Large Industrial Group

Direct Testimony of
Kavita Maini

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 Kavita Maini. I am the principle and sole owner of KM Energy Consulting, LLC.

Q. Please state your business address.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. Please summarize your educational background and experience

A. I graduated from Marquette University, Milwaukee, Wisconsin with a Masters in Business (1986) and a Masters in Applied Economics (1991). From 1991 to 1997, I worked for Wisconsin Power & Light as a Market Research Analyst and Senior Market Research Analyst. From 1997 to 1998, I worked as Senior Analyst at Regional Economic Research, Inc. in San Diego, California. From 1998 to 2002, I worked as a Senior Economist at Alliant Energy Integrated Services' Energy Consulting Division. Since 2002, I have been an independent consultant.

As an independent consultant, I have assisted industrial, commercial and institutional customers with issues related to rate design in various regulated states and provided electricity and natural gas RFP services to such customers in deregulated states. I have provided technical analysis related to energy policy issues on behalf of an energy user group called the Wisconsin Industrial Energy Group in various Wisconsin regulatory and federal regulatory proceedings. I have also conducted workshops on several energy related matters.

I represent the Wisconsin Industrial Energy Group as a Board Member at the Midwest Reliability Organization ("MRO") and also represent Midwest Industrial Customers ("MIC") at MISO. The MIC is a coalition of four end user associations including the Wisconsin Manufacturers' and Commerce, American Forestry & Paper Association, Wisconsin Paper Council and Wisconsin Industrial Energy Group.

Q. Who are you representing in this proceeding?

A. I am representing the North Dakota Large Industrial Group ("LIG") which is further described in Larry Schedin's testimony.

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

A. As can be noted, 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 companies I represent as it directly affects their competitiveness especially those companies where such costs are a major input.

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" or "North Dakota PSC")?

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

I also recently assisted Larry Schedin who was 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 who is an expert witness in this current rate proceeding as well.

Q. Have you representing an industrial users group in these other North Dakota cases as well?

A. Yes. All the members that I represented in these rate cases are also included in the current rate case proceeding with one exception: Imation. Imation is not participating because it shut down its plant in North Dakota and shifted additional manufacturing to Mexico. Imation participated in the PU-06-290 proceeding regarding time differentiated rates and provided comments emphasizing its need to stay competitive and the inability to pass energy cost increases in an intensely competitive environment.

Q. Is your testimony focused on a particular class of service in this rate case proceeding?

A. Yes. I focus principally on the Large General Service ("LGS") class, but portions of my testimony pertaining to OTP's Renewable Resource Rider ("RRR" or "Rider") will benefit nearly all customer classes.

I will outline concerns and well as provide recommendations regarding OTP's current and proposed cost recovery approach related to the RRR, as well as OTP's proposed rate design changes to rates for the LGS class.

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. Renewable Resource Cost Recovery.

Q. What issue are you covering in this Section?

In this section, I discuss the issues related to the renewable resource recovery rider.

A. Renewable Resource Recovery Rider ("RRR").

Q. What is the RRR?

A. OTP obtained approval of a separate cost recovery mechanism, the RRR, to recover costs of owning wind generation in North Dakota.

The North Dakota Public Service Commission ("NDPSC") granted OTP approval to recover costs associated with its 40.5 MW ownership of the Langdon Wind Energy Center ("Langdon") through the RRR on May 21, 2008, Case No. PU-06-466. In its Order, the NDPSC determined that:

1. Otter Tail's investment in the Langdon project was prudent;

2. The investment should be allocated to North Dakota based on its share of total energy consumed;

3. The RRR should be displayed separately on customers' bills;

4. Otter Tail must make an annual filing each year by September 1 to update the RRR for new projects and adjust for any over or under-recoveries of actual costs; and

5. A return on equity rate of 11.25 percent is to be used until the costs can be rolled into base rates.

The RRR charge approved to be effective June 1, 2008 was $0.00193/KWh.

Q. Did OTP make its annual filing by September 1, 2008, as required under NDPSC decision in Case No. PU-06-466?

A. Yes. OTP submitted its filing on August 29, 2008 and sought approval for revenue requirements associated with 48 MW ownership share in the Ashtabula Wind Energy Center ("Ashtabula"), which became operational in November 2008. In its filing, OTP also provided updated costs associated with the Langdon project since the original filing. Finally, OTP submitted a tracker balance for 2008 that represents a true-up of approved versus recovered costs.

B. <u>Compliance – Renewable Energy Objective ("REO")/Renewable Energy Standard ("RES").</u>

Q. Does North Dakota have a Renewable Portfolio Standard ("RPS") or RES mandate?

A. No. The North Dakota Legislature has established a state renewable and recycled energy objective that 10 percent of all retail electricity sold within the state by the year 2015 be obtained from renewable energy and recycled energy sources. South Dakota has a similar objective.

Q. Does OTP have to comply with an RES/RPS mandate in any state?

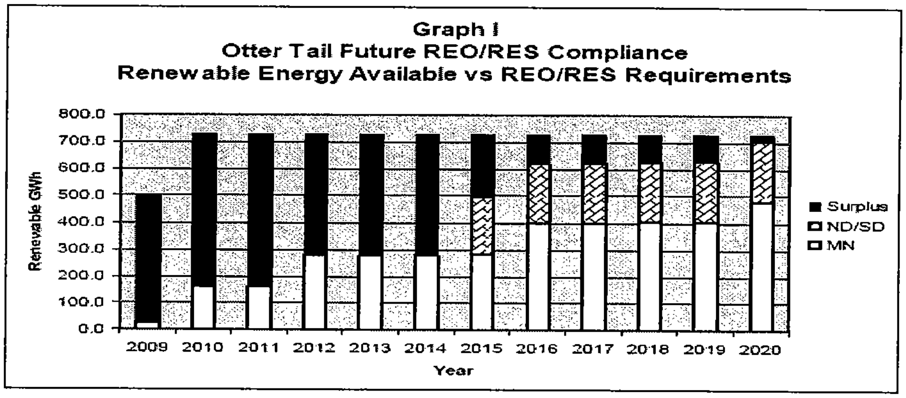
A. Yes. OTP has to meet the RPS mandate in Minnesota that requires that by 2025, 25 percent of all retail electricity sold in Minnesota be generated from renewable resources. OTP's REO/RES Compliance Report submitted to the Minnesota Commission on January 13, 2009 in Docket No. E-999CI-03-869 ("OTP Compliance Report") **LIG Exhibit __ (KM -1)** indicates the state's step-wise increase requirements to meet the 25 percent requirement by 2025.

Q. What is the status of OTP's acquisition of renewable resources?

A. According to 20 of the OTP Compliance Report:

> "With the current renewable resources in existence, under construction, and planned for the next couple of years, Otter Tail does not expect to add more resources for REO-RES compliance until about 2023, if even then. This forecast does not include counting the many small customer owned units currently being installed."

The OTP Compliance Report also includes the following chart which demonstrates that OTP will produce significantly more renewable energy than is required by current objectives for North Dakota. <u>See</u> OTP Compliance Report, p. 15. For example, by 2010, OTP expects to serve about 15 percent of its total retail load by renewable resources – primarily wind.



Q. What do you conclude from OTP's efforts regarding renewable resources?

A. In particular, I conclude that OTP has acquired renewable resources well in advance of meeting the needs of North Dakota renewable objectives.

Q. Why is building wind generation projects well in advance of the need to fulfill renewable objectives a concern?

A. Acquiring these resources so far in advance of need is problematic because it results in unfairly burdening current customers with cost obligations and risks associated with requirements for future customers. In my opinion, OTP has not adequately proven that wind resources will be the least-cost resource to meet capacity or energy deficiency, nor that its addition will not be problematic for the system as wind resources in the region grow.

C. <u>Acquisition of Wind Generation as a Least-Cost Resource.</u>

Q. Does OTP claim that it has acquired the wind generation as least cost resource?

A. Yes. OTP's Responses to LIG IR Nos. 7 and 78 suggest that OTP has installed wind because it is a least-cost resource and directs that the Minnesota 2005 IRP be reviewed. **<u>See</u> LIG Exhibit __ (KM -2); LIG Exhibit __ (KM -3).**

Q. After a review of the Minnesota 2005 IRP, OTP's 2006 and 2008 supplemental filings and the Minnesota Public Utility Commission's ("Minnesota PUC") 2006 Orders, have you concluded that wind generation up to 160 MW has been chosen since it is a least cost resource?

A. No. I could not reach that conclusion for reasons discussed below.

Q. What is your understanding of the chronology of events that led to the approval of up to 160 MW of wind generation by the Minnesota PUC?

A. My understanding of the chronology of events that led up to 160 MW of approval of wind generation by Minnesota PUC is as follows:

1. In OTP's 2005 IRP (<u>See</u> **LIG Exhibit __ (KM -4),** it is stated that 70.5 MW of wind was manually implemented in the model (Section 9-4); It is not indicated whether the manual implementation was forced in spite of this generation not being least cost; OTP's 2005 IRP further states that an additional 20 MW of wind was selected in 2012 if total costs are 3 cents/KWh flat costs over the life of the installation. OTP appears to use 30 years as useful life as indicated under the Wind Sensitivity Section (Section 9-8).

2. OTP's 2005 IRP also indicates minimum load problems at the level of wind included in the plan (Section 9-8) thereby implying that the solution was not least cost optimized.

3. On August 9, 2006, the Minnesota PUC's Order indicates that up to 75 MW of wind is approved.

4. OTP's 2006 IRP supplement indicates that the availability of MISO wholesale market energy to back up wind generation is a key determinant in the amount of wind generation the planning model will select. OTP further states that if energy imports are capped and wind must be backed up by peaking capacity, the model will select less wind generation. OTP capped the amount of wind generation due to the back up generation issue.

5. In November 2006, OTP's supplemental comments state "[a]dditional wind had to be forced into the model. IRP Manager determined that it was not economic to add simple cycle combustion turbines to firm up wind generation relative to the costs of other alternatives." (Otter Tail Power Company Reply Comments, Docket No. E017/RP-05-968 – November 29, 2006 **LIG Exhibit __ (KM -5)**).

6. OTP's November 2006 supplemental comments to the Minnesota PUC also indicate that at the Minnesota Department of Commerce's ("Minnesota DOC") request, it made some modeling adjustments that resulted in the model allowing more wind generation since more back up spot energy became available as a result of the adjustment. OTP's comments further appear to indicate that transmission improvements would be needed to allow for the back up energy from MISO market. OTP also indicated that it has not included the cost of such transmission improvements in the model (Otter Tail Power Company Reply Comments Docket No. E017/RP-05-968 – November 29, 2006).

7. In the February 20, 2007 Amended Order by the Minnesota PUC, the Commission granted OTP's request to allow the utility to install up to 160 MW of wind. OTP indicated that it would "like to pursue wind in excess of

75MW" and that the 75MW cap was posing as a financial impediment to securing financing. The Minnesota PUC acknowledged that OTP already has authority pursuant to the REO and community-based energy development (C-BED) statutory requirements, to exceed the 75 MW level mentioned in the Minnesota PUC's Order. The Minnesota PUC granted approval to OTP for building up to 160 MW of wind.

Q. What do you conclude from the chronology of these events which led up to 160 MW of wind generation to be approved by Minnesota PUC?

A. I conclude the following:

1. Since the 75 MW were manually input in the model, it is possible that this amount was forced in the model due to REO compliance.

2. OTP acknowledges there are issues related to dumping of surplus energy, as well as limitations regarding procuring backup generation from the MISO spot wholesale market without which additional wind generation is not cost effective. It is unclear how these issues and cost implications were addressed.

3. It is not clear whether OTP accounted for the need of additional regulating reserve associated with wind generation or impact on Revenue Sufficiency Guarantee ("RSG") costs. Since RSG costs are created whenever there are deviations related to load or generator output at MISO, it is likely that RSG costs will also increase.

4. Additional wind up to 160 MW appears to be approved based on the premise that OTP was allowed to build in excess of 75 MW as per statutory provisions in place for REO/RES compliance and not least cost.

5. It is not known what assumptions were used to forecast spot prices in the MISO market in the modeling adjustments identified in OTP's November 2006 supplemental comments. Since the spot market is being modeled to purchase back up energy, the results would likely be very sensitive to the spot market forecast. With the addition of this and other significant amounts of intermittent resources to the system, the spot market will likely have much more significant swings in the future.

6. Cost assumptions used regarding wind in the 2005 plan indicate assumed flat levelized costs over a useful life of 30 years; as the discussion later in my testimony indicates, OTP's proposed revenue requirements are neither using flat levelized costs nor a 30 year useful life.

Q. Did you find any information from NDPSC that provides additional insight regarding the approval of wind generation of up to 160 MW?

A. No.

Q. OTP has stated that wind generation reduces the Cost of Energy ("COE"). Has the COE decreased with the inclusion of wind generation?

A. As Larry Schedin's testimony regarding COE indicates, there is no decrease in OTP's average annual COE between 2007 and 2008.

Q. OTP presented a savings analysis using hourly OTP day ahead Locational Marginal Prices ("LMP") and output from the Langdon project. Do you agree with these savings?

A. No. I do not agree with these savings since OTP does not use the appropriate $/MWh cost to represent Langdon costs that are consistent with OTP's proposed cost recovery approach. I discuss this later in this section in my testimony.

Q. So, what do you conclude overall?

A. I conclude that OTP is building wind generation primarily for REO/RES compliance.

Q. In your opinion, why has OTP acquired renewable resources so far in advance of meeting renewable resource need?

A. I believe that OTP acquired renewable resources so far in advance of need for the following reasons:

1. Cost recovery mechanisms separate from base rate cases in the form of the RRR allow for rapid cost recovery of capital investment without a general rate case.

2. To take advantage of the Federal Production Tax Credit ("FPTC" or "Production Tax Credit").

3. To create surplus asset-based energy to sell to the open market.

4. As demonstrated in responses to LIG IR 4 and 5, OTP has non-regulated ownership and investments in businesses that support the wind industry and benefit from wind expansion. **<u>See</u> LIG Exhibit __ (KM - 6); <u>See</u> LIG Exhibit __ (KM - 7).**

D. <u>Current Cost Recovery Mechanism – RRR.</u>

Q. As a result of the NDPSC Order regarding the RRR on May 21, 2008, Case No. PU-06-466, the Commission required OTP to make an annual filing by September 1 to update the Rider for new projects, and to adjust for any over or under-recoveries of actual costs. Did OTP make its annual filing by September 1, 2008, as required under NDPSC decision in Case No. PU-06-466?

A. Yes. OTP submitted its filing on August 29, 2008 and sought approval for revenue requirements associated with 48 MW ownership share in the Ashtabula project, which became operational in November 2008. In its filing, OTP also provided updated costs associated with the Langdon Investment since the original filing. Finally, OTP submitted a tracker balance for 2008 that represents a true-up of actual versus recovered costs.

Q. What are OTP's proposed revenue requirements for 2009 for the North Dakota jurisdiction?

A. Table 1 shows the proposed revenue requirements summary for 2009 and resulting RRR charge in $/KWh (in tracker summary of its August 29, 2008 filing)

Table 1

SUMMARY	
2009 projected revenue requirements (Ashtabula & Langdon)	$7,522,598
12/31/08 tracker balance	1,818,580
Carrying charge	99,062
Total revenue requirements	$9,440,240
2009 projected sales in mWh	1,851,179
Proposed RR Rider Charge ($/KWh)	$0.00510

The 2009 projected revenue requirements of $7.5 million consist of $2.9 million and $4.6 million for OTP's 40.5 MW and 48 MW ownership in the Langdon and Ashtabula projects respectively.

OTP's filing indicates the December 31, 2008 tracker balance of $1.8 million and represents the amount of under recovery associated with the Langdon investment in 2008. The tracker account information provided by OTP compares costs and the amount recovered through North Dakota retail revenue, by month.

The carrying charge of $99,000 for the tracker balance is based on an assumed prime rate of 5 percent.

The resulting RRR charge for customers after dividing the proposed total revenue requirement of $9.4 million by 1.85 million MWh sales is $0.0051/KWh. This represents a 164 percent increase over the previous RRR charge of $0.00193/KWh. The proposed revenue requirement of $9.44 million is 54 percent higher than the requested base rate case increase of $6.08 million, and represents an overall 7.97 percent increase as compared to the base rate increase of 5.14 percent.

Q. What is your overall concern about this increase?

A. My overall concern is the rate shock implications of a potentially double-digit increase in rates (5.14 percent for base rates plus 7.97 percent for the RRR). Such an extraordinary increase is particularly problematic for the LIG members and others during the current and substantial economic crisis, especially given no recovery is anticipated anytime soon. The RRR hits high load profile users disproportionately harder, as it is proposed to be recovered through energy only.

As highlighted in Larry Schedin's testimony, some LIG members have had extended shutdown periods since last fall and had a significant number of layoffs. Imposing such an increase during current economic conditions would further exacerbate an already adverse situation.

E. Key Concerns About OTP's Current and Proposed Cost Recovery Approach.

Q. What are your key concerns with OTP's current and proposed cost recovery approach?

A. My key concerns are that OTP's current and proposed cost recovery approach:

1. Exposes ratepayers to all the costs while failing to account for the considerable benefits obtained through increased asset-based wholesale margins and renewable energy attributes/credits (collectively "RECs") sale opportunities.

2. Unfairly subjects all the cost burdens associated with Otter Tail's RES/REO compliance to current ratepayers due to the front-end loading of costs.

3. While OTP's savings analysis using levelized costs indicates savings compared to procuring from MISO's wholesale spot market, OTP's proposed cost recovery approach does not use a levelized approach and highlights the fact that current ratepayers in fact are exposed to costs as opposed to savings.

4. Unfairly results in high load factor customers, such as customers in the LGS class, bearing a larger percent increase as compared to other ratepayer groups because of the energy only allocation.

F. Recommended Adjustments Regarding Cost Recovery Through The RRR.

Q. What are your recommendations regarding the cost recovery for renewable resources via the RRR?

A. I recommend that the proposed revenue requirements be adjusted to reflect the following changes:

1. ROE of 10.75 percent with adjustments as proposed in the partial settlement in the general rate case Docket.

2. Eliminate front-end loading of costs and levelize cost recovery.

3. If Recommendation No. 2 is not pursued, disallow OTP's proposed deferral of Production Tax Credit

4. Spread OTP's tracker balance, due to OTP's delay in recovery, over a period of 10 years.

5. Whether pursuing the levelized approach or OTP's proposed approach, change useful life to 30 years as identified in the Integrated Resource Plan.

6. Incorporate the benefits from selling or banking RECs, as well as incremental wholesale margins resulting from freeing up existing generation after adding wind, renewable energy certificates and any renewable energy sales made to third parties.

7. Change the method of recovery from ratepayers of an energy only charge to energy and demand charge.

I will discuss each of these recommendations with the exception of Recommendation No. 6, which will be discussed in Larry Schedin's Testimony.

G. <u>Recommended Adjustments.</u>

Q. What data did you use to ascertain the impacts of the recommended adjustments in this Section?

A. Except for the impacts described under levelized cost recovery, I used the spreadsheet provided in OTP's Response to LIG IR No. 11 to develop my own spreadsheet. <u>See</u> **LIG Exhibit __ (KM - 8).** I went step wise and documented the impacts of each of the recommended adjustments. In my spreadsheet the results of each of the adjustments are provided, which were developed from the Tracker Summary tab of OTP's Response to LIG IR No. 11, Attachment No. 1. <u>See</u> **LIG TS Exhibit __ (KM - 9).**

1. Return on Equity

Q. Do the proposed revenue requirements for the RRR need to be updated?

A. Yes. The proposed revenue requirements for the Langdon and Ashtabula projects were based on a return on equity rate of 11.25 percent. As a result of the partial settlement in this general rate case (Docket No. PU-08-742), the return on equity should be adjusted downward to 10.75 percent.

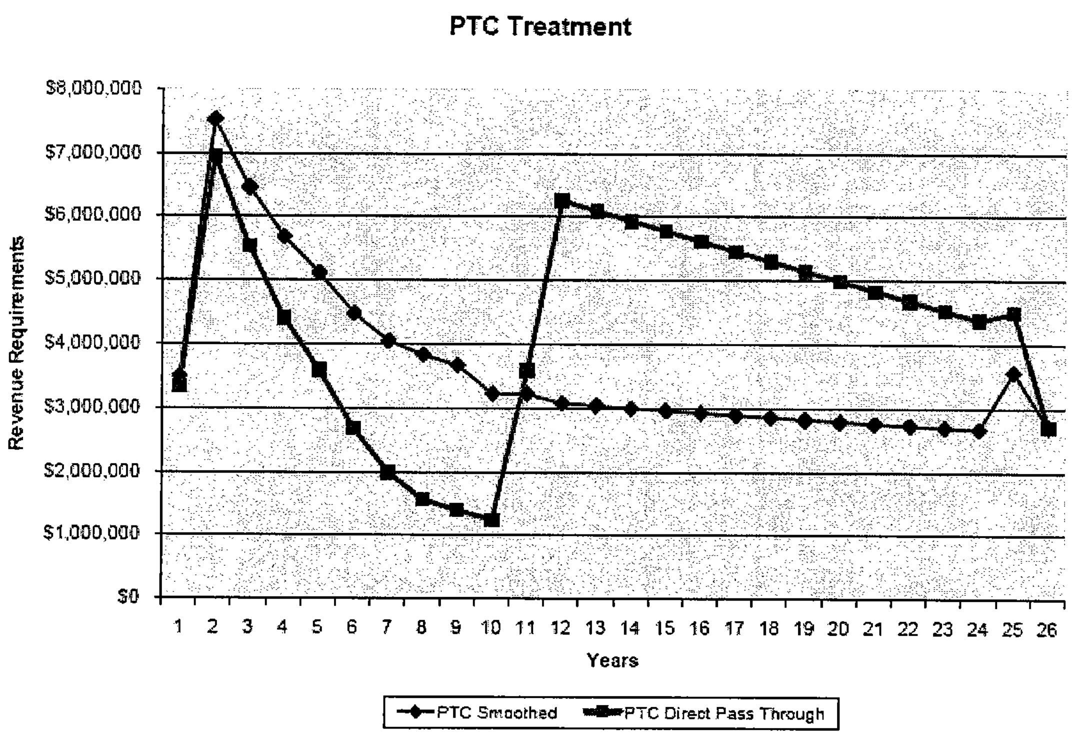
Q. What impact does this have on the proposed revenue requirement for the Rider for 2009?

A. My spreadsheet referenced above provides the monthly summary results of the impact on revenue requirements. This decreases the projected 2009 revenue requirement by **[Trade Secret Starts]** **[Trade Secret Ends]** (non-tracker portion).

2. Levelized Cost Recovery

Q. What is OTP's current amortization method?

A. Presently, OTP is front-end loading its cost recovery. OTP's chart below which was provided by OTP indicates the front-loading. <u>See</u> OTP Response to LIG IR No. 93, attached as **LIG Exhibit __ (KM - 10).** The chart was presented to demonstrate partial normalizing of the Production Tax Credit, an issue which is discussed later in my testimony. Notwithstanding, this chart demonstrates the heavily front-loaded nature of the cost recovery as proposed (in blue diamonds).



Q. What are your concerns with this approach?

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A. Since OTP's acquisition of renewable resources through primarily wind generation is built far in advance of need, this approach results in ***current*** ratepayers unfairly and unnecessarily bearing higher costs

Q. Is OTP's proposed method an accepted method by the Commission?

A. Yes. OTP's current method is a traditionally accepted method of cost recovery. Like any other utility, OTP appreciates the rapid recovery of costs in earlier years. However, I am concerned that such an approach is over burdening current customers especially during these depressed economic times.

Q. Is there an alternative method to OTP's current cost recovery approach?

A. Yes. An alternative approach is to utilize the levelized method used in wind PPAs. This is the approach that I recommend to levelize the costs in a manner similar to the PPAs signed for wind generation. For example, OTP has a 19.5 MW 25-year PPA with FPL at the rate of **[Trade Secret Begins]** **[Trade Secret Ends]**. <u>See</u> OTP Response to LIG IR No. 27. <u>See</u> **LIG Exhibit __ (KM - 11).** There is no front-end or back-end loading. Rather, this flat rate is levelized over the period of the PPA. Table 2 (BELOW) shows an example of such cost recovery for the 40.5 MW Langdon project.

OTP provided the levelized annual cost per MWh for this investment in response to LIG IR No. 131, attachment 1, which is attached hereto as **LIG Exhibit __ (KM - 12).** As Table 2 below indicates,the product of the $/MWh cost provided by OTP (LIG IR No. 131) and wind output (LIG IR No. 12) results in annual revenue requirements of **[Trade Secret Begins]** **[Trade Secret Ends]** of which the North Dakota jurisdictional share is **[Trade Secret Begins]** **[Trade Secret Ends]**. <u>**See**</u> **LIG Exhibit __ (KM - 13).** This would result in a **[Trade Secret Begins]** **[Trade Secret Ends]** RRR charge every year and would be a more reasonable charge especially given current economic conditions. A flat revenue requirement would also be a more equitable way of recovery from current and future ratepayers.

Table 2: Levelized Recovery Approach Results

[Trade Secret Begins]

[Trade Secret Ends]

Q. What level of reduction would this resulting RRR charge be compared to the RRR charges in 2008?

A. This would be a **[Trade Secret Begins]** **[Trade Secret Ends]** reduction over 2008 RRR charges of $0.00193/KWh and a much more significant reduction compared to the proposed RRR for 2009.

Q. Did OTP provide a savings analysis to demonstrate there are savings of owning wind generation compared to procuring spot purchases from MISO's wholesale market?

A. Yes. OTP conducted an hourly analysis for 2008, using hourly Langdon output and multiplying this hourly output with the hourly differential between Langdon's levelized cost of **[Trade Secret Begins]** **[Trade Secret Ends]** and OTP's day ahead LMP. The result indicated a savings of roughly **[Trade Secret Begins]** **[Trade Secret Ends]**. See OTP Response to LIG IR No. 131.

Q. Is OTP using the appropriate $/MWh cost for Langdon as the basis of comparison? Why or why not?

A. OTP is not using the appropriate $/MWh cost for the basis of comparison since as pointed out earlier, OTP's approach is not levelized and results in higher costs in earlier years. See OTP Response to LIG IR No. 27, Attachment 1. The $/MWh cost that is consistent with OTP's approach is **[Trade Secret Begins]** **[Trade Secret Ends]** in 2008, Using this $/MWh cost results in a cost of roughly **[Trade Secret Begins]** **[Trade Secret Ends]** instead of any savings. The computation is attached as **LIG Exhibit __ (KM - __)**. This result further reinforces the recommendation that the levelized cost approach should be used as it provides a benefit to current ratepayers as well.

Q. Why else should the Commission consider recommending that OTP use the levelized recovery option that you just described?

A. This approach will result in equitable recovery from current and future ratepayers. In addition, this approach will also help mitigate the rate shock impact during the current recession when businesses and ratepayers are really hurting.

3. OTP's proposal of deferring the Federal Production Tax Credit ("FPTC" or "Production Tax Credit")

Q. Is OTP receiving the FPTC for the Langdon and Ashtabula plants?

A. Yes. OTP is receiving the FPTC for both owned investments.

Q. What is the FPTC?

A. The FPTC is equal to the product of the actual wind output multiplied by $21/MWh and is credited against income taxes for the first 10 years of a project. The FPTC is intended to reduce the cost of wind energy during the first 10 years of operations when wind ownership costs are the generally the highest.

Q. How did OTP treat the federal production tax credit in its filing for approval of the Langdon investment in early 2008?

A. It was proposed to be flowed directly through as credits are received.

Q. What change is OTP proposing to make in the treatment of the production tax credit?

A. OTP proposes to partially normalize the PTC by deferring increasing amounts of the credit over its assumed useful life of 25 years. OTP proposes to do this by increasing the deferred amount by 10 percent each year. In other words, starting in year 1, there would be no deferral, in year 2, there would be a 10 percent deferral, in year 3, a 20 percent deferral and so on. The amount deferred is then normalized over the remaining life of the project – 24 years in year two, 23 years in year three and so on. OTP states that this will levelize the effects of the credit and smooth the resulting renewable factor over the life of each project.

Q. Did OTP misapply its proposed approach in the treatment of the production tax credit to derive the proposed revenue requirements for Langdon and Ashtabula?

A. Yes. OTP is deferring 10 percent and 20 percent in 2008 and 2009 for Langdon, which are years 1 and 2 of its commercial operation respectively. Instead, according to its proposed approach, it should have not deferred any amount in the first year (2008) and 10 percent in the second year (2009). In addition, Ashtabula commenced commercial operation in December 2008. However, OTP started deferring 10 percent for Ashtabula in January 2009. Instead, OTP should not have deferred any FPTC amounts until December 2009, when it should have deferred the amount by 10 Percent. OTP Response to LIG IR No. 11, Attachment 1 shows the calculations provided by OTP that indicate misapplied deferral method. See **LIG TS Exhibit __ (KM - 9),** Attachment 1, lines 31-36 Langdon TS Rows E-AH, lines 32-37 Ashtabula TS Rows V-AH.

Q. What impact does correcting for this misapplication have on the proposed revenue requirements?

A. The revenue requirements reduce by **[Trade Secret Starts]** **[Trade Secret Ends]** million for the Langdon and Ashtabula facilities and the 13/31/08 tracker amount reduces by **[Trade Secret Starts]** **[Trade Secret Ends]** See **LIG Exhibit __ (KM - 14).**

Q. Even if OTP had correctly applied its proposed treatment of the FPTC, do you agree with proposed approach?

A. No. I believe that the FPTC should be credited as OTP receives it and as OTP had initially proposed it in its filing for the Langdon project in early 2009.

Q. Why do you disagree with OTP's proposed approach of the treatment of the FPTC?

A. For two reasons – First, OTP is front-end loading the costs of its Langdon or Ashtabula projects as described earlier. OTP levelization of the FPTC, and not the overall investment, will result in an inconsistent treatment of costs.

The FPTC was intended to provide an incentive to build wind resources by reducing the high cost of ownership during the first 10 years. OTP's proposed approach does not pass on that benefit to current ratepayers, but does pass through the high cost of the wind investment without any normalizing.

Second, given the poor economic conditions and current recession, ratepayers, especially businesses such as members of the LIG simply cannot afford to take unnecessary electric rate increases during the current recession and further be at a competitive disadvantage.

Therefore, if OTP continues to utilize its existing method and not levelize costs in a manner consistent with its PPA arrangements, then I recommend that OTP's proposed method of partially deferring the PTC be disallowed.

Q. What are the resulting impacts on the revenue requirements for 0 percent deferral of the PTC?

A. **LIG Exhibit __ (KM - 14)** shows the resulting impacts on the revenue requirement for 0 percent deferral of the FPTC. As the exhibit indicates, the non-tracker balance is reduced to **[Trade Secret Starts]** **[Trade Secret Ends]** the same amount as after adjusting for OTP's misapplication since PTC was 0 percent deferred in the first year of Langdon and Ashtabula commercial operations.

Q. Will you consider OTP's approach of smoothing the FPTC reasonable under any circumstances?

A. I will consider OTP's approach of smoothing the FPTC reasonable if OTP's method of cost recovery uses my recommended levelized approach.

Q. What assumptions does OTP utilize for the useful life for the Langdon and Ashtabula projects for purposes of amortization?

A. 25 years.

Q. Do you recommend a change in this assumption?

A. Yes. I recommend that the useful life be increased to 30 years. Since OTP's choice of wind generation was based on the analysis conducted in the Integrated Resource Plan and OTP assumed 30 years, I recommend that this adjustment be made for whichever method is chosen for cost recovery (i.e., current front-end loading or levelized).

Q. What impact does the change in useful life have on the proposed revenue requirements?

A. This reduces the non-tracker revenue requirement to **[Trade Secret Starts]** . **[Trade Secret Ends]** **<u>See</u> LIG Exhibit __ (KM -14).**

Q. Are you recommending any other changes to the tracker balance?

A. Yes. I am recommending that the tracker true up amount from the previous year be amortized over a period of 10 years. The assets (energy produced) that caused these deferred costs (true-up) are not just providing benefits to ratepayers in 2009. So, while OTP should be entitled to recovery, it should not be recovering true-up dollars entirely from 2009 ratepayers as such recovery would be punitive to that group. It is more reasonable to recover those costs evenly over a 10 year period. Using the approved rate of return of 8.62 percent over a 10 year period causes an annual net present value of $224,415 per-year, plus carrying costs. This is a much more economic and reasonable annual true-up recovery, especially in the current economic downturn compared to $1.8 million plus carrying costs proposed by OTP for 2009.

Q. Please summarize all the changes that you have recommended so far aside from your levelized cost recovery recommended option described earlier

A. Table 3 below provides the summary of adjustments that I am recommending aside from the levelized cost recovery approach. Note that carrying costs are not included in demonstrating these adjustments. As can be noted, I am recommending that the proposed 2009 revenue requirements be adjusted downward by $2.88 million. Assuming that $/KWh charge is an appropriate method of recovering the revenue requirements, this reduces the charge from $0.0051/KWh to $0.0035/KWh.

Table 3: Cost Impacts of Recommended
Adjustments to OTP's Cost Recovery Approach
[Trade Secret Starts]

[Trade Secret Ends]

Q. Are you recommending any further adjustments?

A. Yes. While OTP is seeking 100 percent recovery for the costs of the Langdon and Ashtabula wind projects, there is no recognition of the incremental asset-based intersystem sales opportunity it creates for OTP's existing generation fleet. In addition, as the cost of these wind assets have been and are recovered through the Rider, any energy sold from those assets to third parties should likewise be immediately credited to ratepayers through the Rider. Similarly, any RECs generated should also be immediately recovered through the Rider in the year that they are created. Some, though paid for by North Dakota Ratepayers will be used to satisfy Minnesota requirements. These benefits are described in Larry Schedin's Testimony and need to be treated as savings before finalizing the adjustments to the revenue requirements.

Q. What method does OTP use to recover revenue requirements from ratepayers?

A. As discussed earlier, OTP charges a $/KWh charge that is calculated by dividing the annual revenue requirement by the retail MWh sales.

Q. What are the resulting implications of using this method?

A. High load factor customers unfairly bear a disproportionate share of costs.

Q. Do you find this method reasonable? Why or why not?

A. No. I do not find this method reasonable because wind generation is neither built to satisfy base load energy use nor peak load requirement. It is an intermittent resource and is built to primarily fulfill a policy objective. As such, in my opinion, classifying wind as all energy related as is currently done is not a reasonable assumption. In fact, OTP has taken capacity credits based on MAPP accreditation rules for the Langdon project. See OTP Response to LIG IR No. 7, attached **LIG Exhibit __ (KM - 2).** OTP should therefore either use a 50/50 demand to energy split or, in the alternative, use its equivalent peaker ("EP") method to classify wind, as it would any other owned generation.

Q. Did you ask OTP to simulate the OTP proposed revenue requirement (i.e., without any adjustments) using the EP method and calculating a resulting $/KW and $/KWh charge as an example of an alternative approach to use?

A. Yes. OTP provided results of using the EP method and applying 28.11 percent demand and 71.89 percent energy split and the 2009 sales forecasts used in the rider filing. Table 4 shows the results **(corrected LIG-009, LIG-145 and LIG-151). See LIG Exhibit __ (KM - 15), LIG Exhibit __ (KM - 16) and LIG Exhibit __ (KM - 17).**

OTP also stated in response to LIG IR No. 9 that while it does not agree with this approach, should such an approach be approved, the demand factor should be 20% instead of 28.11% as MISO currently uses 20%. MISO is using the 20% as a default number and is currently in the process of developing an accreditation factor methodology that would be more location specific. For example, the Langdon plant has a higher capacity factor at 40% and it is most likely that once MISO's methodology is finalized, Langdon's accredited capacity will be double what it is today.

Therefore, I recommend that the Commission consider a 50/50 energy to demand split or the energy to demand split from the existing EP method until MISO's method is finalized.

Table 4: RRR Charges Using after applying the EP Method

North Dakota	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	kWh by class	Rider Revenue	Revenue Demand and Energy Basis	$ Demand	$/KW/MO	$ Energy	$/kWh	D1 Allocator	E2 Allocator
Residential	469,667,495	$2,396,116	$2,620,709				$0.00560	32.49991%	26.02714%
Farm	23,340,678	$119,026	$136,348				$0.00584	1.67424%	1.35442%
General Service	426,055,767	$2,162,913	$2,430,179				$0.00569	30.38358%	23.92815%
Large General Service	679,335,290	$3,464,338	$3,183,894	$621,919	$0.7109	$2,361,975	$0.00348	30.97313%	34.80357%
Irrigation	795,240	$4,065	$2,564				$0.00322	0.00000%	0.03777%
Outdoor lighting	22,947,135	$117,021	$112,538				$0.00490	0.88920%	1.31055%
CPA	17,790,035	$90,726	$96,514				$0.00542	1.14303%	0.97519%
Controlled water heating	18,154,083	$92,579	$81,032				$0.00446	0.14196%	1.13849%
Controlled interruptible	169,821,083	$866,024	$687,634				$0.00405	2.07428%	9.32117%
Controlled Deferred	21,270,404	$108,471	$80,748				$0.00380	0.22066%	1.10353%
Total ND	1,851,178,792	$9,440,271	$9,440,240	$2,653,651		$2,361,975		100.00000%	100.00000%

Table 2 below shows the calculation of column (C) in Table 1.

Table 2

Demand/Energy Percent Split	(A) Factor	(B) ND Percent	(C) RESIDENTIAL	(D) FARMS	(E) GENERAL SERVICE	(F) GENERAL SERVICE	(G) IRRIGATION	(H) OUTDOOR LIGHTING	(I) CPA	(J) WATER HEATING	(K) SERVICE INTERRUPT	(L) SERVICE DEFERRED
	D1	200,222	84,247	4,340	78,768	80,289	-	2,305	2,962	368	5,377	572
	D1 %	41.65%	22.50%	1.67%	30.35%	30.97%	0.00%	0.89%	1.14%	0.14%	2.07%	0.22%
	E2	1,621,589	422,402	24,607	448,232	656,908	-	24,702	19,381	9,540	-	8,607
	E2%	25.73%	26.05%	1.35%	23.93%	34.80%	0.04%	1.31%	0.96%	1.14%	9.32%	1.10%
28.11%	Demand	$2,653,651	862,434	44,429	806,274	821,919	-	23,596	30,332	3,767	55,044	5,805
71.89%	Energy	$6,786,588	1,766,355	91,919	1,623,905	2,361,975	2,954	88,942	66,182	77,265	632,590	74,943
		$9,440,240	2,629,789	136,348	2,430,179	3,183,894	2,954	112,538	96,514	81,032	687,634	80,748

Percent Demand/Energy split is same amount used in Test Year CCOSS and JCOSS in Case No. PU-08-862

Q. Should the RRR charges remain as a separate line item in customer bills?

A. Yes. As a separate line item, this increases transparency regarding the cost recovery regarding wind owned resources. In addition, LIG is recommending that incremental margins associated with existing displaced generation as a result of wind owned generation be flowed through as described in Larry Schedin's Testimony. These can be facilitated effectively through the existing Rider. Also, to the extent capacity costs are a part of RRR cost recovery, they cannot be recovered through the FCA.

III. Rate Design.

Q. Please describe this section of your testimony.

A. I will compare OTP's existing and proposed rate design structures for large customers, point out rate design concerns, and suggest modifications.

Q. Will you be addressing issues related to CCOSS responsibility to the LGS class?

A. No. The issues and proposed changes to the CCOSS are being addressed in Larry Schedin's Testimony. To the extent that any changes are approved for the CCOSS responsibility, they will need to be reflected in the revenue requirements to the LGS class. I will be addressing issues related to OTP's proposed rate design changes assuming OTP's proposed revenue requirements.

A. **Existing Rates.**

Q. What are the existing OTP rate options commonly used by large customers?

A. For purposes of their CCOSS, OTP groups the large customer rate options in a single class called the Large General Service ("LGS") rate class. However, specific major rates within the LGS class are the LGS, Large General Service Time of Day ("LGS-TOD") and RTP rates. OTP is also proposing a new rate called the LGS Rider that lists guidelines in developing a customized interruptible rate.

Q. Describe the principal billing determinants of energy and demand included in the existing Large General Service Rate.

A. OTP's basic LGS rate is a block rate with two demand blocks and three energy blocks Table 5 shows the energy and demand charges for the secondary class. The rate structure format for the primary and transmission voltage levels is identical, with lower charges related to higher voltage service. The energy charge for all consumption includes $0.016473 per KWh in base fuel plus purchased energy costs. The rate includes COE and other charges. The energy and demand charge components are below.

Table 5: Existing LGS Rate – Secondary Service Level

Demand Charge ($/KW)	Secondary Service
First 100 KW of Billing Demand	$8.33
Excess KW of Billing Demand	$6.80
Energy Charge ($/KWh)	
All over 360 KWh per KW of Billing Demand	$0.02935
First 700,000 KWh	$0.03784
Excess	$0.02979
Monthly Minimum	Demand Charge

Q. Please describe the energy and demand charges related to the existing LGS-TOD rate.

A. This rate is available to any customer with billing demand of 80 KW or higher and consists of an on peak, shoulder peak and off-peak energy charges. Definition of on, shoulder peak and off peak hours varies by summer (June through September) and winter (October through May). The rate incurs a distribution facilities charge ($/KW) that varies by demand level for secondary service level only. This could be considered an energy only rate since it has no demand charges reflective of generation capacity. Table 6 shows the energy and distribution facilities charges for the secondary class. As with the current LGS rate, the rate structure for the primary and transmission voltage levels is similar, with lower charges for subsequently higher voltage service levels. The rate incurs COE and other charges. The demand and energy components are below.

Table 6 : Existing LGS TOD Rate – Secondary Service Level

Distribution Facilities Charges	Secondary Service
Less than 150 KW	$0.20
150KW to 299 KW	$0.20
300 KW to 499 KW	$0.16
Greater than 500 KW	$0.13
Energy Charge ($/KWh)	
Winter	
Peak	$0.0692
Shoulder	$0.0476
Off Peak	$0.0140
Summer	
Peak	$0.0106
Shoulder	$0.0369
Off Peak	$0.0129

Q. Did the existing LGS-TOD replace a prior one?

A. No. Although OTP has had a time differentiated in the Minnesota jurisdiction, it did not have one in North Dakota until the current LGS-TOD rate was introduced in 2007. In essence, OTP went from the extreme of having no TOD rate to the other extreme by introducing a complicated and flawed three-time period differentiated (on peak, shoulder peak, off peak) and two-season differentiated energy only rate.

Q. Are there any customers currently on the LGS-TOD rate?

A. No, none.

Q. In your opinion, why are there no customers on this rate?

A. The existing rate sends erroneous pricing signals as it has no demand charges to reflect capacity and other fixed costs that do not vary with energy use. Consequently, it is punitive to high load factor customers. In addition, the rate is complicated by the inclusion of shoulder peak, which includes weekend hours. I am not aware of any investor owned utility rate in the Midwest that does not consider all weekend hours as off peak. Typical time differentiated rates have on peak and off peak energy charges and summer and winter demand charges where demand charges are based a set definition of on peak billing demand only. OTP's present LGS-TOD rate is not set from a practical perspective and does not consider customers' ease of understanding and administration perspective.

My recommended changes discussed later in the testimony will result in a "user friendly" rate design that customers are accustomed to from their experience in other jurisdictions.

B. <u>OTP'S Proposed Changes to LGS Rate and LGS-TOD Rate.</u>

Q. What are OTP's proposed changes to the demand and energy components of the LGS rate?

A. The LGS rate has been modified to include a single energy charge for summer months (June through September) and a single energy charge for winter months (October through May). Demand charges are also seasonally differentiated. There is a facilities charge that varies for customers less than 1 MW and 1 MW and greater. Table 7 shows the demand and energy related components of the rate at the secondary service level.

Table 7 : OTP Proposed LGS Rate

Energy Charges ($/KWh)	Secondary Service
Summer	$0.05065
Winter	$0.05113
Demand Charges ($/KW)	
Summer	$7.13
Winter	$2.88
Facilities Charge ($/KW)	
Less than 1 MW	$0.30
Eq or More than 1 MW	$0.15

Q. What is the impact of this proposed rate on LGS customers?

A. Witness Prazak's testimony provides a chart showing the average monthly bill impacts to the LGS customers. <u>See</u> Witness Prazak Testimony, Figure 10, p. 35. Witness Prazak explains 95% of the customers will see a decrease and 5% of the customers with highest usage will see an increase. While the chart in the testimony indicates that 5% of the customers will receive a 7% increase, a revised chart was later provided by OTP that revised this increase to 5%. <u>See</u> OTP Response to LIG IR No. 56, attached as **LIG Exhibit __ (KM - 18).** Witness Prazak explains that the increase to customers with the highest usage is due to the removal of declining demand and declining load factor structures. The remaining customers will receive a 95% decrease with some customers receiving up to a 15% decrease. The customers receiving the highest increase are most likely manufacturers who are large employers and contribute significantly to the North Dakota economy.

Q. Does this result make sense?

A. No.

Q. What are OTP's proposed changes to the LGS-TOD rate?

A. The LGS-TOD rate has been modified to include seasonally and time differentiated demand charges. The facilities charge is now exactly the same as OTP's proposed LGS rate.

Table 8 : OTP's Proposed LGS-TOD

Energy ($/KWh)	Secondary Service
Summer	
On Peak	$0.07803
Shoulder	$0.05981
Off Peak	$0.03562
Winter	
On Peak	$0.07002
Shoulder	$0.05695
Off Peak	$0.04020
Demand ($/KW)	
Summer	
On Peak	$5.72
Shoulder	$1.58
Winter	
On Peak	$2.21
Shoulder	$0.52
Facilities Charge ($/KW)	
Less than 1 MW	$0.30
1 MW or greater	$0.15

Please describe the time period defined as on, shoulder and off peak?

The below table is extracted from NERA Consulting's Marginal Cost of Electric Study Report provided in given in response to LIG IR 29, **LIG Exhibit __ (KM - 19).** This figure provides the time periods defined as on, shoulder and off peak. As is demonstrated, time period differentiations look very complicated. These time period differentiations are the same as OTP's existing rate that no customer is currently using.

Table 1. Costing/Pricing Periods

Summer: June – September		
	Peak:	Monday - Friday, 1 pm - 7 pm
	Shoulder:	Monday - Friday, 9 am - 1 pm and 7 pm - 10 pm
		Weekends, 9 am - 10 pm
	Off-Peak:	Monday - Friday, 10 pm - 9 am
		Weekends, 10 pm - 9 am
Winter: October – May		
	Peak:	Monday - Friday, 7 am - 12 noon and 5 pm - 9 pm
	Shoulder:	Monday - Friday, 6 am - 7 am, 12 noon - 5 pm and 9 pm - 10 pm
		Weekends, 6 pm - 10 pm
	Off-Peak:	Monday - Friday, 10 pm - 6 am
		Weekends, 10 pm - 6 pm

Table 2. Illustration of Costing/Pricing Periods

SEASON DEFINITION	
Month	Inclusion
January	1
February	1
March	1
April	1
May	1
June	2
July	2
August	2
September	2
October	1
November	1
December	1

Off-Peak = O
Shoulder = S
Peak = P

COSTING PERIOD: WINTER (1)			
Hour Ending	Weekday	Saturday	Sunday
1	O	O	O
2	O	O	O
3	O	O	O
4	O	O	O
5	O	O	O
6	O	O	O
7	S	O	O
8	P	O	O
9	P	O	O
10	P	O	O
11	P	O	O
12	P	O	O
13	S	O	O
14	S	O	O
15	S	O	O
16	S	O	O
17	S	O	o
18	P	O	O
19	P	S	S
20	P	S	S
21	P	S	S
22	S	S	S
23	c	o	o
24	c	O	O

COSTING PERIOD: SUMMER (2)			
Hour Ending	Weekday	Saturday	Sunday
1	O	O	O
2	O	O	O
3	O	O	O
4	O	O	O
5	O	O	O
6	O	O	O
7	O	O	O
8	O	O	O
9	O	O	O
10	S	S	S
11	S	S	S
12	S	S	S
13	S	S	S
14	P	S	S
15	P	S	S
16	P	S	S
17	P	S	S
18	P	S	S
19	P	S	S
20	S	S	S
21	S	S	S
22	S	S	S
23	O	O	O
24	O	O	O

C. <u>OTP's Proposed Methodology For Rate Design.</u>

Q. What methodology are OTP's proposed changes based on?

A. OTP used marginal cost analysis in order to allocate costs within classes after embedded costs were allocated by class.

Q. Who conducted the marginal cost analysis?

A. OTP retained the rate design expertise of Witness Parmesano from NERA, a national economics firm. Witness Prazak then made some further changes to meet OTP's design criteria

Q. Has Witness Parmesano identified the same rate design objectives as Witness Prazak?

A. Yes.

Q. What is your understanding of how Witness Parmesano conducted the analysis to estimate marginal costs of providing electricity service?

A. My understanding is that Witness Parmesano developed marginal costs for each cost component. For marginal costs of energy and generation capacity, she used a regional forecast. For transmission, she used the costs for wholesale transmission rates. For distribution sub stations and trunk feeders, she used OTP's recent and forecast growth-related expenditures and load growth. For local distribution facilities, she based estimates on the cost of typical equipment configurations for customers of various types and sizes. Lastly, marginal customer costs were based on the cost of typical meters and service drops and recent levels of customer related expenses.

D. <u>Concerns With OTP/NERA Proposed Approach for Rate Design.</u>

Q. Do you have any concerns with the OTP/NERA proposed approach for rate design?

A. Yes. I have the following concerns with the proposed approach:

1. By using regional forecasts for marginal energy and marginal capacity costs that are sensitive to the time period that they were generated, OTP unnecessarily creates an unstable foundation for setting rates.

2. Known factors known to OTP are ignored, such as its plans to construct Big Stone II to address base load resource deficiency and high transmission costs associated with CapX 2020 are not reflected in the demand charges of the LGS rate and LGS-TOD rate.

3. The proposed rates results in over recovery from high load factor customers with flatter load profiles.

4. The proposed rate unfairly recovers larger than average class increases from a small portion of the customers and provides decreases to remaining customers, with some customers receiving double digit decreases.

5. Proposed time of day rate remains complicated

6. Voltage level discounts for taking service at higher than secondary service levels are inadequate

I discuss each of these concerns below.

1. Using Regional Forecasts creates an unstable foundation for setting rates.

Q. What is the weakness associated with the regional marginal energy and capacity forecasts?

A. Regional forecasts, by their very nature, are based on expectations and assumptions regarding various factors during the time period that they are generated. For example, the regional forecast would most likely look different if generated today as opposed to when this analysis was conducted last year. This is because market conditions driving the forecast including fuel costs have changed. An obvious illustration is the significant decline in natural gas prices since last year. Using forecasts that change and become outdated on a daily basis results in an unstable foundation to develop rates. A more stable foundation is needed.

2. Demand charges are not reflective of known capital investment plans

Q. Has OTP acknowledged that it is expecting high infrastructure investments for the period 2008 through 2012?

A. Yes. Witness Brause states that its anticipated capital investments for the 5 year period of 2008 through 2012 are $880 million. <u>See</u> Witness Brause Testimony, p. 15. These costs include costs of OTP's share of Big Stone II, which is being constructed to meet OTP's growing baseload deficiency and CapX 2020 transmission projects. <u>Id.</u>, p. 16.

These costs should be reflected in the form of higher demand charges in rates, which are a pricing signal for fixed infrastructure costs. Furthermore, since OTP is a winter peaking utility, the demand charges should be higher than they are proposed, in the LGS and LGS- TOD rate.

Q. Did OTP rely on the regional marginal capacity pricing forecast to announce its plans for Big Stone II?

A. No. OTP based its decision to build Big Stone II on its Integrated Resource Plan that indicated a baseload deficiency.

Q. Should OTP have waited to get a pricing signal from the regional market prior considering plans to build Big Stone II?

A. No, because if OTP waited for this pricing signal, it would have already been too late. Power plants, and in particular baseload plants, have a long lead time of construction. If OTP were to wait for this pricing signal, ratepayers would be exposed to high costs until the baseload deficiency is fulfilled.

Q. So, does this mean that for capacity costs that ultimately get reflected in demand charges in rates, OTP does not need to rely on a regional marginal capacity forecast but its own investment plan?

A. Yes. OTP operates in jurisdictions with no retail choice and has an obligation to serve. As such, OTP's plans to construct Big Stone II are based on an identified base load deficiency in its Integrated Resource Plan. Costs are approved by the Commission and are therefore, known costs specific to OTP. Consequently, OTP does not need a regional forecast to provide a pricing signal to customers. It must use its own known costs to provide the pricing signal.

3. Over-recovery of costs from high load factor customers.

Q. Please explain how costs are over recovered from high load factor customers.

A. Since OTP's proposed demand charges do not reflect OTP's known plans for capital investment, the pricing signal is distorted. This provides the erroneous signal that capacity is relatively inexpensive. The result is an under recovery in the demand charges in the proposed rates and consequently, over recovery in the energy charges to meet the proposed revenue requirements. This results in being punitive for the high load factor customers who have more efficient load profiles. High load factor customers also end up subsidizing low load factor customers.

Example 1, below provides a simple illustration of how this subsidy occurs.

Q. Are there any other reasons why you think that costs are over recovered from high load factor customers in the proposed LGS rate?

A. Yes. Typically, high load factor customers have larger off peak use when OTP's variable costs of generating are lower. Using a seasonally differentiated average energy rate as proposed in the LGS rate, results in over recovery of costs. So, while the resulting unit cost is lower for a high load factor customer owing to the fact that the costs are spread over a larger amount of KWhs, the rate increase associated with the proposed LGS rate demonstrates the over recovery.

Q. Please explain with an example.

A. OTP's response in LIG IR 56 provides an illustrative example of the impact of the proposed changes to the LGS rate on customers with 50%, 75% and 100% load factor respectively. As the response indicates, the rate increase to a 50%, 75% and 100% load factor customers is 4.5%, 1% and 5.5% respectively. OTP states that the customers with the highest load factors will continue to pay the lowest unit cost.

Paying the lowest cost is an obvious outcome since the costs are spread over a larger amount of energy consumptions for a 100% load factor customer as opposed to a 50% or 75% load factor customer. A 100% load factor customer has higher off peak usage relative to other customers. The example provided by OTP illustrates that even though a customer with a 100% load factor has higher off peak usage, the rate increase is the largest. This is an unfair result.

EXAMPLE 1

The following example demonstrates the subsidy that a high load factor customer provides a low load factor customer:

Assume a class is made up of two customers with a combined demand of 1 MW and combined consumption of 500 MWh per month. Each customer has a demand of 500 kW. Assume a revenue requirement of $20,000.

Customer A's monthly consumption = 170,000 kWh (47% load factor)
Customer B's monthly consumption= 330,000 kWh (90% load factor).

Assume variable energy-related cost is 2.0¢ per kWh, demand cost is $10 per kW and total class revenue requirement is set at this total cost of $20,000
[(2.0¢ x 500,000 kWh = $10,000) + ($10 x 1,000 kW= $10,000)]. = $20,000

The total cost of serving customer A is $8,400 [(2.0¢ x 170,000 kWh = $3,400) + ($10 x 500 kW = $5,000)].
The total cost of serving customer B is $11,600
[(2.0¢ x 330,000kWh = $6,600) + ($10 x 500 kW = $5,000)].

Now, let's assume that instead of setting energy and demand charges equal to the corresponding costs, energy charges are set at 3.0¢. Revenue from the energy charge would be $15,000 (3.0¢ x 500,000) leaving $5,000 to be recovered from the demand charge ($20,000 revenue requirement less $15,000 of energy charge revenue). Thus, the demand charge would be set at $5.00 per kW ($5,000 ÷ 1,000 kW).

With these charges, customer A with the lower load factor would have a monthly bill of $7,600 [(3.0¢ x 170,000 kWh = $5,100) + ($5.00 x 500 kW = $2,500)]

Customer B with the higher load factor would pay $12,400 [(3.0¢ x 330,000 = $9,900) + ($5.00 x 500 kW = $2,500)].

<u>This example shows us that, because energy charges are set above energy costs, the high-load factor customer – customer B – is charged rates that cover not only its cost of service, but also an $800 subsidy to customer A.</u>

4. Unfair burden of recovering revenue requirements from a small set of customers typically manufacturing companies.

Q. Is gradualism one of OTP's rate structure objectives?

A. Yes. Witnesses Prazak and Parmesano both cite gradualism as one of the rate structure objectives?

Q. Is the proposed rate design resulting in a fair and gradual change for all customers in the LGS rate class?

A. No. The proposed rate results in 5% of the customers who are larger sized bearing higher rate increases than the proposed rate class increase of 1% and 95% of the customers getting a decrease. In fact, some customers get a 15% rate decrease.

In response to LIG IR 56, OTP states:

> Attachment No. 1 in LIG-056 is an updated Duo-Decile chart for the large general service customers. In the original Decile chart, on page 35 of Mr. Prazak's testimony, the COE adjustment for one customer's estimated bill was incorrectly applied to all customers' present year bills based on usage for purposes of the Decile chart only. OTP has now correctly assigned this COE adjustment to the correct customer, which is the largest customer overall. The result of this reallocation is shown in the last Decile, which decreased from a positive 7% (as filed in testimony) to a positive 4% (corrected in IR ND LIG-056) change in monthly bill. This reallocation also changed all other deciles, reducing their decrease. For example in the original Decile chart the first Decile showed a monthly bill decrease of 20%. In the updated Decile chart the first Decile will have a monthly bill decrease of 15%."

5. Concerns with OTP's proposed LGS-TOD rate.

Q. What are your concerns with the OTP's proposed LGS-TOD rate?

A. No customers are currently using this rate. While the proposed LGS-TOD is an improvement over the existing rate since it now includes demand charges as a separate rate component, (1) as stated above, the on peak demand charges are understated – *Demand charges are not reflective of known capital investment plans*, and (2) the rate design remains complicated.

Since OTP has never had a TOD rate prior to the existing problematic rate, that no customer currently uses, it would be preferable to introduce a simpler rate.

6. Voltage level discounts for taking service at higher than secondary service levels are inadequate.

What are your concerns about the voltage level discounts?

Table _ shows the voltage level discount from the secondary to the primary level for OTP's proposed LGS rate. As the table indicates, the discounts are less than 1%, a very low amount and could not possibly cover lines losses and the savings associated with taking service at a higher voltage level. For example, Xcel Energy's voltage discount at the primary level is at $0.85/KW for demand and $0.007/KWh for energy.

Table 9 : OTP's Proposed Rate – Voltage Level Discount from Secondary to Primary Level

	Secondary	Primary	Voltage Discount
Energy $/KWh			
Summer	$0.05065	$0.05045	$0.00020
Winter	$0.05113	$0.05090	$0.00023
Demand $/KW			
Summer	$7.13	$7.08	$0.05000
Winter	$2.88	$2.86	$0.02000

E. Proposed Modifications.

1. LGS Rate Modifications.

Q. Based on your concerns above, what guidelines are you proposing to modify OTP's proposed LGS rate?

A. I am recommending the following modifications OTP's proposed LGS rate:

1. The rate increase should be spread more evenly as opposed to a smaller percent of the customers bearing a more than class average rate increase and the remaining customers getting a rate increase.

2. For reasons highlighted in Section D (above), the demand charges should be set higher and provide a pricing signal that indicates that capacity is not cheap. For example, one way to get part way is to set the winter demand charge equal to the summer demand charge. Table 10 shows the billing determinant for the LGS secondary service level as an illustration (billing determinants obtained from Witness Prazak's Testimony. See Witness Prazak Testimony, Exhibit DGP1 Schedule 2 page 10. Once I modified the demand related costs, I readjusted the energy charges using the same Summer/Winter relationship as the OTP proposal.

Table 10: LGS Billing Determinants – Secondary Service

LGS BILLING DETERMINANTS					
SECONDARY SERVICE					
EXISTING RATES	Units	$/Unit	Total Amount		
Energy over 360 per KW	113,192,890	0.02935	$3,322,211		
First 700,000	155,805,630	0.03784	$5,895,685		
Excess KWh	102,552,256	0.02979	$3,055,032		
ENERGY	371,550,776		$12,272,928		
First 100KW of demand	139,916	8.33	$1,165,500		
Excess KW of demand	585,733	6.8	$3,982,984		
DEMAND			$5,148,485		
Cost of Energy	371,550,776	0.01309	$4,865,193		
		LIG Rate Proposal		OTP Proposed	
	Units	$/Unit	Total Amount	$/Unit	Total Amount
Customer Charge	1505	$40	$60,200	$40	$60,200
Facilities <1MW	343844	$0.30	$103,153	$0.30	$103,153
Facilities >=1MW	502,868	$0.15	$75,430	$0.15	$75,430
Summer - Energy	133,483,932	$0.04538	$6,058,007	$0.05064	$6,759,626
Non Summer - Energy	237,431,610	$0.04581	$10,877,685	$0.05112	$12,137,504
Summer - Demand	264,134	$7.13	$1,883,275	$7.13	$1,883,275
Non Summer - Demand	461,515	$7.13	$3,290,602	$2.88	$1,329,163
			$22,348,352		$22,348,352
DEMAND			$5,173,877		$3,212,439
High load factor credit	Needs development				
Source: Exhibit (DGP-1) Schedule 2					

3. The energy rates should be set after deducting the amount established for demand under Recommendation No. 2 above. Winter and summer energy rates should follow the relationship prevalent in OTP's **existing** marginal energy costs.

4. OTP should develop a high load factor credit to negate the over recovery of charges from high load factor customers as described in Section D3 above. For example, Xcel Energy's approved rates in North Dakota have such a credit to counter the over recovery.

5. OTP needs to reassess the voltage discounts for higher voltage levels service levels in order to provide the proper price signal.

Q. What should be done about these modifications to OTP's proposed rate design to the LGS rate?

A. The NDPSC should order OTP to use these guiding principles and move further with my idea of raising demand charges, using OTP's known and existing marginal energy costs to develop the winter/summer energy rate and introducing a high load factor credit such that accurate pricing signals are provided regarding high capacity costs, voltage level differentials, winter/summer energy cost relationships and high load factor customers do not subsidize low load factor customers.

2. LGS-TOD Rate Modifications.

Q. Based on your concerns above, what modification to OTP's proposed LGS-TOD rate should be made?

A. I am recommending the following guidelines to modify OTP's proposed LGS-TOD rate:

1. The rate design should be more conventional and easier to understand to facilitate acceptance and participation in the rate.

    i. For example, OTP could set a single demand charge for the summer months and a single demand charge for the winter months. These charges should be higher for reasons cited earlier. Similar to Xcel's Commission-approved rates in North Dakota, OTP could set the same demand charges for the TOD rate as those set for the LGS rates.

    ii. The energy rates should be set after deducting the amount established for demand under (i) above. OTP could include an on-peak and off-peak energy charge that is seasonally differentiated. OTP could use Xcel's definition for on- and off-peak in North Dakota. Also, similar to Xcel's methodology of utilizing an on- and off-peak ratio of its existing marginal energy costs to develop the on- and off-peak energy rate, OTP's existing marginal energy cost relationships should be used to develop the resulting on- and off-peak energy rates.

    iii. Introduce a high load factor credit similar to the one approved by the Commission for Xcel.

    iv. OTP needs to reassess the voltage discounts for higher voltage levels service levels in order to provide the proper price signal.

Q. What should be done about these guiding principles to modify OTP's proposed rate design to the LGS rate?

A. The Commission should order OTP to use these guiding principles and move further with my idea of raising demand charges, simplifying the rate and introducing a high load factor credit such that the rate is simpler, accurate pricing signals are provided regarding high capacity costs, voltage service differentials on and off peak energy rates are reflective of OTP's existing marginal costs and high load factor customers do not subsidize low load factor customers.

Q. Does this conclude your testimony?

A. Yes.