Large Industrial Group

Direct Testimony of
Larry L. Schedin PE

Before the
North Dakota Public Service Commission

In the Matter of the Application of Otter Tail Power Company's Annual Filing for Renewable Resource Cost Recovery Factor

AND

In the Matter of the Application of Otter Tail Corporation for Authority to Increase Rates for Electric Service in North Dakota

Docket No. PU-08-862 AND PU-08-742 Combined

Exhibit __

April 2, 2009

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I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Larry L Schedin. I am a registered Professional Engineer. I am the president and owner of LLS Resources, LLC.

Q. Please state your business address.

A. My office is located at 12 South 6th Street, Suite 1137, Minneapolis, Minnesota, 55402

Q. Who are you representing in this proceeding?

A. I am representing the North Dakota Large Industrial Group ("LIG").

Q. Please describe the LIG.

A. The LIG is a coalition of eight Otter Tail Power Company's ("OTP" or "Otter Tail") large commercial-industrial customers engaged in agri-product processing, manufacturing and other commercial-industrial activities. LIG members provide major employment opportunities in North Dakota and provide products to highly competitive regional, national and international markets.

Q. Please describe these companies.

A. The companies and basic operating characteristics are as follows:

- **Cargill, Incorporated** – Founded in 1865, a privately held company with 160,000 employees in 67 countries, an international producer and marketer of food, agricultural, financial and industrial products and services. In Otter Tail's North Dakota service territory, at Spiritwood, Cargill operates the world's largest malting operation and in Fairmont, Cargill operates a flour mill. Cargill also has operations in Wahpeton, Fargo and West Fargo. As a practical matter, this proceeding and the electric rates we pay affect our world-wide competitiveness with respect to products from these locations.

  Cargill does have a commitment to conservation and the environment. As such, Cargill has taken the following conservationist steps:

  1. Improvement of energy efficiency by 20 percent over 2001 fiscal year baseline;
  2. Increase use of renewable energy by 10 percent;
  3. Reduce greenhouse gas intensity by 8 percent against 2006 fiscal year baseline;

4. Improve freshwater efficiency by 2 percent against 2006 baseline, increasing volume necessarily improves per unit energy efficiency, which is how Cargill has decreased the per-ton energy component of its Spiritwood units.

- **Tharaldson Ethanol Plant I, LLC** – Began operations in 2008 in Casselton, ND in the business of producing ethanol. Tharaldson primarily serves the entire United States in an industry that is highly competitive with other producers throughout the Country. Energy is one of the largest inputs driving the overall costs of ethanol, so small changes in electric prices have material impacts in the competitive position of the company. Tharaldson provides a proximate location for North Dakota farmers to sell their grain and directly provides approximately 50 jobs at its Casselton location.

- **Goodrich Corporation** – Located in Jamestown, Goodrich Cargo Systems division has two facilities, which provide employment for 560 individuals. At these two locations, Goodrich conducts aerospace design and manufacturing for products that are shipped worldwide. Goodrich utilizes numerous local providers for services, materials and supplies, including Progress Enterprises. Due to the downturn in business, competitive pricing is an ever increasingly important concern and a drop in business has resulted in a November 2008 temporary shutdown and layoff of 35 employees.

  Goodrich has recently invested hundreds of thousands of dollars in conservation actions including; lighting retrofits, buss bar replacement and installation of a capacitor bank.

- **Bobcat Corporation** – Bobcat has three locations in North Dakota, among them within OTP's service area, Bobcat has a major manufacturing facility in Gwinner. In North Dakota Bobcat has approximately 2,000 employees and has 18 production suppliers representing $27M in an annual out-sourced direct costs, in addition, hundreds of local and direct material suppliers are provided business by Bobcat.

  Bobcat operates in a worldwide market and has been significantly impacted by the global economic downturn. A significant portion of business is tied to the residential housing industry, resulting in a loss of business of approximately 40 percent and eight weeks of shutdown over the last four months. Bobcat has taken on numerous projects to save costs and energy, which have resulted in significant drops in both peak demand and total energy consumption on a per-unit basis.

- **PrimeWood Inc**. – Founded in Wahpeton, ND in 1987, PrimeWood originally manufactured and sold solid millwork components. In the following years, PrimeWood converted to engineered wood products, veneer raised panels and ridged thermal foil products, and began to supply products to the kitchen and bath industries. More recently, PrimeWood developed processes in horizontal work surfacing, producing large parts and components for institutional and commercial customers. Currently, PrimeWood employs approximately 220 workers, down from 550 three years ago.

PrimeWood is facing increasing competition from importers, which makes increasing utility prices even more difficult to absorb.

- **Cavendish Farms, Inc**. – Cavendish Farms Inc. has a Jamestown, North Dakota facility employing 210 people on a full-time basis to convert and process frozen potato products. Cavendish operates in a competitive industry that spans North America. Cavendish's ability to remain competitive in the industry effects multiple suppliers including three trucking or transport companies, twenty five farmers, three fertilizer suppliers, two corrugate suppliers and a ingredient supplier all located in North Dakota.

  Cavendish has started six sigma products to eliminate electricity waste and have been successful in these conservation efforts by reducing peak demand while increasing product output by 15%.

- **Archer Daniels Midland Company** - ADM on a daily basis turns crops into renewable products that are sold within the region, United States and Worldwide. At its' more than 230 processing plants crops are turned into products for food, animal feed, chemical and energy uses. In North Dakota, ADM has approximately 120 employees at its processing facility in Enderland, North Dakota. Energy costs are one of the Enderland facilities' largest monthly operating expenses and any change in operating costs from its Enderland facility can have a significant effect on the competitiveness of its North Dakota facilities as the inputs and outputs are commodities that can be easily moved from a higher cost processing facility to a lower cost one.

- **ComDel Innovation Inc.** – Headquarted in Wahpeton, ND, ComDel employs approximately 150 people. ComDel is a contract development and manufacturing company with primary capabilities in machining, plastic injection molding, metal stamping and automated assembly. ComDel operates in a competitive nationwide and worldwide marketplace.

  Energy accounts for ComDel's second largest operating expense and has created a competitive disadvantage in relation to other companies when its energy costs increase to a greater extent than that experienced by competitors. While some costs from energy suppliers are beyond ComDel's control, Comdel is taking steps to increase conservation efforts, including: (1) installing more efficient lighting, (2) equipment shutdown projects, and (3) conversion to more efficient equipment.

Q. How are LIG members affected by this rate case proceeding?

A. LIG members represent companies that are a significant source of employment and tax revenues in North Dakota. All these companies operate in a highly competitive environment and, as such, are constantly driven to be efficient and drive down costs. These companies have a commitment to energy conservation and have implemented several energy efficiency initiatives in an effort to be cost competitive. The current economic downturn has already resulted in job losses and temporary shutdown for some of our members.

Increases in electricity costs are a major concern for the LIG as it directly affects their competitiveness especially those companies where such costs are a major input. LIG wants to make sure supply is reliable and secure but has an interest in not paying for more than they are responsible for.

Q. Please state your educational and professional background.

A. Please see the summary of my educational and professional experience attached hereto as **LIG Exhibit __ (LLS-1)**.

Q. Have you ever testified in other utility proceedings?

A. Yes, in numerous cases, including federal, state and local proceedings.

Q. Has any of your recent experience been with OTP proceedings closely related to this current case before the North Dakota Public Service Commission ("NDPSC")?

A. Yes. I was an expert witness before the NDPSC representing the ND OTP Large Industrial Group in OTP's Cost of Fuel Adjustment Clause Tariff Case No. PU-05-131 in April of 2007 and in OTP's ND Time of Day Tariff Case No. TOD PU-07-03.

I was also recently an expert witness for the Minnesota Chamber of Commerce ("MN Chamber") in OTP's general rate case, MPUC Docket No. E-002/GR-07-1178 and Xcel Energy's general rate case, MPUC Docket No. E-002/GR-05-1428, both in Minnesota.

Q. How was the Xcel general case related to OTP's current rate case?

A. In addition to examining traditional rate case items, I analyzed the impact of the MISO Day 2 market on Xcel's retail Fuel Cost Adjustment ("FCA"). As a participant in this case, I assisted the MN Chamber in reaching a settlement on this issue and others, including the sharing of wholesale margins.

Q. How did the Xcel settlement impact OTP?

A. As follow-on to my work on the Xcel general rate case, I participated as a MN Chamber representative in the MISO Stakeholder Group set up as an attempt to reach a settlement in MPUC Docket No. E-002/M-04-1970 dealing with costs to be passed through the FCA. OTP was a member of the Stakeholder Group along with the three other Minnesota Investor Owned Utilities's ("IOUs") all impacted by MISO related FCA issues. The Stakeholder Group, including OTP, accepted a settlement based essentially on the one negotiated in the Xcel rate case

Q. Did the Stakeholder Group, including OTP, reach a settlement which was also adopted by the NDPSC?

A. Yes. In Case No. PU-05-131, the NDPSC accepted the MN MISO settlement with some minor adjustments in order to conform to ND state law.

Q. Did the ND or MN MISO settlements include a sharing of OTP's wholesale trading margins?

A. No. Both Xcel and Alliant Energy settled their wholesale margin sharing issues earlier in their respective MN general rate cases, and the MPUC noted that wholesale margin sharing would be an issue for OTP in OTP's subsequent general rate case before the MPUC under MN Docket No. E017/GR-07-1178, which is now complete. The ND settlement in NDPSC Case No. PU-05-131 stated that OTP was required to file a general rate case in ND on or about November 1, 2008 aimed at resolving the wholesale margin issue in ND along with other general rate case issues.

Q. Please explain your involvement in MN Docket No. E-017/GR-07-1178 (OTP's general rate case in MN)?

A. My testimony in that case examined OTP's request to recover increases in its MN jurisdiction revenue requirements via rate design, allocations and other changes along with its recovery of MISO Day 2 Market costs, including fuel and purchased energy, (via OTP's COE) as well as its proposal to share wholesale trading margins.

Q. Were OTP's wholesale margin sharing issues resolved in its MN rate case?

A. Yes. My testimony in this case will include a discussion of the MN settlement and compare it with my recommendations in this ND case.

Q. Were you involved with the MN Chamber in any on-going FCA issues in MN involving OTP?

A. Yes. I represented the MN Chamber as a member of a Stakeholder Group under Generic MN FCA Docket No. E999/CI-03-802 which dealt with FCA forecast reporting requirements and the on-going viability of automatic FCA's in MN.

Q. How was that issue resolved?

A. That case resulted in agreement among MN IOU's, the MPUC and the MN Chamber requiring the IOU's to provide FCA forecasts upon request to customers signing confidentiality agreements.

Q. Have you been involved in any other recent regulatory proceedings impacting OTP?

A. Yes, I represented several key segments of the environmental community, including Wind on the Wires and the Izaak Walton League, in 2008 as an expert witness in MPUC Docket No. E002/CN-06-1115, called the CapX 2020 Docket under which various MN and ND utilities requested a certificate of need to construct three 345 KV transmission lines in MN. OTP plans to own portions of the CapX 2020 facilities which are important to almost all MN and ND utilities.

Q. What was your testimony in that case?

A. I generally supported the utility Applicants' requests and went one step further by recommending that certain parts of the projects be upsized to allow for future needs.

Q. Was your upsizing testimony accepted?

A. Yes. The utilities and the Administrative Law Judge ("ALJ") accepted my upsizing proposal which the utilities subsequently further expanded. The ALJ's order adopting much of my testimony was issued on February 27, 2009.

Q. What is the purpose of your testimony in this case?

A. My testimony in this case examines OTP's request to recover increases in its ND jurisdictional revenue requirements via rate design, allocations and other changes, along with its requested recovery of costs resulting from its investments in wind farms. My testimony also includes recovery of fuel and purchased energy costs (via OTP's COE), sharing of wholesale trading margins as well as its proposal to recover costs of the Langdon and Ashtabula wind farms via a separate renewable resource rider (RRR).

Q. Is your testimony focused on a particular class of service?

A. Yes. I focus principally on the Large General Service ("LGS") class, but portions of my testimony, such as OTP's wholesale margins and OTP's General Service Rules, will benefit almost all customer classes.

Q. Have you worked with other experts in preparing your direct testimony in this case?

A. Yes, I work regularly with Kavita Maini, Senior Rate Economist and associate in Oconomowoc, Wisconsin who has appeared as an expert witness in an OTP case in ND and has provided technical support in many of my projects. She is an expert in MISO matters and has an extensive analytic background and knowledge of commercial/industrial rate design as well as the MISO Day 2 Market. Ms. Maini's credentials show that she represents the Midwest Industrial Customers, an ad hoc coalition of four associations, in matters before MISO and is also a Board Member of the relatively new Midwest Reliability Organization ("MRO") created as a result of tighter reliability regulation under the federal Energy Policy Act of 2005. She is providing separate testimony in this case. I also regularly work with other industry experts as issues with particular specialty require. In this case Jim Erickson assisted in researching a couple of issues.

Q. Does this testimony include all of the issues you are concerned with?

A. Based on the information we have today, yes. The discovery response period, timing of when we got all of the initial filings in these proceedings and constrained timeframe in these cases has limited our ability to thoroughly prepare. LIG has a number of outstanding information requests or information requests that were received at the time of filing, which may refine or add concerns. If any supplement is necessary, LIG will make every effort to do so timely.

II. WHOLESALE MARGINS AND RNEWABLE ENERGY CREDITS (REC)

Q. Why are wholesale margins important in this proceeding?

A. In its settlement agreement with LIG in Case No. PU-05-131, the Commission ordered OTP to address wholesale revenue margin sharing in its next rate case which must be filed by November 1, 2008.

Q. Did OTP comply with this order?

A. Yes. In this current proceeding, OTP includes a mechanism for wholesale margin sharing, both asset-based and non asset-based.

A. <u>Asset-Based Wholesale Margins.</u>

Q. Please explain OTP's proposed mechanism for sharing its asset-based wholesale margins.

A. OTP proposes to include a 2003-2007, 5-year average of its wholesale margins (or $4.133 million) as a credit to base rate expenses with any excess accruing to OTP to supposedly offset the need for future rate cases.

Q. Do you agree with OTP's proposal?

A. No, I do not.

Q. Please describe why you disagree.

A. I feel that if a base amount is to be credited to base rate expenses, OTP's proposal is too low recognizing that its 5-year average includes wholesale margins prior to startup of the MISO Day 2 market on April 1, 2005. Startup of the MISO market fundamentally changed and dramatically increased OTP's opportunity for wholesale margins. As such, if OTP's request is granted, pre-MISO market margins should be excluded from the average, and 2008 margins should be included. Subsequent to startup of the MISO Day 2 market, OTP's wholesale trading margins have remained relatively constant as follows:

OTP's ASSET-BASED WHOLESALE MARGINS

Year	Margins (in $ 1000's)
2005	$4,746
2006	$4,531
2007	$4,462
2008	$4,600
TOTAL	**$18,339**
4-YR AVERAGE	$4,585
OTP PROPOSAL	$4,133
DIFFERENCE	**$452**

Q. Please describe your proposal.

A. My proposal is to include only the more representative years starting with the beginning of the MISO Day 2 Market.

Q. What is the result of your analysis?

A. Selecting data beginning with 2005 results in a 4-year average (2005-2008) of $4.585 million which is $452,000 greater than OTP's proposal. If an amount is shared by being included in base rates, then $4.585 million is the amount which should be included.

Q. Did the MPUC adopt a most recent 4-year average approach in the in OTP's recent MN rate case MPUC Docket No. E-017/GR-07-1178?

A. Yes. The MPUC also decided to include one of the years excluded by OTP as an "outlier" in spite of OTP's claims that margins earned that year were excessive and not typical.

Q. Does the MISO Day 2 Market have any other impact on wholesale margins?

A. Yes. The Day 2 Market fundamentally changed the way asset based resources are bid and sold, to a large extent the procedure is greatly streamlined as there is no longer any negotiations via utility-by-utility contacts for price discovery in selling ratepayer resources. Since the utility cannot do anything to increase profits (it is a function of market clearing price) no incentive is needed to have a utility maximize profits. Ratepayers have paid for these resources and should receive 100 percent of the benefits associated with them. Especially in this economy, when so many companies are struggling to even break even fiscally, the utility does not need any additional "perks" for asset-based wholesale margin trading beyond their guaranteed return.

Q. Do you have any other concerns regarding sharing of wholesale margins?

A. Yes. I'm also concerned that locking in a fixed amount as a credit to base expenses will exclude a further substantial increase when OTP's 160 MW of wind turbine capacity releases a substantial amount of energy to be sold in the MISO Day 2 Market thereby significantly increasing asset-base margins.

Q. What is your recommendation regarding this up-side potential?

A. I recommend that any increases in wholesale margins above and beyond amounts included in base rates due to wind resources or other causes be shared so that retail customers receive via OTP's RRR 85% of the increase and OTP receives 15% of the increase.

Q. What portion of asset-based margins should be included as an offset to expenses in OTP's RRR?

A. This should be an estimate of the increase in OTP's asset based margins made available by the addition OTP's owned wind resources. To the extent that wind generation is displacing existing generation and freeing it up for asset based sales, the associated incremental margins should flow through the established RRR. The amount would be determined by estimating margin sales without the wind resources and margin sales with the resources.

To ascertain this amount, I am awaiting OTP's Response to LIG IR No. 144 containing quantitative analysis with and without wind generation.

B. <u>Non Asset-Based Wholesale Margins.</u>

Q. How does OTP propose to treat non asset-based margins in this rate case?

A. OTP proposes to share with its retail customers, 15 percent of its non asset-based margins as reimbursement for its trading costs (staff and related expenses) included in base rates. This amount would never be negative. In addition, please see OTP's Response to LIG IR No. 39 for further explanation, which is attached hereto as **LIG Exhibit __ (LLS-3).**

Q. What is the revenue impact of OTP's proposal?

A. OTP states that the revenue amount to be credited to ND retail customers under its proposal is 15 percent of about $1.96 million which is approximately $294,000.

Q. How does this compare with the sharing mechanism approved by the NDPSC in Xcel's recent ND rate case?

A. OTP claims (See Witness Beithon's Testimony, P. 21, L. 27-28) that their proposal is identical to the one approved for Xcel. It is not. The settlement and order in the Xcel case called for 50 percent sharing.

Q. What is the appropriate level of sharing if it is not fixed?

A. Since this activity is done with ratepayer assets (employees, equipment, computers, taxes, etc) it should be a substantial amount to reflect these costs, yet it should allow for a fair return for Otter Tail since they are using their own resources/risk of loss. Considering these factors, 50% with a guaranty of never going negative is appropriate.

Q. Are there other options for dealing with these margins?

A. Yes, Otter Tail could reimburse ratepayers with a fixed amount in rate base for the cost of ratepayer resources that are used in this activity, together with a lesser portion of profits for the added value Otter Tail gets through using ratepayer's assets. Similar to how Otter Tail deals with these profits in Minnesota

Q. How does OTP's ND proposal in this case compare to the mechanism approved by the MPUC in OTP's recent MN case?

A. The MPUC initially accepted the ALJ's recommendation that OTP pass 10 percent of its non asset-based margins as a credit to retail customers via the FCA, but also remove $993,000 of costs attributed to its non asset-based margin trading from base expenses. However, after hearing OTP's arguments related to OTP's petition for re-hearing on this issue, the MPUC changed its position and removed the requirement for the 10 percent non asset-based margin sharing revenue altogether in order to match the $993,000 of disallowed expenses. This completely isolates the results of OTP's non asset-based margin trading from retail rates.

Q. Can testimony submitted in the Minnesota case be used as a yardstick to measure the reasonableness of OTP's proposal of 15% sharing of non-asset based margins with retail customers?

A. Yes. The Minnesota Order (E-017/GR-07-1178), on page 27, notes OTP allocated $993,173 to OTP's Minnesota non-regulated operations for non-asset based sales. Assuming that the Minnesota portion was determined based on the E-2 Energy Allocation factor of 52.015871% (per final Jurisdictional COSS provide by Ron Spangler December, 19, 2008) then the total OTP cost would be $1,909,365 ($993,173/.52015871). The North Dakota portion would be $1,909,365 x .41017975 (ND Test Year E-2 Allocation Factor) = $783,183. This merely reimburses ratepayers for the cost of using ratepayer employees, overhead, facilities and equipment, an additional amount should be allocated as benefit sharing for use of ratepayer's assets/investment. An additional 15% of the margins that exceed $783,183 is reasonable. This is substantially greater (2.66 times) than OTP proposal of 15 percent of about $1.96 million which is approximately $294,000, thereby indicating that OTP's proposal is low.

Q. What is your recommendation for the treatment of non asset-based margins in this case?

A. As stated earlier, I recommend that OTP be ordered to share 50% of its non-asset based trading margins with its retail customers.

C. <u>Renewable Energy Credits (REC).</u>

Q. What are REC's?

A. These are per-KWh credits attached to energy from qualified renewable energy resources defined under state law such as wind generation.

Q. How are these credits recorded and tracked?

A. REC's and REC ownership and transactions are tracked by a multi-state system called M-Rets.

Q. Is OTP accumulating RECs?

A. Yes. In OTP's direct testimony, (<u>see</u> OTP Initial RRR Filing) as well as OTP's responses to LIG IR Nos. 13 & 133 (attached hereto as **LIG Exhibit ___ (LLS-4 and LLS-5)**. OTP states that it is accumulating and banking REC's associated with output of its wind resources.

Q. What is your concern?

A. OTP claims the right to sell these REC's to any market it wishes without clarifying that these benefits will be assigned to the retail customers paying for the wind resources. However, it is very important that the REC's are credited to retail customers rather than to OTP as a utility. The attached quote from Spectron Group Report, (January 14, 2009)(setting value for the "Front Half 2009" for National Green-E Certificate Wind qualified energy the price would be from .190 cents/kWh to .285 cents/kWh) indicates a significant value to the REC's. OTP does not need REC's in North Dakota until 2015, long after they have been generated and likely expired. Since North Dakota ratepayers paid for 41.02% (E2 allocator) of the assets that generate REC's, North Dakota ratepayers should be allocated the value of REC's currently at their market value. **LIG Exhibit __ (LLS-6).**

Q. What is your recommendation?

A. I recommend that the value of REC's be treated like the additional wholesale margins made possible by wind resources, which means that REC values should be credited to OTP's RRR in the year they are created.

III. ANCILLARY SERVICE MARGINS (ASM)

Q. Please define Ancillary Services and the importance of this concept to this proceeding.

A. Ancillary Services include:

1. Scheduling and Dispatch
2. Reactive Power
3. Regulation and Load Following
4. Energy Imbalance
5. Spinning Reserve
6. Supplemental Reserve

As one of many control area operators, OTP was providing some of these services prior to startup of the new MISO Ancillary Services Market on January 6, 2009. Beginning on January 6, the many control areas within MISO were consolidated into a single ASM market under MISO thereby eliminating OTP's responsibility to provide such services (See Witness Beithon's Testimony, P, 49, L. 17-19).

Q. Has OTP indicated any proposed changes to the treatment of ASM related costs and revenues as a result of MISO's ASM market launch?

A. OTP states in Response to LIG IR No. 73, **LIG Exhibit __ (LLS-7)**:

> "OTP is not proposing a change to the way ancillary services are recovered in this case. Ancillary services have been in the base rates of OTP previously. The Midwest Independent System Operators ancillary services market (MISO ASM) is so new that OTP doesn't know the full impacts of the MISO ASM at this point. The MISO ASM was not a known and measurable change at the time this case was filed and still is not fully known. OTP has not requested any special treatment for the MISO ASM outside of this case. At this point in time OTP does not anticipate any ancillary service margins net of the increased expenses. With only a couple weeks of experience in January 2009 OTP had a net (revenues and expenses) ASM expense of $36,563. Of course if MISO changes the way ASM is operated, OTP would review the appropriateness of continuing the existing treatment for ASM and propose changes to the NDPSC as appropriate."

Q. What is your concern with OTP's approach?

A. I am concerned that OTP's approach is not consistent with how it participates in the ASM market. Since OTP is participating in the ASM market, it needs to provide the NDPSC with regular reporting of the MISO related credits obtained and charges paid similar in format to the MISO Day 2 costs provided as documentation for the COE.

Q. What do you recommend?

A. I recommend that any action regarding OTP's proposed ASM related charges and credits be deferred for one year, during which period OTP makes monthly reports to the Commission on how ASM has impacted the relevant MISO accounts. After this time period, OTP should submit a report to the Commission documenting the relevant information. Based on this information, the NDPSC should hold a hearing to determine an appropriate treatment of these costs and revenues.

Q. Given that ASM margin sharing has been an issue in Minnesota as well, what action has the Minnesota Commission taken in this regard?

A. As a result of the complexity and unknown impact of the market, the Minnesota Commission has taken similar action to make sure a reasonable result is arrived at.

IV. FUEL COST ADJUSTMENT ("FCA") ALSO CALLED COST OF ENERGY ("COE") ISSUES

Q. What are your concerns regarding OTP's FCA?

A. I have several concerns as set forth below.

A. Jurisdictional Differences. OTP starts with total system fuel and purchased energy costs and allocates these costs to its operating jurisdictions on a KWh basis so that over a prescribed time period OTP recovers its fuel plus purchased energy costs but no more. Although different jurisdictional monthly averaging techniques are used to smooth the month-to-month variations, the definition of the total amounts to be passed on to customers via the FCA vary significantly from MN to ND (i.e., there are four elements described in the ND FCA and six in MN). These element descriptions should be identical. OTP should therefore be ordered to either adopt in ND (1) the elements in the MN version or, in the alternative, (2) file an FCA in MN compatible with the ND version.

B. Proper Cost of Fuel Account. OTP's FCAs state that the cost of fuel included in the monthly FCA's should be the amount in FERC fuel inventory Account 151. This is not correct because the amount included in the FCA is not the total inventory asset amount in Account 151, but rather is the amount fuel withdrawn from Account 151 and consumed/expense to Accounts 501 and 547 for a specific month. OTP should therefore be ordered to clarify this distinction.

C. Adjustment to Purchased Energy Costs. The FCAs in both jurisdictions limit the recovery of purchased energy costs to Account 555 costs "...exclusive of capacity and demand charges". However, OTP is improperly including some capacity and demand charges associated with its wind PPA's and flowing these costs to customers via the FCA.

Q. Is it your understanding that OTP is passing 100 percent of its wind turbine PPA costs on to retail customers via the FCA?

A. Yes. This is confirmed by OTP's response to LIG IR No. 77, which states that the FCA does not recover fixed costs and by OTP's response to LIG IR No. 166 which states the FCA does not recover capacity costs either. **LIG Exhibit ____ (LLS-8) amd (LLS-9).**

Q. Should these total PPA amounts amount be allowed to pass through OTP's FCA without adjustment even though the amount OTP purchases is all on a KWh basis?

A. No.

Q. Please explain why.

A. This is because the wind PPA costs include a capacity component which can be imputed.

Q. Why are capacity costs related to wind farms important here?

A. Although PPA costs are paid to developers on a KWh basis, a capacity allocation must be imputed to these purchased energy costs related to the accredited capacity value of wind turbines.

Q. Please provide an example.

A. OTP's Response to LIG IR No. 20 (attached hereto as **LIG Exhibit ___ (LLS-10)** shows that OTP received a substantial monthly capacity credit from the Langdon PPA associated with 19.5 MW of purchased wind capacity. This monthly credit averaged 30.8 percent of the 19.5 MW of nameplate capacity resulting in a reduced amount of purchased capacity or peaking turbine installation otherwise required to meet OTP's load plus reserve requirement. This capacity component has value toward meeting OTP's load plus reserve capacity obligation for its entire system. By also recovering the capacity component in its FCA, OTP is double recovering.

Q. What action should the Commission order?

A. The Commission should order that OTP retroactively remove the value of capacity credits from the total amount of Langdon and other wind PPA costs which were incorrectly passed through the FCA and credit the amount removed to present customers via the FCA. On a forward looking basis, OTP should include the corresponding capacity value of its wind PPA's as a capacity cost in base rates and allocated accordingly. However, the amounts removed from the FCA plus the amounts remaining should not exceed actual amounts paid to developers under the PPAs.

The foregoing indicates why the RRR cannot be included as part of the FCA unless the imputed capacity component is first removed. Because of the large cost impact of the RRR, I recommend that it remain as a separate line item on each customer's bill, as ordered by the Commission during it interim application.

D. <u>COE Volatility and Trends.</u>

Q. What method does OTP use to calculate the COE applicable for each month?

A. As stated earlier, OTP uses a four month rolling average methodology to calculate the COE applicable for each month. For example, the COE to be effective on March 12, 2009, uses data from October 2008, November 2008, December 2008 and January 2009. Therefore, there is essentially a six month lag between the time costs are actually incurred for the retail sales to when they are actually displayed on the customers' bills.

Q. Did you use an alternative method to analyze the COE trend?

A. Yes. I de-averaged the OTP four month COE average to a monthly average. I did this by using cost specific data for the actual month that it was incurred and adjusted the energy costs for the over/under recovery. Similarly, I used retail sales adjusted for losses for the actual month.

Q. Did you analyze the trends in OTP's COE?

A. Yes I compared OTP's COE to my de-averaged monthly COE. Figure 1 is a plot comparing OTP's actual COE and de-averaged FCA by month for the time period December 2006 to November 2008. The following graph shows the monthly de-averaged numbers for this time period.

Figure: 1

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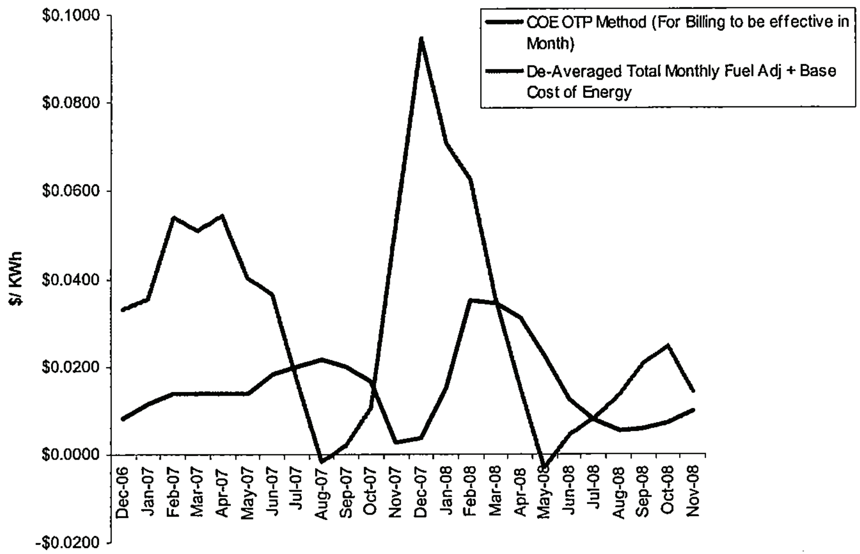

Q. What does this figure show?

A. This figure shows the following:

1. By averaging the COE over a period of four months, the current COE smoothes the volatility inherent that is depicted in the monthly de-averaged COE; and

2. De-averaged monthly COE shows some decline in 2007 with a sharp increase towards the end of 2007 owing most likely to the big stone outage. In 2008, while the monthly deaveraged COE declines from the sharp increase associated with Big Stone outage, it increases just before summer before falling in November 2008.

Q. Can the decline towards the end of 2008 be attributable to wind owned resources?

A. Not necessarily. Fuel prices, especially natural gas, have been on a sharp decline owed to depressed demand and other reasons during the current economic downturn.

Q. What other analysis did you conduct on the COE?

A. I calculated the total annual COE costs and energy retail sales adjusted for losses using the monthly de-averaged data for the time period December 2006 through November 2007 and December 2007 through November 2008.

Q. What did this analysis indicate?

A. **Table 1** shows the results. As the Table indicates, the average annual COE using the de-averaged monthly data shows a slight increase for the time period December 2007 through November 2008 compared to the previous 12 month period.

Table 1: Average Annual COE Comparisons

Time Period	Usage Adj. for losses	Adjusted Net Energy Costs	Average Annual COE ($/KWh)
Dec 2006 - Nov 2007	3,737,262,097	$123,792,549	$0.03312
Dec 2007 - Nov 2008	3,734,074,187	$127,753,365	$0.03421

Q. What does OTP claim about COE costs in 2008?

A. OTP claims in its initial compliance filing for Docket PU-08-862 that a major benefit of the OTP owning wind resources is the COE has decreased. The results indicated in Table 1 do not support OTP's claim and, in fact, show a slight increase.

Q. Even if the COE had shown a decrease in 2008, could this decrease be directly attributable to OTP's wind owned resources?

A. No. Even if the COE had shown a decrease on an annual basis, it could not be all attributable to OTP's wind owned resources because as mentioned earlier, fuel prices fell significantly during 2008 due to depressed demand in the economic downturn.

V. OTP's PRESENT COE PROCEDURES OVERSTATE DELIVERED ENERGY COSTS BY INCLUDING A 12 PERCENT NET ENERGY LOSS FACTOR

Q. Please explain what this overstatement of loss impacts.

A. It does not affect the Interim rates and it does not affect base rates. This is a change that affects the ongoing COE calculation that results in over recovery in the monthly COE charge.

Q. Please explain why OTP current ND COE Adjustment procedures overstate delivered energy costs by including a 12 % net energy loss factor.

A. In the course of reviewing OTP January 27, 2009 February 2009 Fuel Cost Adjustment Letter (PU-09-41 Filed 1/27/2009) **(LIG Exhibit ___ (LLS-11)**,Schedule?) it became obvious that OTP is overstating energy losses in determining the sales to native retail customer which results in lower assumed sales. OTP determines Retail Sales by multiplying 0.88 (1.00-.12) times the Net Energy kWh at the generation level. Adjusted net energy cost divided by an understated Retail Sales amount yields an overstated Delivered Cost per kWh. The Delivered Cost per kWh is subtracted by the COE Base Cost to determine the COE Adjustment per kWh. The 12% system wide factor energy loss factor is too high and understates retail kWh sales.

Q. Can you support your claim that the 12% energy loss factor used by OTP overstates losses?

A. Yes. I have reviewed the energy losses incorporated by OTP into this rates proceeding and into their recent Minnesota case. OTP's total Test Year ND kWh sales are 1,765,782,420 (Exhibit__(DGP-1), Schedule 1). OTP ND Test Year kWh sales adjusted for line losses to the generation level can be determined by using the E-2 Energy Allocation Factor. The ND E-2 Allocation Factor from the Test Year (Exhibit_(PJB-1), Schedule 11A, page 7 of 8) Jurisdictional COSS is 1,884,859,000 kWh. Thus, OTP Test Year ND losses are 0.0632 (1-(1,765,782,420/1,884,859,000) or 6.32%. This loss rate seems reasonable based on my experience with OTP's recent MN rate case and other Midwest utilities.

OTP's total Test Year MN kWh sales were 2,106,630,635 (Compliance Filing, Schedule 5, page 2 of 2) and the E-2 MN Jurisdictional Allocation Factor kWh units were 2,231,278,000 or 52.02% (2006 Test Year Jurisdictional CCOSS based on the Commission's Final Order provided by Ron Spangler 12-19-08). Thus, OTP's Test Year losses are 0.0559 (1-(2,106,630,635/2,231,278,000) or 5.59%. The MN loss factor is lower than North Dakota as I would expect because approximately 20% of MN retail sales are served at high voltage transmission of 115 kV and thus has lower line losses.

OTP's system loss factor can be determined by weighting each jurisdictions loss factors. I have assumed South Dakota's loss rate would approximate North Dakota's. The MN E-2 Allocation Factor was 52.02% of the total. The weighted average OTP system losses for retail sales can be determined as follows:

Figure 2

Otter Tail Power Company

Revised System Loss Factor

Weighting of Jurisdictional Loss Factors

Jurisdiction	Sales Ratio	Juris. Loss Rate	Weighted Loss Rate
Minnesota	0.5202	5.59%	2.91%
North and South Dakota	0.4798	6.32%	3.03%
Total	1.0000		5.94%

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Q. What is the impact of this of using the system loss factor of 5.94% rather the 12% used by OTP?

A. If the OTP ND COE Adjustment incorporates a more realistic loss factor the annual costs to ratepayers will decrease by approximately $2.3 million per year. The following figure support this estimate:

Figure 3

Otter Tail Power Company
North Dakota COE Adjustment Calculation
Impact of Overstate Energy Loss Factor
February 2009 COE Billing Parameters

	OTP as Filed	Corrected Loss Factor	Change
Adjusted Net Energy Costs	$ 29,385,564	$ 29,385,564	
Net Energy - kWhs	1,480,856,321	1,480,856,321	
Energy Loss Adjustment Factor	0.8800	0.9406	
Energy Adjusted to Retail Sales	1,303,153,562	1,392,893,456	
Delivered Cost per kWh	$ 0.022550	$ 0.021097	
Base Cost per kWh	$ 0.030945	$ 0.030945	
Energy Cost Adjustment/kWh	$ (0.008395)	$ (0.009848)	
Energy Cost Adj./kWh Rounded	$ (0.0084)	$ (0.0098)	$ (0.0015)
Test Year ND kWhs Subject to the COE Adjustment			1,575,937,982
Estimated Annual Impact of Overstated Loss Factor			$ (2,289,524)

Notes:
-Billing parameters per OTP January 27, 2009 correspondence to Darrel Nitschke regarding the February 2009 Fuel Cost Adjustment (PU-09-41 Filed 1/27/2009)
-Energy Adjustment Loss factor is based on OTP Jurisdictional E-2 Allocation Factors used in the current North Dakota proceeding and OTP MN Docket No. E-017/GR-07-1178

Q. Should OTP be allowed to continue to use the 12% system loss factor to determine estimated system retail sales?

A. No. The above figure shows that if OTP is allowed to continue to use the excessive 12 % system energy loss rate it will result in overcharging North Dakota ratepayer approximately $2.3 million per year.

Q. Mr. Schedin, please summarize your recommendation on how to improve the accuracy and fairness of OTP ND COE calculations.

A. My immediate recommendation is to require OTP to use a system energy loss factor of 5.94% rather than the 12% in calculating the ND monthly COE Adjustment. This correction in loss factors will save ND ratepayers approximately $2.3M per year and results in a more fair and reasonable rates.

I would also recommend that using OTP's retail kWh sales by jurisdiction is more accurate than determining a proxy for system retail sales by adjusting monthly net energy by a constant loss factor.

VI. OTP HAS UNDERSTATED PRESENT RATE REVENUES BY $3.3M RESULTING IN OVER RECOVERY FOR INTERIM RATES

Q. Please describe the OTP's North Dakota COE Adjustment Clause.

A. OTP's COE Adjustment Clause adjusts rates to reflect changes in average cost of fuel and purchase power. Monthly average fuel and purchase power costs can vary widely based on loads, cost of fuel and purchase power, and the availability of OTP's own generation fleet because of planned and forced outages, etc. This rate adjustment mechanism is based on the most recent 4 month period plus unrecovered prior cumulative energy costs. This tariff ensures full cost recovery of OTP's eligible COE costs.

Q. Does OTP ND COE Adjustment Clause ensure the full recovery of OTP eligible costs?

A. Yes. However, the COE Adjustment Clause does not ensure full recovery of costs for a specific period (month or year) that the eligible fuel and purchase power costs were incurred. The recovery of cost is delayed because the COE Adjustment Clause rate is based on the most recent 4 month period and thus will not match current month/year fuel and purchase power costs.

Q. When using a historic test year, will the actual billed COE Adjustment Clause revenues ever match the COE eligible expenses included in the test year?

A. The actual billed COE Adjustment Clause revenues will likely never match the test year COE eligible fuel and purchase power costs. The timing of revenue recovery lags the costs and can result in over or under collection of the billed COE Adjustment

Clause revenues depending on the period and the changes in the monthly costs of fuel and purchase power costs.

Q. How does OTP's financial reporting to shareholders and the investment communities deal with the matching of fuel cost and fuel cost recovery?

A. OTP accrues revenues related to fuel and purchase power costs in excess of amounts recovered in base rates but not yet billed through the COE Adjustment Clause. This accrual of revenue is necessary to accurately report the Otter Tail's financial performance.

OTP's 2007 Report to Shareholders states the following:

> "Rate schedules applicable to substantially all customers include a fuel clause adjustment (FCA) – under which the rates are adjusted to reflect changes in average cost of fuels and purchase power – and a surcharge for recovery of conservation-related expenses. Revenue is accrues for fuel and purchase power costs incurred in excess of amounts recovered in base rates but not yet billed through the FCA."

See OTP 2007 Shareholder Report, p. 44, Schedule 1 (attached hereto as **LIG Exhibit ___ (LLS-12))**.

OTP's "Accrued Cost-of-Energy Revenue" balance sheet account was increased from $10,735,000 as of December 31, 2006 to $19,452,000 as of December 31, 2007. It should also be noted that this balance was decreased in 2008 to $8,982,000 for December 31, 2008. OTP's increase in 2007 accrued revenues balance was necessary to match the increased fuel and purchase power cost in 2007 that have yet to be recovered in 2007 through OTP's FCA and COE tariffs. If OTP did not include the $19,452,000 in accrued revenues, OTP reported revenue would be significantly lower and thus distorting the Otter Tail's actual performance for 2007. The same holds true in OTP's North Dakota Initial Rate filing in this proceeding. Ignoring the lag in the COE Adjustment Clause understates OTP's returns and thus overstates their rate relief needs for the 2007 test year. The NDPSC must recognize the COE Adjustment Clause revenue in excess of any recovered in base rates but not yet billed in order to determine fair and reasonable rates. See Shareholder Report, p. 51.

Q. What COE Adjustment Revenues did OTP include in their determination of Present Rate Revenues?

A. In **LIG Exhibit ___ (LLS-13),** *Excess Rev. Collected in Interim Rates Before Int. Rate Adjustment*, I have totaled the OTP Filed Present Rate COE Adjustment Clause Revenues included in Exhibit__(DGP-1), Schedules 1 and 2. They have included $19,550,518 of Test Year Present Rate COE Adjustment Clause Revenues. The average Present Rate COE Adjustment Clause revenue recognized is 1.241 cents/kWh based on the total COE Adjustment Clause revenues/kWh subject to the Interim Rate COE Adder.

Q. What change in the COE Base is OTP proposing in this proceeding?

A. OTP's Present Rate COE Base is 1.6473 cents/kWh. OTP is proposing an increase in the COE Base to 3.0945 cents/kWh. The new COE Base is determined on the fuel and purchase power cost included in the determination of the test year revenue requirement. The increase in the COE Base is 1.4472 cents/kWh. OTP has included a Change in The Base Cost of Energy Adder of 1.447 cents per kWh as a billing item in Interim Rates.

Q. Does OTP Present Rate COE Adjustment Clause revenues match the change in COE eligible cost included in the determination of the test year revenue requirement?

A. No. OTP's Present Rate Revenues would need to include COE Adjustment Clause revenues that would average 1.4472 cents/kWh (OTP's proposed change in the COE Base) in order for OTP's Present Rate COE Adjustment Clause revenue match test year fuel and purchase power costs.

Q. Have you quantified the impact of OTP's understatement of Present Rate COE Adjustment Revenues?

A. Yes. The calculations provided in my *Excess Rev. Collected in Interim Rates Before Int. Rate Adjustment* shows that change in Present Rate and the Proposed/Interim Rate COE Adjustment bases (1.447 cents/kWh) times the KWh subject to the Interim COE Adder generate $22,803,823. Thus, OTP would be required include " Accrued Cost-of-Energy Revenue" of $3,253,305 ($22,803,823 - $19,550,518) in order to have the test year Present Rate COE Adjustment Clause revenues match the test year COE eligible fuel and purchase power costs.

Q. Do you propose an adjustment of Present Rate revenues and what amount?

A. I am proposing to include an additional $3,253,305 of test year "Accrued Cost-of -Energy Revenue" not yet billed through OTP's Present Rate COE Adjustment Clause. This additional revenue has been earned by OTP in 2007 and will be billed to North Dakota ratepayers in 2008 so that test year COE Adjustment Revenues will match the test year COE eligible fuel and purchase power costs.

Q. Please explain the impact of OTP's understatement of Present Rate revenues will have on the final rate determination in this proceeding.

A. OTP has overstated their revenue deficiency. The following figure shows the OTP's filed versus LIG proposed corrections:

Figure 4

OtterTail Power Company
Present Rate Revenues and Proposed Increase
OTP Filed Versus LIG Proposed

	OTP Filed Present Rate		LIG Proposed Present Rate	
Base Revenue	$	98,758,659	$	98,758,659
COE Revenue	$	19,550,518	$	19,550,518
Accrued COE Rev.	$	-	$	3,253,305
Total Present Rate Rev.	$	118,309,177	$	121,562,482
Filed Final Rate Rev. Req.	$	124,393,180	$	124,393,180
Required Increase	$	6,084,003	$	2,830,698
% Increase		5.14%		2.33%

OTP should recognize $3,253,305 of accrued COE revenues in determining Present Rate revenues to ensure that COE revenues match COE eligible expenses included in the test year revenue requirement. This ensures that OTP has not overstated their revenue deficiency and prevents over recovery during the application of Interim Rates. The inclusion of Accrued COE Revenues does not change the Filed Final Revenue Requirement.

<u>OTP Violated Interim Rate Procedures.</u>

Q. Has OTP violated the North Dakota's Interim Rate Procedures?

A. Yes. OTP has changed exiting rate design by increasing Interim Rates, before the Interim Rate Adjustment, by 1.447 cents/kWh yet including only COE Adjustment Clause revenue of 1.241 cents/kWh for in the calculation of Present Rate Revenues. **LIG Exhibit ___ (LLS-14),** *LGS Revenues, Filed Present/Interim Before Int. Rate Adjustment*, demonstrates that OTP's Interim Rate for the LGS Rate Class is $751,852 higher than the Present Rate Revenues even before the Interim Rate Adjustment is applied. Present Rate Revenues would equal Interim Rate Revenues, before the Interim Rate Adjustment, if there was no change in existing rate design.

Q. Please explain the impact of OTP's understatement of Present Rate revenues will have on the application of Interim Rates in this proceeding.

A. See Figure ? below.

<u>Figure 5</u>

OtterTail Power Company
Excess Interim Rate Increase Granted
OTP Filed Versus Interim Rate Relief Granted

	OTP Filed Present Rate	Interim Rate Relief Granted	Excess Interim Rate
Base Revenue	$ 98,758,659	$ 98,758,659	
COE Revenue	$ 19,550,518	$ -	
Interim Rate COE Adder	$ -	$ 22,803,823	
Total Rate Revenue	$ 118,309,177	$ 121,562,482	$ 3,253,305
Interim Rate Adjustment	4.07%	4.07%	
Interim Rate Adjustment Rev.	$ 4,815,184	$ 4,947,593	$ 132,410
Total Interim Rates	$ 123,124,361	$ 126,510,075	$ 3,385,715

Figure 5 shows that OTP's Interim Rates generate $3,384,088 more revenue than the Commission intended when is granted a 4.02% Interim Rate Adjustment of OTP's Filed Present Rate Revenues.

Q. Please explain the impact of OTP's understatement of Present Rate revenues will have on the determination of Interim Rates and any Interim Rate refund.

A. Interim Rate logic is based on no change in Interim Rate design to ensure that Present Rate revenues equal the Interim Rate revenues before the Interim Rate Adjustment is applied. Thus, the following hold true:

1. Present Rate revenues = Interim Rate revenues before the Interim Rate Adjustment. Thus, the only difference between Present Rate revenue and Interim Rate revenue is the Interim Rate Adjustment revenue.

2. Proposed Rate Revenue = Present Rate revenues + Rate increase.

3. Proposed Rate Revenue = Interim Rate, before the Interim Rate Adjustment, revenues + ((Rate increase/Interim Rate increase)x(Interim Rate Adjustment revenues)).

OTP's approved Interim Rate revenues before the Interim Rate Adjustment are $3,253,305 greater than Present Rate revenues, because OTP changed the Interim Rate by improperly zeroing out the COE Adjustment. Thus, Interim Rate logic cannot be applied because the following hold true:

1. Present Rate revenues = Interim Rate revenues, before the Interim Rate Adjustment, less $3,253,305.

2. Proposed Rate revenue = Present Rate revenue + Rate Increase.

3. Proposed Rate revenue = Interim Rate, Before the Interim Rate Adjustment, revenue – $3,253,305 + ((Rate Increase/Interim Rate Increase) x (Interim Rate Adjustment revenue)).

Q. What is your recommendation on how the NDPSC should treat the recognition of COE Adjustment Clause revenues in this rate proceeding?

A. OTP should be required to include "Accrue Cost-Of-Energy Revenue" of $3,253,305 in Present Rate Revenue in order to match test year COE Adjustment Clause revenues and COE eligible fuel and purchase power costs included in the test year revenue requirement. This additional Present Rate revenue ensures that there is no change in rate design. Present Rate revenue will equal Interim Rate revenues before the Interim Rate Adjustment, thus allowing normal Interim Rate logic and procedures to be applied.

The separation of the COE cost from all non-energy revenue requirements would also be acceptable. This approach ensures that timing of the recovery of COE related costs do not distort and confuse the cost recovery of OTP Interim Rate revenue requirements.

VII. OTP's FAS 106 Transition Costs Should Be Denied As They Are Not Funded

Q. Please describe FAS 106.

A. The Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 106 (FAS 106), *Employers Accounting for Postretirement Benefits Other Than Pensions* in 1990. OTP's adopted the standard in 1993. The net periodic postretirement benefit cost includes several components. OTP began to amortize "its transition obligation related to postretirement benefits earned of approximately $14,964,000 over a period of 20 years."(Page 44 of Otter Tail Corporations 2008 Annual Report)

Q. What is OTP's Other Postretirement Benefit Obligations and has OTP funded this obligation?

A. OTP's projected Benefit Obligation at December 31, 2008 was $32,621,000 (Page 66 of Otter Tail Corporations 2008 Annual Report). OTP has no plan assets set aside to cover this obligation. This is an unfunded liability.

Q. Have other investor owned utilities operating in North Dakota funded their Other Postretirement Benefit Obligations?

A. Yes. I have only checked on MDU Resources Group and Xcel Energy. They both have specific plan assets set aside to cover Other Postretirement Benefit Obligations. MDU and Xcel have set up funds similar to their pension funds to ensure that funds are set aside from revenues received from current ratepayers to fund future Other Postretirement Benefits Obligations of current utility employees once retired. In fact for Xcel, it's a condition of allowing FAS 106 cost recovery that they fund their obligations in several jurisdictions where they operate.

Q. Has OTP recorded FAS 106 as a utility operating expense yet failed to fund this obligation?

A. It is my understanding that OTP expensed the FAS 106 costs for financial reporting including reporting ND returns. They have recognized a balance sheet Benefit Obligation but have not set aside any funds in any trust to cover these future benefit obligations. OTP has had the money and has had rates sufficient to fund this obligation put have made a decision not to fund this obligation.

Q. Is it too late for OTP to fund its Other Postretirement Benefit Obligations?

A. No. It will be more of a challenge to OTP because it is in the 17th year of a 20 year amortization to cover its Other Postretirement Benefit Obligations. Unfunded employee benefit obligations are one of the problems facing the US auto industry.

Q. Why does the LIG object to the inclusion of OTP's FAS 106 transition obligation costs in the ND Retail electric rates?

A. We object to the inclusion of the FAS 106 transition costs based on the following:

1. Regulators and ratepayers were never given the opportunity to review the prudency and reasonableness of OTP other post retirement benefits. They have provided no support of the underlying benefits and their costs in this proceeding.

2. OTP has not funded its Other Postretirement Benefit Obligations. Funding ensures that current ratepayers will not have to pay twice for retiree Other Postretirement Benefits. If OTP had funds set aside to match their $32.6M Benefit Obligation as of 12/31/08,

then future ratepayers would be less exposed to covering the cost of OTP Benefit Obligations.

3. OTP could have funded the obligation but choose not to from annual FAS 106 expense levels or during periods of over earnings. If ND grants full cost recovery, were does the revenue/cash in excess of current year pay as you go expenses end up?

4. The Minnesota Commission declined to grant recovery of Otter Tail's FAS 106 transition costs in Docket No. E-017/GR-07-1178 issued on August 1, 2008. If North Dakota grants full recovery of OTP's FAS 106 expense request, how will North Dakota ratepayer be compensation in the future for paying more than MN ratepayers? Are there any future benefits for North Dakota ratepayers? How will OTP keep records and adjust to shifting jurisdictional and regulated/non-regulated allocations?

5. Setting Final North Dakota electric rates in 2009 with an amortization expense that concludes in 2012 will result in unfair and unreasonable electric rates if OTP does not file a rate proceeding to change rates by 2013.

Q. Mr. Schedin, please summarize the LIG position on FAS 106 Transition cost recovery.

A. LIG recommends that OTP not be allowed to recovery any FAS 106 Transition costs until it funds their Other Postretirement Benefit Obligations for all its regulated operations. Full funding provides the following protections:

- Protects ratepayers from paying twice.
- It protects ratepayers from paying for a transition obligation that benefits other jurisdiction where this cost has been disallowed.
- It improves the financial strength of OTP by eliminating a significant unfunded liability that ratepayers have been funding.
- Improved financial strength will help reduce OTP's cost of capital for utility operations
- Protects OTP employees

VIII. CLASS COST OF SERVICE STUDY (CCOSS).

A. <u>Base (Unadjusted) CCOSS Results.</u>

Q. Did OTP conduct a CCOSS as part of this proceeding?

A. Yes. In order to determine the revenue deficiency allocated to each class of service, OTP conducted a fully allocated CCOSS using the Equivalent Peaker ("EP") method, the same methodology as applied in MN. Witness Beithon presented the results of this study on page 60 of his direct testimony.

Q. What revenue deficiency does the base CCOSS show for the LGS and Residential Rate Classes?

A. The base CCOSS shows that the General Service Class should receive a 6.59 percent revenue decrease while the Residential class should receive a 16.28 percent increase.

B. Adjusted CCOSS Results

Q. Did OTP strictly adhere to its base CCOSS in making its recommended revenue deficiency calculations?

A. No. Using ambiguous criteria such as rate continuity and rate shock, OTP modified results of its base CCOSS.

Q. What major changes resulted from OTP's adjustments?

A. The comparison set forth by LIG Table 2 (see below) taken from selected data presented by Witness Beithon on pages 60 and 61 of his direct testimony shows a major shift from OTP's base CCOSS results.

Table 2. Comparison of Base (Undjusted) and Adjusted CCOSS Results

	Unadjusted Rev (%)	Adjusted Revenue (%)
CLASS	Deficiency %	Deficiency %
Residential	16.28%	7.50%
Farms	21.17%	7.50%
General Service	-7.95%	0.95%
Large General Service	-6.59%	1.00%
Irrigation	74.69%	10.00%
Lighting	41.70%	25.00%
OPA	28.77%	14.00%
Controlled Ser. Water Htg	54.30%	10.00%
Controlled Service Interr.	60.51%	35.00%
Controlled Serv. Deferred	21.40%	11.00%
Weighted Average	5.14%	5.14%

Table 2 shows that OTP has turned a deserved 6.59 percent rate decrease for the Large C&I class into a 1.00 percent rate increase on the arbitrary bases of rate continuity and rate shock avoidance. This represents a shift of $2.75 million to the Large General Service, which is entirely unreasonable.

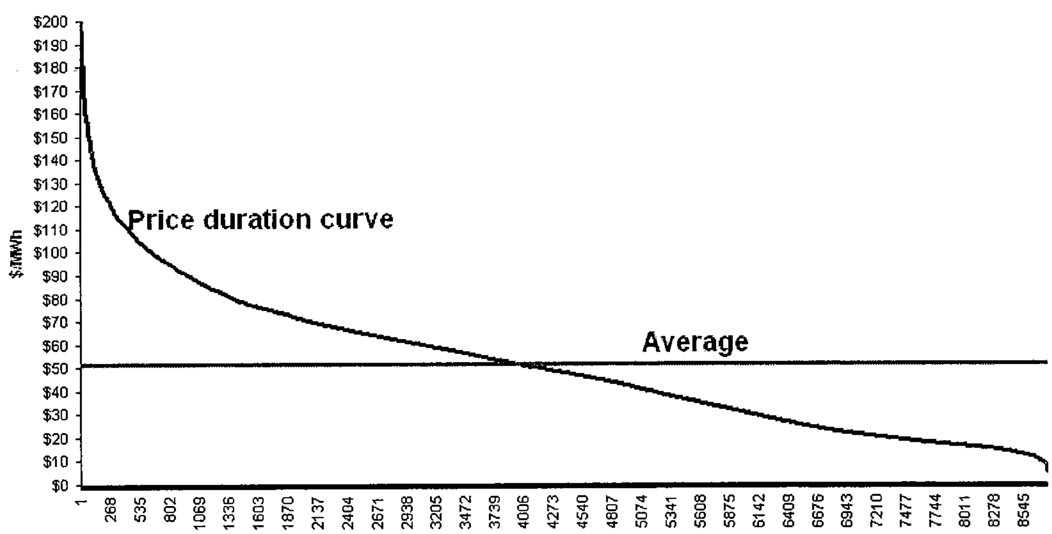
Q. What is your recommendation?

A. I recommend that OTP be ordered to base its revenue deficiency by rate class on the base (unadjusted) CCOSS results. In this case there will not be rate shock regardless of whether costs are shifted or not and ratepayers should pay the costs they shift onto the system.

Q. Do you have any other concerns regarding OTP's CCOSS?

A. Energy costs are over allocated to high load factor customer classes OTP's energy costs are allocated to classes without considering time of use. This is problematic because OTP's energy costs actually vary by time of use. Figure 6 shows the price duration curve for OTP's Day Ahead Locational Marginal Prices ("LMP") for its load zone for 2007. The OTP day ahead LMPs are used as a proxy for OTP's internal marginal energy costs. OTP's internal marginal energy costs should show a similar relationship since these costs are used to submit offers in the MISO market and form the basis of the OTP LMPs. As a result of ignoring time of use, costs are over recovered from high load factor classes. Data provided in OTP's Response to LIG IR No. 54 (attached hereto as **LIG Exhibit ___ (LLS-15)**) indicates that the LGS Class has the highest monthly load factors compared to any other class.

Figure 6: Price Duration Curve & Average



Q. Is OTP familiar with the E-8760 allocator?

A. Yes. I asked OTP if it was applying the E-8760 method and if not to explain reasons why. The response was that OTP is not currently applying this method but was planning to investigate the implementation of the E8760 allocator before it files its next

Minnesota rate case (<u>See</u> OTP's response to LIG IR No. 28, attached hereto as **LIG Exhibit ___ (LLS-16)**).

Q. What data inputs are needed to develop an E-8760 allocator?

A. Hourly load profiles of each of the customer classes and OTP system as well as OTP's hourly marginal energy costs.

Q. Do you know if OTP has hourly load profiles for all customer classes?

A. I am not certain that OTP has hourly load profiles for all customer classes but I am sure that it has such data for the LGS class. It is possible that OTP may have representative hourly profiles for all other classes.

Q. In the absence of availability of hourly data for all classes, what do you recommend?

A. In the absence of availability of hourly data for all classes, I recommend that OTP use known hourly data and apply the E8760 for these classes and use the existing energy sales plus loss method for classes without such data. This approach could be used until OTP has the information necessary to conduct the E8760 for all classes.

IX. GENERAL RULES AND REGULATIONS

Q. What are your concerns regarding OTP's General Rules and Regulations?

A. I could not locate a markup set of OTP's General Rules and Regulations showing the extensive set of OTP's changes. I therefore worked with the unmarked, entirely new set of General Rules and Regulations included in Volume 3, Tariffs.

Q. What were your initial observations?

A. I noted that OTP included some of the modifications that had been settled in OTP's recent Minnesota case.

A. <u>Service Agreement Terms.</u>

Q. Please provide an example.

A. I have been concerned regarding a customer's options to change electric rates if a more suitable option exists as well as the contract term once the customer has transferred to an alternate rate as discussed in Section 1.02 entitled Application for Service to which OTP has referred in its Response to LIG IR No. 47, which is attached hereto as **LIG Exhibit ___ (LLS-17)**. This section states the following:

> "A Customer may take service pursuant to any Commission-approved rate(s) for which the Customer qualifies. The customer making application for service must be of legal age (18). The Customer is required to take service under the selected rate(s) for a minimum of one (1) year, unless the Customer desires to change its service to any rate offering that is newly approved within the one-year period and for which the Customer qualifies. If a Customer changes its service to a different rate, the Customer shall not be permitted to change back to the originally applicable rate for a period of one (1) year. A Customer shall provide the Company at least 45 days prior notice in the event of any requested change."

Q. Are there any further changes you are recommending to the foregoing?

A. Although I am pleased to note improvements from OTP's earlier version, I am concerned with the condition that the rate to which the customer wishes to transfer must have been newly approved by the Commission within a one-year period. I recommend that this one-year provision be removed on the basis that a customer's usage profile may change at any time, and the customer should not be blocked from a lower cost rate option however long the rate has been in effect. I also recommend that a customer not be blocked for a whole year from returning to an original rate on the basis that the customer's usage may have changed (possibly from an economic downturn or business position) and that this condition be removed as well. Many times a move from one rate to another is done with the expectation of savings when working through the options with Otter Tail, especially when dealing with the complex rates offered by Otter Tail this requirement is appropriate.

B. <u>Combined Metering.</u>

Q. What does OTP's General Rules and Regulations state regarding combined metering?

A. OTP's proposed General Rules and Regulations stage the following with respect to combined metering:

> "SEC 4.14 COMBINED METERING: Combined Metering is defined as the addition of multiple service or metering points so that the energy and demand is registered on one meter. This results in coincident demand for these loads, thus treating it as one larger load for billing one rate. To qualify for Combined Metering a Customer must be served at a premises consisting of contiguous property with the same occupant and each service entrance to be combined must have a minimum entrance rating of 750 kVa (750 kVa entrance at various voltages which is equivalent to: 900 amps @ 277/480; 1800 amps @ 120/240 delta; 2100 amps @ 120/208 wye). Combined Metering can be accomplished with hardware or software totalizers or by installing primary metering. The Company will, in its sole discretion, reasonably determine whether to use primary

metering or totalizing for any particular Customer that qualifies for Combined Metering."

Q. What is your concern regarding the foregoing conditions?

A. My concern is with the minimum service entrance size which I recommend should be eliminated. OTP has not provided a satisfactory reason for this minimum size, and metering technology has advanced to the point where totalizing signals from a group of meters should not have a service size threshold.

C. Availability of Forecasts

Q. What new rule do you recommend that should be added related to FCA?

A. I recommend that the General Rules and Regulations state that upon signing a confidentiality agreement, a customer must be provided with a FCA forecast along with backup details consistent with the settlement Agreement in ND Case No. PU-05-131 and with OTP's response to LIG IR No. 64, which is attached hereto as **LIG Exhibit __ (LLS-18).**

Q. What new rule do you recommend with respect to other forecasts?

A. I recommend that the General Rules and Regulations state that upon signing a confidentiality agreement, a customer must be provided with a forecast for all riders as they are an increasing component of ratepayer bills and are important to understand for budgeting purposes.

Q. Does this conclude your testimony?

A. Yes.

Resume of Larry L. Schedin PE

Firm Name: **LLS Resources, LLC**

Address: **12 South 6th Street, Suite 1137** **Title:** Owner
Minneapolis, MN 55402
Phone: (612) 343-8188 **Total Professional Experience:** 44 years

Education:

Masters Degree in Engineering Management - Massachusetts Institute of Technology,
Alfred P. Sloan Fellow, Massachusetts Institute of Technology
Bachelor of Electrical Engineering - The University of Minnesota
Graduate Study in Electrical Engineering – The University of Minnesota

Professional registrations and licenses:

Registered Professional Engineer, State of Minnesota - current
Lifetime Member of the Institute of Electrical and Electronics Engineers Inc.

Awards, publications, etc:

Currently publishes and edits Minnesota Chamber of Commerce Quarterly Energy Bulletin for Chamber members

Published and edited "Energy Bulletin" a monthly energy news update for large energy users in the Chicago area, 1985 - 2000

VIII World Energy Conference Paper: "Integration of Energy Resources in the North Central United States and Manitoba, Canada for the Production of Electrical Energy." Presented in Bucharest, Romania, 1971

Massachusetts Institute of Technology Thesis: "Strategic Planning in the Utility Industry," 1976

Laventhol & Horwatch Perspective, Spring/Summer 1980, "Energy Management: An Accounting Approach to Cutting Costs." Co-authored with Miles H. Locketz and Richard M. Sherman

Previous Employment:

Larry L. Schedin started his own energy consulting business, Schedin & Associates Inc. in 1980 after 18 years with Northern States Power Company, a large electric and gas utility company serving over two million people in a four-state service area. His utility experience included a variety of management positions such as;

Director of Corporate Planning (1976-78)
General Manager of Rates (1971-75)
Manager of Power Supply Coordination (1970-71)
System Planning Engineer and other engineering positions (1961-70)

In 1998, Alliant Energy of Madison, Wisconsin purchased Schedin & Associates Inc. and operated the business as part of their non-regulated consulting business subsidiary named

Alliant Energy Integrated Services, LLC. Mr. Schedin continued to manage the Minneapolis office for Alliant Energy until early 2004. In March, 2004 Mr. Schedin began a new business named LLS Resources, LLC where he continues to serve a broad range of commercial, industrial, institutional and utility clients.

Brief Summary of Relevant Experience, including Special Achievements:

Mr. Schedin has taken an active role developing strategic energy plans, and advising industrial, utility, commercial and institutional clients as a technical consultant and an expert rate witness. His current emphases include wind and other alternative energy development along with negotiation of energy purchase and sales agreements. His clients include large corporations such as General Mills, Inc., American Crystal Sugar Company, CITGO Petroleum, Coca-Cola, the Minnesota Chamber of Commerce, the University of Minnesota and others. He also serves as an expert witness in utility regulatory proceedings both at the federal and state levels. Besides starting several businesses, Mr. Schedin's achievements include:

- Introduced the concept of off-site renewable distributed generation in Minnesota to encourage customer ownership of wind farms and other forms of renewable generation in Minnesota, 2007.

- In cooperation with Caterpillar, CITGO Refining, General Mills Inc., Mobil Oil Refinery and others, Mr. Schedin helped form the Illinois Industrial and Institutional Customers for Electrical Restructuring (I^3CER) Group to help draft the Illinois electric restructuring law, 1996 & 1997.

- In 1985, Mr. Schedin assisted a nucleus group of industrial customers to organize the Chicago Area Energy Users (CAEU) group with the purpose of improving the rates and policies of Northern Illinois Gas Company, Peoples Gas Light & Coke Company, North Shore Gas Company and Commonwealth Edison Company. Throughout the 1980's and 1990's this group helped to develop the new guidelines for delivering deregulated natural gas to the Chicago area. Mr. Schedin has continued to act as technical support advisor, counselor, organizer, administrator and energy expert for groups of customers who come together with a common need to understand the changing energy environment.

- Selected as technical advisor to The Minnesota Energy Consumers (MEC) Group, Minnesota's largest energy users in 1998.

- Testified before U.S. Congress House of Representatives.

- Testified before the Atomic Energy Commission (AEC), now the Nuclear Regulatory Commission (NRC).

- Testified before many state agencies regarding gas and electric utility rates, all on behalf of large energy users.

A detailed description of Mr. Schedin's expert witness and expert opinion experience is available upon request in a separate document.

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	Large Industrial User Group
Analyst:	Larry Schedin
Date of Request:	1/22/2009
Date Received:	1/22/2009
Date Due:	2/20/2009

Information Request No. ND LIG-039
Regarding the discussion on non-asset based wholesale margins on pages 3 and 4 of witness Prazak's testimony, what criteria was used to suggest that 15% of such margins be shared?

RESPONSE:
Reference Witness Beithon's testimony pages 24 and 25.

The first criterion is the incremental costs of this activity are less than 15 percent.

The second criterion is a comparison to Xcel. Fifteen percent for OTP North Dakota ($293,667) is greater than 100% of Xcel North Dakota's non-asset based margins used in its most recent North Dakota general rate case ($260,000).

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	2/13/2009

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	Large Industrial User Group
Analyst:	Larry Schedin
Date of Request:	1/19/2009
Date Received:	1/19/2009
Date Due:	2/18/2009

Information Request No. ND LIG-013
Does OTP have a mandatory RPS standard in North Dakota? If not, how does OTP plan to pass100% of the gains from the sale of renewable energy certificates associated with the renewable resource attribute of the Langdon and Ashtabula wind farms?

RESPONSE:

OTP does not have a mandatory RPS in North Dakota. OTP does have a 10 percent Renewable Energy Objective (REO) beginning in 2015 in North Dakota.

At this time OTP has not sold any Renewable Energy Credits (RECs). In the event that RECs are sold, North Dakota customers will be credited with their allocated share of that revenue in the Renewable Resource Rider. In order to comply with RPS/REO standards in Minnesota, North Dakota and South Dakota, OTP intends to bank, or store, RECs for future compliance when necessary.

Responding Witness:	Bernadeen Brutlag
Title:	Manager, Regulatory Services
Department:	Regulatory Services
Telephone:	(218) 739-8289
Date of Response:	2/13/2009

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	North Dakota Large Industrial Energy Users
Analyst:	Larry Schedin
Date of Request:	2/19/2009
Date Received:	2/19/2009
Date Due:	3/23/2009

Information Request No. ND LIG-133
How many REC's or attributes does OTP currently have banked? What is the value assigned to them and how is the value assigned? Please provide data for 2008 through 2010.

RESPONSE:
As of February 23, 2009, Otter Tail has 359,010 active certificates held in its M-RETS account. That number of renewable energy credits (RECs) includes all RECs created for renewable energy generated through December 2008; however, not all of those RECs are available to Otter Tail for its own use. Some of those RECs will be retired in the first quarter of 2009 to comply with state renewable energy regulations for 2007 and 2008 and to account for the wind generation used to serve Otter Tail's *Tail*Winds program. A portion of the active certificates in Otter Tail's account belong to other generator owners and will be transferred to those owners' M-RETS accounts or held for those owners who do not have an M-RETS account at this time. For example, the joint owners of Big Stone Plant own nearly 1,056 RECs for their share of the 2,290 RECs created by Big Stone Plant's biomass generation. Likewise, the University of Minnesota - Morris owns a share of the 5,886 RECs generated by their wind turbine for the wind generation they have used on campus.

The RECs are not assigned a value.

Otter Tail has no RECs to report for future generation because certificates are only created for reported historical generation.

Responding Witness:	Bernadeen Brutlag
Title:	Manager, Regulatory Services
Department:	Regulatory Services
Telephone:	(218) 739-8289
Date of Response:	3/23/2009

1

LIG Exhibit __ (LLS-__)
Docket No. PU-08-862 AND PU-08-742

PECTRO ETER

+1 360-892-3300 or +1 201-610-1597 *Wednesday 14 January 2009* enviro.us@spectrongroup.com

EMISSIONS

NOx SIP Call ($/tonne)

	Bid	Offer
2008	525	675
2009	[illegible]	750
2010	505	750

NOx RECLAIM Coastal C2 ($/tonne)

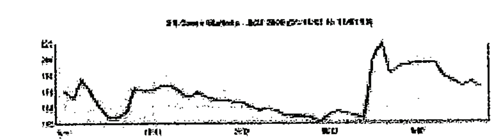
	Bid	Offer
2008	1.40	2.80
2009	3.00	4.25
2010	3.00	4.50

RGGI ($/tonne)

	Bid	Offer
2009	3.50	4.00

SO2 ($/tonne)

	Bid	Offer
2008	177	181
2009	174	182
2010	91	95
2011	[illegible]	95
2012	86	92
2013	83	88
2014	78	87
2015	[illegible]	77



EUA (EUR/tCO2)

	Bid	Offer
Spot	12.95	13.00
Dec-09	13.35	13.40
Dec-10	13.70	13.75
Dec-11	14.21	14.26
Dec-12	14.88	14.93
Dec-09-12	14.04	14.09

CER (EUR/tCO2)

	Bid	Offer
Dec-09	11.60	11.90
Dec-10	11.62	11.92
Dec-11	11.68	11.98
Dec-09-12	11.67	11.97

RENEWABLE ENERGY CREDITS

		Bid	Offer
Connecticut Class I	2008	24.00	29.00
	2009	27.50	34.00
	2010	24.00	32.00
	2011	26.00	32.00
Connecticut Class II	2008	0.40	0.80
	2009	1.00	1.25
New Jersey Class I	2009	4.00	5.50
	2010	17.50	[illegible]
	2011	18.00	20.50
New Jersey Class II	2009	1.00	1.20
	2010	1.10	1.50
	2011	1.10	1.50
New Jersey SRECS	2009	650.00	685.00
	2010	540.00	626.00
	2011	460.00	650.00
Massachusetts	2008	28.00	34.00
	2009	34.00	36.00
	2010	35.00	40.00
Maryland Tier I	2007	0.35	0.60
	2008	0.35	0.75
	2009	0.75	1.10
Maryland Tier II	2007	0.30	0.60
	2008	0.35	0.55
	2009	0.40	0.55
ERCOT	2007	0.75	2.00
	2008	0.75	2.00
	2009	1.30	2.25
National Green-E Certificate Wind	Back Half 2007	0.50	1.70
	Front Half 2008	0.75	2.00
	Back Half 2008	1.75	2.20
	Front Half 2009	1.90	2.85
	Back Half 2009	2.60	3.60
	Front Half 2010	2.60	3.75
WECC Green-E Certifiable Wind	Back Half 2007	2.00	[illegible]
	Front Half 2008	2.10	3.00
	Back Half 2008	4.60	5.75
	Front Half 2009	5.00	6.25
	Back Half 2009	5.50	6.25
National Green-E Any Technology	Back Half 2007	0.50	1.70
	Front Half 2008	0.75	2.00
	Back Half 2008	1.75	2.20
	Front Half 2009	1.90	2.85
	Back Half 2009	2.40	3.60
	Front Half 2010	2.50	3.75

US Emissions House Of The Year 2008 - Energy Risk

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	Large Industrial User Group
Analyst:	Larry Schedin
Date of Request:	1/22/2009
Date Received:	1/22/2009
Date Due:	2/20/2009

Information Request No. ND LIG-073
How is OTP proposing to pass through ancillary service wholesale margins?

RESPONSE:
OTP is not proposing a change to the way ancillary services are recovered in this case. Ancillary services have been in the base rates of OTP previously. The Midwest Independent System Operators ancillary services market (MISO ASM) is so new that OTP doesn't know the full impacts of the MISO ASM at this point. The MISO ASM was not a known and measurable change at the time this case was filed and still is not fully known. OTP has not requested any special treatment for the MISO ASM outside of this case. At this point in time OTP does not anticipate any ancillary service margins net of the increased expenses. With only a couple weeks of experience in January 2009 OTP had a net (revenues and expenses) ASM expense of $36,563. Of course if MISO changes the way the ASM is operated, OTP would review the appropriateness of continuing the existing treatment for ASM and propose changes to the NDPSC as appropriate.

Responding Witness:	Pete Beithon
Title:	Manager Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	02/20/2009

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	Large Industrial User Group
Analyst:	Larry Schedin
Date of Request:	1/22/2009
Date Received:	1/22/2009
Date Due:	2/20/2009

Information Request No. ND LIG-077
Does the current FCA include recovery of any fixed costs? If so, please provide associated workpapers.

RESPONSE:
No.

Responding Witness:	Pete Beithon
Title:	Manager Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	02/20/2009

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	North Dakota Large Industrial Energy Users
Analyst:	Larry Schedin
Date of Request:	3/2/2009
Date Received:	3/2/2009
Date Due:	4/1/2009

Information Request No. ND LIG-166
Are all costs associated with the Langdon PPA 19.5 flowed through the FCA? Please explain how the Langdon PPA costs are recovered.

RESPONSE:
Please refer to IR ND LIG-101. The costs charged per MWH under the PPA are included in the costs of energy.

Responding Witness:	Pete Beithon
Title:	Manager, Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	4/1/2009

Table 1 Langdon Wind Center Capacity Accreditation in MAPP		
Month	**OTP Ownership (MW)**	**OTP Purchase (MW)**
March 2008	12.557	7.804
April 2008	10.529	5.479
May 2008	11.478	5.43
June 2008	14.451	7.836
July 2008	6.226	2.596
August 2008	7.725	4.513
September 2008	5.933	2.563
October 2008	20.096	9.805
November 2008	10.814	5.689
December 2008	21.533	8.497

The Ashtabula Wind Farm just became eligible for capacity accreditation as of December 16, 2008. Since the accredited capacity is based on after-the-fact actual performance analysis, Otter Tail does not yet know what the capacity credit will be. The January numbers will not be calculated until the first week of February.

Otter Tail is considering withdrawing from MAPP, and only being part of the Midwest Independent Transmission System Operator (MISO) Module E Resource Adequacy Requirement. The new Module E requirements are to be in effect as of June 1, 2009. The Business Practices Manual (BPM) is still being drafted and the proposed rules are not yet in place. MISO did conduct a loss-of-load-probability (LOLP) reserve requirement study in late 2008 to establish the reserve margin requirements to be in effect as of June 2009. MISO did not study the reserve implications of variable capacity generation such as wind on reserve margin requirements. This was omitted in order to complete the LOLP study in time to be used for the new Module E timeline as required by the Federal Energy Regulatory Commission (FERC). In lieu of studying the impact, MISO has proposed to accredit wind generation at 20% of nameplate capacity for the first year, until MISO has had time to model wind as part of the LOLP study. It must also be noted that Otter Tail has officially notified MISO of its potential withdrawal as of the end of 2009. That notice is the result of potential transmission cost allocations in future years, so the potential exists that Otter Tail will not be a member of MISO either.

Responding Witness: Pete Beithon
Title: Manager, Regulatory Economics
Department: Regulatory Services
Telephone: (218) 739-8607
Date of Response: 2/13/2009

215 South Cascade Street
PO Box 496
Fergus Falls, Minnesota 56538-0496
218 739-8200
www.otpco.com (web site)

RECEIVED

JAN 27 2009

PUBLIC SE... COMMISSION

OTTER TAIL POWER COMPANY

VIA ELECTRONIC DELIVERY

January 27, 2009

Mr. Darrel Nitschke
Director of Administration
North Dakota Public Service Commission
600 E. Boulevard Ave., Dept. 408
Bismarck, ND 58505-0480

Dear Mr. Nitschke:

For the four-month period ending December 31, 2008, the rate for the Cost of Energy Adjustment is ($.0084) per kWh. Otter Tail Power Company proposes to bill at this rate effective February 2, 2009.

The following additional information is provided:

Average costs from previous month's adjustment:	$ .024011
Average costs from current month's adjustment:	$ .022550
Difference – (Increase) Decrease:	$ .001461

The net effect of this fuel adjustment is to increase the rate by $.0015. The total resulting adjustment for the current billing period will then be ($.0084) per kWh.

Information supporting the adjustment is enclosed. The costs reported in the supporting detail are based on the provisions of the Cost of Energy Adjustment Clause rate schedule approved by the Commission on May 2, 1983, in Case No. 10,334. Effective with interim rates in Case No. PU-08-862, the base cost of energy is $0.030945. Additionally, Midwest ISO Day 2 costs are accounted for as authorized by the Commission's Order in Case No. PU-05-131 issued on August 8, 2007. A detailed schedule of the items included in the calculation is enclosed.

Otter Tail Power Company submits seven (7) copies each of the following:

1) Calculation of the February 2009 Cost of Energy Adjustment Clause based on the four-month period ending December 2008.

2) Monthly Detail of MISO Day 2 Charges by Charge Type for ND FCA marked as Attachment A.

3) Monthly MISO Day 2 Charges for ND Fuel Clause Adjustment marked as Attachment B.

4) Monthly MISO Day 2 Charges for ND Non-Fuel Clause Adjustment marked as Attachment C.

5) Detail of MISO Day 2 Charges by Charge Group for Current Month marked as Attachment D.

6) Otter Tail Power Company's Plant Conditions for November and December 2008 marked as Attachment E.

Also enclosed this month is our $600.00 check for the 2009 Cost of Energy Adjustment filing fees.

Sincerely,

Jill R. Bjorgum

Jill R. Bjorgum
Regulatory Transactions Specialist
Regulatory Services

Enclosures

cc: NDPSC – electronic copy

NORTH DAKOTA

OTTER TAIL POWER COMPANY
COST OF ENERGY ADJUSTMENT
FOR BILLING TO BE EFFECTIVE FEBRUARY 2, 2009

EFFECTIVE 2/02/09
CYCLE '1'
RATE LEVEL 44

ENERGY COSTS	2008 September	2008 October	2008 November	2008 December	Total This Period
Purchased Power	$ 7,192,854	$ 6,713,728	$ 5,489,258	$ 3,292,580	$ 22,688,420
Steam Plant Generation	$ 4,854,401	$ 5,550,936	$ 5,514,464	$ 6,430,992	$ 22,350,793
Other Plant Generation	$ 208,752	$ 84,368	$ 225,056	$ 679,741	$ 1,197,917
Hydro Plant Generation	$ -	$ -	$ -	$ -	$ -
Coyote Coal Conv. Tax	$ 25,074	$ 25,910	$ 25,074	$ 25,910	$ 101,968
Less: Intersystem Sales	$ (6,525,421)	$ (5,686,342)	$ (4,026,646)	$ (1,692,955)	$ (17,931,364)
Net Retail MISO Day 2	$ 1,743,137	$ 1,444,492	$ 2,422,938	$ 4,460,553	$ 10,071,121
NET ENERGY COSTS	$ 7,498,797	$ 8,133,093	$ 9,650,145	$ 13,196,820	$ 38,478,854
Prior (over) under recovery					$ (9,093,291)
Adjusted Net Energy Costs					$ 29,385,564

ASSOCIATED ENERGY -- KWH	2008 September	2008 October	2008 November	2008 December	Total This Period
Net Generation - Steam	251,996,063	294,213,869	298,059,068	341,828,814	1,186,097,814
Other Plant IC Generation	2,918,587	583,731	2,992,163	8,461,388	14,955,869
Hydro Plant Generation	1,392,796	1,573,365	2,144,989	2,049,120	7,160,270
Wind	8,957,082	15,609,405	12,083,639	32,132,456	68,782,582
Purchased Power	407,517,793	276,064,801	261,152,876	102,961,282	1,047,696,752
Total Energy	672,782,321	588,045,171	576,432,735	487,433,060	2,324,693,287
Less Intersystem Sales	(426,333,192)	(290,941,425)	(250,536,563)	(102,232,403)	(1,070,043,583)
Net Retail MISO Day 2	48,031,055	34,054,110	53,984,883	90,136,569	226,206,617
Net Energy - KWHs	294,480,184	331,157,856	379,881,055	475,337,226	1,480,856,321

Energy Adjusted to Retail Sales (Net Energy X (1.00 - .12))	1,303,153,562
Delivered Cost per kWh	$ 0.022550
Base Cost per kWh	$ 0.030945
Energy Cost Adjustment -- Per kWh	$ (0.0084)

TRUE UP FOR DECEMBER

1)	Net Energy (kWhs) Less 12% Losses	418,296,759
2)	Net Energy Costs for the System -- Most recent month	$ 13,196,820
3)	Base Cost Recovered (1 X Base Cost of Fuel)	$ 12,944,193
4)	Net to be Recovered from COE (2 - 3)	$ 252,627
5)	COE Recovery Rate Effective for December	$ 0.0105
6)	Amount Recovered by COE (5 X 1)	$ 4,392,116
7)	Over / (Under) Recovery (4 - 6)	$ 4,139,489
8)	Cumulative Over / (Under) Recovery	$ 9,093,291

Public Document - Trade Secret Data Has Been Excised

Otter Tail Power Company
Monthly Detail of MISO Day 2 Charges by Charge Type for ND FCA
December 2008* includes any adjustments

DoC No.	Line #	Charge Type Description	Acct	Total	FCA Retail	FCA Other	FCA Total	Non-FCA
1	2	DA Asset Energy Amt	555.02		$ 4,531,422.66	$ -	$ 4,531,422.66	
5	9	DA Non-asset Energy Amt	555.09		$ (391,572.10)	$ -	$ (391,572.10)	
12	12	DA Virtual Energy Amt	555.12		$ -	$ -	$ -	
13	19	RT Asset Energy Amt	555.19		$ 69,986.11	$ -	$ 69,986.11	
22	26	RT Non-Asset Energy Amt	555.26		$ 35,441.27	$ -	$ 35,441.27	
27	32	RT Virtual Energy Amt	555.32		$ -	$ -	$ -	
		ENERGY CHARGES TOTAL		$ 2,586,817.64	$ 4,245,277.94	$ -	$ 4,245,277.94	$ (1,658,460.30)
4	1	DA Mkt Admin Amt	555.01		$ 64,049.91	$ -	$ 64,049.91	
2	3	DA FBT Congestion Amt	555.03		$ (74,245.07)	$ -	$ (74,245.07)	
3	4	DA FBT Loss Amt	555.04		$ 1,000,868.10	$ -	$ 1,000,868.10	
6	5	DA Congestion Rebate on COGA	555.05		$ -	$ -	$ -	
7	6	DA Losses Rebate on COGA	555.06		$ -	$ -	$ -	
8	7	DA Congestion Rebate on Option B GFA	555.07		$ 74,400.01	$ -	$ 74,400.01	
9	8	DA Losses Rebate on Option B GFA	555.08		$ (497,965.29)	$ -	$ (497,965.29)	
10	10	DA Revenue Sufficiency Guarantee Distribution Amt	555.10		$ 8,007.30	$ -	$ 8,007.30	
11	11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.11		$ (10,966.62)	$ -	$ (10,966.62)	
29	13	FTR Mkt Admin Amt	555.13		$ 6,050.66	$ -	$ 6,050.66	
28	14	FTR Hourly Allocation Amt	555.14		$ (200,626.35)	$ -	$ (200,626.35)	
30	15	FTR Monthly Allocation Amt	555.15		$ (1,884.43)	$ -	$ (1,884.43)	
31	16	FTR Monthly Transaction Amt	555.16		$ 282.10	$ -	$ 282.10	
32	17	FTR Yearly Allocation Amt	555.17		$ -	$ -	$ -	
19	18	RT Mkt Admin Amt	555.18		$ 4,534.95	$ -	$ 4,534.95	
15	20	RT FBT Congestion Amt	555.20		$ -	$ -	$ -	
16	21	RT FBT Loss Amt	555.21		$ -	$ -	$ -	
17	22	RT Congestion Rebate on COGA	555.22		$ -	$ -	$ -	
18	23	RT Loss Rebate on COGA	555.23		$ -	$ -	$ -	
14	24	RT Distribution of Losses Amt	555.24		$ (283,827.19)	$ -	$ (283,827.19)	
20	25	RT Misc Amt	555.25		$ (7,543.98)	$ -	$ (7,543.98)	
21	27	RT Net Inadvertent Amt	555.27		$ 4,734.36	$ -	$ 4,734.36	
23	28	RT Revenue Neutrality Uplift Amt	555.28		$ 73,804.76	$ -	$ 73,804.76	
24	29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555.29		$ 56,010.37	$ -	$ 56,010.37	
25	30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.30		$ (9,344.63)	$ -	$ (9,344.63)	
26	31	RT Uninstructed Deviation Amt	555.31		$ 2,477.64	$ -	$ 2,477.64	
	38	FTR ARR FTR TXN	555.38		$ (196,586.94)	$ -	$ (196,586.94)	
	39	FTR ARR ARR TXN	555.39		$ 303,658.73	$ -	$ 303,658.73	
	41	FTR ARR STG2 DIST	555.41		$ (25,978.22)	$ -	$ (25,978.22)	
		ENERGY CHARGES TOTAL		$ (64,284.18)	$ 289,910.17	$ -	$ 289,910.17	$ (354,194.35)
		TOTAL MISO DAY 2 CHARGES		$ 2,522,533.46	$ 4,535,188.11	$ -	$ 4,535,188.11	$ (2,012,654.65)
		Less Schedule 16 & 17 (Lines 1, 13, and 18)		$ -	$ (74,635.52)		$ (74,635.52)	$ -
		TOTAL FOR ND COST OF ENERGY ADJUSTMENT		$ 2,522,533.46	$ 4,460,552.59		$ 4,460,552.59	$ (2,012,654.65)

Otter Tail Power Company
Monthly MISO Day 2 Charges for ND Fuel Clause Adjustment
January - December 2008
Includes Any Adjustments

DoC No.	Line #	Charge Type Description	Acct	JANUARY	FEBRUARY	MARCH	APRIL
		Day Ahead & Real Time Asset & Non Asset Energy & Loss					
1	2	DA Asset Energy Amt	555.02	$ 4,381,994.18	$ 6,453,628.27	$ 3,800,146.98	$ 2,756,081.31
3	4	DA FBT Loss Amt	555.04	$ 1,029,052.98	$ 1,265,087.21	$ 1,325,481.58	$ 1,091,682.99
5	9	DA Non-asset Energy Amt	555.09	$ (104,227.57)	$ (79,350.06)	$ (644,466.42)	$ (777,798.77)
13	19	RT Asset Energy Amt	555.19	$ (336,707.29)	$ (1,682,689.39)	$ (2,279,682.00)	$ (2,106,127.57)
14	24	RT Distribution of Losses Amt	555.24	$ (221,976.42)	$ (380,805.74)	$ (207,619.69)	$ (57,370.11)
16	21	RT FBT Loss Amt	555.21	$ -	$ -	$ -	$ -
22	26	RT Non-Asset Energy Amt	555.26	$ (12,894.12)	$ 9,755.75	$ 27,498.66	$ 15,455.11
		TOTAL		$ 4,735,241.76	$ 5,585,626.04	$ 2,021,359.11	$ 921,922.96
		Virtual Energy					
12	12	DA Virtual Energy Amt	555.12	$ -	$	$ -	$ -
27	32	RT Virtual Energy Amt	555.32	$ -	$ -	$ -	$ -
		TOTAL		$ -	$ -	$ -	$ -
		Schedules 16 & 17					
4	1	DA Mkt Admin Amt	555.01	$ 59,960.37	$ 81,913.83	$ 47,809.47	$ 46,740.13
19	18	RT Mkt Admin Amt	555.18	$ 3,644.33	$ 5,557.74	$ 4,043.42	$ 4,933.79
29	13	FTR Mkt Admin Amt	555.13	$ 3,768.55	$ 4,022.82	$ 3,202.85	$ 2,202.59
		TOTAL		$ 67,373.25	$ 91,494.39	$ 55,055.74	$ 53,876.51
		Congest & FTRs					
2	3	DA FBT Congestion Amt	555.03	$ 40,280.69	$ 11,880.26	$ 30,672.12	$ 44,840.10
15	20	RT FBT Congestion Amt	555.20	$ -	$ -	$ -	$ -
28	14	FTR Hourly Allocation Amt	555.14	$ (6,557.65)	$ 10,715.87	$ (5,165.07)	$ (640.82)
30	15	FTR Monthly Allocation Amt	555.15	$ (14,795.15)	$ (941.93)	$ (202.53)	$ (36.32)
32	17	FTR Yearly Allocation Amt	555.17	$ -	$ -	$ -	$ (1,564.19)
31	16	FTR Monthly Transaction Amt	555.16	$ -	$ (198.21)	$ 27.93	$ 14.36
	38	FTR_ARR FTR_TXN	555.38	$ -	$	$	$ -
	39	FTR_ARR ARR_TXN	555.39	$ -	$ -	$ -	$ -
	41	FTR_ARR STG2_DIST	555.41	$ -	$ -	$ -	$ -
		TOTAL		$ 18,927.89	$ 21,455.99	$ 25,332.45	$ 42,613.13
		RSG & Make Whole Payments					
10	10	DA Revenue Sufficiency Guarantee Distribution Amt	555.10	$ 16,648.68	$ 23,072.69	$ 14,489.31	$ 5,156.11
11	11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.11	$ -	$ (442.29)	$ (2,034.49)	$ (30.40)
24	29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555.29	$ 34,488.11	$ 78,435.96	$ 93,421.93	$ 112,487.38
25	30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.30	$ -	$ -	$ -	$ -
		TOTAL		$ 51,136.79	$ 101,066.36	$ 105,876.75	$ 117,613.09
		Revenue Neutrality Uplift					
23	26	RT Revenue Neutrality Uplift Amt	555.28	$ 108,425.46	$ 133,352.41	$ 76,232.16	$ 67,563.96
		TOTAL		$ 108,425.46	$ 133,352.41	$ 76,232.16	$ 67,563.96
		Other Charges					
20	25	RT Misc Amt	555.25	$ (216.16)	$ 28.34	$ 0.05	$ -
21	27	RT Net Inadvertent Amt	555.27	$ (12,746.68)	$ (12,888.77)	$ 32,105.90	$ 32,616.22
26	31	RT Uninstructed Deviation Amt	555.31	$ (1,585.86)	$ 9.63	$ 30.36	$ 3,105.92
		TOTAL		$ (14,548.70)	$ (12,850.80)	$ 32,136.31	$ 35,812.14
		Grandfathered Charge Types					
6	5	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$ -
7	6	DA Losses Rebate on COGA	555.06	$ -	$	$	$ -
8	7	DA Congestion Rebate on Option B GFA	555.07	$ (40,120.49)	$ (11,385.64)	$ (30,355.12)	$ (44,437.66)
9	8	DA Losses Rebate on Option B GFA	555.08	$ (512,095.75)	$ (629,453.98)	$ (659,648.42)	$ (543,404.04)
17	22	RT Congestion Rebate on COGA	555.22	$ -	$ -	$	$ -
18	23	RT Loss Rebate on COGA	555.23	$ -	$ -	$	$ -
		TOTAL		$ (552,216.24)	$ (640,839.62)	$ (690,003.54)	$ (587,841.70)
		TOTAL MISO DAY 2 CHARGES - Fuel Clause Adjustment		$ 4,414,340.21	$ 5,279,304.77	$ 1,625,988.96	$ 651,560.09
		Less Schedule 16 & 17 (Lines 1, 13, and 18)		$ (67,373.25)	$ (91,494.39)	$ (55,055.74)	$ (53,876.51)
		TOTAL FOR MN COST OF ENERGY ADJUSTMENT		$ 4,346,966.96	$ 5,187,810.38	$ 1,570,933.24	$ 597,683.58

DoC No.	Line #	Charge Type Description	Acct	MAY	JUNE	JULY	AUGUST	SEPTEMBER
		Day Ahead & Real Time Asset & Non Asset Energy & Loss						
1	2	DA Asset Energy Amt	555.02	$ 2,610,138.79	$ 2,626,801.81	$ 1,428,447.33	$ 1,495,464.60	$ 1,043,369.95
3	4	DA FBT Loss Amt	555.04	$ 445,377.59	$ 569,073.49	$ 822,725.01	$ 845,954.66	$ 534,240.58
5	9	DA Non-asset Energy Amt	555.09	$ (726,564.50)	$ (801,323.75)	$ (993,420.46)	$ (929,723.75)	$ (669,804.09)
13	19	RT Asset Energy Amt	555.19	$ (1,323,473.39)	$ (553,458.71)	$ (134,758.52)	$ (241,888.89)	$ 1,109,728.95
14	24	RT Distribution of Losses Amt	555.24	$ (49,627.27)	$ (94,332.76)	$ (66,331.67)	$ (96,117.51)	$ (72,655.59)
16	21	RT FBT Loss Amt	555.21	$ -	$ -	$ -	$ -	$ -
22	26	RT Non-Asset Energy Amt	555.26	$ 855.35	$ 20,102.66	$ 1,734.68	$ 3,973.45	$ 5,336.82
		TOTAL		$ 956,706.57	$ 1,766,862.74	$ 1,058,396.37	$ 1,077,662.56	$ 1,950,126.62
		Virtual Energy						
12	12	DA Virtual Energy Amt	555.12	$ -	$ -	$ -	$ -	$ 39,948.00
27	32	RT Virtual Energy Amt	555.32	$ -	$ -	$ -	$ -	$ (36,146.03)
		TOTAL		$ -	$ -	$ -	$ -	$ 3,801.97
		Schedules 16 & 17						
4	1	DA Mkt Admin Amt	555.01	$ 37,612.51	$ 46,750.54	$ 43,404.59	$ 40,332.20	$ 40,272.17
19	18	RT Mkt Admin Amt	555.18	$ 3,737.63	$ 4,040.22	$ 2,165.43	$ 2,996.19	$ 2,027.83
29	13	FTR Mkt Admin Amt	555.13	$ 2,459.34	$ 5,202.09	$ 4,324.61	$ 5,552.88	$ 5,837.34
		TOTAL		$ 43,809.48	$ 55,992.85	$ 49,894.63	$ 48,881.27	$ 48,137.34
		Congest & FTRs						
2	3	DA FBT Congestion Amt	555.03	$ (13,793.55)	$ (78,816.22)	$ 33,885.13	$ 1,403,008.61	$ 258,817.25
15	20	RT FBT Congestion Amt	555.20	$	$ -	$ -	$ -	$ -
28	14	FTR Hourly Allocation Amt	555.14	$ (84.22)	$ (82,850.10)	$ (90,179.19)	$ 99,996.19	$ 9,777.18
30	15	FTR Monthly Allocation Amt	555.15	$ (33.78)	$ (112.67)	$ (4,514.73)	$ (12,143.10)	$ (1,324.52)
32	17	FTR Yearly Allocation Amt	555.17	$ (653,053.78)	$ -	$ -	$ -	$ -
31	16	FTR Monthly Transaction Amt	555.16	$ 88.12	$ 12.25	$ 4,035.00	$ (437.46)	$ 14.23
	38	FTR_ARR FTR_TXN	555.38	$ -	$ (25,135.01)	$ (25,135.01)	$ (25,135.01)	$ (39,412.16)
	39	FTR_ARR ARR_TXN	555.39	$ -	$ 25,134.91	$ 25,134.91	$ 25,134.91	$ 39,412.60
	41	FTR_ARR STG2_DIST	555.41	$ -	$ (34,719.43)	$ (38,801.27)	$ (36,760.35)	$ (24,615.90)
		TOTAL		$ (666,877.21)	$ (196,486.27)	$ (95,575.16)	$ 1,453,663.79	$ 242,668.68
		RSG & Make Whole Payments						
10	10	DA Revenue Sufficiency Guarantee Distribution Amt	555.10	$ 4,925.42	$ 14,509.21	$ 5,817.22	$ 4,000.48	$ 3,824.57
11	11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.11	$ -	$ (2,316.08)	$ (988.16)	$ (16.37)	$ (2,207.90)
24	29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555.29	$ 30,729.29	$ 51,165.88	$ 37,206.52	$ 24,369.64	$ 27,289.34
25	30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.30	$ (121.55)	$ (2,389.26)	$ (1,886.08)	$ (38,083.14)	$ (8,797.08)
		TOTAL		$ 35,533.16	$ 60,969.75	$ 40,149.50	$ (9,729.39)	$ 20,108.93
		Revenue Neutrality Uplift						
23	26	RT Revenue Neutrality Uplift Amt	555.28	$ 38,736.90	$ 138,176.58	$ 52,575.78	$ 63,003.04	$ 44,729.38
		TOTAL		$ 38,736.90	$ 138,176.58	$ 52,575.78	$ 63,003.04	$ 44,729.38
		Other Charges						
20	25	RT Misc Amt	555.25	$ (356.39)	$ 8,061.03	$ (316.63)	$ (11,987.66)	$ (2,735.21)
21	27	RT Net Inadvertent Amt	555.27	$ 7,416.41	$ (208.23)	$ 5,897.87	$ (704.88)	$ 1,969.06
26	31	RT Uninstructed Deviation Amt	555.31	$ (2,698.69)	$ 2,348.42	$ 494.01	$ 246.95	$ 7,703.15
		TOTAL		$ 4,361.33	$ 10,201.22	$ 6,075.25	$ (12,445.59)	$ 6,937.00
		Grandfathered Charge Types						
6	5	DA Congestion Rebate on COGA	555.05	$ -	$	$ -	$ -	$ -
7	6	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -	$ -
8	7	DA Congestion Rebate on Option B GFA	555.07	$ 13,745.67	$ 78,457.96	$ (33,826.37)	$ (1,404,480.23)	$ (259,566.85)
9	8	DA Losses Rebate on Option B GFA	555.08	$ (221,084.95)	$ (282,504.86)	$ (409,222.53)	$ (420,801.57)	$ (265,668.24)
17	22	RT Congestion Rebate on COGA	555.22	$	$ -	$ -	$ -	$ -
18	23	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -	$ -
		TOTAL		$ (207,339.28)	$ (204,046.90)	$ (443,048.90)	$ (1,825,281.80)	$ (525,235.09)
		TOTAL MISO DAY 2 CHARGES - Fuel Clause Adjustment		$ 204,930.95	$ 1,631,669.97	$ 668,467.47	$ 795,753.88	$ 1,791,274.83
		Less Schedule 16 & 17 (Lines 1, 13, and 18)		$ (43,809.48)	$ (55,992.85)	$ (49,894.63)	$ (48,881.27)	$ (48,137.34)
		TOTAL FOR MN COST OF ENERGY ADJUSTMENT		$ 161,121.47	$ 1,575,677.12	$ 618,572.84	$ 746,872.61	$ 1,743,137.49

DoC No.	Line #	Charge Type Description	Acct	OCTOBER	NOVEMBER	DECEMBER	YEAR TO DATE
		Day Ahead & Real Time Asset & Non Asset Energy & Loss					
1	2	DA Asset Energy Amt	555.02	$ 1,072,038.62	$ 1,668,237.19	$ 4,531,422.66	$ 33,867,771.69
3	4	DA FBT Loss Amt	555.04	$ 573,494.99	$ 652,519.61	$ 1,000,868.10	$ 10,155,558.79
5	9	DA Non-asset Energy Amt	555.09	$ (543,928.51)	$ (392,390.85)	$ (391,572.10)	$ (7,054,660.83)
13	19	RT Asset Energy Amt	555.19	$ 629,112.66	$ 840,072.70	$ 69,986.11	$ (6,009,885.34)
14	24	RT Distribution of Losses Amt	555.24	$ (63,687.23)	$ (98,260.32)	$ (283,827.19)	$ (1,692,611.50)
16	21	RT FBT Loss Amt	555.21	$ -	$ -	$ -	$
22	26	RT Non-Asset Energy Amt	555.26	$ 5,959.88	$ 7,980.60	$ 35,441.27	$ 121,200.11
		TOTAL		$ 1,672,990.41	$ 2,678,158.93	$ 4,962,318.85	$ 29,387,372.92
		Virtual Energy					
12	12	DA Virtual Energy Amt	555.12	$ -	$ -	$ -	$ 39,948.00
27	32	RT Virtual Energy Amt	555.32	$ (0.03)	$ -	$ -	$ (36,146.06)
		TOTAL		$ (0.03)	$ -	$ -	$ 3,801.94
		Schedules 16 & 17					
4	1	DA Mkt Admin Amt	555.01	$ 50,105.25	$ 52,573.81	$ 64,049.91	$ 611,524.78
19	18	RT Mkt Admin Amt	555.18	$ 3,216.84	$ 4,866.43	$ 4,534.95	$ 45,764.80
29	13	FTR Mkt Admin Amt	555.13	$ 3,678.07	$ 3,228.30	$ 6,050.66	$ 49,530.10
		TOTAL		$ 57,000.16	$ 60,668.54	$ 74,635.52	$ 706,819.68
		Congest & FTRs					
2	3	DA FBT Congestion Amt	555.03	$ 94,931.85	$ 87,640.62	$ (74,245.07)	$ 1,839,101.79
15	20	RT FBT Congestion Amt	555.20	$ -	$ -	$ -	$ -
28	14	FTR Hourly Allocation Amt	555.14	$ 7,367.92	$ 34,029.43	$ (200,626.35)	$ (224,216.81)
30	15	FTR Monthly Allocation Amt	555.15	$ (2,863.44)	$ (639.38)	$ (1,884.43)	$ (39,491.98)
32	17	FTR Yearly Allocation Amt	555.17	$ -	$ -	$ -	$ (654,617.97)
31	16	FTR Monthly Transaction Amt	555.16	$ (388.98)	$ 1,449.00	$ 282.10	$ 4,898.34
	38	FTR_ARR FTR_TXN	555.38	$ (39,412.16)	$ (39,412.16)	$ (196,586.94)	$ (390,228.45)
	39	FTR_ARR ARR_TXN	555.39	$ 39,412.60	$ 39,412.60	$ 303,658.73	$ 497,301.26
	41	FTR_ARR STG2_DIST	555.41	$ (25,164.18)	$ (25,162.17)	$ (25,978.22)	$ (211,201.52)
		TOTAL		$ 73,883.61	$ 97,317.94	$ (195,380.18)	$ 821,544.66
		RSG & Make Whole Payments					
10	10	DA Revenue Sufficiency Guarantee Distribution Amt	555.10	$ 4,012.33	$ 4,714.52	$ 8,007.30	$ 109,177.84
11	11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.11	$ -	$ -	$ (10,966.62)	$ (19,002.31)
24	29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555.29	$ 27,130.42	$ 29,814.62	$ 56,010.37	$ 602,549.46
25	30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.30	$ (23,338.35)	$ (3,131.38)	$ (9,344.63)	$ (87,091.47)
		TOTAL		$ 7,804.40	$ 31,397.76	$ 43,706.42	$ 605,633.52
		Revenue Neutrality Uplift					
23	26	RT Revenue Neutrality Uplift Amt	555.28	$ 69,686.30	$ 23,141.09	$ 73,804.76	$ 889,427.82
		TOTAL		$ 69,686.30	$ 23,141.09	$ 73,804.76	$ 889,427.82
		Other Charges					
20	25	RT Misc Amt	555.25	$ (1,000.74)	$ (1,275.55)	$ (7,543.98)	$ (17,342.90)
21	27	RT Net Inadvertent Amt	555.27	$ (573.68)	$ 3,000.37	$ 4,734.36	$ 60,617.95
26	31	RT Uninstructed Deviation Amt	555.31	$ 442.85	$ 1,628.74	$ 2,477.64	$ 14,293.12
		TOTAL		$ (1,131.57)	$ 3,353.56	$ (331.98)	$ 57,568.17
		Grandfathered Charge Types					
6	5	DA Congestion Rebate on COGA	555.05	$ -	$ -	$ -	$
7	6	DA Losses Rebate on COGA	555.06	$	$ -	$	$
8	7	DA Congestion Rebate on Option B GFA	555.07	$ (93,369.05)	$ (85,917.28)	$ 74,400.01	$ (1,836,855.05)
9	8	DA Losses Rebate on Option B GFA	555.08	$ (285,371.58)	$ (324,513.94)	$ (497,965.29)	$ (5,051,735.15)
17	22	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -
18	23	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -
		TOTAL		$ (378,740.63)	$ (410,431.22)	$ (423,565.28)	$ (6,888,590.20)
		TOTAL MISO DAY 2 CHARGES - Fuel Clause Adjustment		$ 1,501,492.65	$ 2,483,606.60	$ 4,535,188.11	$ 25,583,578.51
		Less Schedule 16 & 17 (Lines 1, 13, and 18)		$ (57,000.16)	$ (60,668.54)	$ (74,635.52)	$ (706,819.69)
		TOTAL FOR MN COST OF ENERGY ADJUSTMENT		$ 1,444,492.49	$ 2,422,938.06	$ 4,460,552.59	$ 24,876,758.83

Otter Tail Power Company
Monthly MISO Day 2 Charges for ND Non-Fuel Clause Adjustment
January - December 2008
Includes Any Adjustments

DoC No.	Line #	Charge Type Description	Acct	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	YEAR TO DATE
Day Ahead & Real Time Asset & Non Asset Energy & Loss																
1	2	DA Asset Energy Amt	555.02													
3	4	DA FBT Loss Amt	555.04													
5	9	DA Non-asset Energy Amt	555.09													
13	19	RT Asset Energy Amt	555.19													
14	24	RT Distribution of Losses Amt	555.24													
16	21	RT FBT Loss Amt	555.21													
22	26	RT Non-Asset Energy Amt	555.26													
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,494,720.88
Virtual Energy																
12	12	DA Virtual Energy Amt	555.12													
27	32	RT Virtual Energy Amt	555.32													
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (295,710.60)
Schedules 16 & 17																
4	1	DA Mkt Admin Amt	555.01													
19	18	RT Mkt Admin Amt	555.18													
29	13	FTR Mkt Admin Amt	555.13													
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 215,441.28
Congest & FTRs																
2	3	DA FBT Congestion Amt	555.03													
15	20	RT FBT Congestion Amt	555.2													
28	14	FTR Hourly Allocation Amt	555.14													
30	15	FTR Monthly Allocation Amt	555.15													
32	17	FTR Yearly Allocation Amt	555.17													
31	16	FTR Monthly Transaction Amt	555.16													
	38	FTR_ARR_FTR_TXN	555.38													
	39	FTR_ARR_ARR_TXN	555.39													
	41	FTR_ARR_STG2_DIST	555.41													
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (915,146.17)
RSG & Make Whole Payments																
10	10	DA Revenue Sufficiency Guarantee Distribution Amt	555.1													
11	11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.11													
24	29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555.29													
25	30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.3													
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (436,056.71)
Revenue Neutrality Uplift																
23	28	RT Revenue Neutrality Uplift Amt	555.28													
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 109,603.28
Other Charges																
20	25	RT Misc Amt	555.25													
21	27	RT Net Inadvertent Amt	555.27													
26	31	RT Uninstructed Deviation Amt	555.31													
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,589.85
Grandfathered Charge Types																
6	5	DA Congestion Rebate on COGA	555.05													
7	6	DA Losses Rebate on COGA	555.06													
8	7	DA Congestion Rebate on Option B GFA	555.07													
9	8	DA Losses Rebate on Option B GFA	555.08													
17	22	RT Congestion Rebate on COGA	555.22													
18	23	RT Loss Rebate on COGA	555.23													
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		TOTAL MISO DAY 2 CHARGES - Non-Fuel Clause Adjustment		$ (2,809,912.09)	$ (1,352,503.40)	$ 2,321,320.87	$ 5,960,941.60	$ 3,275,514.71	$ 8,570,397.12	$ (2,059,195.75)	$ (480,283.92)	$ 5,903,034.98	$ 1,598,306.73	$ 1,287,475.61	$ (2,012,654.65)	$ 20,202,441.81
		Less Schedule 16 & 17 (Lines 1, 13, and 18)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		TOTAL FOR MN COST OF ENERGY ADJUSTMENT		$ (2,809,912.09)	$ (1,352,503.40)	$ 2,321,320.87	$ 5,960,941.60	$ 3,275,514.71	$ 8,570,397.12	$ (2,059,195.75)	$ (480,283.92)	$ 5,903,034.98	$ 1,598,306.73	$ 1,287,475.61	$ (2,012,654.65)	$ 20,202,441.81

Public Document - Trade Secret Data Has Been Excised

Otter Tail Power Company
Detail of MISO Day 2 Charges by Charge Group for Current Month - ND
December 2008* includes any adjustments

DoC No.	Line #	Charge Type Description	(A) Acct	(B) Retail Debits	(C) Retail Credits	(D) Retail Adjustments	(E) Net Retail	(F) Net Intersystem	(G) Total	(H)** Charge types with MWH for Retail	
		Day Ahead & Real Time Asset & Non Asset Energy & Loss									
1	2	DA Asset Energy Amt	555.02	$ 34,908,914.86	$ (30,377,492.20)	$	$ 4,531,422.66			737,067	(649,146)
3	4	DA FBT Loss Amt	555.04	$ 1,000,868.10	$	$ -	$ 1,000,868.10				-
5	9	DA Non-asset Energy Amt	555.09	$ 995,253.97	$ (1,386,826.07)	$ -	$ (391,572.10)			21,441	(25,930)
13	19	RT Asset Energy Amt	555.19	$ 1,186,197.44	$ (1,179,999.94)	$ 63,788.61	$ 69,986.11			28,781	(29,418)
14	24	RT Distribution of Losses Amt	555.24	$ -	$ (279,437.49)	$ (4,369.70)	$ (283,827.19)			-	-
16	21	RT FBT Loss Amt	555.21	$ -	$ -	$	$				
22	26	RT Non-Asset Energy Amt	555.26	$ 2,351,074.69	$ (2,315,633.42)	$	$ 35,441.27			48,568	(47,371)
		TOTAL		$ 40,442,309.06	$ (35,539,389.12)	$ 59,398.91	$ 4,962,318.85	$ -	$ -	835,856	(751,866)
		Virtual Energy									
12	12	DA Virtual Energy Amt	555.12	$ -	$ -	$ -	$			-	-
27	32	RT Virtual Energy Amt	555.32	$ -	$ -	$ -	$			-	-
		TOTAL		$ -	$ -	$ -	$ -	$ -	$ -	-	-
		Schedules 16 & 17									
4	1	DA Mkt Admin Amt	555.01	$ 63,959.28	$ -	$ 90.63	$ 64,049.91				-
19	18	RT Mkt Admin Amt	555.18	$ 5,049.30	$ -	$ (514.35)	$ 4,534.95			-	-
29	13	FTR Mkt Admin Amt	555.13	$ 6,050.66	$ -	$ -	$ 6,050.66			-	-
		TOTAL		$ 75,059.24	$ -	$ (423.72)	$ 74,635.52	$ -	$ -	-	-
		Congest & FTRs									
2	3	DA FBT Congestion Amt	555.03	$ 42,983.10	$ (117,228.17)	$ -	$ (74,245.07)			-	-
15	20	RT FBT Congestion Amt	555.20	$ -	$ -	$	$ -			-	-
28	14	FTR Hourly Allocation Amt	555.14	$ 61,692.44	$ (262,319.06)	$ 0.27	$ (200,626.35)			-	-
30	15	FTR Monthly Allocation Amt	555.15	$ -	$ (1,885.39)	$ 0.96	$ (1,884.43)			-	-
32	17	FTR Yearly Allocation Amt	555.17	$ -	$ -	$	$ -			-	-
31	16	FTR Monthly Transaction Amt	555.16	$ 34,734.84	$ (34,453.40)	$ 0.66	$ 282.10			-	-
	38	FTR_ARR_FTR_TXN	555.38	$ 15,617.08	$ (212,204.02)	$	$ (196,586.94)			-	-
	39	FTR_ARR_ARR_TXN	555.39	$ 319,275.81	$ (15,617.08)	$ -	$ 303,658.73			-	-
	41	FTR_ARR_STG2_DIST	555.41	$ -	$ (25,978.22)	$	$ (25,978.22)			-	-
		TOTAL		$ 474,303.27	$ (669,685.34)	$ 1.89	$ (195,380.18)	$ -	$ -	-	-
		RSG & Make Whole Payments									
10	10	DA Revenue Sufficiency Guarantee Distribution Amt	555.10	$ 8,007.29	$ -	$ 0.01	$ 8,007.30			-	-
11	11	DA Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.11	$ -	$ (10,966.62)	$ -	$ (10,966.62)			-	-
24	29	RT Revenue Sufficiency Guarantee First Pass Distribution Amt	555.29	$ 67,169.16	$ -	$ (11,158.79)	$ 56,010.37			-	-
25	30	RT Revenue Sufficiency Guarantee Make Whole Pymt Amt	555.30	$ -	$ (5,680.22)	$ (3,664.41)	$ (9,344.63)			-	-
		TOTAL		$ 75,176.45	$ (16,646.84)	$ (14,823.19)	$ 43,706.42	$ -	$ -	-	-
		Revenue Neutrality Uplift									
23	28	RT Revenue Neutrality Uplift Amt	555.28	$ 109,203.74	$ (41,994.20)	$ 6,595.22	$ 73,804.76			-	-
		TOTAL		$ 109,203.74	$ (41,994.20)	$ 6,595.22	$ 73,804.76	$ -	$ -	-	-
		Other Charges									
20	25	RT Misc Amt	555.25	$ -	$ (2,839.55)	$ (4,704.43)	$ (7,543.98)			-	-
21	27	RT Net Inadvertent Amt	555.27	$ 10,089.74	$ (8,344.69)	$ 2,989.31	$ 4,734.36			-	-
26	31	RT Uninstructed Deviation Amt	555.31	$ 2,477.64	$ -	$ -	$ 2,477.64			-	-
		TOTAL		$ 12,567.38	$ (11,184.24)	$ (1,715.12)	$ (331.98)	$ -	$ -	-	-
		Grandfathered Charge Types									
6	5	DA Congestion Rebate on COGA	555.05	$ -	$ -	$	$ -			-	-
7	6	DA Losses Rebate on COGA	555.06	$ -	$ -	$ -	$ -			-	-
8	7	DA Congestion Rebate on Option B GFA	555.07	$ 102,628.20	$ (28,228.19)	$ -	$ 74,400.01			-	-
9	8	DA Losses Rebate on Option B GFA	555.08	$ -	$ (497,965.29)	$	$ (497,965.29)			-	-
17	22	RT Congestion Rebate on COGA	555.22	$ -	$ -	$ -	$ -			-	-
18	23	RT Loss Rebate on COGA	555.23	$ -	$ -	$ -	$ -			-	-
		TOTAL		$ 102,628.20	$ (526,193.48)	$ -	$ (423,565.28)	$ -	$ -	-	-
		TOTAL MISO DAY 2 CHARGES		$ 41,291,247.34	$ (36,805,093.22)	$ 49,033.99	$ 4,535,188.11	$ (2,012,654.65)	$ 2,522,533.46	835,856	(751,866)
		Less Schedule 16 & 17 (Lines 1, 13, and 18)		$ (75,059.24)	$ -	$ 423.72	$ (74,635.52)				
		TOTAL FOR ND COST OF ENERGY ADJUSTMENT		$ 41,216,188.10	$ (36,805,093.22)	$ 49,457.71	$ 4,460,552.59				

Net MISO Charges for Retail = (B) + (C) + (D) $ 4,460,552.59

Net KWH for retail = ((G) + (H)) * 1,000 83,990,462 — 83,990,462

* covers time period of 11-27-08 to 12-30-08 ** increased for losses of 2.8%

	Net Retail	Net MISO KWH (adjusted cumulatively)
MISO Book Totals	$ 4,411,094.88	83,990,462
December Adjustments	$ 49,457.71	6,146,107
Total MISO	$ 4,460,552.59	90,136,569

ATTACHMENT E

Otter Tail Power Company
Plant Conditions

Plant Conditions for December 2008

Big Stone: The unit generated 329,434 net MWh for the month. December's availability was 100%. Equivalent availability in December was 98.3%. Fuel prices were about 1% under budget.

Coyote: The Unit generated 245,512 MWh net for the month of December. Availability for the month was 84.1% due to a scheduled wash outage, a boiler circ pump valve packing failure and a low drum level trip during a startup. The wash outage was 10 hours longer than planned to replace a boiler circ pump. Fuel costs were 14% above budget for the month.

Hoot Lake: Unit 2 generated 36,038.5 MWh net in December, and had an availability of 100 percent and an equivalent availability of 97.8 percent. Fuel costs were on budget.

Unit 3 generated 46,194.7 MWh net, an availability of 93.3 percent, and an equivalent availability of 93.1 percent. Fuel costs were on budget.

Plant Conditions for November 2008

Big Stone: The unit generated 286,192 net MWh for the month. Availability was 94.6% for the month. The unit was forced off line on the 8th due to a reheat tube leak. Fuel prices were about 2% under budget.

Coyote: The Unit generated 273,122 MWh net for the month of October. Availability for the month was 95.5% because of an outage to repair a windbox leak and a tube leak. Fuel costs were 16% above budget for the month. The plant did see almost a 4% drop in the fuel price for the 4th quarter, this overall fuel price was still 16% above budget for the month as budget had also predicted a drop in price for the 4th quarter.

Hoot Lake: Unit 2 generated 18,648.8 MWh net in November, and had an availability of 58.9 percent. The unit was down part of the month to resolve a generator vibration issue that has been an issue since the spring overhaul. That problem is now fixed. Fuel costs were about 2% over budget.

Unit 3 generated 42,207.1 MWh net and had an availability of 95.6 percent. Fuel costs were about 2% over budget.

and interpreted. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

For the Company's operating companies recognizing revenue on certain products when shipped, those operating companies have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

Electric customers' meters are read and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a fuel clause adjustment (FCA)—under which the rates are adjusted to reflect changes in average cost of fuels and purchased power—and a surcharge for recovery of conservation-related expenses. Revenue is accrued for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the FCA.

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered.

The Company's unrealized gains and losses on forward energy contracts that do not meet the definition of capacity contracts are marked to market and reflected on a net basis in electric revenue on the Company's consolidated statement of income. Under SFAS No. 133 as amended and interpreted, the Company's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. The Company is required to mark to market these forward energy contracts and recognize changes in the fair value of these contracts as components of income over the life of the contracts. See note 5 for further discussion.

Plastics operating revenues are recorded when the product is shipped.

Manufacturing operating revenues are recorded when products are shipped and on a percentage-of-completion basis for construction type contracts.

Health Services operating revenues on major equipment and installation contracts are recorded when the equipment is delivered or when installation is completed and accepted. Amounts received in advance under customer service contracts are deferred and recognized on a straight-line basis over the contract period. Revenues generated in the imaging operations are recorded on a fee-per-scan basis when the scan is performed.

Food Ingredient Processing revenues are recorded when the product is shipped.

Other Business Operations operating revenues are recorded when services are rendered or products are shipped. In the case of construction contracts, the percentage-of-completion method is used.

Some of the operating businesses enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The Company's consolidated revenues recorded under the percentage-of-completion method were 30.1% in 2007, 25.1% in 2006 and 17.9% in 2005. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company's wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized. The following table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	December 31, 2007	December 31, 2006
Costs Incurred on Uncompleted Contracts	$ 286,358	$ 257,370
Less Billings to Date	(292,692)	(284,273)
Plus Estimated Earnings Recognized	38,275	35,955
	$ 31,941	$ 9,052

The following costs and estimated earnings in excess of billings are included in the Company's consolidated balance sheet. Billings in excess of costs and estimated earnings on uncompleted contracts are included in Accounts Payable.

(in thousands)	December 31, 2007	December 31, 2006
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 42,234	$ 38,384
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(10,293)	(29,332)
	$ 31,941	$ 9,052

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI) were $36,161,000 as of December 31, 2007. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

FOREIGN CURRENCY TRANSLATION

The functional currency for the operations of the Canadian subsidiary of Idaho Pacific Holdings, Inc. (IPH) is the Canadian dollar. This subsidiary realizes foreign currency transaction gains or losses on settlement of receivables related to its sales, which are mostly in U.S. dollars, and on exchanging U.S. currency for Canadian currency for its Canadian operations. This subsidiary recorded foreign currency transaction losses of $656,000 ($393,000 net-of-tax) in U.S. dollars in 2007 as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar in 2007. Transaction gains and losses in 2006 and 2005 were not significant due to the relative stability of the currencies in those years. The translation of Canadian currency into U.S. dollars is performed for balance sheet accounts using exchange rates in effect at the balance sheet dates, except for the common equity accounts which are at historical rates, and for revenue and expense accounts using a weighted average exchange during the year. Gains or losses resulting from the translation are included in Accumulated Other Comprehensive Income (Loss) in the equity section of the Company's consolidated balance sheet.

The functional currency for the Canadian subsidiary of DMI, formed in November 2005, is the U.S. dollar. There are no foreign currency translation gains or losses related to this entity. However, this subsidiary may realize foreign currency transaction gains or losses on settlement of liabilities related to goods or services purchased in Canadian dollars. Foreign currency transaction losses related to balance sheet adjustments of Canadian dollar liabilities to U.S. dollar equivalents and realized losses on settlement of those liabilities were $102,000 ($61,000 net-of-tax) in U.S. dollars in 2007 as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar in 2007.

SHIPPING AND HANDLING COSTS

The Company includes revenues received for shipping and handling in operating revenues. Expenses paid for shipping and handling are recorded as part of cost of goods sold.

information that would benefit the electric utility's off-system sales. The Division of Operation Audits of the OMOI has not issued an audit report. The Company cannot predict if the results of the audit will have any impact on the Company's consolidated financial statements.

BIG STONE II PROJECT

On June 30, 2005 the electric utility and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant's nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules have been established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

The electric utility and the coalition of six other electric providers filed an application for a Certificate of Need for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. Evidentiary hearings were conducted in December 2006 and all parties submitted legal briefs. The Administrative Law Judges (ALJs) on August 15, 2007 recommended approval of the Certificate of Need subject to potential conditions. The electric utility and project participants addressed the ALJs' recommended potential conditions in an August 31, 2007 proposed settlement agreement with the MNDOC that was entered into the record of the Certificate of Need/Route Permit dockets. The MPUC had not acted on the applications or the proposed settlement agreement when Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. On October 19, 2007 the MPUC requested that the ALJs recommence proceedings in the matter and that the remaining project participants file testimony describing and supporting a revised Big Stone II project. The remaining five participants filed testimony on November 13, 2007. On December 3, 2007 the ALJs issued an order refining the scope of the additional proceedings. Evidentiary hearings were held on January 23-25, 2008. The electric utility anticipates the ALJs will issue their report and recommendation in March 2008 and the MPUC will decide the matters in April 2008. The electric utility's integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. In addition to approval of the Certificate of Need/Route Permit applications for the transmission line project, approval of this IRP is pending with the MPUC.

A filing in North Dakota for an advanced determination of prudence of Big Stone II was made by the electric utility in November 2006. Evidentiary hearings were held in June 2007. The NDPSC decision was delayed because of the change in ownership of the project. The administrative law judge in the matter scheduled supplemental hearings in April 2008.

The electric utility and the coalition of six other electric providers filed an Energy Conversion Facility Siting Permit Application for Big Stone II with the South Dakota Public Utilities Commission (SDPUC) on July 21, 2005. The permit was granted by the SDPUC on July 14, 2006 but was appealed by a group of interveners on the basis that carbon dioxide concerns had not been adequately addressed. In February 2007, a South Dakota circuit court judge issued an opinion affirming the decision of the SDPUC to grant the siting permit for Big Stone II. The permit was appealed to the South Dakota Supreme Court. On January 16, 2008 the South Dakota Supreme Court unanimously affirmed the SDPUC's decision to grant Big Stone II project participants a site permit. A permit application for the South Dakota portion of the transmission line for Big Stone II was filed with the SDPUC on January 16, 2006 and was approved by the SDPUC on January 2, 2007.

As of December 31, 2007 the electric utility has capitalized $8.2 million in costs related to the planned construction of Big Stone II. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

4. REGULATORY ASSETS AND LIABILITIES

The following table indicates the amount of regulatory assets and liabilities recorded on the Company's consolidated balance sheets:

(in thousands)	December 31, 2007	December 31, 2006
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$ 26,933	$ 36,736
* Accrued Cost-of-Energy Revenue	19,452	10,735 *
Deferred Income Taxes	8,733	11,712
Reacquisition Premiums	3,745	2,694
MISO Schedule 16 and 17 Deferred Administrative Costs—MN	855	541
Deferred Marked-to-Market Losses	771	—
MISO Schedule 16 and 17 Deferred Administrative Costs—ND	576	—
Deferred Conservation Program Costs	518	1,036
Accumulated ARO Accretion/Depreciation Adjustment	345	249
Plant Acquisition Costs	107	151
Total Regulatory Assets	$ 62,035	$ 63,854
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 57,787	$ 58,496
Deferred Income Taxes	4,502	5,228
Deferred Marked-to-Market Gains	271	—
Gain on Sale of Division Office Building	145	151
Total Regulatory Liabilities	$ 62,705	$ 63,875
Net Regulatory Liability Position	$ 670	$ 21

The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs were required to be recognized as components of Accumulated Other Comprehensive Loss in equity under SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans*, adopted in December 2006, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates. Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next nine months. The regulatory assets and liabilities related to Deferred Income Taxes result from changes in

Otter Tail Power Company
Excess Revenue Collected in Interim Rates Before the Interim Rate Adjustment
Test Year Billing Units

1	2	3	4	5	6	7
Line	Service Schedule	kWh Subject to Int. COE Adder	Present Rate COE Adj Rev.	Int. Rate Base COE Adder	Interim Rate COE Adder Rev.	Additional Int. Rate COE Rev.
1	**Residential**					
2	Res. Service	363,213,626	$ 4,618,436	$ 0.01447	$ 5,255,701	$ 637,265
3	Res. Dem. Control	94,191,264	$ 1,154,182	$ 0.01447	$ 1,362,948	$ 208,766
4	**Farm Service**	22,040,877	$ 232,482	$ 0.01447	$ 318,931	$ 86,449
5	**Small Commercial**					$ -
6	Gen. Serv <20 kW	78,513,827	$ 1,007,900	$ 0.01447	$ 1,136,095	$ 128,195
7	Com. Dem. Control < 20 kW	255,633	$ 3,176	$ 0.01447	$ 3,699	$ 523
8	Elec. Climate Contr. < 20 kW	3,423,858	$ 42,675	$ 0.01447	$ 49,543	$ 6,868
9	Gen. Serv >=20 kW	290,406,932	$ 3,545,338	$ 0.01447	$ 4,202,188	$ 656,850
10	Com. Dem. Control >= 20 kW	4,047,528	$ 56,355	$ 0.01447	$ 58,568	$ 2,213
11	Elec. Climate Contr. >= 20 kW	42,175,165	$ 522,314	$ 0.01447	$ 610,275	$ 87,961
12	Commercial TOU	-	$ -	$ 0.01447	$ -	$ -
13	**Large Commercial**					
14	LGS	555,574,413	$ 7,287,310	$ 0.01447	$ 8,039,162	$ 751,852
15	LGS TOD	-	$ -	$ 0.01447	$ -	$ -
16	Real Time Pricing	58,538,439	$ 282,325	$ 0.01447	$ 847,051	$ 564,726
17	LGS Rider	-	$ -	$ 0.01447	$ -	$ -
18	LGS Off-Peak Rider	9,906,458	$ 122,120	$ 0.01447	$ 143,346	$ 21,226
19	**Irrigation Services**					
20	Irrigation Option #1	286,564	$ 4,556	$ 0.01447	$ 4,147	$ (409)
21	Irrigation Option #2	370,817	$ 5,896	$ 0.01447	$ 5,366	$ (530)
22	**Outdoor Lighting**					
23	Outdoor -Energy Only	477,874	$ -	$ 0.01447	$ 6,915	$ 6,915
24	Outdoor Non-Metered	-	$ -	$ 0.01447	$ -	$ -
25	**Other Public Authorites**					
26	Muni Pump Serv	16,990,520	$ 228,168	$ 0.01447	$ 245,853	$ 17,685
27	Civil Defense-Fire	-	$ -	$ 0.01447	$ -	$ -
28	**Water Heating , Controlled**	19,784,836	$ 257,934	$ 0.01447	$ 286,287	$ 28,353
29	**Interruptible Loads**					
30	Inter. Load CT Metering	-	$ -	$ 0.01447	$ -	$ -
31	Inter. Load Self Contained Mtr.	631,764	$ 5,446	$ 0.01447	$ 9,142	$ 3,696
32	Bulk Inter. Load	-	$ -	$ 0.01447	$ -	$ -
33	Standby Service	121,000	$ -	$ 0.01447	$ 1,751	$ 1,751
34	**Heat Storage**					
35	Def. Load Controlled Serv.	14,986,587	$ 173,905	$ 0.01447	$ 216,856	$ 42,951
36	Fix Time of Delivery Serv.		$ -	$ 0.01447	$ -	$ -
37	**Small Power Producer Rider**	-	$ -	$ 0.01447	$ -	$ -
38	Total	1,575,937,982	$ 19,550,518		$ 22,803,823	$ 3,253,305
39	Rev./kWh		$ 0.01241		$ 0.01447	$ 0.00206

Notes:

-Present Rate COE Adjustment Revenue per Volume 2B, Exhibit___(DGP-1), Schedule 2

-KWh sales subject to Interim Change In Base COE Energy per Volume 2B, Exhibit___(DGP-1), Schedules 1 and 2 plus review of Interim Rate Tariff Sheets (Volume 1)

Otter Tail Power Company
LGS Revenues-Filed Present/Interim Before Interim Rate Adjustment
Test Year Billing Units

Voltage Level	Component	Units		Rate/Unit	Present Rate Rev.	Int. Rate Rev. Before Int. Rate Adj.	Int. Rate Rev. Before Int. Rate Adj Increase
Secondary	Energy over 360 per kW	113,192,890	kWh	$ 0.02935	$ 3,322,211	$ 3,322,211	
	First 700000 kWh	155,805,630	kWh	$ 0.03784	$ 5,895,685	$ 5,895,685	
	Excess kWh	102,552,256	kWh	$ 0.02979	$ 3,055,032	$ 3,055,032	
	First 100 kW of demand	139,916	kW	$ 8.33	$ 1,165,500	$ 1,165,500	
	Excess kW of demand	585,733	kW	$ 6.80	$ 3,982,984	$ 3,982,984	
	TailWinds Revenue	-	kWh	$ 0.01600	$ -	$ -	
Primary	Energy over 360 per kW	79,883,763	kWh	$ 0.02935	$ 2,344,588	$ 2,344,588	
	First 700000 kWh	23,382,633	kWh	$ 0.03784	$ 884,799	$ 884,799	
	Excess kWh	81,708,724	kWh	$ 0.02979	$ 2,434,103	$ 2,434,103	
	First 100 kW of demand	53,915	kW	$ 8.04	$ 433,477	$ 433,477	
	Excess kW of demand	232,905	kW	$ 6.51	$ 1,516,212	$ 1,516,212	
Transmission	Energy over 360 per kW		kWh	$ 0.02935	$ -	$ -	
	First 700000 kWh		kWh	$ 0.03784	$ -	$ -	
	Excess kWh		kWh	$ 0.02979	$ -	$ -	
	First 100 kW of demand		kW	$ 7.23	$ -	$ -	
	Excess kW of demand		kW	$ 5.65	$ -	$ -	
	Unbilled kWh	(951,483)	kWh		$ 44,000	$ 44,000	
	MISO Adjustment				$ 256,128	$ 256,128	
	COE Adjustment	555,574,413	kWh	$ 0.01312	$ 7,287,310	n/a	
	Int. Change in Base COE	555,574,413	kWh	$ 0.01447	n/a	$ 8,039,162	
Total					$ 32,622,029	$ 33,373,881	$ 751,852

Note:
Billing Units and Present Rate Revenues per Volume 2B, Exhibit___(DGP-1), Schedule 2, page 10 of 36

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to: Large Industrial User Group
Analyst: Larry Schedin
Date of Request: 1/22/2009
Date Received: 1/22/2009
Date Due: 2/20/2009

Information Request No. ND LIG-054
Please provide the following:

1. The average monthly load factor, average annual load factor, monthly energy consumption, and billed demand by each rate class for the last 2 most recent years.

2. The average monthly and average annual load factor for North Dakota system-wide.

RESPONSE:

Attached are five pdf files containing the data requested in ND LIG-054. Load Research data was utilized in the responses. OTP is providing our most recent two years of complete Load Research data (2006 and 2007).

1. The average monthly load factor, energy consumption, and demand by rate class are included in following files:

Attachment 1 of ND LIG 054.pdf
Attachment 2 of ND LIG 054.pdf

The average annual load factors are contained in the files:

Attachment 3 of ND LIG 054.pdf
Attachment 4 of ND LIG 054.pdf

When viewing the files "Attachment 3 of ND LIG 054.pdf" and "Attachment 4 of ND LIG 054.pdf", note that Irrigation and Lighting have no load factors available. This

Responding Witness: David G. Prazak
Title: Supervisor, Pricing
Department: Regulatory Services
Telephone: (218) 739-8595
Date of Response: 2/20/2009

is due to the fact that neither irrigation loads nor lighting loads are in use during the hour of system peak used in the calculation of the load factor.

2. The average monthly and average annual load factor for North Dakota is in the file:

Attachment 5 of ND LIG 054.pdf

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	2/20/2009

2007 Annual ND Load Factors

Month	Load Factor
January	78.23%
February	81.53%
March	71.87%
April	66.59%
May	77.63%
June	67.46%
July	66.71%
August	71.22%
September	68.12%
October	75.94%
November	70.54%
December	81.00%
Annual Load Factor:	64.99%

2006 Load Factors, KWH and KW

Class	Class Name	Month	Load Factor	Monthly KWH	Monthly KW
101	Residential	1	69.72%	44,416,202	85,622
		2	68.38%	43,422,695	94,503
		3	70.31%	40,569,480	77,555
		4	61.21%	28,466,191	64,595
		5	53.88%	26,684,474	66,567
		6	49.91%	27,437,421	76,346
		7	52.29%	37,612,849	96,690
		8	55.33%	29,900,409	72,634
		9	62.76%	25,480,607	56,385
		10	62.35%	31,387,042	67,659
		11	56.36%	37,357,182	92,056
		12	66.29%	47,827,589	96,973
102	Farm	1	75.89%	1,960,874	3,473
		2	71.39%	1,851,509	3,860
		3	74.06%	1,637,251	2,971
		4	62.00%	1,313,010	2,941
		5	58.61%	1,587,385	3,641
		6	59.69%	1,111,100	2,585
		7	56.40%	1,389,905	3,312
		8	61.22%	1,370,565	3,009
		9	64.39%	1,476,851	3,186
		10	55.83%	2,871,695	6,913
		11	63.55%	2,713,533	5,930
		12	68.30%	2,744,784	5,401
103	General Service	1	62.15%	43,194,872	93,415
		2	61.91%	41,723,079	100,290
		3	61.51%	40,904,629	89,385
		4	56.50%	32,695,058	80,366
		5	56.82%	32,257,664	76,305
		6	54.46%	32,228,549	82,198
		7	57.18%	30,779,486	72,357
		8	59.21%	31,825,983	72,245
		9	53.24%	27,874,948	72,724
		10	57.24%	33,784,438	79,326
		11	55.98%	35,967,794	89,241
		12	55.63%	38,852,286	93,867
104	Large General Service	1	84.12%	36,227,220	57,885
		2	84.54%	33,248,141	58,524
		3	84.20%	36,363,281	58,046
		4	81.78%	34,790,575	59,086
		5	80.27%	36,309,550	60,801
		6	78.39%	36,025,878	63,828
		7	80.47%	38,110,327	63,655
		8	84.41%	38,916,009	61,969
		9	79.88%	34,288,139	59,619
		10	81.13%	35,247,093	58,395
		11	80.47%	33,259,653	57,402
		12	79.26%	34,295,643	58,159
105	Irrigation	1		-	-
		2		-	-
		3		-	-
		4		-	-
		5	12.82%	31,865	334
		6	31.21%	230,606	1,026
		7	54.56%	436,452	1,075
		8	29.38%	216,542	991
		9	10.64%	8,537	111
		10	13.94%	18,223	176
		11		-	-
		12		-	-
106	Lighting	1	60.22%	2,466,052	5,505
		2	54.83%	2,059,252	5,589
		3	48.11%	1,958,935	5,473
		4	40.97%	1,610,885	5,461

North Dakota Case PU-08-862
Attachment 1 to IR ND LIG-054
Page 1 of 2

2006 Load Factors, KWH and KW

Class	Class Name	Month	Load Factor	Monthly KWH	Monthly KW
		5	35.08%	1,416,361	5,427
		6	31.97%	1,259,825	5,473
		7	33.55%	1,363,092	5,460
		8	38.88%	1,578,004	5,459
		9	45.59%	1,796,236	5,472
		10	52.56%	2,138,684	5,469
		11	58.74%	2,326,833	5,502
		12	61.99%	2,552,823	5,535
107	OPA	1	53.25%	1,610,983	4,067
		2	67.00%	1,332,435	2,959
		3	62.23%	1,450,092	3,132
		4	67.38%	1,378,323	2,841
		5	67.57%	1,434,248	2,853
		6	73.90%	1,551,815	2,918
		7	72.07%	1,672,088	3,118
		8	68.07%	1,464,942	2,980
		9	64.93%	1,228,937	2,628
		10	60.59%	1,277,399	2,834
		11	62.58%	1,248,685	2,771
		12	64.23%	1,474,841	3,088
108	Water Heating	1	29.29%	1,996,759	9,164
		2	27.21%	1,821,887	8,963
		3	33.16%	2,020,891	8,192
		4	31.35%	2,069,945	9,172
		5	34.12%	1,951,369	7,688
		6	34.32%	1,665,570	6,741
		7	23.97%	1,532,633	8,593
		8	34.44%	1,530,508	5,974
		9	30.87%	1,582,776	7,120
		10	26.26%	1,747,865	8,946
		11	25.85%	1,790,801	9,622
		12	45.34%	1,954,051	5,792
109	Controlled Service Interruptible	1	62.98%	19,312,109	41,216
		2	66.48%	21,906,437	49,049
		3	62.20%	18,917,309	40,876
		4	36.27%	9,045,417	34,636
		5	36.65%	6,343,606	23,266
		6	62.88%	4,330,811	9,568
		7	62.95%	4,437,531	9,475
		8	58.51%	4,345,598	9,982
		9	36.33%	5,006,840	19,143
		10	47.49%	11,819,147	33,449
		11	54.95%	17,584,672	44,447
		12	60.01%	22,470,095	50,326
110	Controlled Service Deferred	1	55.43%	2,118,409	5,136
		2	54.35%	2,400,660	6,573
		3	50.90%	1,930,621	5,098
		4	30.20%	881,525	3,135
		5	35.30%	401,723	1,530
		6	47.10%	199,019	587
		7	44.71%	167,029	502
		8	47.04%	132,945	380
		9	32.81%	214,949	907
		10	43.22%	1,012,021	3,147
		11	47.22%	1,897,321	5,580
		12	53.10%	2,336,185	5,913

2007 Load Factors, KWH and KW

Class	Class Name	Month	Load Factor	Monthly KWH	Monthly KW
101	Residential	1	68.34%	49,567,658	97,482
		2	70.80%	45,644,617	95,939
		3	65.82%	35,958,278	73,425
		4	58.08%	30,442,127	72,793
		5	60.59%	25,087,942	55,654
		6	50.89%	28,771,141	78,370
		7	54.94%	36,698,241	89,776
		8	53.27%	29,838,988	75,284
		9	49.57%	24,843,329	69,612
		10	66.06%	28,908,797	58,817
		11	58.92%	38,431,830	90,591
		12	72.36%	51,227,214	95,148
102	Farm	1	65.82%	2,640,475	5,392
		2	69.33%	2,280,798	4,896
		3	56.53%	1,865,131	4,482
		4	59.26%	1,583,737	3,712
		5	61.33%	1,355,413	2,970
		6	56.64%	1,366,025	3,350
		7	51.00%	1,500,710	3,955
		8	58.61%	1,830,271	4,197
		9	53.65%	1,823,487	4,720
		10	54.31%	4,078,866	10,095
		11	63.96%	3,249,418	7,056
		12	68.85%	3,797,471	7,413
103	General Service	1	61.13%	40,505,211	89,061
		2	63.39%	39,103,402	91,800
		3	58.06%	35,678,950	82,599
		4	54.85%	30,269,841	76,644
		5	56.14%	28,165,016	67,426
		6	55.28%	27,668,055	69,521
		7	55.89%	31,318,439	75,176
		8	57.28%	33,177,647	77,847
		9	52.25%	29,981,281	79,699
		10	56.33%	34,874,558	83,208
		11	56.78%	38,408,765	93,950
		12	60.37%	44,378,345	98,807
104	Large General Service	1	84.22%	36,206,192	57,783
		2	84.22%	32,710,307	57,795
		3	83.29%	36,609,803	59,076
		4	78.79%	35,508,552	62,594
		5	79.19%	37,721,179	64,022
		6	77.36%	38,723,409	69,525
		7	78.31%	42,404,297	72,782
		8	79.62%	40,515,248	68,399
		9	77.96%	38,491,117	68,577
		10	82.38%	37,933,924	61,906
		11	81.89%	35,417,394	60,071
		12	80.93%	36,083,844	59,932
105	Irrigation	1		-	-
		2		-	-
		3		-	-
		4		-	-
		5	17.36%	49,098	380
		6	22.19%	120,752	756
		7	56.30%	286,887	685
		8	31.72%	133,695	566
		9	9.97%	27,975	390
		10	13.44%	14,316	143
		11	1.17%	1	0
		12		-	-
106	Lighting	1	60.25%	2,502,015	5,582
		2	54.90%	2,122,090	5,752

2007 Load Factors, KWH and KW

Class	Class Name	Month	Load Factor	Monthly KWH	Monthly KW
		3	44.47%	1,855,011	5,607
		4	40.71%	1,612,405	5,501
		5	35.12%	1,430,002	5,473
		6	31.97%	1,265,831	5,498
		7	33.52%	1,371,529	5,500
		8	38.82%	1,586,835	5,494
		9	45.56%	1,809,710	5,517
		10	52.36%	2,152,005	5,525
		11	58.50%	2,337,045	5,549
		12	61.98%	2,587,742	5,611
107	OPA	1	68.58%	1,500,475	2,942
		2	70.42%	1,477,190	3,121
		3	72.78%	1,551,875	2,866
		4	68.05%	1,418,004	2,896
		5	67.77%	1,392,166	2,761
		6	67.45%	1,511,241	3,112
		7	67.86%	1,611,128	3,191
		8	65.06%	1,502,123	3,103
		9	65.46%	1,213,228	2,574
		10	64.49%	1,186,874	2,473
		11	64.87%	1,221,572	2,623
		12	67.94%	1,363,181	2,697
108	Water Heating	1	26.97%	1,761,815	8,779
		2	40.76%	1,788,100	6,528
		3	30.35%	1,956,253	8,862
		4	44.91%	1,885,685	5,831
		5	47.64%	1,779,247	5,020
		6	39.74%	1,596,594	5,580
		7	22.48%	1,515,268	9,059
		8	38.33%	1,493,096	5,236
		9	37.88%	1,503,088	5,511
		10	38.37%	1,618,451	5,670
		11	27.57%	1,590,855	8,014
		12	24.27%	1,829,435	10,132
109	Controlled Service Interruptible	1	59.08%	24,078,211	54,781
		2	63.51%	23,162,378	54,289
		3	53.92%	17,627,029	43,940
		4	40.50%	12,722,642	43,632
		5	44.10%	5,430,477	16,551
		6	51.80%	3,847,700	10,317
		7	53.54%	3,871,588	9,720
		8	59.98%	3,845,743	8,618
		9	42.98%	5,036,631	16,274
		10	44.62%	8,686,163	26,165
		11	52.06%	19,412,711	51,789
		12	66.18%	24,163,027	49,073
110	Controlled Service Deferred	1	49.23%	2,810,362	7,673
		2	53.01%	2,629,026	7,380
		3	48.35%	1,921,702	5,342
		4	35.25%	1,035,947	4,082
		5	41.35%	345,168	1,122
		6	52.40%	238,441	632
		7	40.12%	221,020	740
		8	53.29%	186,303	470
		9	39.93%	235,030	618
		10	39.97%	715,403	2,406
		11	45.37%	1,637,959	5,014
		12	53.97%	2,625,701	6,539

2006 Annual Load Factors

Class	Class Name	Load Factor
101	Residential	63.83%
102	Farm	78.84%
103	General Service	66.65%
104	Large General Service	91.55%
105	Irrigation	N/A
106	Lighting	N/A
107	OPA	78.12%
108	Water Heating	45.98%
109	Controlled Service Interruptible	40.46%
110	Controlled Service Deferred	36.65%

2007 Annual Load Factors

Class	Class Name	Load Factor
101	Residential	62.06%
102	Farm	86.93%
103	General Service	56.14%
104	Large General Service	93.20%
105	Irrigation	N/A
106	Lighting	N/A
107	OPA	66.11%
108	Water Heating	65.03%
109	Controlled Service Interruptible	47.98%
110	Controlled Service Deferred	26.28%

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	Large Industrial User Group
Analyst:	Larry Schedin
Date of Request:	1/22/2009
Date Received:	1/22/2009
Date Due:	2/20/2009

Information Request No. ND LIG-028
On pages 15-16, witness Parmesano discusses Zins testimony in the recent Xcel energy case to demonstrate that the Commission has had occasion to review a rate based on marginal costs. The excerpt provided from Zins testimony identifies using the "E8760" energy allocator to allocate energy costs to classes.

1. Has OTP used the E8760 energy allocator method to allocate energy costs to classes?
2. If so, please provide the references to the specific volume and also associated workpapers.
3. If not, please explain why not?

RESPONSE:

1. No.
2. Not applicable.
3. OTP has not thoroughly studied what is needed to develop an E8760 factor. Also, OTP does not know the cost of additional equipment (metering, software, etc.) that would be needed to implement an E8760 energy factor. In Minnesota, OTP has committed to investigate before it files its next Minnesota rate case what may be required and the costs and benefits of implementing an E8760 allocator for rate design.

Responding Witness:	Pete Beithon
Title:	Manager, Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	2/20/2009

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	Large Industrial User Group
Analyst:	Larry Schedin
Date of Request:	1/22/2009
Date Received:	1/22/2009
Date Due:	2/20/2009

Information Request No. ND LIG-047
What is the minimum contract term for signing up for the proposed LGS time-of-day rate? The proposed tariff suggests that "contract period will be outlined in agreement.

RESPONSE:

One year. In OTP's proposed General Rules and Regulations, Section 1.02 Application for Service states, "If a Customer changes its service to a different rate, the Customer shall not be permitted to change back to the originally applicable rate for a period of one (1) year." This condition is applicable to the proposed LGS TOD (Section 10.05). Also, OTP may require the customer to enter into a three-year minimum revenue guarantee, which is outlined in Section 5.02 to OTP's General Rules and Regulations.

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	2/20/2009

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	Large Industrial User Group
Analyst:	Larry Schedin
Date of Request:	1/22/2009
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Information Request No. ND LIG-047
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RESPONSE:

One year. In OTP's proposed General Rules and Regulations, Section 1.02 Application for Service states, "If a Customer changes its service to a different rate, the Customer shall not be permitted to change back to the originally applicable rate for a period of one (1) year." This condition is applicable to the proposed LGS TOD (Section 10.05). Also, OTP may require the customer to enter into a three-year minimum revenue guarantee, which is outlined in Section 5.02 to OTP's General Rules and Regulations.

Responding Witness:	David G. Prazak
Title:	Supervisor, Pricing
Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	2/20/2009

Otter Tail Corporation d/b/a
OTTER TAIL POWER COMPANY
North Dakota Case No: PU-08-742 and PU-08-862

Response to:	Large Industrial User Group
Analyst:	Larry Schedin
Date of Request:	1/22/2009
Date Received:	1/22/2009
Date Due:	2/20/2009

Information Request No. ND LIG-064
Please discuss OTP's ability to meet with and discuss or provide regular forecasts regarding the energy adjustment and renewable cost recovery rider.

RESPONSE:

OTP does provide regular forecasts regarding the energy adjustment to Large Industrial Customers. In addition OTP has discussed the renewable cost recovery rider with these customers. These projections are based on several assumptions that may, and often do, change with time. For this reason Otter Tail Power requires that Otter Tail Power's Industrial Services Engineers meet directly with our Large Industrial Customers to answer any questions regarding the accuracy and use of this information. Attachment 1 to ND LIG-064 is an example from last November of the information Otter Tail Power provides. Following the initial meeting, customers may request that updated information be sent to them as needed.

Responding Witness:	Pete Beithon
Title:	Manager Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	02/20/2009

Actual and Forecasted Fuel Clause Adjustment (FCA) Rates For North Dakota
2008-2009

OTTER TAIL POWER COMPANY

	FCA RATE - ND
September-2008	$0.00560
October-2008	$0.00720
November-2008	$0.00990
December-2008	$0.01050
January-2009	($0.00680)
February-2009	($0.00850)
March-2009	($0.00340)
April-2009	$0.00240
May-2009	$0.00360
June-2009	$0.00510
July-2009	$0.00300
August-2009	($0.00230)
September-2009	($0.00530)
October-2009	($0.00800)
November-2009	($0.00790)
December-2009	($0.00680)
Average projected for 2009	($0.00291)

Forecast updated in November 2008

Based on Actual

The renewable rider for Sep - Dec 2008 is $.00193. The rider is expected to be $.00510 for Jan - Dec 2009.
The benefit of the Renewable Energy Facilities reduces the FCA rate.

Disclaimer Statement

This document includes forward-looking as well as historical information. These statements are based on Otter Tail Power Company's historical costs and kWh's as well as current future expectations, which are subject to uncertainty and changes in circumstances. Actual results may differ materially from these expectations due to a number of factors including, but not limited to, market valuations of forward energy contracts, weather conditions, fuel and purchased power costs, transportation costs, plant availability and any other factors outside of Otter Tail Power Company's control. Otter Tail Power Company makes no representation and accepts no liability for the content or for the consequences of any actions taken on the basis of this information provided.