offset the FCA during times when purchased power costs have increased.

With respect to non-asset based margins, OTP proposed customers receive 15 percent of non-asset based margins and that any margins earned be calculated annually after the close of the calendar year and credited to the fuel adjustment clause if the calendar year balance is positive and then distributed over the ensuing twelve months. OTP's non-asset based activity is unregulated and outside the normal course of OTP's regulated utility operations. Staff and the LIG proposed the use of a fixed credit to the base rate revenue requirement instead of a variable credit in order to reflect that the costs that should be allocated to this activity do not vary as significantly as the market. The parties agreed to a fixed credit of $560,000 to the base rate revenue requirement based upon an OTP cost study.

Miscellaneous Expense Adjustments

The Settlement Agreement reflects the parties' agreement that a reduction of the revenue requirement in the amount of $158,000 is appropriate as a resolution to several miscellaneous adjustments recommended in the Direct Testimony of Mr. Majoros. Fifty Thousand Dollars of the $158,000 represents a reduction to OTP's requested economic development expenses. OTP had originally requested $500,000 for economic development expense. The adjustment results in a reduction of the economic development expense to a total of $450,000.

DSM and Energy Conservation

The Settlement Agreement removes all costs for new Demand Side Management (DSM) and Energy Efficiency Programs (EEP). Rather than include these expenses in base rates, the parties have agreed that any new DSM or 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 instead of in base rates.

Midwest ISO Schedules 16 and 17 Costs

The parties agreed that Midwest ISO Schedules 16 and 17 costs, both deferred and current amounts, should be recovered through the FCA rather than through base rates. The parties agreed that recovering these costs through the FCA is reasonable given that, like other Midwest ISO Day 2 charge types recovered through the FCA, they are nondiscretionary charges billed per kWh by the Midwest ISO for administration of the Midwest ISO energy market. This adjustment decreases OTP's base rate increase by $566,009. It does not, however, impact the overall revenue increase, since the recovery of these costs is being moved from base rates to the FCA.

OTHER NECESSARY ADJUSTMENTS

OTP's revenue requirement model relies on certain secondary allocation factors that are generated within the model. Making the above-described adjustments to OTP's cost of service model also results in reductions to the cash working capital in the amount of $7,266 and to jurisdictional allocations in the amount of $150,417.

ISSUES TO BE ADDRESSED IN OTP'S FUTURE RATE CASES

In addition to the above-referenced adjustments to revenue requirements in this case, the parties have agreed that OTP will address in its next general rate case the following issues:

1. The fair allocation of renewable energy credits amongst OTP's jurisdictions;
2. The separation of energy costs from its base rates so that the aggregate amount for all cost of energy will be seen as a single line item on customer bills;
3. The use of an E8760 allocator for class cost of service study development purposes and for purposes of allocating fuel costs between classes; and
4. The inclusion of the Ashtabula and Langdon Wind Farm costs in base rates.

ALLOCATIONS FOR THE RATE CASE

The Settlement Agreement includes proposed class cost allocations for rate design purposes as reflected in Table 3 on page 9. These agreed upon class cost allocations reflect the agreed to adjustments in base rate revenue requirements described earlier in this Memorandum and other adjustments to OTP's originally proposed class cost allocations. The parties agreed that these class cost allocations fairly balance cost and non-cost considerations and arrive at class cost allocations that are reasonable and non-discriminatory. In addition to those class allocations, the parties have agreed that if the Commission determines that it is appropriate for OTP to recover DSM and 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, even if some or all of the EEP programs are found to benefit the LGS class.

RATE DESIGN

Staff and LIG concurred with the changes originally proposed by OTP for all Rate Schedules except for Residential, Residential Demand Control, Farm Service, General Service Less than 20 kW, Large General Service, and Large General Service Time of Day. The settlement position reached between Staff, LIG, and OTP was the result of numerous iterations of possible rate design alternatives for these rates. OTP, Staff and LIG analyzed each alternative to determine whether rate design objectives were being met and whether disproportionate rate impacts could be mitigated. The final settlement rate design strikes a balance of these rate design considerations. Each of these rate schedules is discussed below.

Residential Service Rate

OTP's initial filing proposed eliminating the declining block structure in favor of a flat seasonally differentiated volumetric charge. The proposal also included a new flat Monthly Facilities Charge of $5 for all customers, and discontinued the existing customer charge differential for urban (Zone 1) and rural (Zone 9) customers.

Staff concurred with discontinuing the urban and rural customer charge differential, but opposed having a separate Facilities Charge. Since OTP proposed that all residential customers be charged the same flat Facilities Charge, Staff proposed including the Facilities Charge within the Customer Charge. Combining these two charges will avoid customer confusion that having an additional line item on the bill may cause. OTP proposed an $8 Customer/Facilities Charge; the settlement stipulation

reflects an $8 Customer Charge (with no separate Facilities Charge). This results in a $3.26 increase for Zone 1 customers and a $2.35 increase for Zone 9 customers over present rates.

While Staff understands the rationale behind OTP's proposal to flatten OTP's present declining block rate structure and adopt a seasonally differentiated energy rate, Staff recommended that rate design changes should be more gradual to avoid customer confusion and unusual bill impacts. The overall increase for the residential class, which is composed of residential service and residential service-demand control, is 6.00 percent with the Residential Service rate receiving a 5.40 percent increase. Staff believed the increases for high usage customers were too dramatic.

The settlement rate schedule reduces the current number of rate blocks in the declining block structure from three to two in the winter, and from three to one block in the summer. Staff suggested mitigating the winter season by adding back in a declining block to reduce the winter electric heating increases for larger customers. The settlement rate design marks the initial step towards seasonally differentiated flat summer and winter rates in a gradual fashion to mitigate rate shock and customer concerns.

Residential Demand Control Rate (RDC)

OTP's original proposal added a $9 Facilities Charge to recognize that RDC customers generally have larger capacity service facilities, incorporated a flat seasonally differentiated energy charge, and changed the demand charge to a slightly higher charge in the summer than winter to reflect OTP's summer marginal capacity costs. As indicated in David Prazak's original Exhibit ___ (DGP-1) Schedule 1, the

residential class increase requested was 7.50 percent. The RDC rate requested was a 14.67 percent increase versus a 6.22 percent increase for the Residential Service rate.

As discussed with respect to the Residential Service rate, Staff was concerned about the higher increase to the RDC rate in relation to the Residential Service rate and the overall increase. In order to mitigate Staff's concern regarding the RDC rate increase, OTP adjusted the revenue requirement of the RDC rate by shifting a portion of the revenue requirements to the Residential Service rate. This settlement adjustment resulted in an overall increase for the residential class of 6.00 percent with the RDC rate receiving a 9.36 percent increase.

The settlement rates reflect the seasonally differentiated energy charge, a moderate increase in demand charges, and the addition of the facilities charge within the customer charge.

Farm Service

OTP's originally proposed Farm Service rate eliminated the declining block structure in favor of a flat, seasonally differentiated energy charge. OTP's proposed rates also would have increased the existing Customer Charge by $0.49 to $8.00, eliminated the charge for transformer facilities, and instituted a new surcharge for customers using three-phase service that varied depending on whether the customer is served from overhead or underground facilities and whether the customer's transformer is below 25 kVA or is 25 kVA and greater.

Staff's concerns with OTP's Farm Service rate proposals were similar to its concerns with OTP's Residential Service proposal. That is, OTP's proposed rate design

had large bill impacts for high usage customers. These changes should be made more gradually to avoid rate shock and fairness concerns.

The settlement rate reduces the existing declining block structure from three blocks to two blocks, and reduces the energy rates between the blocks in an effort to move towards a flatter rate structure. The settlement rate includes the Customer Charge and eliminates the Transformer Facilities Charge that OTP had proposed. The three-phase surcharge also was reduced in proportion to the agreed to revenue requirement.

General Service Less Than 20 kW

OTP's original proposal eliminated the declining block structure and demand charge in favor of a seasonally differentiated volumetric charge. OTP also proposed discontinuing the existing zone differential in the Customer Charge and increasing the Customer Charge to $10. OTP's proposed rates would have resulted in a $3.35 increase for Zone 1 customers and a $2.05 increase for Zone 2 customers. A new flat Facilities Charge was proposed for all customers; $3 for secondary services and $2 for primary services.

Staff opposed the flat energy rate for small general service customers based on rate stability and gradualism. However, Staff supported eliminating the load factor block and demand charge to allow for a simpler, more transparent structure for small customers. Staff also recommended combining the Facilities Charge with the Customer Charge and eliminating the existing zone differential. The settlement rate reflects a $13 Customer Charge, resulting in an overall increase of $6.35 for secondary Zone 1 customers and $5.05 for Zone 2 customers.

Large General Service

OTP's original proposal eliminated the declining block and load factor block structures in favor of a single block with seasonal demand and energy charges. In addition, the proposed rate eliminated the current ratchet for billing demand and added a facilities charge which varied by voltage level and size (above and below 1000 kW). The bill impacts for the OTP proposed rates showed a decrease for about 95 percent of the customers, and an increase for the remaining 5 percent of the customers.

Both Staff and the LIG were concerned about the bill impacts of OTP's proposed design. OTP worked closely with the Staff and LIG to adjust the equity of bill impacts across the rate class. LIG proposed a number of adjustments, such as varying summer/winter energy and demand levels as well as re-introducing load factor blocks at different hour-block levels. An equitable solution between Staff, LIG, and OTP required analyzing many different scenarios. Eventually, all parties agreed to advance a customer charge, a separate facilities charge which varies by voltage level and size (above and below 1000 kW), seasonally differentiated 2-block energy charge and a flat seasonal demand charge. The energy and demand charges deviated from the marginal cost approach originally proposed by OTP in order to produce a settlement rate that had rate impacts acceptable to the parties.

Large General Service Time of Day

OTP's original proposal introduced demand charges to the current "energy-only" 3-period (on-peak, shoulder, and off-peak) per season design. The current design was a new rate design in North Dakota and approved by the Commission in Case No. PU-07-03. The original proposal in this rate case was intended to align with OTP's approved

Large General Service Time of Day offerings in its other jurisdictions. LIG suggested a different approach by advancing a 2-period on/off peak with a load-factor block design, similar to Xcel Energy's Minnesota General Time of Day Service (approved by Minnesota Commission in Docket No. E002/GR-08-1065).

The settlement rate design follows the same structure as OTP's proposed design. OTP, LIG and staff agreed that the Large General Service – Time of Day Rate will be introduced on an experimental basis and will be re-evaluated in OTP's next rate case.

Changes to Other Rate Schedules

A. Eliminate Declining Blocks

Declining block and load factor block structures were eliminated in the following rate schedules in favor of flat, seasonally differentiated energy charges:

General Service – Less than 20 kW

General Service - 20 kW and Greater

Municipal Pumping

Controlled Service - Interruptible Load Rider < 80 kW Self-Contained Metering

OTP's proposed flat, seasonally differentiated energy charges are based on the marginal costs of purchasing power on the Midwest ISO market. Since OTP does not have the available capacity as it did in 1983 when the declining block structures were last approved, flat rates that encourage conservation of energy are reasonable.

B. Seasonally Differentiated Energy Charges – Irrigation Service

The Irrigation Service flat energy rate was modified to include a seasonal differential. The seasonal rate differential is supported by both the energy and generation capacity costs provided in OTP's 2009 Marginal Cost Study.

C. Penalty Rates

The following rate schedules included a new or significantly increased penalty rate for unauthorized use during control periods:

Controlled Service - Interruptible Load Rider CT Metered

Controlled Service - Interruptible Load Rider < 80 kW

Controlled Service - Deferred Load Rider

Fixed Time of Delivery Rider

Penalty rates are based on the number of hours of load control and the associated marginal costs (energy and demand) during those control hours. OTP calculates an average cost of market power during all hours of load control. A customer operating during the control period will pay the regular rate plus the penalty rate during the control period even if OTP does not have to purchase the power through the Midwest ISO. This penalty provision is intended to send a clear and appropriate price signal to not use energy during control periods.

<u>Applying the Fuel Clause Adjustment to All Rate Schedules</u>

OTP's proposal added the fuel clause adjustment (FCA) to six rate schedules:

Schedule 11.03 Outdoor Lighting – Energy Only Dusk to Dawn

Schedule 11.04 Outdoor Lighting Dusk to Dawn

Schedule 14.04 Controlled Service - Interruptible Load Rider CT Metered,

Schedule 14.05 Controlled Service - Interruptible Load Rider (Less than 80 kW),

Schedule 14.07 Fixed Time of Delivery, and

Schedule 14.12 Controlled Service - Bulk Interruptible.

The customers on rates 11.03, 11.04, 14.04, 14.05, and 14.07 have been receiving service and not paying for increases in fuel and purchased power costs that have occurred since OTP's last rate case in 1983. As a result of including fuel costs in base rates in the current case, the average increase for the approximately 21,000 lighting fixtures is 20 percent. For the 419 Controlled Service - Interruptible Load Rider CT Metered customers the average increase is 32.56 percent, and for the 5,491 Controlled Service - Interruptible Load Rider Self-Contained Metered (Less than 80 kW) customers the average increase is 21.60 percent. Lastly, the average increase for the 1,605 Fixed Time of Delivery customers is 18.58 percent. .

The Controlled Service - Bulk Interruptible rate schedule has no customers on it at this time. Recall the Bulk Interruptible rate schedule requires a customer-specific contract and pricing, and also requires Commission approval.

Overall, Staff agrees with OTP that the FCA should be included in the above rates going forward.

Canceled Rate Schedules

OTP proposed eliminating the following two general service rate schedules that currently have customers:

General Service - Commercial Demand Control and

General Service - Electric Climate Control.

OTP has provided adequate support to justify eliminating these rates.

General Service - Commercial Demand Control has been an experimental rate for over 20 years and currently has 26 customers. These customers will qualify for either the General Service – Less than 20 kW or General Service – 20 kW and Greater rate. The 9 customers who qualify for General Service – Less than 20 kW will receive on average a 14.30 percent increase in rates. The other 17 customers who qualify for General Service – 20 kW and Greater will receive on average a 17.39 percent increase in rates. Other rate options are available for some customers including Commercial Time of Use and other rate riders such as dual fuel or possibly Real-Time Pricing (RTP). The primary reason for closing this experimental rate is due to the low participation and duplication of other available rate options, described above.

General Service - Electric Climate Control (ECC) has been closed to new customers since 1983 (Case No. 10334). The primary reason for canceling this rate schedule is due to the administrative complexities – for both customer and company. The ECC rate design is not a load control rate but instead offers various rates, conditions, and allowances for space heating, cooling, electric cooking or process heating. Identifying and tracking these specific allowances is time consuming and can be confusing to customers. Due to these complexities and to reiterate that the rate has been closed to new customers since 1983, the ECC should be canceled.

The ECC currently has approximately 527 customers. These customers will qualify for either the General Service – Less than 20 kW or General Service – 20 kW and Greater rate. The 169 customers who qualify for General Service – Less than 20 kW will receive on average a 7.71 percent increase in rates. The other 358 customers

who qualify for General Service – 20 kW and Greater will receive on average a 20.50 percent increase in rates. The settlement rates reflect the movement of these customers to appropriate General Service rate schedules based on the customers demand reading for the most recent 12 months Other rate options are available for some customers including Commercial Time of Use and other rate riders such as dual fuel or possibly Real-Time Pricing (RTP).

OTP also proposed canceling the Large General Service Off-Peak Rider, which has 2 customers. The settlement rates anticipate the movement of these 2 customers to the Large General Service rate schedule. On the Large General Service rate schedule these 2 customers will receive on average a 0.26 percent increase. The Large General Service Off-Peak Rider is a variant of the Large General Service Time of Day. To employ both rate schedules would be duplicative. As mentioned, these customers also may consider the Large General Service Time of Day, and possibly the RTP Rider.

New Rate Schedules

Commercial Time of Use - Under this schedule, General Service customers with demand of at least 20 kW per month pay a higher rate in those hours defined by OTP to be periods of peak conditions. The proposed rate has a flat, seasonally differentiated energy rate that varies between declared-peak, intermediate-peak, and off-peak time periods, as well as a demand charge only in the shoulder period. This new structure gives a strong price signal to customers during critical hours.

Large General Service Rider - Customers would take service on this rider in order to allow the Company to interrupt load above the customer's baseline load. Customers would see savings since the rate structure would discount demand charges.

Controlled Service - Interruptible Load Rider CT-Metered Option B - This option will allow motor, fan and pump load up to 5 percent of the metered maximum demand to be on the same meter as a customer's controlled heating load. The rate is in contrast to the current option (Option A) which requires motor, fan and pump load, used to distribute the heat, to be connected separately under the appropriate General Service rate schedule.

The parties have made several other relatively minor changes to tariff language, many of which are merely corrections of typographical errors, which are reflected in the Settlement Agreement (pages 12-13 and on Attachment D to the Settlement Agreement).

INTERIM RATES

The parties agreed upon how refunds for interim rates shall be calculated. That agreement is reflected on Attachment C of the Settlement Agreement. For calculating the final interim rate refund, Attachment C will be updated to reflect actual data through the end of the interim rate period.

FUEL CLAUSE ADJUSTMENTS

Parties have agreed that effective with the first month in which bills are rendered containing final rates; OTP will use actual retail sales in calculating the FCA instead of a 12 percent line loss factor for purposes of calculating the retail sales for the FCA. This change will have no affect on either the interim or final rate revenue requirement and is to be applied prospectively.

The parties have also agreed that Midwest ISO ASM revenues and expenses will be included in the FCA calculation, and thereby all Midwest ISO ASM margins will be reflected in the FCA. Additionally, asset based margins will be credited to the FCA, as previously indicated, based on a forecast for the current time period and thereafter trued up based upon actual margins. In this way, the margins will be treated as credits offsetting fuel costs.

SETTLEMENTS REGARDING THE RENEWABLE RESOURCE RIDER

The parties have agreed that the Commission should issue an Order finding OTP's investment in the Ashtabula Wind Energy Center prudent and approving the 2009 Renewable Resource Cost Recovery Rider as filed. The parties have also agreed that OTP will commence implementation of a new Renewable Resource Rate of $.00372 to be effective for bills rendered on and after September 1, 2009. This rate reflects adjustments in the ROE from 11.25 percent to 10.75 percent, the recovery of unrecovered 2008 costs over 48 months, beginning January 1, 2010, and the removal of OTP's proposed partial levelizing of the production tax credit.

In OTP's next annual Renewable Resource Cost Recovery filing, in addition to these adjustments to the revenue requirement, the parties have agreed that renewable rider cost recoveries will be allocated between customer classes, with 20 percent allocated based upon demand and 80 percent based on energy, and within the LGS class the revenue allocation will be collected through both a demand and energy charge using the same 20 percent demand, 80 percent energy allocation. Because the demand allocation is based upon MISO's current capacity accreditation for wind facilities, and because MISO is currently conducting studies to refine that accreditation, the parties

have agreed that the 20/80 allocation percentages shall be adjusted as necessary to correspond with the weighted average level of capacity approved by MISO for projects being recovered through the renewable resource rider.

The parties have also agreed that the renewable cost recovery rate should be combined with the fuel clause adjustment on customer bills and reflected as a single "energy adjustment." This will reduce the potential for customer confusion and more accurately reflects that the wind projects are not merely additional costs for customers but also result in reduced purchased power costs.

OTP has also agreed to monitor its E-2 allocation factor and address in its annual renewable cost recovery filings any material change that may occur to that allocation factor for jurisdictional purposes.

OTHER TERMS AND CONDITIONS

As indicated previously in this Memorandum, the parties have agreed that OTP shall refund to customers earnings above the authorized ROE of 10.75 percent. Pursuant to the Agreement, if Otter Tail earns in excess of 10.75 percent in 2009 or 2010 calendar years, OTP will refund to customers 50 percent of earnings above 10.75 percent up to and including 11.25 percent and 75 percent of earnings above 11.25 percent.

The parties have also agreed to a moratorium on electric base rate increases until January 1, 2011.

CONCLUSION

Based on the foregoing, Staff asks that the Settlement Agreement be approved.