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?

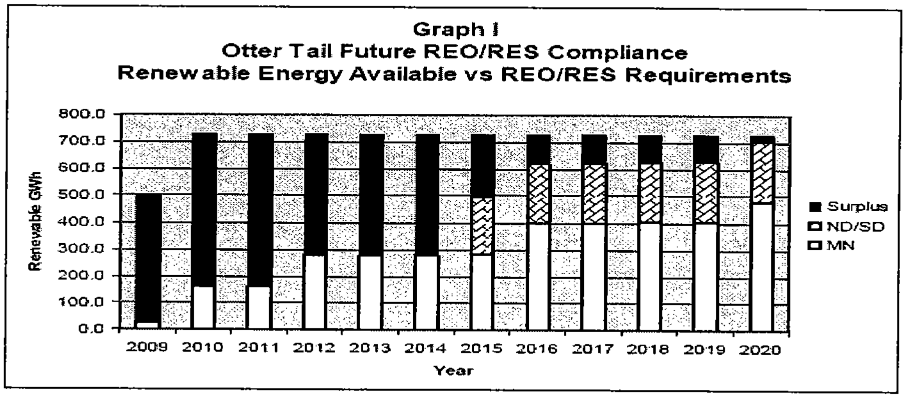
A. Yes. OTP has to meet the RPS mandate in Minnesota that requires that by 2025, 25 percent of all retail electricity sold in Minnesota be generated from renewable resources. OTP's REO/RES Compliance Report submitted to the Minnesota Commission on January 13, 2009 in Docket No. E-999CI-03-869 ("OTP Compliance 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.



Graph I
Otter Tail Future REO/RES Compliance
Renewable Energy Available vs REO/RES Requirements

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. <u>Key Concerns About OTP's Current and Proposed Cost Recovery Approach.</u>

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. <u>Recommended Adjustments Regarding Cost Recovery Through The RRR.</u>

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.

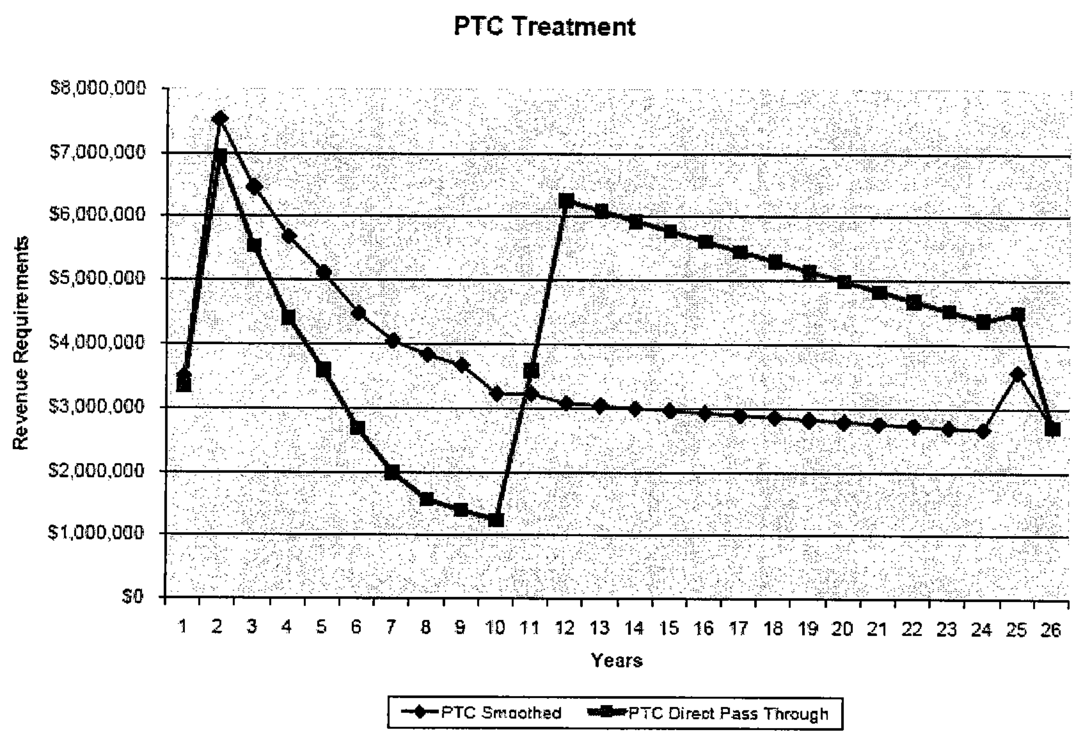
Q. What impact does this have on the proposed revenue requirement for the Rider for 2009?

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?

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]**. See OTP Response to LIG IR No. 27. **See 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]**. **See 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. <u>See</u> **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]** <u>**See**</u> **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]

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[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). <u>See</u> 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	$2,296,116	$2,628,789				$0.00560	32.49891%	28.02714%
Farm	23,340,678	$119,026	$136,348				$0.00584	1.67424%	1.35442%
General Service	428,055,787	$2,162,913	$2,430,179				$0.00568	30.38356%	23.92815%
Large General Service	679,335,290	$3,464,338	$3,183,894	$821,919	$0.7109	$2,361,975	$0.00348	30.97313%	34.80357%
Irrigation	795,240	$4,066	$2,564				$0.00322	0.00000%	0.03777%
Outdoor lighting	22,947,135	$117,021	$112,538				$0.00490	0.68920%	1.31055%
CPA	17,790,035	$90,726	$96,514				$0.00542	1.14303%	0.97519%
Controlled water heating	18,154,003	$92,579	$81,032				$0.00446	0.14196%	1.13849%
Controlled interruptible	169,821,063	$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

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
Demand/Energy Percent Split	Factor	ND Percent	RESIDENTIAL	FARMS	GENERAL SERVICE	GENERAL SERVICE	IRRIGATION	OUTDOOR LIGHTING	CPA	WATER HEATING	SERVICE INTERRUPT	SERVICE DEFERRED
	D1	259,222	84,247	4,340	[illegible]	80,289	-	2,306	2,063	369	5,377	572
	D1 %	41.65%	32.50%	1.67%	30.38%	30.97%	0.00%	0.69%	1.14%	0.14%	2.07%	0.22%
	E2	1,621,589	422,402	24,607	448,232	665,906	-	24,702	18,381	8,540	-	8,667
	E2%	58.73%	28.03%	1.35%	23.93%	34.80%	0.04%	1.31%	0.98%	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	5,855
71.89%	Energy	$6,786,589	1,766,355	91,919	1,623,905	2,361,975	2,564	88,942	66,182	77,265	632,590	74,893
		$9,440,240	2,628,789	136,348	2,430,179	3,183,894	2,564	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. <u>Rate Design.</u>

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. See 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%. See 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

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		O	O
9		O	O
10		O	O
11		O	O
12		O	O
13	S	O	O
14	S	O	O
15	S	O	O
16	S	O	O
17	S	O	o
18		O	O
19		S	S
20		S	S
21		S	S
22	S	S	S
23	o	o	o
24	o	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		S	S
15		S	S
16		S	S
17		S	S
18		S	S
19		S	S
20	S	S	S
21	S	S	S
22	S	S	S
23	O	O	O
24	O	O	O

C. OTP's Proposed Methodology For Rate Design.

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. Concerns With OTP/NERA Proposed Approach for Rate Design.

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)].

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.

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.

REO-RES Compliance Report
to the
Minnesota Public Utilities Commission
Docket No. E017/M-09-19

Report RP09-1
Otter Tail Power Company
Resource Planning Department
January 15, 2009

PREFACE

This document is the biennial report of Otter Tail Corporation, d/b/a Otter Tail Power Company, to the Minnesota Public Utilities Commission (PUC) on the Company's efforts and status on compliance with the Minnesota Renewable Energy Objective (REO) and Renewable Energy Standard (RES) contained in Minn. Statute §216B.1691. The PUC has implemented additional requirements and direction applicable to this report in Orders issued under Docket No. E999/CI-03-869. This particular biennial report is required by the PUC's Order dated November 12, 2008, and is required to be submitted by January 15, 2009.

The PUC has required this report and all subsequent REO-RES Compliance Reports to be submitted as miscellaneous tariff filings under the Commission's rules of practice and procedure.

To protect individual customer data, the names of individual customer-owned generation facilities is replaced with a customer designation. These facilities tend to be quite small, generally less than 100 kW each.

Questions and comments regarding the information and data contained herein should be addressed to Bryan D. Morlock, P.E. at 218-739-8269 or bmorlock@otpco.com.

TABLE OF CONTENTS

I. INTRODUCTION

Pursuant to Minn. Stat. §216B.1691 Subd. 3 and Minnesota Public Utility Commission Orders dated June 1, 2004 and November 12, 2008 in Docket E-999/CI-03-869, Otter Tail Corporation, d/b/a Otter Tail Power Company (Otter Tail or Company), makes this information filing as a miscellaneous tariff filing, Docket E017/M-09-19. This filing contains information on historical and expected future compliance with the Minnesota Renewable Energy Objective (REO) and Renewable Energy Standard (RES).

As the following pages of this report demonstrate, Otter Tail is well on the way to implementing renewable resources as part of its diverse resource portfolio and expects to be in full compliance of any and all renewable energy objectives and standards within all three state jurisdictions in which Otter Tail serves.

II. JURISDICTIONAL REQUIREMENTS

Otter Tail serves retail load in Minnesota, North Dakota, and South Dakota. All three state jurisdictions have some sort of renewable energy objective (REO) or renewable energy standard (RES). Discussion of compliance efforts with any single jurisdiction also requires a discussion of the other two jurisdictions so that a complete understanding of the Company's compliance efforts can be obtained. The following sections describe the requirements in each of the state jurisdictions.

Minnesota

Otter Tail is required to make a good faith effort to comply with the state REO through 2011. Beginning with 2012 the requirement switches to an RES. The state requirements[1] increase in a step-wise fashion, consisting of:

- 2007 – 1% of retail sales
- 2010 – 7% of retail sales
- 2012 – 12% of retail sales
- 2016 – 17% of retail sales
- 2020 – 20% of retail sales
- 2025 – 25% of retail sales.

Eligible energy technologies for compliance include solar, wind, hydroelectric with a capacity of less than 100 MW, hydrogen,[2] or biomass. Biomass includes landfill gas, anaerobic digestion, and mixed municipal solid waste or refuse-derived-fuel from mixed municipal solid waste as a primary fuel. Electricity generated by the combustion of biomass through co-firing with other fuels counts up to the percentage amount of biomass fuel relative to total fuel, only if the generating facility was constructed in compliance with new source performance standards promulgated under the federal Clean Air Act or if the facility employs the maximum achievable or best available control technology for that type of facility.

[1] These REO and RES requirements only apply to utilities without nuclear generating assets. Utilities with nuclear generating assets have a more aggressive standard as detailed in Minn. Stat. §216B.1691.

[2] Provided that after January 1, 2010 the hydrogen must be generated from the other eligible energy technologies listed.

North Dakota

The state REO is 10% of retail sales by the year 2015, and includes both renewable energy and recycled energy. The calculation contains a provision to reduce the amount of retail sales by any hydroelectric energy that cannot be counted toward the REO.[3] Renewable electricity and recycled energy includes electricity generated from solar, wind, biomass,[4] geothermal, hydrogen,[5] hydroelectric (must be from a facility with an in-service date of no earlier than January 1, 2007 or from efficiency improvements to a facility existing as of August 1, 2007), and recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process. Recycled energy does not include any system whose primary purpose is the generation of electricity.

South Dakota

The state REO is 10% of retail sales by the year 2015, and includes both renewable energy and recycled energy. The legislation appears to be very similar to the North Dakota requirements. The calculation contains a provision to reduce the amount of retail sales by any hydroelectric energy from a facility with an in-service date prior to July 1, 2008.[6] Renewable electricity and recycled energy include electricity generated from solar, wind, biomass,[7] geothermal, hydrogen,[8] hydroelectric (statutes seem to imply it must be from a facility with an in-service date of no earlier than July 1, 2008), and recycled energy systems producing electricity from currently unused waste heat resulting from combustion or other processes into electricity and which do not use an additional combustion process. Recycled energy does not include any system whose primary purpose is the generation of electricity.

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[3] North Dakota Century Code §49-02-30.

[4] Including agricultural crops and wastes and residues, wood and wood wastes and residues, animal wastes, and landfill gas.

[5] Provided that the hydrogen is generated from a source listed in this section of North Dakota Century Code §49-02-25.

[6] South Dakota Codified Laws §49-34A-103.

[7] Includes agricultural crops and wastes and residues, wood and wood wastes and residues, animal and other degradable organic wastes, and landfill gas.

[8] Provided that the hydrogen is generated from a source listed in this section of South Dakota Codified Laws §49-34A-94.

III. MIDWEST RENEWABLE ENERGY TRACKING SYSTEM

Otter Tail has registered almost all renewable energy resources within the Midwest Renewable Energy Tracking System (M-RETS). There is a number of small customer owned units, generally less than 50 kW each, which the Company has not registered. The customers self-serve a portion of their own load with Otter Tail receiving the remaining surplus energy. Otter Tail does pay the cost, both initial and annual fees, to register a facility in M-RETS and the cost per renewable energy credit (REC) can become quite high on these small units. Otter Tail has raised this issue within the M-RETS administration and is seeking methods to reduce the registration cost for the small units. It is expected that at some point these small units will be registered. For 2008, the amount of unregistered renewable energy was about 260 MWh, only about 0.08% of the over 308,000 MWh of renewable energy.

Otter Tail has developed an account structure within M-RETS to help segregate RECs by type and usage. For customer-owned facilities that self-serve customer load, all of the generation is reported within M-RETS. Otter Tail then transfers RECs associated with the energy used to self-serve load into an account in the customer's name, for their use as they deem appropriate. The RECs associated with energy purchased by Otter Tail will remain in the Otter Tail account.

The Otter Tail M-RETS accounts include a retirement account by state jurisdiction by year. Thus it will be easy to verify the amount of RECs retired annually for compliance with each state's requirements. RECs associated with **Tail*Winds***, the Company's green pricing program, are retired into separate state jurisdiction accounts to ensure proper accounting for the green pricing tracker balance.

Retired RECs will be tracked on a calendar year basis. The M-RETS system became operational in the last half of 2007. While Otter Tail began recording renewable energy within M-RETS late in 2007, the Company intends to begin full use of the M-RETS system for reporting verification beginning with the first full calendar year commencing January 1, 2008.

Otter Tail has not sold or purchased any RECs separate from the renewable energy. All energy currently being used for compliance is energy generated by Otter Tail or energy purchased by Otter Tail under power purchase agreements.

Otter Tail did sell 3,736,752 kWh of wind generation, including the RECs, during 2008. This energy came from the Ashtabula wind farm which was in start-up phase prior to the availability of the transmission outlet facilities. This energy was sold to Minnkota Power Cooperative through a lower voltage tie.

IV. RENEWABLE ENERGY RESOURCES

The breakdown of existing and potential future renewable energy resources for Otter Tail, to the extent known, at the time of this report are shown in Appendix A. The data provided includes the name of the facility, kW rating, vintage, technology and energy source, whether owned or through a PPA, and state eligibility. For customer-owned facilities, the customer name is not provided in order to protect customer information.

The information provided includes future resources which may or may not be constructed, but for which development work has commenced. There are additional renewable energy facilities which are under discussion, but these have not been included in the data since they are still in preliminary stages of feasibility studies. The data includes resources that will count as renewable energy in at least one of the three states, as well as hydro resources that do not count as renewable energy but are used in the compliance calculation in North and South Dakota.

Annual generation or purchased energy from the renewable energy resources is detailed in Appendix C for the years 2005 – 2008.

V. 2005 – 2007 HISTORICAL REO-RES COMPLIANCE

The 2005-2007 REO compliance is shown in Table I for both the Minnesota and non-Minnesota jurisdictions. The load data and generation data behind these values is shown in Appendix C. For all resources, except resources used for green pricing, the renewable energy is allocated via load ratio share for these three years. Green pricing energy does not count in MN, and the portion counted in the non-Minnesota portion of the service territory is the actual green pricing energy sold.

The renewable energy compliance percentage declines from 2005 to 2007 due to the loss of a major renewable resource. From 1992 – 2006 Otter Tail received 30,000 – 35,000 MWh of wood waste fueled biomass energy from a customer-owned cogeneration facility. That facility was closed on August 30, 2006 without prior notice to Otter Tail. The loss of the renewable energy negatively impacted Otter Tail's compliance.

The Commission approved the addition of 75 MW of new wind generation in its August 9, 2006 Order in Otter Tail's resource plan filing docket, E-017/RP-05-968. In its subsequent February 20, 2007 Order the Commission increased the amount of approved wind additions to 160 MW. The first 60 MW of the new wind generation began operation in late 2007 and early 2008, and the next 48 MW began commercial operation in November 2008. These wind additions offset the loss of the biomass generation.

Table I
2005 – 2007 REO Compliance

Year	Minnesota	Non-Minnesota
2005	3.35%	3.04%
2006	2.62%	2.26%
2007	2.16%	1.85%

Preliminary 2008 compliance is shown in the next section.

VI. 2008 REO Compliance

The 2008 REO compliance data is considered preliminary since the year just ended. Otter Tail has made every effort to ensure that the data is accurate, but changes may occur. Because of the magnitude of the Company's recent renewable energy additions relative to the REO requirement any potential data changes are likely to only have a small impact on the results.

The Company brought on-line 60 MW of new wind generation at the Langdon Wind Energy Center[9] in late 2007 and early 2008. Otter Tail also began operation of 48 MW[10] of wind turbines in the Ashtabula project in October 2008. All Ashtabula energy and associated RECs during the October-November 2008 time period were sold to Minnkota Power Cooperative. The transmission outlet to Otter Tail was not operational until the beginning of December 2008. The amount of energy and associated RECs sold was 3,736,752 kWh.

The 2008 specific renewable resource generation is shown in Appendix C. The compliance allocations and calculations beginning in 2008 and going forward are different than the methodology used in the 2005-2007 time period. Through the use of the M-RETS system, Otter Tail anticipates optimizing the use of RECs for compliance, rather than simply doing a load ratio allocation. Otter Tail also intends to bank some RECs to ensure compliance due to any unanticipated events or issues. At this point in time Otter Tail hasn't determined its exact plan for use and allocation of RECs due to uncertainty surrounding its planned 49.5 MW M-Power project scheduled for late 2009.

Table II shows 2008 retail load and renewable generation compliance percentage, assuming all renewable energy is allocated.

[9] Otter Tail owns 40.5 MW and purchases 19.5 MW from NextEra Energy (formerly FPL Energy).
[10] The 48 MW of wind generation from Ashtabula is all owned by Otter Tail.

Table II Otter Tail 2008 REO Compliance				
Jurisdiction	**Retail Sales MWh**	**Hydro Adj. to Sales MWh**[11]	**Renewable MWh**	**REO %**
Minnesota	2,179,449	0	169,967.3	7.80%
Non-Minnesota	2,035,993	149,976.7	138,751.7	7.36%

[11] North Dakota and South Dakota retail sales can be adjusted downward for any hydro energy utilized, which cannot be counted as renewable energy for REO compliance. Any non-compliance hydro energy was allocated between the jurisdictions based on load ratio share.

VII. RENEWABLE RESOURCE PLAN

The second page of Appendix A details the additional renewable energy resources that are in the planning stage and have moved beyond the initial investigation stage. All of the additional planned renewable resources would be expected in the next 1 – 2 ½ years if they reach operation.

Contracts have been executed for the 49.5 MW M-Power project, scheduled for construction in 2009. The final project go-ahead has not been given due to the current economic situation.

The heat recovery project is in the negotiation stages. A term sheet was provided to the project developer and has been approved to proceed by the developer. While the energy from this project does not qualify to count toward the Minnesota REO-RES, it does count toward REO compliance in North and South Dakota. This would free up wind RECs from those two states to be used for Minnesota compliance.

The 4.5 MW MSW-fueled facility has been in limbo for some time, but a decision should be made by the project owner in the near future whether this project will proceed.

The rest of the identified resources are individual turbine installations over which Otter Tail does not have control. The Company is working with these entities to help move their projects forward toward implementation. Some of the projects are fairly certain to move forward and be operational in 2009.

Otter Tail has clearly demonstrated its commitment toward compliance, as 108 MW of the 160 MW approved by the Commission is already in operation. Contracts have been signed for an additional 49.5 MW in the M-Power project. Eight customer-owned wind turbines, totaling about 840 kW, have been added in the past 1 ½ years. Seven more customer-owned facilities, totaling about 4800 kW, are in the planning stages.

The addition of the renewable resources is being accomplished within the economic parameters included in the resource plan evaluation for the 160 MW of wind generation approved by the Commission. Power purchase agreements (PPAs) are being negotiated under existing tariffs[12] that are based on avoided costs or established by state rules and requirements, or under avoided cost methodologies. Retail customers have thus been protected and Otter Tail is working to keep rates as low as possible.

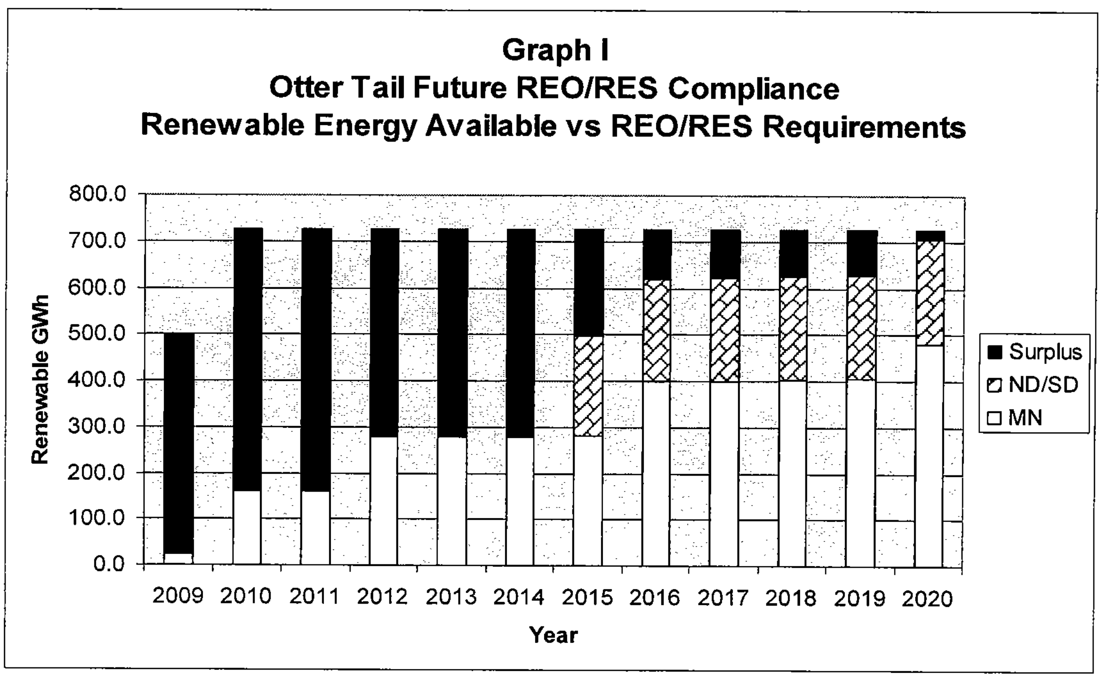
Thus far Otter Tail has not had any entity make use of a C-BED (Community Based Energy Development) tariff, although a number of C-BED qualifying facilities have been added to the system. The facility owners thus far have chosen to not use C-BED. Some of the planned facilities listed in Appendix A do intend to use the C-BED tariff, but those PPAs are not yet completed. Every C-BED proposal that has been received by Otter Tail to date has been above avoided cost or above the cost of obtaining other wind generation resources. Otter Tail does expect to be filing some C-BED tariff PPAs during 2009 that will be above avoided cost, in an effort to implement state objectives regarding C-BED.

[12] Small power producer tariffs and distributed generation tariff.

VIII. FORECAST OF FUTURE REO-RES COMPLIANCE

Otter Tail is just completing construction of the 48 MW Ashtabula Wind Farm and is working toward construction of the 49.5 MW M-Power Wind Farm in 2009. Combined with the 60 MW the Company receives from the Langdon Wind Farm completed in late 2007/early 2008 Otter Tail is well positioned to comply with the renewable energy objectives and standards in all three states. Final commitments to the M-Power Wind Farm have not yet been made.

Graph I shows the Company's expected available renewable energy compared to the REO-RES requirements going out to 2020. The graph assumes that all RECs are counted in the year they are generated and are not banked for future compliance use. The graph does not include new customer-owned facilities that may be developed. Otter Tail is seeing significant customer interest in owning wind generation. The Company is obligated to purchase any renewable energy offered from customers under the federal Public Utility Regulatory Policies Act of 1978 (PURPA).



The North Dakota and South Dakota requirements are very similar and are lumped together in the graph. As demonstrated in Graph I, Otter Tail expects by the end of 2010 to have sufficient renewable energy available to comply with state REO-RES requirements until at least 2020.

IX. BARRIERS TO REO-RES COMPLIANCE

The most significant obstacles fall into four basic categories, including:

- Transmission
  - Interconnection queue
  - Transmission delivery service
  - LMP prices
- Turbine availability
- Developer knowledge
- Economic and financing issues

Interconnection Queue

The Midwest Independent Transmission System Operator (MISO) interconnection queue has been a major impediment to the development of any resources due to the significant backlog of requests. In late August 2008 the Federal Energy Regulatory Commission (FERC) approved revisions to the MISO interconnection queue process which Otter Tail believes will help to alleviate the backlog. It is expected that many projects that were simply attempting to reserve a spot in the queue will drop out, and future requests will more likely come from serious projects. Previously projects could submit a request and then remain in suspension for several years, tying up the queue. The ability to suspend a project in the queue is now limited to a much shorter term and only for force majeure reasons. All existing projects in the queue will need to transition to the new process, and MISO has issued a report detailing the status of each interconnection project and the required steps to complete the transition to the new process. The down side to the changes is that developers will have to be ready to make their application deposits and have other benchmarks in place in order to proceed in the new queue process.

Transmission Delivery – As a member of MISO Otter Tail must have firm delivery transmission service for any project to count as a network resource. At the present time transmission service is severely hampered by transmission constraints and the ability to get delivery service is limited. Otter Tail has benefited from the fact that almost 100% of the Company's system is located to the west of the North Dakota Export Boundary, and generation can generally be delivered to load without crossing that constraint. However, there are other wind projects being developed in the Otter Tail service territory for other utilities that are using up the available transmission service. Otter Tail is a part of the CAPX 2020 group proposing new major high voltage transmission. If approved and constructed, the CAPX 2020 transmission additions will be a considerable help in reducing constraints. CAPX 2020 additions currently proposed will not come close to addressing the future transmission needs of projects in the queue. CAPX 2020 is studying the situation to determine what other new transmission resources are likely to be required.

Otter Tail is also one of the participating utilities in Minnesota Public Utility Commission Docket Nos. CN-05-619 and TR-05-1275, seeking approval to build additional transmission facilities in southwest Minnesota. This transmission would be constructed with the capability to be uprated to carry wind generation from the area. At this point in time more than forty wind generation projects have interconnection requests in the MISO queue that depend upon the addition of this transmission.

<u>LMP Prices</u>

The Location Marginal Price (LMP) is beginning to be impacted by the magnitude of the wind development taking place. The lack of adequate transmission for delivery service is causing wind generation to be economically stranded at times of plentiful wind and less than peak loads. Otter Tail wind resources at times receive less than full MISO market price because of inadequate transmission to move the energy where it is needed. As a result, the LMP price at the wind farm declines and can become negative at times. Otter Tail has to pay MISO to keep the wind generation operating at those times. This situation is being exacerbated as the amount of wind generation on the system increases. The end result is that wind generation becomes less economic and increases costs to the customer. The only cure is to increase transmission capability. The previously mentioned transmission project efforts will help to alleviate the situation, although even more transmission will be needed.

Turbine Availability

The lack of available wind turbines is making the addition of wind generation resources very difficult. Turbines are readily available in small sizes (less than 100 kW), but the demand is so high for utility scale turbines that manufacturers are reticent to deal with anyone who is not a major player in the industry. Project developers that want to construct one or two turbines have asked Otter Tail for assistance in obtaining wind turbines, but there is little that Otter Tail can do. Even Otter Tail is too small to have significant direct access to wind turbines. Otter Tail discussed the possibility of increasing its order size for turbines for the Company's projects but was unable to do so. In some cases manufacturers prohibit the reselling of their new turbines. There aren't any utility solutions available to the problem, as long as demand for wind turbines remains high.

Developer Knowledge

The larger developers know what they are doing with wind development. Otter Tail has experienced difficulty with small developers, community-based wind developers, and customers who consider building wind generation. These entities in general simply do not have the background and have not spent the time to learn about wind generation prior to beginning to investigate a project. Where possible, Otter Tail steers these individuals to available resources from the states, American Wind Energy Association, and others to assist with developer education.

Economic and Financing Issues

The recent economic downturn is expected to have a dampening effect on the development of renewable resources. Some major wind developers have already announced intentions to scale back their development plans for the near-term future. While Otter Tail has not seen any specific project delays or cancellations in wind projects yet, such actions are expected by most wind industry publications. Small wind development may especially be impacted in their efforts to obtain project financing.

X. SUMMARY

Otter Tail has stepped forward with its development of renewable resources for a variety of reasons and is completing new renewable energy facilities at a pace much faster than needed to comply with REO-RES requirements. The most recent Company integrated resource plan called for 160 MW of new wind generation. With the M-Power project, Otter Tail will have completed that amount of wind generation addition to the system. Part of the reason for accelerated implementation is economics, as the cost of wind generation is escalating at a rate as fast or faster than any other generating technology. Also, the federal Production Tax Credit (PTC) is not likely to be available for the long term, so Otter Tail is taking advantage by moving forward early. The PTC reduces the cost of wind generation by about 33%.

The Company has also taken advantage of significant wind development incentives in North Dakota. Currently those incentives also have a sunset provision, so early implementation of wind generation has accessed those incentives.

With the current renewable resources in existence, under construction, and planned for the next couple of years, Otter Tail does not expect to need 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. There are many uncertainties going forward with all forecasts, including load growth, conservation efforts, and customer-owned renewable resources.

Otter Tail expects its next resource plan filing to provide updated information regarding the long-term view of REO-RES compliance.

Appendix A – Renewable Energy Resources

Existing Renewable and Recycled Generating Facilities

Name	State	kW Rating	Vintage	Technology	Power Source	Owned/PPA	State Eligibility
Customer A	MN	225	1997	Wind	Wind	PPA	MN, ND, SD
Customer B	SD	90	2002	Wind	Wind	PPA	Tail*Winds*[13]
Hendricks	MN	900	2001	Wind	Wind	PPA	Tail*Winds*[13]
Borderline	MN	900	2003	Wind	Wind	PPA	MN, ND, SD
FPLE ND Wind II	ND	21,000	2003	Wind	Wind	PPA	MN, ND, SD
Customer C	ND	50	1985	Wind	Wind	PPA	MN, ND, SD
FPLE Langdon	ND	19,500	2007	Wind	Wind	PPA	MN, ND, SD
OTP Langdon	ND	40,500	2008	Wind	Wind	Owned	MN, ND, SD
Customer D1	MN	1,650	2005	Wind	Wind	PPA	MN, ND, SD
Customer E	ND	660	2008	Wind	Wind	PPA	MN, ND, SD
Customer F	MN	39.5	2008	Wind	Wind	PPA	MN, ND, SD
Customer G	MN	39.5	2008	Wind	Wind	PPA	MN, ND, SD
Customer H	MN	39.5	2008	Wind	Wind	PPA	MN, ND, SD
Customer I	MN	35	2007	Wind	Wind	PPA	MN, ND, SD
Customer J	MN	1.8	2008	Wind	Wind	PPA	MN, ND, SD
Customer K	MN	1.8	2008	Wind	Wind	PPA	MN, ND, SD
Customer L	ND	20	2008	Wind	Wind	PPA	MN, ND, SD
Big Stone Plant	SD	475,000	1975	Steam	Biomass	Owned	ND, SD[14]
Bemidji Hydro	MN	740	1907	Hydro	Water	Owned	MN
Taplin Gorge	MN	560	1925	Hydro	Water	Owned	MN
Hoot Lake	MN	1,000	1914	Hydro	Water	Owned	MN
Pisgah	MN	520	1918	Hydro	Water	Owned	MN
Wright	MN	400	1922	Hydro	Water	Owned	MN
Dayton Hollow	MN	970	1909	Hydro	Water	Owned	MN
WAPA Allocation	Several	5,566	Various	Hydro	Water	PPA	None[15]
Manitoba Hydro	Manitoba	50,000	Various	Hydro	Water	PPA	None[15]
Ashtabula Wind	ND	48,000	2008	Wind	Wind	Owned	MN, ND, SD

[13] At this time Tail*Winds* energy counts in ND and SD, but not MN. Tail*Winds* is the Company's green pricing tariff and the energy is counted only as customers purchase the energy, not as it is generated.

[14] Only the biomass portion of the fuel is counted.

[15] This hydroelectric energy does not count toward the MN REO-RES, but can be subtracted from ND and SD retail sales in the calculation of the compliance with the renewable and recycled energy objective in those states.

Appendix A – Renewable Energy Resources
Planned and Expected Future Renewable Generating Facilities

Name	State	kW Rating	Vintage	Technology	Power Source	Owned/PPA	State Eligibility
M-Power Wind	ND	49,500	2009	Wind	Wind	Owned	MN, ND, SD
Customer D2	MN	1,500	2009	Wind	Wind	PPA	MN, ND, SD
Customer D3	MN	1,500	2009	Wind	Wind	PPA	MN, ND, SD
Customer M	MN	20	2009	Wind	Wind	PPA	MN, ND, SD
Customer N	MN	250	2009	Wind	Wind	PPA	MN, ND, SD
Customer O	MN	1,500	2009	Wind	Wind	PPA	MN, ND, SD
Customer P	MN	7,000-8,000	2010	Binary Cycle	Waste Heat	PPA	ND, SD
Customer Q	MN	4,500	2010	Steam	MSW	PPA	MN
Customer R	MN	25	2009	Wind	Wind	PPA	MN, ND, SD
Customer S	MN	2.4	Unknown	Wind	Wind	PPA	MN, ND, SD

Appendix B
Report Requirements Cross-reference

Statute or Order	Subdivision or Item Number	Requirement	Included
216B.1691	3a(1)	Status of the utility's renewable energy mix relative to the objective and standards.	Yes
216B.1691	3a(2)	Efforts taken to meet the objective and standards.	Yes
216B.1691	3a(3)	Any obstacles encountered or anticipated in meeting the objective or standards.	Yes
216B.1691	3a(4)	Potential solutions to obstacles.	Yes
E-999/CI-03-869 June 1, 2004 Order	11	In their biennial filings demonstrating compliance with the renewable energy objectives, utilities shall address the following two sets of criteria, which the Commission will use in evaluating their compliance with the "good faith efforts" standard set by statute: A. Demonstrated commitment to a specific plan. Each utility must file a plan that reasonably details the steps to be taken to reach the renewable energy objectives, with an accompanying timetable. B. Demonstrated financial commitments to build facilities or to purchase energy to meet the renewable energy objective, including but not limited to project financing; purchase and ordering of equipment: and expenditures to hire construction firms if needed. C. Demonstrated commitments to construction of physical infrastructure to meet the renewable energy objectives, including but not limited to ordering equipment; hiring construction firms; and/or contracting for a renewable energy objectives site. D. Demonstrated legal and contractual commitments to purchase or build the facilities to meet the renewable energy objectives, including but not limited to contracts for sites on which to build; contracts for labor and equipment; arrangements for insurance and liability, etc. E. Demonstrated commitment to meet regulatory requirements in timely fashion, including but not limited to federal, state, county, township and municipal permitting and any other regulatory obligations, such as filed plans for facility construction in the	Yes

		Commission's biennial transmission planning process under Minn. Stat. 216B.2425. F. Demonstrated commitment to transmission access for the renewable energy objectives facilities, including but not limited to initiation or participation in transmission studies or provision of interconnection and transmission service for these facilities. G. Demonstrated commitment to openness and transparency. This requires full public access to all non-proprietary information relating to meeting the renewable energy objectives, including but not limited to actions taken for financial commitments; construction of physical infrastructure; legal and contractual commitments; compliance with regulatory requirements; and transmission access. H. Demonstrated reasonable efforts to adequately consider technical feasibility and to protect against undesirable impacts on system reliability and undesirable economic impacts on ratepayers, including, but not necessarily limited to, the following factors: 1. Maintaining or improving the adequacy and reliability of utility service. 2. Keeping the customer's bills and the utility's rates as low as practicable, given regulatory and other constraints. 3. Minimizing adverse socioeconomic effects and adverse effects upon the natural environment. 4. Enhancing the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations. 5. Limiting the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.	
E-999/CI-03-869 November 12, 2008 Order	8a	The information required under the order issued in this case on June 1, 2004	Yes
E-999/CI-03-869 November 12, 2008 Order	8b	All information submitted to the Office of Energy Security for use in preparing its biennial legislative report.	Yes

E-999/CI-03-869 November 12, 2008 Order	8c	Total Minnesota retail sales in megawatt-hours for each year relevant to compliance	Yes
E-999/CI-03-869 November 12, 2008 Order	8d	An accounting of all renewable energy being provided by a utility's own generating facilities and being provided through purchased power agreements.	Yes
E-999/CI-03-869 November 12, 2008 Order	8e	An accounting of what portion, if any, of the renewable energy identified in part d has been allocated to meet the renewable energy requirements of other states or the requirements of green pricing programs.	Yes
E-999/CI-03-869 November 12, 2008 Order	8f	Historical compliance information and plans for ensuring ongoing and future compliance.	Yes
E-999/CI-03-869 November 12, 2008 Order	8g	A description of whether and how the transmission service queue maintained by the Midwest Independent Transmission System is or may be a factor affecting compliance .	Yes
E-999/CI-03-869 November 12, 2008 Order	9	Biennial compliance reports shall be clearly labeled, and preferably labeled "REO-RES Compliance Report."	Yes
E-999/CI-03-869 November 12, 2008 Order	10a	The status of the utility's renewable energy mix relative to the objective and standards.	Yes
E-999/CI-03-869 November 12, 2008 Order	10b	Efforts taken to meet the objective and standards.	Yes
E-999/CI-03-869 November 12, 2008 Order	10c	Any obstacles encountered or anticipated in meeting the objective or standards.	Yes
E-999/CI-03-869 November 12, 2008 Order	10d	Potential solutions to the obstacles.	Yes

Appendix C - 2005 to 2008 Renewable Energy Resource Breakdown

Retail Sales[1]	2005 MWh	2006 MWh	2007 MWh	2008 MWh
Minnesota	2,018,332	2,085,660	2,127,863	2,179,449
Non-Minnesota	1,884,858	1,902,110	1,990,177	2,035,993
Total	3,903,190	3,987,770	4,118,040	4,215,442

Renewable Resources[2]	2005 MWh	2006 MWh	2007 MWh	2008 MWh	2005 Compliance Minnesota MWh	2005 Compliance Non-Minnesota MWh	2006 Compliance Minnesota MWh	2006 Compliance Non-Minnesota MWh	2007 Compliance Minnesota MWh	2007 Compliance Non-Minnesota MWh	2008 Compliance Minnesota MWh	2008 Compliance Non-Minnesota MWh
Ainsworth Biomass	30,717.1	20,388.6	0.0	0.0	15,883.8	14,833.4	10,663.5	9,725.1	0.0	0.0	0.0	0.0
BSPI Biomass[3]	953.8	1,165.1	1,163.8	868.0	0.0	460.6	0.0	555.7	0.0	562.4	0.0	868.0
Customer D1	2,163.5	2,155.8	1,453.8	1,142.2	1,118.8	1,044.8	1,127.5	1,028.3	751.2	702.6	590.5	551.6
Customer A	19.6	23.8	19.4	38.7	10.1	9.5	12.4	11.3	10.0	9.4	20.0	18.7
Borderline Wind	2,342.4	2,465.3	2,410.9	1,345.9	1,211.2	1,131.1	1,289.4	1,175.9	1,245.8	1,165.2	695.9	650.1
Hendricks Wind[4]	2,425.6	2,604.9	2,801.3	2,455,694.0	0.0	855.7	0.0	842.8	0.0	857.8	0.0	833.0
Customer C	0.8	0.0	0.0	3.4	0.4	0.4	0.0	0.0	0.0	0.0	1.8	1.7
FPLE ND Wind II	71,954.2	60,933.5	62,760.3	60,623.4	37,207.4	34,746.8	31,869.1	29,064.4	32,429.3	30,330.9	31,343.2	29,280.2
Customer B	148.2	200.3	199.3	141.3	46.1	71.6	0.0	0.0	0.0	0.0	0.0	0.0
Customers F, G, H, I, J, K	0.0	0.0	7.4	34.9	0.0	0.0	0.0	0.0	3.8	3.6	18.1	16.9
Langdon Wind	0.0	0.0	1,970.0	203,599.2	0.0	0.0	0.0	0.0	1,017.9	952.1	105,264.0	98,335.3
Ashtabula Wind[8]	0.0	0.0	0.0	16,745.8	0.0	0.0	0.0	0.0	0.0	0.0	8,657.8	8,088.0
Customer E	0.0	0.0	0.0	224.4	0.0	0.0	0.0	0.0	0.0	0.0	116.0	108.4
OTP Hydro[6]	23,445.7	18,363.4	20,370.5	23,260.1	12,123.7	0.0	9,604.3	0.0	10,525.8	0.0	23,260.1	0.0
MHEB 2005[7]	23,444.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MHEB 2010[7]	207,806.0	205.0	207,650.0	280,548.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WAPA NA Tribes[7]	29,928.1	29,870.4	29,870.4	29,972.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total					67,601.5	53,153.8	54,566.2	42,403.6	45,983.9	34,584.0	169,967.3	138,751.7
% of Retail					3.35%	3.04%	2.62%	2.26%	2.16%	1.85%	7.80%	7.36%

1. Retail Sales & Revenue Annual Statistical Report
2. Energy Breakdown Report for Environmental Disclosure
3. BSPI biomass counts in the Dakotas, but not Minnesota
4. Hendricks is used for TailWinds energy, which counts in the Dakotas, but not in Minnesota
5. Customer B wind became part of TailWinds energy 9/1/2005, and from that point on counts in the Dakotas only and not in Minnesota. 1/1/2005-8/31/2005 generation was 89.132 MWh.
6. The OTP hydro counts in MN, but not in the Dakotas. Hydro energy is subtracted from retail sales in the Dakotas.
7. This hydro energy does not count in any state, but can be subtracted from retail sales in the Dakotas.
8. Includes only the amount kept by OTP, and does not include the amount sold to Minnkota Power Cooperative.

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-007
Please provide a copy of OTP's most recent Resource Plan and the Resource Plan which committed OTP to the procurement of wind generation.

RESPONSE:
Otter Tail Power Company's 2005 Resource Plan and subsequent updates can be found on the Company's website at:

http://www.otpco.com/NewsInformation/IntegratedResourcePlan.asp

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 Group
Analyst:	Larry Schedin
Date of Request:	2/02/2009
Date Received:	2/02/2009
Date Due:	3/04/2009

Information Request No. LIG-078
Is OTP using 100% of its wind resources to satisfy Minnesota's requirements to acquire renewable energy generation? If not, please explain what percent is used to satisfy Minnesota's requirements and how that amount is determined.

RESPONSE:

No. Our wind resources have been installed as a least cost resource. (See Minnesota's 2005 IRP included in response to ND 02-183.) The benefits of this least cost resource are shared equally by customers in all of our jurisdictions. While these resources do help OTP satisfy its Renewable Energy Standard in Minnesota and the Renewable Energy Objective in North and South Dakota, they would have been installed with or without these renewable requirements because they were the least cost resource.

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

TRADE SECRET

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-004
Please provide information on volume and dollars collected by OTP's affiliates, as well as OTP's unregulated subsidiaries or divisions, on both the Langdon and Ashtabula wind farms.

RESPONSE:
Please see Attachment 1 to ND LIG-004 – TRADE SECRET.

Responding Witness:	Pete Beithon
Title:	Manager, Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
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-005
Do OTP's unregulated subsidiaries or divisions provide services to FPL or other partners in the Langdon and Ashtabula wind farms? If so, specify by the company providing such service and the year service was provided for 2006, 2007 and 2008.

RESPONSE:
Ashtabula was constructed in 2008. Langdon was primarily constructed in 2007, with a small portion falling into 2008. There was no construction on either wind farm in 2006. For the Langdon and Ashtabula wind farms, three wholly owned subsidiaries of Otter Tail Corporation were involved in the chain of supply for both wind farms. They are: DMI Industries (DMI), Ventus Energy Systems (Ventus), and Lynk3 Technologies (Lynk3).

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

TRADE SECRET

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-011
Please provide all the revenue requirement calculations and associated financial analysis and workpapers for the Langdon and Ashtabula wind farms that result in the proposed energy charge per KWh by jurisdiction. Please provide the financial analysis in an "Excel spreadsheet format with formulae intact.

RESPONSE:
See Attachment 1 to IR ND LIG-011 (TRADE SECRET).

Responding Witness:	Bernadeen Brutlag
Title:	Manager, Regulatory Services
Department:	Regulatory Services
Telephone:	(218) 739-8289
Date of Response:	2/17/2009

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:	2/04/2009
Date Received:	2/04/2009
Date Due:	3/06/2009

Information Request No. ND LIG-093
Provide a year-by-year breakdown of each revenue requirement item in the 25-year amortization schedule proposed by OTP for the Rider after the addition of the Ashtabula project.

Also, please provide a levelized amortization schedule of annual revenue requirements for this same period with the same present value of revenue requirements as the OTP proposal. Plot the levelized amortization as a straight line on the same graph showing OTP's Direct Pass-Through method and OTP's Smoothing method.

RESPONSE:

Attachment 1 to IR ND LIG-093 shows the combined North Dakota revenue requirements for both Langdon and Ashtabula for 25 years. This is only the revenue requirements for these two projects and does not include possible increases in the tracker balance caused by lags in cost recovery.

OTP's proposal does not include a present value component; we are unsure how to respond to this part of the request.

Attachment 2 to IR ND LIG-093 is a graph showing 25 years of revenue requirements under two scenarios: (1) OTP's proposed smoothing method and (2) the direct pass-through of the PTC.

Responding Witness:	Bernadeen Brutlag
Title:	Manager, Regulatory Economics
Department:	Manager, Regulatory Services
Telephone:	(218) 739-8289
Date of Response:	3/6/2009

North Dakota

Langdon and Ashtabula

	Year	ND Revenue Requirements
1	2007	0
2	2008	$3,502,427
3	2009	7,522,598
4	2010	6,459,737
5	2011	5,682,854
6	2012	5,114,218
7	2013	4,486,051
8	2014	4,051,600
9	2015	3,830,900
10	2016	3,671,367
11	2017	3,222,216
12	2018	3,224,493
13	2019	3,076,053
14	2020	3,037,837
15	2021	3,000,304
16	2022	2,963,471
17	2023	2,927,360
18	2024	2,891,992
19	2025	2,857,388
20	2026	2,823,571
21	2027	2,790,563
22	2028	2,758,389
23	2029	2,727,072
24	2030	2,696,637
25	2031	2,667,110
26	2032	3,568,502
27	2033	2,709,055

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-027
Please compare the per KWH and per MW cost of the Langdon PPA and OTP's cost of recovery to ratepayer's for OTP's ownership of Langdon that is included in the Renewable Rider, both annually as well as for the term of the PPA. Please also provide a copy of the PPA.

RESPONSE:
Attachment 1 to IR ND LIG-027 (TRADE SECRET) shows the cost per MWH of the Langdon PPA and the Langdon wind generation owned by OTP as it is proposed to be collected in the Renewable Resource Cost Recovery Rider. The PPA price is exclusively based on delivered energy (MWH).

Attachment 2 to IR ND LIG-027 (TRADE SECRET) is the Langdon PPA.

Responding Witness:	Pete Beithon
Title:	Manager, Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	2/17/2009

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-131
Please provide savings analysis of utilizing wind generation. Provide hourly and monthly on- and off-peak numbers to demonstrate the savings. Please provide this analysis for 2007, 2008 and projected for 2009 and 2010. Please describe the methodology used including references of LMP data used for each of the jurisdictions.

RESPONSE:

Attached as a spreadsheet (Attachment 1 to IR ND LIG-131) is an hourly analysis for the 40.5 MW OTP owned portion of the Langdon wind farm for 2008. The bulk of the construction took place in late 2007, so there is very little hourly data to analyze for 2007. The savings as indicated in the spreadsheet is **[TRADE SECRET DATA HAS BEEN EXCISED]** for 2008. OTP has not done a detailed projection for 2009 and 2010.

The accompanying spreadsheet (Attachment 1 to IR ND LIG-131) is an hourly analysis of the 40.5 MW Langdon wind farm performance. The columns are as follows:

A) Date (HE) – this column indicates the date and the hour ending time.

B) 40.5 Rate MWh generated – this column is the actual generation for the hour of the OTP owned 40.5 MW portion of the Langdon wind farm.

C) OTP Wind Gen Price (Levelized) – this is the 25 year anticipated levelized cost per MWh for the Langdon wind farm.

D) OTP DA Load Zone LMP – This is the day ahead load zone LMP price for the entire OTP load zone (OTP does not distinguish between MN, ND, and SD for load zone purposes).

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

E) Price Diff – This column is a formula (D - C). This column indicates the difference between market price and the levelized cost for each hour in 2008.

F) Savings (Cost) – This column is a formula (E*B). It indicates the weighted average benefit/(cost) of the energy produced for that particular hour.

Here are some notes that explain the summary numbers at the top of the spreadsheet that pertain to this IR.

A) 2008 Langdon Savings levelized vs market - this is a sum of the hourly savings (cost) column.

B) 2008 Langdon Savings Levelized vs market (MWh) – this is the savings from (A) divided by the actual MWh generated.

C) Weighted average DA load zone LMP – this cell takes the levelized cost of Langdon ($31.91) plus the Langdon Savings per MWh ($13.25) to arrive at a weighted average DA load zone LMP.

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

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-012
What is the actual capacity factor for the Langdon wind farm? What are the forecasted capacity factors for both the Langdon and Ashtabula wind farms? Please provide this information in an Excel spreadsheet format.

RESPONSE:
The net capacity factor as used in this response is computed as a percentage, where the numerator is the energy actually generated and the denominator is the maximum possible generation for the time period. This is not the same as the capacity credit we receive from MAPP. See response to IR LIG-20.

The Langdon wind farm became operational in mid-January 2008 with all wind turbines on-line by April 2008. The 40.5 MW portion of the wind farm that OTP owns generated 133,583 MWh in 2008.

During the startup period of January 2008 through March 2008 the energy generated from the Langdon wind farm was 24,233 MWh. The resulting net capacity factor is 27.4%, calculated as follows: 24,233 MWh / [2,184 hours X 40.5 MW].

After the startup period (April 2008 through December 2008) the energy generated from the Langdon wind farm was 109,350 MWh. The resulting net capacity factor is 40.9%, calculated as follows: 109,350 MWh / [6,600 hours X 40.5 MW].

The Renewable Resource Cost Recovery Rider filing (PU-08-742) used an estimated net capacity factor for Langdon of 42% and for Ashtabula of 41% for the purpose of calculating the Federal production tax credit, which is based on kWh generated.

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

TRADE SECRET

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-009
Please recalculate the Renewable Rider related charges in cents/KWh (energy charge) and$/KWh (demand charge) to all customer classes after classifying the wind generation into demand and energy using OTP's existing equivalent peaker method to classify other generation. Please provide these charges by service class and by North Dakota and Minnesota jurisdictions.

RESPONSE:

The following table is corrected to use the E2 energy factor. The original response used the E1 factor which was not appropriate as some kWh are not included in the E1 factor.

As stated in the original response to IR ND LIG-0009, "*OTP does not agree that the existing equivalent peaker method is appropriate to apply to non-dispatchable wind generation. However, the following information is provided for North Dakota as directed in this question. See the table below. This comparison uses the class demand and energy allocations for North Dakota in this case. A 28.11% demand and 71.89% energy split was used based on this case and the 2009 sales forecasts used in the rider filing. This case is only a North Dakota case, thus Minnesota is not provided here.*" If a demand component were to be used for wind generation, 28.11% is not appropriate as wind generation is not dispatchable. MISO uses a 20% capacity value currently for wind generation planning purposes.

Responding Witness:	Pete Beithon
Title:	Manager, Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	3/12/2009

Corrected
North Dakota

	kWh by class	Rider Rate	Rider Revenue	Revenue D & E	D & E Rev/kWh
Residential	469,667,495	$0.00510	2,395,116	2,628,789.13	0.00560
Farm	23,340,678	$0.00510	119,028	136,347.69	0.00584
General Service	428,055,767	$0.00510	2,182,913	2,430,179.32	0.00568
Large General Service	679,335,290	$0.00510	3,464,338	3,183,894.10	0.00469
Irrigation	795,240	$0.00510	4,055	2,563.61	0.00322
Outdoor lighting	22,947,135	$0.00510	117,021	112,537.77	0.00490
OPA	17,790,835	$0.00510	90,726	96,514.42	0.00542
Controlled water heating	18,154,083	$0.00510	92,579	81,032.07	0.00446
Controlled interruptible	169,821,863	$0.00510	866,024	687,633.82	0.00405
Controlled Deferred	21,270,404	$0.00510	108,471	80,747.63	0.00380
Total ND	1,851,178,792		9,440,271	9,440,240	

As originally included in IR ND LIG-009 using E1 energy allocator

North Dakota

	kWh by class	Rider Rate	Rider Revenue	Revenue D & E	D & E Rev/kWh
Residential	469,667,495	$0.00510	2,395,116	2,671,653	0.00569
Farm	23,340,678	$0.00510	119,028	147,387	0.00631
General Service	428,055,767	$0.00510	2,182,913	2,681,979	0.00627
Large General Service	679,335,290	$0.00510	3,464,338	3,566,691	0.00525
Irrigation	795,240	$0.00510	4,055	-	-
Outdoor lighting	22,947,135	$0.00510	117,021	126,952	0.00553
OPA	17,790,835	$0.00510	90,726	107,240	0.00603
Controlled water heating	18,154,083	$0.00510	92,579	41,173	0.00227
Controlled interruptible	169,821,863	$0.00510	866,024	55,044	0.00032
Controlled Deferred	21,270,404	$0.00510	108,471	42,119	0.00198
Total ND	1,851,178,792		9,440,271	9,440,240	

Responding Witness:	Pete Beithon
Title:	Manager, Regulatory Economics
Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	3/12/2009

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-145
Based on OTP's response to LIG IR No. 009, please provide the resulting $/KWh energy charge and $/KW demand charge for each customer class after simulating the following for the OTP Renewable Rider:

1. Please use OTP's current equivalent peaker method to classify wind like any other OTP owned generation prior to the jurisdictional split. Please provide the numerical analysis that indicates how the classification is conducted for all units including wind. Please provide the resulting jurisdictional splits.

2. Next, please allocate to the customer classes by jurisdiction including all demand metered and non demand metered customers. Include interruptible load.

3. Provide resulting $/KWh energy charge and $/KW demand charge for 2009.

RESPONSE:
Table 1 has columns marked $ Demand and $ Energy showing separately the revenue requirements from demand and energy using the equivalent peaker method that OTP used in Case No. PU-08-862. The percent allocated to demand is 28.11% based on OTP's base/peak split for 2007 for all units. The balance of the $9,440,271 revenue requirements is allocated to energy. The revenue requirements are allocated to class based on OTP's E2 energy allocator (which includes all kWh for all classes) and OTP's D1 demand allocator which is OTP's peak demand allocation factor. For the purposes of this exercise, OTP used the 2007 ND Test Year E2 and D1 allocation factors from Case No. PU-08-862. In Table 1 OTP takes the revenue requirements based on demand and energy, adds them together for non-demand billed classes and divides them by the total 2009 forecast kWh by class (as used in the filing in Case No. PU-08-742). For large general service OTP has taken the KW billing and kWh billing determinants from this

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Date of Response:	3/23/2009

case and divided the KW revenue requirements and kWh revenue requirements to determine the Rev/KW and the Rev/kWh.

Table 1

North Dakota	(A) kWh by class	(B) Rider Revenue	(C) Revenue Demand and Energy Basis	(D) $ Demand	(E) $/KW/MO	(F) $ Energy	(G) $/kWh	(H) D1 Allocator	(I) E2 Allocator
Residential	469,667,495	$2,395,116	$2,628,789				$0.00560	32.49991%	26.02714%
Farm	23,340,678	$119,028	$136,348				$0.00584	1.67424%	1.35442%
General Service	428,055,767	$2,182,913	$2,430,179				$0.00568	30.38358%	23.92815%
Large General Service	679,335,290	$3,464,338	$3,183,894	$821,919	$0.7189	$2,361,975	$0.00348	30.97313%	34.80357%
Irrigation	795,240	$4,055	$2,564				$0.00322	0.00000%	0.03777%
Outdoor lighting	22,947,135	$117,021	$112,538				$0.00490	0.88920%	1.31055%
OPA	17,790,835	$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	169,821,863	$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) OPA	(J) WATER HEATING	(K) SERVICE INTERRUPT	(L) SERVICE DEFERRED
	D1	259,222	84,247	4,340	78,761	80,289	-	2,305	2,963	368	5,377	572
	D1 %	41.65%	32.50%	1.67%	30.38%	30.97%	0.00%	0.89%	1.14%	0.14%	2.07%	0.22%
	E2	1,621,989	432,402	24,607	448,292	655,998	-	24,702	18,381	8,940	-	8,667
	E2%	39.73%	26.03%	1.35%	23.93%	34.80%	0.04%	1.31%	0.98%	1.14%	9.32%	1.10%
28.11%	Demand	$2,653,651	862,434	44,428	806,274	821,919	-	23,596	30,332	3,767	55,044	5,856
71.89%	Energy	$6,786,588	1,766,355	91,919	1,623,905	2,361,975	2,564	88,942	66,182	77,265	632,590	74,892
		$9,440,240	2,628,789	136,348	2,430,179	3,183,894	2,564	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

Responding Witness: Pete Beithon
Title: Manager, Regulatory Economics
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Date of Response: 3/23/2009

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-151
Regarding LIG IR No. 009, please describe in further detail the methodology used to calculate the results presented in your response. Show this methodology/numerical analysis in an Excel spreadsheet format with formulae intact. Additionally, was interruptible load excluded in doing the reallocation?

RESPONSE:
Interruptible load was not excluded in the reallocation. OTP inadvertently used the E1 factor instead of the E2 factor in the response to IR LIG-009. Attachment 1 to ND LIG-151 is an Excel spreadsheet showing the calculations on the corrected IR LIG-009 basis.

Responding Witness:	Pete Beithon
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Department:	Regulatory Services
Telephone:	(218) 739-8607
Date of Response:	3/23/2009

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-056
On page 35 of witness Prazak's testimony:

1. Please explain how OTP came to the conclusion that only 5%, or approximately 6 customers, will see an increase in their average monthly energy bill.

2. Please provide supporting data, i.e., energy usage (KWh), billed KW, and load factor.

Please demonstrate, by providing numerical analysis and description of methodology, how OTP reached the conclusion "the increase for the 5% with highest usage is primarily due to the removal of the declining demand block and declining energy load factor block structures".

RESPONSE:

1. The conclusion from Mr. Prazak's testimony (p. 36) is based on the result of the analysis of Figure 10, as described below.

   As also described in Mr. Prazak's Testimony (p. 16), OTP illustrates proposed customer impacts by using bar charts showing average monthly bill changes (dollar amounts and percentages) for duo-deciles (20 equal segments), ordered by average monthly kWh or MWh use, from smallest to largest. OTP took each customer's billing determinants from 2007 and re-billed them on the existing rates and on the proposed rates. The size of the bar on the chart represents the size of the increase in dollars for the average customer in that decile on proposed rates. Bars under the x-axis show a decrease, while the ones above the axis will have an increase in rates.

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

Attachment 1 ND 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%.

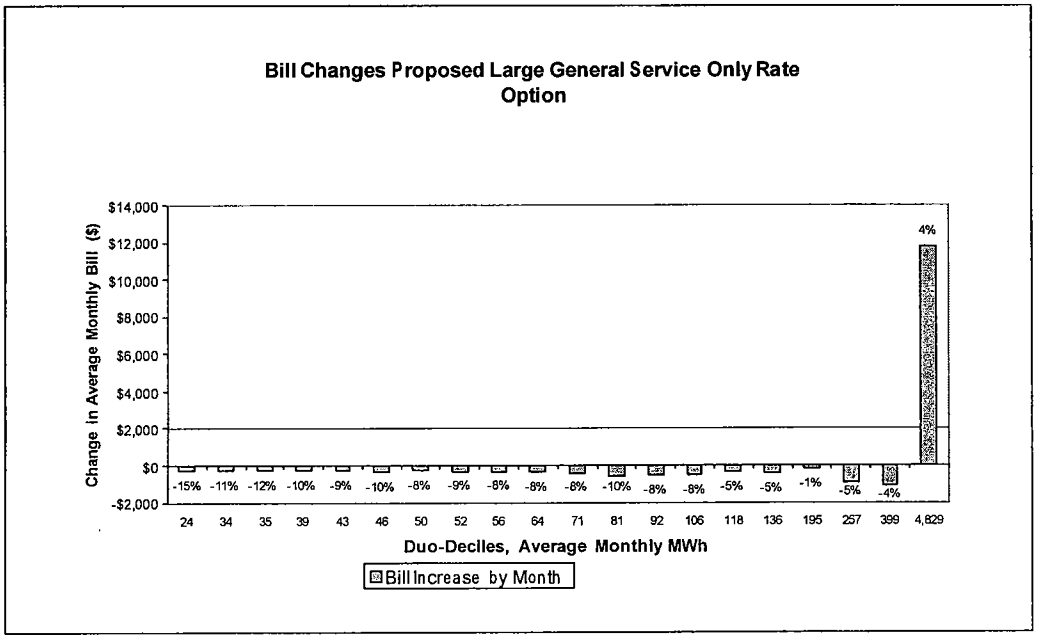
2. Please see Attachment 2 of ND LIG-056, which supports Attachment 1 ND LIG-056. The attachment contains the average energy, demand, and load factor for the duo-decile.

3. Attachment 3 of ND LIG-056 demonstrates, with numerical analysis, how OTP reached the conclusion "the increase for the 5% with highest usage is primarily due to the removal of the declining demand block and declining energy load factor block structures." To illustrate, three different customers, each with the same demand but different load factors (50, 75 and 100%) are compared between present and proposed rates as described below.

   On present rates the two customers (75 and 100% load factor) are consuming most of their energy on the discounted load factor block and the discounted excess kWh block. Most of their demand is being billed on the discounted demand block. With these discounted blocks going away under proposed rates these two customers will pay the same energy and demand rates as the other Large General Service customer (i.e. 50% load factor).

   Therefore, as Attachment 3 ND LIG-056 illustrates, higher load factor customers continue to pay less than smaller load factor LGS customers for the average kWh on their overall bill (see column Present H and Proposed F). This attachment demonstrates customers with more energy use in the present load factor block and discounted excess block will have a greater increase in costs primarily due to the removal of these blocks.

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


Bill Changes Proposed Large General Service Only Rate Option
Change in Average Monthly Bill ($)
$14,000
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$0
-$2,000
-15% -11% -12% -10% -9% -10% -8% -9% -8% -8% -8% -10% -8% -8% -5% -5% -1% -5% -4% 4%
24 34 35 39 43 46 50 52 56 64 71 81 92 106 118 136 195 257 399 4,829
Duo-Deciles, Average Monthly MWh
Bill Increase by Month

Large General Service Duo Decile Data

Decile	MWhs	MW	Load Factor %
5	24	67.9	55.5%
10	34	71.2	64.9%
15	35	84.6	58.5%
20	39	92.8	58.7%
25	43	94.8	62.9%
30	46	109.6	57.3%
35	50	116.0	58.6%
40	52	125.9	58.1%
45	56	144.2	54.6%
50	64	141.3	63.6%
55	71	167.0	60.4%
60	81	215.1	54.0%
65	92	259.8	54.1%
70	106	254.7	59.1%
75	118	248.1	67.1%
80	136	310.5	61.3%
85	195	371.9	72.7%
90	257	555.6	64.8%
95	399	816.3	66.9%
100	4,829	7999.4	77.0%

LGS Secondary Service Analysis

kW	Load Factor %	kWhs
3,000	100%	2,190,000
3,000	75%	1,642,500
3,000	50%	1,095,000

Present Rate Bill Calculation

(A) First 100 kW	(B) Excess kW	(C) Energy >360*kW	(D) Next 700,000 kWh	(E) Excess	(F) COE Avg. Cost	(G) Total Bill	(H) Avg. Cost per kWh	(I) Load Factor %
$833	$19,720	$32,579	$26,488	$11,320	$28,733	$119,673	$0.05464	100%
$833	$19,720	$16,509	$26,488	$11,320	$21,550	$96,420	$0.05870	75%
$833	$19,720	$440	$26,488	$11,320	$14,366	$73,168	$0.06682	50%

Proposed Rate Bill Calculation

	(A) Customer Charge	(B) Facilities Charge	(C) kW Charge	(D) Energy Charge	(E) Total Bill	(F) Avg. Cost per kWh	(G) Load Factor %
Summer	$40	$450	$21,390	$110,902	$132,782	$0.06063	100%
Summer	$40	$450	$21,390	$83,176	$105,056	$0.06396	75%
Summer	$40	$450	$21,390	$55,451	$77,331	$0.07062	50%
Winter	$40	$450	$8,640	$111,953	$121,083	$0.05529	100%
Winter	$40	$450	$8,640	$83,965	$93,095	$0.05668	75%
Winter	$40	$450	$8,640	$55,976	$65,106	$0.05946	50%

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-029
Regarding witness Parmesano's discussion of marginal costing methods starting on page 17:

1. Please provide a copy of marginal cost study and associated work papers.

2. Is this the same marginal cost study that witness Prazak refers to on pages 7 and 8 of his testimony as covering the period 2008 through 2012?

RESPONSE:

1. Please see Attachment 1 of ND LIG-029 (TRADE SECRET), which contains the 2009 OTP Marginal Cost Study, used in this proceeding.

   The associated work papers are not included in this response as the request is overly broad. If specific workpapers on specific subjects are sought, they should be identified with specificity.

2. Yes.

Responding Witness:	David G. Prazak
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Department:	Regulatory Services
Telephone:	(218) 739-8595
Date of Response:	02/20/2009

October 10, 2008

Privileged and Confidential
Prepared at Request of Counsel

Otter Tail Power Company
Marginal Cost of Electric Service Study for North Dakota and South Dakota Rate Cases

Prepared for:

Otter Tail Power Company

NERA
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Contents

List of Tables

I. INTRODUCTION

Otter Tail Power Company (OTP) retained NERA Economic Consulting to prepare an estimate of the company's marginal costs of supplying electricity for the years 2008-2012, for use in rate case filings in North Dakota and South Dakota. All costs are expressed in 2009 dollars. This report describes the methods for estimating marginal generation, transmission, distribution and customer-related costs and presents summary tables of the results.

What are marginal costs? Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must answer the question: What are the additional costs that would be incurred with changes in kilowatt-hours of energy, kilowatts of demand and number of customers? Because the cost of additional consumption may differ depending upon the time of the change in output, it is important to estimate time-differentiated marginal costs of electricity.

Our method for estimating marginal costs is based on the system planning process, and takes into account the wholesale market and transmission access arrangements specific to the environment where the utility operates. We determine the marginal cost of electricity by examining the utility's planning processes to determine what drives new investment and purchase/sale decisions and how changes in consumption affect utility system operations. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurements can be made.

II. COSTING/PRICING PERIODS

In this study we developed hourly marginal cost estimates for each time-varying component of marginal cost: generation (energy and capacity), transmission and higher voltage distribution. We then used regression analysis to identify several sets of feasible periods that minimize the squared differences between the individual hourly costs and the average for the period, but also take into consideration other factors. We constrained the number of seasons to two and number of diurnal periods to three, based on previous consultations with OTP staff. We gave added weight to patterns of hourly costs in the colder months within the eight-month "winter" season. In addition to accurately reflecting cost patterns, we also aimed to define periods that customers would understand and remember. TOD rates will not be effective if they are so complicated that customers do not choose to try them, or so confusing that customers have trouble remembering when the periods change. Working with OTP staff, we determined that the periods developed for the Minnesota rate case in 2007 (shown in Tables 1 and 2) are still applicable.

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
[redacted]

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

III. MARGINAL GENERATION COSTS

OTP actively participates in the Midwest ISO (MISO) electricity wholesale market, buying and selling on a short-term and long-term basis to minimize the cost of serving its retail customers and maximize profits on off-system (wholesale) sales. Even if OTP builds new generating units to meet load growth because it expects the cost of the new unit to be lower than the market price, the value of that unit's generation (and OTP's opportunity cost) is the market price. Thus, in a competitive electricity market, the marginal cost of generation is defined by market prices.

An increment of native load in any hour requires the utility to purchase more energy or sell less to the market. Thus the market price of energy is the basis for OTP's marginal energy cost.[1] An increment of load in some hours may require the utility to reduce the size of a capacity sale, arrange for additional generating capacity, pay penalties for not meeting capacity requirements, or incur market prices for energy that include a capacity (or shortage) element, depending on the timing of the load increase and the rules in effect. MISO establishes minimum planning reserve requirements for its members. As a result, separate markets for energy and capacity have developed, with generators recovering some of their fixed costs in the capacity market.[2] Under these market arrangements, the marginal cost of generation in a given hour is the sum of the spot price of energy and the hourly equivalent of the market price of capacity.

In applying the conceptual framework outlined above, three specific steps must be followed:

1. estimate the marginal energy cost for each hour based on a forecast of regional spot market energy prices;
2. estimate the market price of capacity in the MISO region;
3. convert the capacity market prices into hourly marginal capacity costs, taking into account OTP's probability of peak and the specific MISO reserve requirement rules, as explained in Section III.B.

[1] The market prices must be adjusted for cash working capital and losses to produce marginal costs at the customer meter level.

[2] There is often some capacity element in the spot price of energy as well, as impending shortages drive the market-clearing price above the marginal running cost of the marginal unit.

A. Marginal Energy Cost

OTP provided a May 2008 - April 2012 monthly forecast of market prices at MISO's Minnesota Hub, developed by the firm Powerlytix, for MISO's broadly defined peak and off-peak periods.[3]

We shaped these monthly energy peak and off-peak market price forecasts[4] using monthly average historical day-ahead hourly prices at the Minnesota hub covering the period May 1, 2006 to April 30, 2008. Table 2 shows the resulting forecast of energy market prices for 2008-2012, averaged over the costing periods described in Section II.

Table 3. 2008 – 2012 Market Price Forecast by Costing Period

		Summer Season			Winter Season		
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
		(2009 Cents per kWh)					
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2008	12.4209	9.5776	5.8801	9.7599	7.7185	4.7414
(2)	2009	11.8689	9.1536	5.5700	10.5184	8.5916	6.1157
(3)	2010	10.8282	8.1140	4.5314	9.6320	7.6840	5.1152
(4)	2011	10.5344	7.8445	4.2835	9.1956	7.2127	4.4913
(5)	2012	10.5851	7.8825	4.3101	9.1664	7.1840	4.4647

To convert these to energy marginal costs at customers' meters, it is necessary to make two adjustments. The first adjustment is a small factor to account for the cost of financing working capital necessary because OTP must pay for energy purchases before it is reimbursed by its customers. The cost of financing the balance includes a cost-of-capital component (OTP's estimated weighted-average cost of capital) and an income tax component that accounts for the fact that the equity portion of the financing is taxable. Second, they must be adjusted for marginal energy losses incurred in moving the energy through OTP's local transmission and distribution systems. Marginal energy losses are higher when energy is delivered at lower voltage levels. In addition, losses increase with the square of the load (all else equal) at any given voltage level. Thus there is a different loss adjustment factor for each hour and for each voltage level of service. The derivation of these marginal energy loss factors is described in

[3] The MISO period definition is as follows: On-peak is Monday – Friday, hours ending 7-22. Off-peak is all other hours.

[4] Plus actual average day-ahead prices for the Minnesota hub for January – April 2008.

Section VI.E. The market prices and marginal energy costs after these two adjustments are shown on Table 3.

Table 4. 2008-2012 Marginal Energy Cost by Costing Period

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
2008						
Market Price	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2009						
Market Price	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2010						
Market Price	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2011						
Market Price	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2012						
Market Price	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					

B. Marginal Generation Capacity Cost

Starting in January 2009, new MISO Resource Adequacy rules will require each load-serving entity (LSE) to demonstrate that it has sufficient planning reserves to meet their month's peak

load plus 15 percent.[5] The required reserve margin is calculated based upon MISO loss-of-load expectation (LOLE) studies that take into account the load diversity within MISO. At the beginning of each year each LSE will be required to submit a forecast of its monthly peak loads for the following 14 months, along with a resource plan that shows how it plans to meet the monthly peak demands plus the required reserve margin.

Each LSE will have to demonstrate that it is in compliance with the resource adequacy requirements 30 days in advance, or be subject to a penalty. Therefore, the very short-term marginal capacity cost is the probability of OTP's not meeting its capacity requirement multiplied by the applicable penalty.[6] However, for purposes of this marginal cost study, we have assumed that OTP plans for sufficient capacity so that it is unlikely to face the MISO penalty.[7]

On a planning basis, the marginal generation capacity cost in a given hour depends on the market price of capacity in the region, the probability that a marginal increase in OTP's load in that hour will require OTP to arrange for additional capacity (either through a capacity purchase or by selling less to the market) to meet its monthly capacity reserve requirements, and the required reserve margin.

1. Capacity market price forecasts

The market value of capacity in the region depends upon regional supply and demand conditions. Transactions are negotiated bilaterally in the MISO region, as there is no central clearing house for capacity transactions and no comprehensive record of prices and terms agreed.

While in theory capacity transactions in MISO may be done on a monthly basis, OTP Power Services indicates that short-term capacity transactions in MISO are primarily seasonal, rather than monthly. For example, if incremental capacity must be purchased for the month of July in order to meet planning requirements for that month, OTP must typically enter into a capacity transaction for the entire six-month MISO summer season (May – October).

OTP provided estimates of representative summer and winter capacity prices for the years 2008-2012, as shown in Table 4.[8]

[5] MISO is currently completing a study to determine whether the reserve margin required will be 15% or lower to allow achieve a Loss of Load Expectation of 1 day in 10 years. The study is not expected to be completed until the end of 2008; therefore we used 15% as a placeholder.

[6] The penalties for non-compliance have yet to be determined and approved by FERC.

[7] Real-time pricing options might incorporate short-run, penalty-based marginal capacity costs.

[8] These prices are also used by OTP for its Integrated Resource Planning (IRP).

Table 5. Forecast of Regional Capacity Market Prices

Year	Summer Capacity $ per kW-season (2009$)	Winter Capacity $ per KW-season (2009$)
2008	[TRADE SECRET DATA HAS BEEN EXCISED]	[TRADE SECRET DATA HAS BEEN EXCISED]
2009	[TRADE SECRET DATA HAS BEEN EXCISED]	[TRADE SECRET DATA HAS BEEN EXCISED]
2010	[TRADE SECRET DATA HAS BEEN EXCISED]	[TRADE SECRET DATA HAS BEEN EXCISED]
2011	[TRADE SECRET DATA HAS BEEN EXCISED]	[TRADE SECRET DATA HAS BEEN EXCISED]
2012	[TRADE SECRET DATA HAS BEEN EXCISED]	[TRADE SECRET DATA HAS BEEN EXCISED]

2. Time-differentiating Marginal Capacity Costs

Given the expected requirement to purchase capacity on a seasonal basis, OTP's marginal generation capacity cost in any hour is a function of (1) the seasonal price (2) the probability that the hour will be OTP's peak hour in the six-month MISO season, and (3) the required reserve margin. An hour that is not OTP's seasonal peak hour has zero marginal capacity cost, because no additional capacity requirement would be triggered if load grew by a small amount in that hour. If load were reduced by a small amount, OTP could not sell additional capacity because it would need that capacity to meet its requirement based on that season's expected peak demand.

The analysis requires estimating seasonal probability of peak, which indicates the relative likelihood that an hour is the season's peak hour, and therefore affects the level of capacity required for the entire season. As a result, assuming that the MISO Resource Adequacy rule requires a 15-percent reserve margin, the marginal capacity cost to OTP in a given hour under the new MISO Resource Adequacy requirements can be expressed algebraically as follows:

$$MCC_{h,s} = RPP_{s,h} \cdot 1.15\ MCP_s$$

where:

$MCC_{h,s}$ = marginal capacity cost in hour h and season s;

MCP_s = market capacity price per kW-season in season s;

$RPP_{s,h}$ = relative probability that hour h is OTP's seasonal peak in season s.

The relative seasonal probabilities of peak (based on OTP's costing periods) were calculated using OTP's hourly native loads for the period 2003-2007.

The resulting hourly marginal generation capacity costs, calculated according to the formula above, were then adjusted for marginal energy losses through OTP's transmission and distribution systems for the various voltage levels of service.[9] We also applied a factor to account for financing of cash working capital. The marginal capacity costs, expressed on a per-kWh basis and averaged over the hours within each costing period, are shown on Table 6. These same hourly generation capacity costs can be summed across the hours in a period to yield a marginal cost per kW, as shown in Table 7.

[9] An additional kWh of consumption (measured at the OTP consumer's meter) that requires a capacity purchase (or reduced sale), will trigger a transaction that includes marginal energy losses.

Table 6. 2008-2012 Marginal Generation Capacity Cost by Period (cents/kWh)

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
2008						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2009						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2010						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2011						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2012						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 7. 2008-2012 Marginal Generation Capacity Cost by Period ($/kW-month)

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Dollars per kW-month)					
	(1)	(2)	(3)	(4)	(5)	(6)
2008						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2009						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2010						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2011						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					
2012						
Marginal Capacity Costs	[TRADE SECRET DATA HAS BEEN EXCISED]					
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Primary	[TRADE SECRET DATA HAS BEEN EXCISED]					
Secondary	[TRADE SECRET DATA HAS BEEN EXCISED]					

IV. MARGINAL TRANSMISSION COST

OTP's transmission system consists of:

- All of Otter Tail's networked transmission including 345 kV, 230 kV, 115 kV, 69 kV and 41.6 kV facilities. Otter Tail's networked transmission greater than 100 kV has been transferred to the functional control of the Midwest ISO and included as part of the Midwest ISO's regional transmission expansion plan.

- Otter Tail retains control of its transmission facilities below 100 kV, with its planning on these facilities rolling up to the Midwest ISO's regional transmission expansion plan.

The costs of all bulk and load-serving facilities defined as transmission that were in service as of June 2008 within a control area are recovered at the wholesale level in the FERC-approved MISO Network Integration Transmission Service rate (NITS). Effective February 4, 2006, a Network Upgrade Charge (NUC) was established to recover the costs of new facilities above 100 kV,[10] with the costs of new projects allocated to sub-regions and pricing zones following the Midwest ISO's "Regional Expansion Criteria and Benefits" method (RECB) as approved by FERC.[11] Both NITS and NUC rates are assessed on the basis of a LSE's monthly peak demands.[12]

From the point of view of OTP, the marginal cost of transmission is the financial effect of using more or less the transmission system at the time of its monthly peaks. OTP does not write itself a check to pay for the use of the OTP Pricing Zone transmission facilities to serve its native load (the NITS charge).[13] However, both calculations of the MISO NITS and NUC charges assign to OTP a MISO transmission owners' transmission revenue requirement based on the allocation factors and billing determinants specified in the FERC-approved tariffs. Therefore, these charges are implicitly a financial marginal cost of transmission to OTP.[14]

[10] In practice, costs of new facilities above 100 kV with a project cost below $5 million will still be recovered in the NITS rate going forward.

[11] The RECB cost allocation methodology is specified in Attachment FF of the MISO TEMT. The Commission conditionally approved RECB I on February 3, 2006 and RECB II on March 15, 2007. 114 FERC ¶ 61, 106 and 118 FERC ¶ 61, 209, respectively.

[12] MISO rules (Section 34 of TEMT Modules, pages 331-332) call for these rates to be based on demands at the time of the MISO pricing zone's monthly peaks, but in practice individual transmission user monthly peaks are used instead.

[13] *See Midwest ISO.* 122 FERC 61,081 (2008).

[14] The costs of some ancillary services are also marginal financial costs. However, the ancillary services market is still been tested and therefore we were not able to obtain detailed cost forecasts and did not include an ancillary services marginal cost component in this study.

A. Network Integration Transmission Service Rate

The 2008 NITS rate, which recovers the costs of existing transmission facilities within the OTP Pricing Zone, is $3.26/kW-mo. The NITS rate is charged to each transmission user[15] in the OTP Pricing Zone based on their monthly peak loads. The Otter Tail NITS currently recovers the annual transmission revenue requirements for the Great River Energy (GRE) facilities located in the OTP Pricing Zone and for OTP transmission facilities. Missouri River Energy Services (MRES) has applied to become a transmission owner of the Midwest ISO and the bulk of their transmission facilities are located in the OTP Pricing Zone.

To estimate the NITS charges beyond 2008, NERA estimated the annual increase in NITS revenue requirement associated with OTP's applicable new transmission projects, using OTP budgets for 115-kV (below $5 million), 41.6 and 69 kV projects expected to come into service in the period 2008-2012, plus one GRE transmission project below $5M that will go into the OTP NITS zonal rate by 2011. We applied MISO's estimates of annual carrying charges to the budget figures to compute an annual incremental revenue requirement for the OTP Pricing Zone NITS.

To compute an incremental rate, we divided the additional annual OTP NITS revenue requirement, stated in 2009 dollars, by a forecast of the sum of OTP's and GRE's 12 monthly peaks in each year, following MISO Attachment O procedures.[16] We then added the current NITS rate ($3.2591/kW-mo.), adjusted by load growth[17] and stated in 2009 dollars, to obtain a forecast of the total OTP NITS rate in each year, shown in Table 8.

B. Network Upgrade Charge Rate

Forecasting a NUC is rather complex under the new RECB cost-sharing mechanism. Projects rated below 345 kV, at a cost greater than $5M, are allocated on a zonal basis. However, for all new projects rated 345 kV and above, with a project cost of $5M or greater, 20% of the costs are allocated on a system-wide basis. The remaining 80% of the costs are allocated to planning sub-regions (West, Central and East) and pricing zones under a method that differs between economic and reliability projects.[18]

- For economic projects (RECB II), the sub-regional 80% cost allocation is based on the net present value of the economic benefit associated with each sub-region, as determined by a power flow analysis. The cost is then allocated to each individual

[15] Except for certain grandfathered transmission agreements.

[16] For the forecast of OTP's 12 CPs we applied the expected growth in OTP 12 CP forecast (after load management) for the period 2008 – 2012, provided by OTP. For the forecast of GRE's 12 CPs we applied the peak load growth rates forecast in GRE's 2008 Resource Plan.

[17] Load growth every year reduces the per-kW impact of the current revenue requirement in the NITS charge.

[18] To qualify for regional cost sharing under the RECB postage stamp rate, both Baseline Reliability Projects and Regionally Beneficial Projects must include facilities 345kV and above. For transmission projects rated below 345-kV, all costs get allocated on a zonal basis.

pricing zone within the sub-region based on each zone's contribution to MISO's 12 CPs.

- For reliability projects (RECB I), 80% of the costs are allocated to individual pricing zones based on MISO's analysis of "Line Outage Distribution Factors" (LODF).

As a result, the total NUC transmission revenue requirement allocated to the OTP Pricing Zone is the sum of the system-wide allocation, the sub-regional allocation percentages, and the individual LODF allocations corresponding to new projects.[19] The total dollar revenue requirement amount is then divided by the sum of 12 CPs in the OTP zone to establish the corresponding NUC rate.

To estimate the NUC charges corresponding to the OTP Pricing Zone for the period 2008 - 2012, we first restated in 2009 dollars MISO's projections of the NUC-related annual incremental transmission revenue requirements to be allocated to OTP's pricing zone for the same period, based on the MTEP 07 Expansion Plan. A draft MTEP08 was released at the time of completion of the draft report with new approved projects, which we included in our NUC projection. The MTEP08 cost allocation was not yet final so the NUC projections are preliminary.[20]

We divided the annual revenue requirements from the expected project costs allocated to OTP pricing zone by the combined OTP and GRE 12 monthly peak forecast in each year.[21] Next, we added the current OTP NUC charge ($0.00367/kW-mo.) adjusted by load growth[22] and stated in 2009 dollars, to the estimated incremental charge to obtain the NUC rate in each year, as shown in Table 8.

[19] For transmission associated with a new generator interconnection, 50% of the cost is to be paid by the generator, while the remaining 50% allocation is split similar to that noted for RECB I and II such that for projects 345 kV or greater, the costs are allocated 20% system-wide and 100% sub-regional basis and projects below 345 kV are allocated 80% to pricing zones pursuant to the LODF analysis.

[20] NUC revenue requirements were based on MISO MTEP07-RECB-I and draft MTEP08 RECB, with estimated Annual Charges for Allocated Project Cost by Pricing Zone. Provided by Tim Rogelstad and JoAnn Thompson.

[21] For the forecast of OTP's 12 CPs we applied the expected growth in OT's 12 CP forecast (after load management) for the period 2008 – 2012, provided by OTP. For the forecast of GRE's 12 CPs we applied the peak load growth rates forecast in GRE's 2008 Resource Plan.

[22] Load growth every year reduces the per-kW impact of the current revenue requirement in the NUC charge.

Table 8. Summary of 2008 – 2012 NITS and NUC charges in OTP Pricing Zone

		2008	2009	2010	2011	2012
				(2009 $/kW-mo.)		
(1)	NITS charges ($/kW-mo)	$3.3569	$3.0063	$2.9879	$3.0862	$2.9709
(3)	NUC charges ($/kW-mo)	$0.0038	$0.0035	$0.0584	$0.0608	$2.0596
(4)	**Total OTP Transmission Charges ($/kW-mo)**	**$3.3607**	**$3.0098**	**$3.0463**	**$3.1470**	**$5.0306**

C. Marginal Financial Transmission Cost

The MISO NITS and NUC charges are constant every month, as they reflect 1/12 of the applicable revenue requirement per kW. Because these charges are assessed on the basis of a transmission user's monthly peak demands, we identified marginal transmission costs responsibility within each month by estimating the relative probability of a given hour's being the monthly peak. We estimated these probabilities using OTP's native hourly loads for the period 2003-2007.

Table 9 shows the resulting time-differentiated marginal transmission costs for year 2009 by costing period, after adjustments for losses between the OTP system boundary and OTP customers' meters (using estimates of marginal energy losses at the time of each monthly peak) and cash working capital.[23] Transmission costs for other years covered by the study are shown in the Appendix.

[23] The same marginal transmission costs stated on a per kW basis are shown in the summary tables at the end of the report.

Table 9. 2009 Time-Differentiated Marginal Transmission Costs

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Marginal Transmission Service Costs	1.9200	0.1823	0.0058	1.2772	0.2638	0.0093
Marginal Transmission Charges by Voltage Level, Adjusted for Losses						
(2) Transmission	2.1187	0.2014	0.0063	1.4221	0.2949	0.0104
(3) Primary	2.1870	0.2080	0.0065	1.4727	0.3059	0.0109
(4) Secondary	2.1983	0.2091	0.0066	1.4811	0.3077	0.0109

V. MARGINAL DISTRIBUTION COSTS

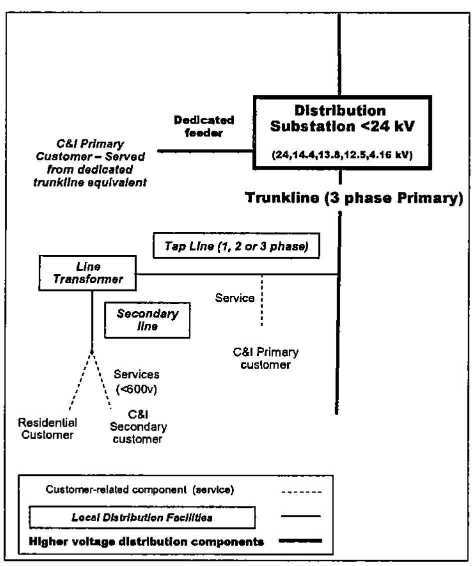
Conceptually, most costing practitioners agree that the design of the distribution system is determined by two major factors: (1) the number and location of customers and (2) their demands. Marginal cost studies have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. This has led to semantics arguments about the definition of the customer-related and demand-related components. In fact, for most distribution systems, this two-part segmentation of distribution equipment is not consistent with the cost drivers, because it ignores the fact that there are two types of demand that determine distribution capacity requirements for a particular customer – design (or contract) demand and near-term demand at time of likely neighborhood peaks.

The diagram below, Table 10, is a simplified representation of OTP's distribution system and the configurations of typical customer connections. The various components are categorized as:

- higher voltage distribution components (shown as bold lines and boxes): distribution substations and primary trunkline feeders.
- local distribution facilities: secondary lines, primary-to-secondary transformers and switchgear and primary taps (shown as solid boxes);
- dedicated feeders used by some large primary customers (shown as a bold line);[24] and
- customer-related service drops (shown as dashed lines).

[24] This study does not calculate separate marginal costs for such customers.

Table 10. Illustration of OTP's Distribution System



OTP adds distribution substations as load grows, either from connection of new customers or growth by existing customers. The trunkline feeders from the substation to the point where the line branches to create a primary tap line also must be upgraded or rerouted as load grows. Because these more extensively shared, higher voltage distribution components are expanded as customer loads grow in critical hours, they are time-differentiated.

Local distribution facilities are designed using engineering design standards that take into consideration the number of customers and the *maximum expected* loads (or "design demands")

of customers who will eventually use those facilities, over the life of the facilities. For example, on average twice as much capacity is built into the local distribution system to serve an apartment with all electric appliances as one with gas appliances. Local distribution facilities for commercial and industrial customers are generally designed on a case-by-case basis, taking into consideration the expected long-term peak demand by the customer.

Because the marginal cost of local distribution facilities is incurred based on design demand, and does not vary with a customer's actual peak load from month to month, these costs are computed as a fixed monthly cost per kW of design (or contract) demand. If necessary, design demand can be represented by some proxy, such as transformer capacity, contract capacity or actual peak in the past 12-24 months.

The service drop in most cases serves a single customer. The service, along with the meter and associated equipment such as current transformer (not shown in the diagram), is treated as part of the marginal customer cost for each class.

A. Distribution Substation and Trunkline Feeder Costs

To estimate the marginal cost of typical distribution substation and trunkline feeder expansion per kW of demand, we typically identify the cost of budgeted load growth-related projects of this type (excluding any replacement projects that do not add capacity) and the load growth that is driving the need for the additional capacity.

In the case of OTP, adequately detailed capital budgets for future years were not available due to uncertainty in load growth. Consequently, we relied on 2005-2008 information to estimate growth-related investment. We divided the sum of growth-related investment (in 2009 dollars) over the period 2005-2008 by the growth in the sum of weather-normalized non-coincident distribution substation annual peaks over the same period.[25] The marginal investment per kW is shown on Table 11.

[25] The substation non-coincident demand (NCD) forecast was developed by Otter Tail using a regression approach.

Table 11. Distribution Substation and Trunkline Feeder Investment

(1)	Investment in Growth-Related Additions to Distribution Substation Plant, 2005-2008 (Thousands of 2009 Dollars)	$8,384
(2)	Estimated Additions to Distribution Substation Non-coincident Demand, 2005-2008 (MW)	83.94
(3)	Marginal Investment in Growth-Related Distribution Substation Facilities per Non-Coincident Kilowatt (2009 Dollars) (1) / (2)	$99.87

1. Distribution Substation Marginal O&M Expenses

Distribution O&M expenses depend on the amount of plant in service. The addition of distribution plant to meet increments in customers or design load or peak substation load gives rise to increased O&M expenses as well. Distribution O&M expenses are, therefore, marginal costs. OTP's FERC Form 1 filings provide 2003-2007 distribution O&M expenses by FERC account. Expenses for individual components (e.g., meters, substations, etc.) were allocated a proportional share of the general overhead O&M categories.[26] The trends in recent average levels of each category of distribution O&M were the starting point for our estimates of marginal O&M expenses.

The 2003-2007 distribution substation O&M expenses, plus associated overheads, were divided by estimates of the sum of non-coincident peak demands at the substations and converted to 2009 dollars, as shown on Table 12. After reviewing the trend in expense per kW (in constant dollars), we used the average of the 2005-2007 values as our estimate of marginal substation O&M expenses.

[26] These general accounts consist of Operation Supervision and Engineering and Maintenance Supervision and Engineering, and Miscellaneous Maintenance Expense.

Table 12. Distribution Substation O&M Expense per kW

	Year	Total Distribution Substation Expenses ('000 Dollars) (1)	Estimated Substation Noncoincident Peak (kW) (2)	Substation Expenses Per kW of Substation Noncoincident Peak Loads (Dollars) (1) / (2) (3)	Weighted Labor and Materials Cost Index (2009=1.00) (4)	Substation Expenses Per kW of Substation Noncoincident Peak Loads (2009 Dollars) (3) / (4) (5)
(1)	2003	1,493.15	768,293	1.94	0.74	2.61
(2)	2004	1,684.36	793,636	2.12	0.78	2.73
(3)	2005	1,869.82	807,232	2.32	0.81	2.85
(4)	2006	2,143.34	836,949	2.56	0.85	3.00
(5)	2007	2,189.67	855,921	2.56	0.91	2.81
(6)	Estimated Annual Distribution Substation O&M Costs (Average of 2005-2007 Values)					$2.89

2. Time-differentiation of Marginal Distribution Substation Costs

Only load growth when capacity is strained triggers additions to the higher voltage distribution system. We analyzed hourly loads on a sample of representative OTP distribution substations for the years 2003-2007.[27]

We estimated the relative probability of peak for months, day-types (weekdays, Saturday, and Sunday) and hours for each substation, taking into account the higher carrying capability of this equipment in cold temperatures. We then calculated weighted averages of these individual substation relative probabilities of peak, with weights representing the estimated number of customers served by substations similar in size and peak season to the sample substations. The period assignment factors are shown on Table 13.

[27] The 2003 data was excluded for two of the representative distribution substations because of irregular or missing data in that year.

Table 13: Probability of Peak for Higher-Voltage Distribution Investment

		Relative Probability of System Peak
Summer Season		
(1)	Peak	36.77%
	Shoulder	25.49%
(2)	Off-Peak	0.33%
(3)	Subtotal	62.59%
Winter Season		
(4)	Peak	14.27%
	Shoulder	5.42%
(5)	Off-Peak	17.73%
(6)	Subtotal	37.41%
(7)	**Total**	100.00%

B. Local Distribution Facility Costs

1. Local Distribution Facility Investment

OTP developed estimates of the typical investment in secondary lines, transformers, and a portion of primary taps for various types and sizes of customers, by applying its standard distribution cost estimation to a range of typical customer characteristics.[28]

Because the marginal cost of local distribution facilities is incurred based on design demand, and does not vary with a customer's actual peak load from month to month, we computed these costs as a monthly cost per kW of design (or contract) demand. We used the transformer capacity divided by the number of customers served from that transformer as the estimated design demand.

The distribution facilities investments for residential and non-residential customer categories are shown on Table 14. Retail customers that take service at a transmission voltage are

[28] OTP also used this approach d to estimate the cost of customer service drops.

responsible for the cost of facilities to tap into the OTP transmission system, and so are excluded from this analysis.

Table 14 also shows distribution facilities (including lighting equipment) investment, provided by OTP, covering four lighting configurations.

Table 14. Marginal Distribution Facilities Investment per kW of Design Demand or per Light

	Customer Class	Average Investment per kW (2009 Dollars) (1)	Average Investment per lamp (2009 Dollars) (2)
	Residential		
(1)	Urban	$150.25	
(2)	Rural	$269.73	
(3)	Apartment, Gas	$154.14	
(4)	Apartment, Elec	$72.88	
(5)	**Farm**	$344.92	
	Small Commercial		
(6)	Stand-Alone customer, overhead	$42.50	
(7)	Stand-Alone customer 3ph, overhead	$69.12	
(8)	Shared-customer 3ph, overhead	$76.92	
(9)	Stand-Alone customer, underground	$104.44	
(10)	Shared-customer 3ph, underground	$170.17	
	Large Commercial		
(11)	101-150kVa, 3ph	$106.46	
(12)	151-300kVa, 3ph	$63.30	
(13)	301-500kVa, 3ph	$44.28	
(14)	>501 kVa, 3ph	$26.84	
	Lighting		
(15)	Area Light 1 HPS 9 (no pole), underground		$1,380.80
(16)	Area Light 1 HPS 9 (no pole), overhead		$1,252.18
(17)	Street Light - (no light, no pole), underground		$798.69
(18)	Street Light - (no light, no pole), overhead		$671.65

2. Local Distribution Facility Operation and Maintenance

Re reviewed the 2003-2007 local distribution facilities O&M expenses, and separated line-related expenses into primary and secondary categories on the basis of miles of conductor. We divided the expenses for each voltage level by estimates of total design demand of customers using those facilities. Total design demand was the product of customer counts and per-customer design demand estimates by customer category, developed from load survey data. We used the average of the 2006 and 2007 values as our estimate of marginal distribution facilities O&M expense.

Table 15. Distribution Facilities O&M Expense per kW of Design Demand

	Year	Distribution Line O&M Expenses	Weighted Labor and Materials Cost Index	Weighted Distribution Line O&M Expenses	Total Estimated Demand	Line O&M Expense per kW of Design Demand: Secondary	Primary
		('000 Dollars)	(2009=1.00)	(2009 $)		(2009 $) (1)/(2) x 0.32	(1)/(2) x 0.54
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2003	4,909.43	0.7449	6,590.72	1,638,944	$1.30	$2.17
(2)	2004	5,070.85	0.7762	6,532.91	1,828,287	$1.16	$1.93
(3)	2005	5,872.89	0.8133	7,221.06	1,924,131	$1.22	$2.03
(4)	2006	7,253.72	0.8541	8,492.82	1,959,734	$1.41	$2.34
(5)	2007	7,803.63	0.9098	8,577.30	2,023,113	$1.38	$2.29
(6)	Estimated Distribution Facilities O&M for a Primary Customer Col. (4) (Average of 2006-2007 Values)						$2.32
(7)	Loss Adjustment Factor for Use of Primary Lines by Secondary Customers						1.023
(8)	Loss Adjusted Estimated Primary Lines O&M Expenses for Secondary Customers Line (6) * Line (7)						$2.37
(9)	Total Estimated Distribution Facilities Line O&M for a Secondary Customer. Line (5) in Col.(3) + Line (8)						$3.75

C. Meter and Service Costs

1. Meter and Service Investment

OTP provided the installed cost of a typical meter (including current transformer, if applicable) and service drop for customer categories. Approximately one in four customers takes service under a base tariff plus a rider requiring a second meter. The typical meter (and associated equipment) and service drop investments, stated in 2009 dollars are shown on Table 16.

Table 16. Investment per Customer in Meters and Services

		Customer Class	Meter	Services	Total
			Investments per customer -(2009 Dollars)-		
			(1)	(2)	(3)
		Residential			
R-01	(1)	Residential	$76.08	$406.10	$482.18
R-03	(2)	Residential Controlled Demand	$375.55	$406.10	$781.65
R-91	(3)	Residential Water Heat Controlled	$257.57	$0.00	$257.57
I-02	(4)	Residential Controlled Dual Fuel	$280.05	$0.00	$280.05
I-03	(5)	Residential Controlled Service Defferred Load	$337.13	$0.00	$337.13
I-04	(6)	Residential Fixed Time Of Delivery	$337.13	$0.00	$337.13
M-42	(7)	Street and Area Lighting	$0.00	$0.00	$0.00
	(8)	Flood Lighting	$0.00	$0.00	$0.00
	(9)	Sign Lighting	$0.00	$0.00	$0.00
	(10)	Energy-Only Street And Area Lighting - Metered	$76.08	$0.00	$76.08
	(11)	Energy-Only Street And Area Lighting - Non-Metered	$0.00	$0.00	$0.00
		Commercial and Industrial			
G-01	(12)	General Service	$320.97	$562.07	$883.04
	(13)	Flood-Athletic Field Lighting- South Dakota Only	$335.26	$0.00	$335.26
G-02	(14)	General Service (Control Demand)	$1,094.90	$492.60	$1,587.50
F-61	(15)	Farm Service	$330.69	$434.72	$765.42
C-02	(16)	Large Commercial Service			
		Secondary	$1,173.12	$25,837.94	$27,011.06
		Primary	$6,831.12	$26,611.21	$33,442.33
C-03	(17)	Large General Service (Real Time Pricing) Primary	$6,831.12	$26,611.21	$33,442.33
C-04	(18)	Large General Service (Off Peak Rider) Primary	$6,831.12	$26,611.21	$33,442.33
C-09	(19)	Large General Service (Time Of Use) Primary	$6,831.12	$26,611.21	$33,442.33
R-91	(20)	Commercial Water Heat Controlled	$257.57	$0.00	$257.57
I-01	(21)	Large Commercial Controlled Dual Fuel	$1,264.65	$0.00	$1,264.65
I-02	(22)	Small Commercial Controlled Dual Fuel	$280.05	$0.00	$280.05
I-03	(23)	Small Commercial Controlled Service Defferred Load	$337.13	$0.00	$337.13
I-04	(24)	Small Commercial Fixed Time Of Delivery	$337.13	$0.00	$337.13
I-06	(25)	Bulk Interruptible Service	$6,831.12	$26,611.21	$33,442.33
M-03	(26)	Irrigation Service	$906.77	$406.10	$1,312.87
M-04	(27)	Commercial Time Of Use	$1,094.90	$26,611.21	$27,706.11
	(28)	Street and Area Lighting	$0.00	$0.00	$0.00
	(29)	Flood Lighting	$0.00	$0.00	$0.00
	(30)	Sign Lighting	$0.00	$0.00	$0.00
	(31)	Energy-Only Street & Area Lighting - Metered	$76.08	$0.00	$76.08
	(32)	Street & Area, Flood and Sign Lighting	$0.00	$0.00	$0.00
	(33)	Other Public Authority	$292.01	$687.11	$979.12

2. Meter and Service Operation and Maintenance Expenses

The meter O&M per weighted customer (using relative meter cost as weights) increased significantly over in the past two years. We used the average over the period 2006-2007 as the estimate of the marginal level of these expenses, as shown on Table 17. Table 18 multiplies the result by the class weights to yield annual meter O&M by class.

Table 17. Meter O&M Expense per Weighted Customer

	Year	Total Meter Operation & Maintenance Expenses	Average Number of Customers	Weighted Average Number of Customers	Meter Expense Per Weighted Customer	Weighted Labor and Materials Cost Index	Meter Expense Per Weighted Customer
		(000's Dollars)		(2) x 1.83	(Dollars) [(1) x 1000]/(3)	(2009=1.00)	(2009 Dollars) (4)/(5)
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2003	1,392.45	177,165	324,863	4.29	0.74	5.75
(2)	2004	1,314.91	177,666	325,782	4.04	0.78	5.20
(3)	2005	1,495.24	178,268	326,885	4.57	0.81	5.62
(4)	2006	2,189.58	179,080	328,375	6.67	0.85	7.81
(5)	2007	2,316.82	178,259	326,869	7.09	0.91	7.79
(6)	Estimated Annual Weighted CT and Meter O&M Expense for the Planning Period (Average of 2006 and 2007 Values)						7.80

Table 18. Meter O&M Expense by Customer Class

		Customer Class	Weighting Factor	Annual Meter Expense Per Customer
				(2009 Dollars) (1) x $7.80
			(1)	(2)
		Residential		
R-01	(1)	Residential Service	1.00	$7.80
R-03	(2)	Residential Service (Control Demand)	1.00	$7.80
R-91	(3)	Water Heating (Controlled)	1.00	$7.80
I-01	(4)	Controlled Service	1.00	$7.80
I-02 & I-03	(5)	Controlled Service	1.00	$7.80
I-04	(6)	Fixed Time Of Delivery Service	1.00	$7.80
	(7)	Street and Area Lighting	0.00	$0.00
	(8)	Flood Lighting	0.00	$0.00
	(9)	Sign Lighting	0.00	$0.00
	(10)	Energy-Only Street And Area Lighting - Metered	1.00	$7.80
	(11)	Energy-Only Street And Area Lighting - Non-Metered	0.00	$0.00
		Commercial and Industrial		
G-01	(12)	General Service < 20 kW	1.00	$7.80
G-01	(13)	General Service >= 20 kW	13.11	$102.24
G-02	(14)	General Service (Control Demand)	13.11	$102.24
F-61	(15)	Farm Service	1.00	$7.80
C-02	(16)	Large Commercial Service		$0.00
		Secondary	26.22	$204.47
		Primary	26.22	$204.47
C-03	(17)	Large General Service (Real Time Pricing)	157.31	$1,226.82
C-04	(18)	Large General Service (Off Peak Rider)	157.31	$1,226.82
C-09	(19)	Large General Service (Time Of Use)	157.31	$1,226.82
R-91	(20)	Water Heating	0.00	$0.00
I-01	(21)	Large Controlled Service	26.22	$204.47
I-02	(22)	Small Controlled Service	9.83	$76.68
I-03	(23)	Small Controlled Service	13.11	$102.24
I-04	(24)	Fixed Time Of Delivery Service	0.00	$0.00
I-06	(25)	Bulk Interruptible Service	157.31	$1,226.82
M-03	(26)	Irrigation Service	9.83	$76.68
M-04	(27)	Commercial Time Of Use	26.22	$204.47
M-42	(28)	Area, Flood & Sign Lighting	0.00	$0.00
	(29)	Streetlighting	0.00	$0.00
	(30)	Other Public Authority	13.11	$102.24

Development of lighting O&M is shown on Table 19. OTP books expenses for both lighting facilities and distribution facilities used by lights in the FERC lighting O&M accounts.

Table 19. Lighting O&M Expense per Light

	Year	Total Lighting Operation Maintenance Expenses ('000 Dollars)	Number of Lights	Lighting Expenses Per Light (Dollars) (1)/(2)*1000	Weighted Labor and Materials Cost Index (2009=1.00)	Lighting Expense Per Light (2009 Dollars) (3)/(4)
		(1)	(2)	(3)	(4)	(5)
(1)	2003	$697	50,928	13.68	0.7449	18.36
(2)	2004	$924	50,589	18.27	0.7762	23.53
(3)	2005	$979	50,854	19.26	0.8133	23.68
(4)	2006	$1,069	50,930	20.99	0.8541	24.57
(5)	2007	$1,131	51,047	22.15	0.9098	24.35
(6)	Estimated Annual Weighted Lighting O&M Expense for Planning Period (Average of 2006-2007)					$24.46

VI. OTHER MARGINAL COSTS

A. Customer Accounts Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are costs that are the function of a number of customers on the system. As a starting point we reviewed OTP's FERC Form 1 customer account and service expense levels for the period 2003-2007.

As shown on Table 20, we divided annual customer accounts expenses for 2003-2007 by weighted customers to obtain a customer accounts expense per weighted customer.[29] The weights reflect the relative cost responsibility of each class for each sub-account, as measured by allocators such as number of customers, or revenue. These allocation factors, covering ten cost-of-service groups employed in OTP's Embedded Cost of Service Study (ECOSS), were combined with new allocators that we developed for specific activities within FERC accounts. We used the average expense per weighted customer over the entire period as an estimate of marginal expense.

Table 20. Customer Accounts Expense per Weighted Customer

		2003	2004	2005	2006	2007
		(1)	(2)	(3)	(4)	(5)
(1)	Customer Accounts Expenses (Thousand Dollars)	$7,398.96	$7,914.07	$7,820.39	$8,366.48	$9,103.00
(2)	Number of Customers	177,165	177,666	178,268	179,080	178,259
(3)	Weighted Customers (2) x 0.98	173,622	174,113	174,702	175,499	174,694
(4)	Expense per Weighted Customer (Dollars) [(1) / (3)] x 1000	$42.62	$45.45	$44.76	$47.67	$52.11
(5)	Labor Cost Index (2009=1.00)	0.80	0.83	0.87	0.90	0.93
(6)	Expense Per Weighted Customer in 2009 Dollars (4) / (5)	$53.36	$54.46	$51.66	$53.03	$55.87
(7)	Estimated Annual Expense Per Weighted Customer For the Planning Period (2009 Dollars) (Average 2003-2007)			$53.67		

[29] FERC account 902 activity 181 (Meter Reading Expenses/Meter Turn-on) expenses were excluded because connection/reconnection costs are incurred specifically for customers requiring these services and are not part of generic marginal customer costs.

We developed the customer accounts expense for each customer class by multiplying the class weighting factor by the expense per weighted customer.[30]

Table 21. Customer Accounts Expense by Customer Class

	Class	Weighting Factor	Annual Customer Accounts Expense Per Customer (2009 Dollars) (1) x $53.67
		(1)	(2)
(1)	Residential	1.00	$53.67
(2)	Farm	1.06	56.86
(3)	Small Commercial	1.47	78.69
(4)	Large Commercial	1.28	68.84
(5)	Lighting	0.57	30.55
(6)	Other Public Authority	1.55	83.37
(7)	Water Heating	0.70	37.47
(8)	Deferred Loads	1.31	70.34
(9)	Controlled Loads	0.81	43.22
(10)	Irrigation Service	1.13	60.66

B. Customer Service and Informational Expenses

Customer service and informational expenses, which include the costs of disseminating information to consumers, vary with the number of customers on the system and are, therefore, marginal.[31] The same procedure used for customer accounts expenses was followed to generate an estimated annual expense per weighted customer (Table 22) and per customer by class (Table 23), using the class weights developed from OTP's ECOSS. We used an average

[30] Note that some tariffs, e.g., General Service (Controlled Demand), are assigned costs under two cost of service groups, in this case Small Commercial and Water Heating.

[31] Note that expenses associated with CIP, a program mandated by Minnesota to promote demand side measures, were omitted because the program is only applicable to Minnesota and funding is based on total revenues before revenue taxes, and is not technically a marginal cost of providing service. Also omitted are expenses related to equipment provided to load control customers. These are costs of the load control program, and not marginal customer costs. Lastly, expenses from marketing products and services (account 908, activity 880) were excluded as they are not marginal costs of providing electric service.

of 2006 and 2007 expenses per weighted customer because the level of these expenses dropped off recently.

Table 22. Customer Informational and Service Expense per Weighted Customer

		2003	2004	2005	2006	2007
		(1)	(2)	(3)	(4)	(5)
(1)	Customer Service and Informational Expenses (Thousand Dollars)	$2,382.23	$2,433.99	$2,434.25	$2,373.64	$2,457.69
(2)	Number of Customers	177,165	177,666	178,268	179,080	178,259
(3)	Weighted Number of Customers (2) x 1.40	248,031	248,733	249,575	250,712	249,563
(4)	Expense Per Weighted Customer (Dollars) [(1) / (3)] x 1000	$9.60	$9.79	$9.75	$9.47	$9.85
(5)	Labor Cost Index (2009=1.00)	0.80	0.83	0.87	0.90	0.93
(6)	Expense Per Weighted Customer in 2009 Dollars (4) / (5)	$12.03	$11.72	$11.26	$10.53	$10.56
(7)	Estimated Annual Expense Per Weighted Customer For the Planning Period (2009 Dollars) (Average 2006-2007)			$10.55		

Table 23. Customer Informational and Service Expense by Customer Class

	Class	Weighting Factor	Annual Customer Service and Informational Expense Per Customer
			(2009 Dollars)
		(1)	(1) x $10.55 (2)
(1)	Residential	1.00	$10.55
(2)	Farm	0.76	8.00
(3)	Small Commercial	3.08	32.43
(4)	Large Commercial	49.57	522.73
(5)	Lighting	0.76	8.00
(6)	Other Public Authority	0.76	8.00
(7)	Water Heating	0.76	8.00
(8)	Deferred Loads	0.76	8.00
(9)	Controlled Loads	0.76	8.00
(10)	Irrigation Service	0.76	8.00

C. Administrative and General Expenses

When a utility adds plant and incurs additional O&M expenses, it typically incurs additional overhead costs as well. Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. General plant typically grows with other types of plant. Our marginal cost study includes plant-related A&G, non-plant-related A&G and general plant loaders to capture these elements of marginal cost.

Based on our understanding of OTP's classification of costs in the various FERC accounts for A&G expenses (including social security and unemployment taxes), we divided these expenses into two categories: (1) those associated with other types of expenses and (2) those associated with plant. We excluded accounts not likely to be marginal with respect to other expenses or plant.[32]

We identified as potentially marginal non-plant related FERC A&G Accounts 408.1 (Social Security and Unemployment Insurance Taxes), 920 (Administrative and General Salaries), 921

[32] We excluded FERC Accounts 922 Administrative Expenses Transferred (Credit), 923 Outside Services Employed, 927 Franchise Requirements, 928 Regulatory Requirements and 930.1 Institutional and Goodwill Advertising Expenses, which we found to be not marginal for OTP.

(Office Supplies and Expenses), 925 (Injuries and Damages), 926 (Employee Pensions), 929 (Transfers and Credits), and 930.2 (Miscellaneous General Expenses).

We opted to divide our analysis of non-plant-related A&G expenses. For post employment benefits where expenditures fluctuate with financial market conditions, overtime levels, and employee retirements (FERC Account 926), and for Social Security and Unemployment Taxes (FERC Account 408.1) which is always marginal, NERA calculated the average ratio of these expenditures to total O&M expenses (excluding fuel, purchased power, total A&G, and transmission by others) over the period 1982-2006.[33] The average ratio during this period was 0.1425 or 14.25%.

NERA plotted the remaining accounts listed above against O&M expenses and found that the relationship was fairly consistent between 1982 and 1997, but was erratic in later years and provides no useful information about recent marginal non-plant-related A&G. As a result, we set this portion of the non-plant A&G loader to zero.Therefore the total non-plant-related A&G loader is equal to the average ratio of non-plant-related A&G expenses (FERC Accounts 926 and 408.1) to O&M expenses over the period 1982-2006, or 14.25%.

For plant-related A&G, we identified two A&G FERC accounts that vary with the amount of plant in service: Maintenance of General Plant and Property Insurance. We used a regression analysis of the first account on cumulative net additions to total electric plant, all in constant dollars, for the period 1982 to 2007, yielding a loader of 0.16 percent. For distribution substations, which require property insurance, we added the average property insurance rate, $0.0677 per $100 or 0.0677 percent, provided by OTP. The composite loader applicable to distribution substations is 0.23 percent, while 0.16 percent is applicable to all other distribution plant. Both plant and non-plant loaders are shown on Table 24.

D. General Plant

General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. The need for general plant typically increases with each marginal increase in production, transmission and distribution plant. However, since 1996 there has been very little change in OTP's general plant. A regression of cumulative net additions to general plant on cumulative net additions to total plant (less general plant) using data from 1996-2007 generated an insignificant t-statistic for the explanatory coefficient and therefore NERA set the general plant loader to zero.

[33] This approach was adopted on account of the shifting, complicated pattern of lags related to personnel actions and over/under-funding of pensions. The year 2007 was excluded from the analysis because of a sharp decline in pension expenses which OTP viewed as irregular due to a significant amount of payroll loading adjustments in that year.

Table 24. Administrative and General and General Plant Loaders

		Estimate of Loading Factor
	Administrative and General Expenses and Social Security and Unemployment Taxes	
(1)	Applicable to Non-Plant-Related Expenses	14.25%
(2)	Applicable to Plant-Related Expenses (Distribution Substations)	0.23%
(3)	Applicable to Plant-Related Expenses (Other Distribution)	0.16%
(4)	General Plant & the Electric Share of Common Plant	0.00%

E. Marginal Losses

The marginal loss calculations in this study are based on variable and total losses at time of system peak at each voltage level for which costs are calculated. Marginal capacity losses applied to distribution substation and trunkline feeder costs reflect the fact that, to accommodate a kW of additional peak load at the customer's meter, facilities must be expanded by successively more than a kW as you move up the distribution system to accommodate the fixed and variable losses on the system in the peak hour. Peak capacity loss factors were developed from OTP's current loss study, the February 2007 System Loss Evaluation, supplemented by the previous loss study.[34]

Marginal energy losses reflect the additional losses incurred to move an added kWh through the system at a particular level of system load. Fixed losses are, by definition, not affected by the increments of load to a fixed system. Only variable losses come into these calculations. Marginal energy losses increase in proportion to the square of the load. We calculated hourly losses by means of an approximation of quadratic losses based on variable losses at system peak load (from OTP's loss studies) and the year 2007 hourly control area loads. These marginal energy losses were applied to the hourly market price estimates and hourly marginal transmission costs.

[34] The 2007 loss study did not provide separate losses for distribution substations and primary lines, so this breakdown was taken from the 1995 loss study.

VII. COMPUTATION OF ECONOMIC CARRYING CHARGES

Section V. above describes the development of estimates of marginal investment in several categories of distribution plant. To be useful in ratemaking and other marginal cost applications, the investment must be converted into annual costs using an economic carrying charge. The annual charge reflects the elements of OTP's revenue requirement associated with incremental plant: return to stockholders and bondholders, depreciation, and taxes. For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. In such a stream, the first year's charge represents the cost in today's dollars of owning the plant or equipment for a year. It also represents the rental rate for such an investment in a competitive market.

Key inputs for the economic carrying charge calculation include: (1) the utility's incremental cost of capital (mix of debt and equity and their respective long-term market costs), (2) the expected inflation rate for that type of plant, net of technical progress, and (3) the average service life and patterns of failure ("Iowa curve") for that type of plant.

OTP foresees financing of incremental investment through sales of common stock and debt over the study period, as illustrated below.

	Share %	Cost %
Common Stock	50.00	10.75
Debt	50.00	6.50

Another integral part of the economic carrying charge calculation is the estimation of the rate of inflation net of technical progress applicable over the life of the investment. We used 3.0 percent as an approximation of the rate of future inflation net of technical progress, based on OTP's use of 3.0 percent in their 10-year financial model.

Finally, an adjustment is required for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. The pattern of expected required replacement for each type of plant is defined by an Iowa Curve. An adjustment for this dispersed pattern of replacements using Iowa Curves was included in the derivation of the economic carrying charges. The results of these economic carrying charge calculations are presented below. The adjustments for dispersed retirements are shown on line (2) of this table.

Table 25. Economic Carrying Charges

	Distribution Substation	Distribution Facilities	Meters
	(1)	(2)	(3)
(1) Present Value of Revenue Requirements Related to Incremental $1,000 Investment	$1,459.55	$1,472.79	$1,453.05
(2) Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment	$71.21	$41.93	$90.87
(3) Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2)	$1,530.76	$1,514.72	$1,543.92
(4) First-Year Annual Economic Charge Related to Incremental $1,000 Investment	$86.86	$77.24	$90.00
(5) First-Year Annual Economic Charge Related to Incremental Investment [(4)/$1,000]	8.69%	7.72%	9.00%

VIII. COMPUTATION OF ANNUAL MARGINAL COSTS

To compute marginal investment for each distribution component of service to annual marginal costs, we adjusted upwards the investment per unit by the general plant loading factor. We multiplied the resulting figures by the annual economic carrying charge percentage plus the plant-related A&G loading factor to yield the annualized plant costs. To these costs we added the associated O&M and A&G expenses and the revenue requirements for working capital.

The computation of working capital includes components for cash, materials, supplies and prepayments. The working capital needs were estimated based on recent historical amounts. The revenue requirement for this working capital was developed from OTP's weighted average cost of capital plus an income tax component that recognizes that the equity portion of return on capital is taxable.

Table 26 shows the derivation of the annual distribution substation and trunkline feeder costs, and Table 27 shows those annual costs adjusted for losses and time-differentiated, using estimates of the relative probability of distribution substation peaks.

Table 26. Derivation of Annual Distribution Substation and Trunkline Feeder Costs

		2009 Dollars per kW
(1)	Marginal Investment per kW	$99.87
(2)	With General Plant Loading (1) x 1.0000	99.87
(3)	Annual Economic Carrying Charge Related to Capital Investment	8.69%
(4)	A&G Loading (plant related)	0.23%
(5)	Total Annual Carrying Charge (3) + (4)	8.91%
(6)	Annualized Costs (2) x (5)	8.90
(7)	O&M Expenses	2.89
(8)	With A&G Loading (7) x 1.1425 (Non-plant Related)	3.30
(9)	Subtotal (6) + (8)	12.20
	Working Capital	
(10)	Material and Supplies (2) x 1.34%	1.34
(11)	Prepayments (2) x 0.13%	0.13
(12)	Cash Working Capital Allowance (8) x -0.31%	-0.01
(13)	Total Working Capital (10) + (11) + (12)	1.46
(14)	Revenue Requirement for Working Capital (13) x 12.19%	0.18
(15)	Total Distribution Substation Costs (9) + (14)	$12.38

Table 27. Time-Differentiated Distribution Substation and Trunkline Feeder Costs by Voltage Level and Period

	Annual Cost		Period Assignment Factor	Seasonal Cost	
	Secondary	Primary		Secondary	Primary
	(2009 Dollars per KW)		(Percent)	(2009 Dollars per KW)	
				(1) x (3)	(2) x (3)
	(1)	(2)	(3)	(4)	(5)
(1) Summer Peak Period	12.88	12.66	37%	4.73	4.65
(2) Summer Shoulder	12.88	12.66	25%	3.28	3.23
(3) Summer Off-Peak Period	12.88	12.66	0%	0.04	0.04
(4) Winter Peak Period	12.88	12.66	14%	1.84	1.81
(5) Winter Shoulder	12.88	12.66	5%	0.70	0.69
(6) Winter Off-Period	12.88	12.66	18%	2.28	2.24

Tables 28 below show the development of the annual marginal cost for local distribution facilities, and lighting. Tables 29 show the annualization of meters and service drops and also include customer-related expenses.

Table 28 (I). Derivation of Annual Distribution Facilities Costs

		Residential				
		Single Family Urban	Single Family Rural	Apartment Gas	Apartment Electric	Farm
		(2009 Dollars per kW)				
		(1)	(2)	(3)	(4)	(5)
(1)	Marginal Investment per kW	$150.25	$269.73	$154.14	$72.88	$344.92
(2)	With General Plant Loading (1) x 1.0000	150.25	269.73	154.14	72.88	344.92
(3)	Annual Economic Carrying Charge Related to Capital Investment	7.72%	7.72%	7.72%	7.72%	7.72%
(4)	A&G Loading (plant-related)	0.16%	0.16%	0.16%	0.16%	0.16%
(5)	Total Annual Carrying Charge (3) + (4)	7.88%	7.88%	7.88%	7.88%	7.88%
(6)	Annualized Costs (2) x (5)	11.84	21.26	12.15	5.74	27.18
(7)	O&M Expense per kW	3.75	3.75	3.75	3.75	3.75
(8)	With A&G Loading (7) x 1.1425 (non-plant related)	4.28	4.28	4.28	4.28	4.28
(9)	Distribution Facilities Related Costs (6) + (8)	16.12	25.54	16.43	10.03	31.47
	Working Capital					
(10)	Material and Supplies (2) x 1.34%	2.01	3.61	2.07	0.98	4.62
(11)	Prepayments (2) x 0.13%	0.20	0.35	0.20	0.09	0.45
(12)	Cash Working Capital Allowance (8) x -0.31%	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
(13)	Total Working Capital (10) + (11) + (12)	2.20	3.95	2.25	1.06	5.06
(14)	Revenue Requirement for Working Capital (13) x 12.19%	0.27	0.48	0.27	0.13	0.62
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	$16.39	$26.02	$16.70	$10.15	$32.08

Table 28 (II). Derivation of Annual Distribution Facilities Costs

		Small Commercial				
		Stand-Alone customer, overhead	Stand-Alone customer 3ph, overhead	Shared-customer 3ph, overhead	Stand-Alone customer, underground	Shared-customer 3ph, underground
		(2009 Dollars per kW)				
		(1)	(2)	(3)	(4)	(5)
(1)	Marginal Investment per kW	$42.50	$69.12	$76.92	$104.44	$170.17
(2)	With General Plant Loading (1) x 1.0000	42.50	69.12	76.92	104.44	170.17
(3)	Annual Economic Carrying Charge Related to Capital Investment	7.72%	7.72%	7.72%	7.72%	7.72%
(4)	A&G Loading (plant-related)	0.16%	0.16%	0.16%	0.16%	0.16%
(5)	Total Annual Carrying Charge (3) + (4)	7.88%	7.88%	7.88%	7.88%	7.88%
(6)	Annualized Costs (2) x (5)	3.35	5.45	6.06	8.23	13.41
(7)	O&M Expense per kW	3.75	3.75	3.75	3.75	3.75
(8)	With A&G Loading (7) x 1.1425 (non-plant related)	4.28	4.28	4.28	4.28	4.28
(9)	Distribution Facilities Related Costs (6) + (8)	7.63	9.73	10.34	12.51	17.69
	Working Capital					
(10)	Material and Supplies (2) x 1.34%	0.57	0.93	1.03	1.40	2.28
(11)	Prepayments (2) x 0.13%	0.06	0.09	0.10	0.14	0.22
(12)	Cash Working Capital Allowance (8) x -0.31%	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
(13)	Total Working Capital (10) + (11) + (12)	0.61	1.00	1.12	1.52	2.49
(14)	Revenue Requirement for Working Capital (13) x 12.19%	0.07	0.12	0.14	0.19	0.30
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	$7.71	$9.85	$10.48	$12.70	$18.00

Table 28 (III). Derivation of Annual Distribution Facilities Costs

		Large Commercial (Secondary)				Very Large Commercial (Secondary TOU)	Large Commercial (Primary)	
		101-150kVa, 3ph	151-300kVa, 3ph	301-500kVa, 3ph	>501 kVa, 3ph	3000 kVa (LGS TOU), 3ph	3000 kVa (LGS), 3ph	5000 kVa (LGS TOU), 3ph
		(2009 Dollars per kW)						
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
(1)	Marginal Investment per kW	$106.46	$63.30	$44.28	$26.84	$ 27.12	$ 7.82	$ 10.60
(2)	With General Plant Loading (1) x 1.0000	106.46	63.30	44.28	26.84	27.12	7.82	10.60
(3)	Annual Economic Carrying Charge Related to Capital Investment	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%
(4)	A&G Loading (plant-related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(5)	Total Annual Carrying Charge (3) + (4)	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%
(6)	Annualized Costs (2) x (5)	8.39	4.99	3.49	2.12	2.14	0.62	0.84
(7)	O&M Expense per kW (Pri)	3.75	3.75	3.75	3.75	3.75	2.32	2.32
(8)	With A&G Loading (7) x 1.1425 (non-plant related)	4.28	4.28	4.28	4.28	4.28	2.65	2.65
(9)	Distribution Facilities Related Costs (6) + (8)	12.67	9.27	7.77	6.40	6.42	3.26	3.48
	Working Capital							
(10)	Material and Supplies (2) x 1.34%	1.43	0.85	0.59	0.36	0.36	0.10	0.14
(11)	Prepayments (2) x 0.13%	0.14	0.08	0.06	0.03	0.04	0.01	0.01
(12)	Cash Working Capital Allowance (8) x -0.31%	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
(13)	Total Working Capital (10) + (11) + (12)	1.55	0.92	0.64	0.38	0.39	0.11	0.15
(14)	Revenue Requirement for Working Capital (13) x 12.19%	0.19	0.11	0.08	0.05	0.05	0.01	0.02
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	$12.86	$9.38	$7.85	$6.44	$6.47	$3.28	$3.50

Table 29. Derivation of Annual Lighting Costs, including Distribution Facilities for Lights

		Lighting			
		Area Light I HPS 9 (no pole), underground	Area Light 1 HPS 9 (no pole), overhead	Street Light - (no light, no pole), underground	Street Light - (no light, no pole), overhead
		(2009 Dollars per fixture)			
		(1)	(2)	(3)	(4)
(1)	Marginal Investment per fixture	$1,380.80	$1,252.18	$798.69	$671.65
(2)	With General Plant Loading (1) x 1.0000	1,380.80	1,252.18	798.69	671.65
(3)	Annual Economic Carrying Charge Related to Capital Investment	7.72%	7.72%	7.72%	7.72%
(4)	A&G Loading (plant-related)	0.16%	0.16%	0.16%	0.16%
(5)	Total Annual Carrying Charge (3) + (4)	7.88%	7.88%	7.88%	7.88%
(6)	Annualized Costs (2) x (5)	108.83	98.69	62.95	52.94
(7)	Lighting O&M Expenses	24.46	24.46	24.46	24.46
(8)	With A&G Loading (7) x 1.1425 (non-plant related)	27.95	27.95	27.95	27.95
(9)	Distribution Facilities Related Costs (6) + (8)	136.77	126.63	90.89	80.88
	Working Capital				
(10)	Material and Supplies (2) x 1.34%	18.50	16.78	10.70	9.00
(11)	Prepayments (2) x 0.13%	1.80	1.63	1.04	0.87
(12)	Cash Working Capital Allowance (8) x -0.31%	(0.09)	(0.09)	(0.09)	(0.09)
(13)	Total Working Capital (10) + (11) + (12)	20.21	18.32	11.65	9.79
(14)	Revenue Requirement for Working Capital (13) x 12.19%	2.46	2.23	1.42	1.19
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	$139.24	$128.87	$92.31	$82.07

Table 30 (I). Derivation of Annual Meter, Service and Customer-Related Costs

		Residential	Residential Controlled Demand	Residential Water Heat Controlled	Residential Controlled Dual Fuel	Residential Controlled Deferred Load	Residential Fixed Time Of Delivery	Area, Flood & Sign Lighting
		(2009 Dollars per Customer)						
a) Investment - Meter Costs		(1)	(2)	(3)	(4)	(5)	(6)	(7)
(1)	Meter Cost Investment per Customer	$76.08	$375.55	$257.57	$280.05	$337.13	$337.13	$0.00
(2)	With General Plant Loading (1) x 1.0000	76.08	375.55	257.57	280.05	337.13	337.13	0.00
(3)	Annual Economic Charge Related to Capital Investment	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
(4)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(5)	Total Carrying Charge Meters (3) + (4)	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%
(6)	Total Annualized Meter Costs (2) x (5)	6.97	34.39	23.59	25.65	30.87	30.87	0.00
b) Investment - Meter Service Drops								
(7)	Service Cost Investment per Customer	$406.10	$406.10	$0.00	$0.00	$0.00	$0.00	$0.00
(8)	With General Plant Loading (1) x 1.0000	406.10	406.10	0.00	0.00	0.00	0.00	0.00
(9)	Annual Economic Charge Related to Capital Investment	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%
(10)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(11)	Total Carrying Charge Services (3) + (4)	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%
(12)	Total Annualized Service Costs (2) x (5)	32.01	32.01	0.00	0.00	0.00	0.00	0.00
c) O&M - Meter, Customer Accounts Expenses, Customer Service								
(13)	Meter and CT O&M Expenses	7.80	7.80	7.80	7.80	7.80	7.80	0.00
(14)	Customer Accounts Expenses	53.67	91.14	37.47	43.22	70.34	70.34	30.55
(15)	Customer Service and Informational Expenses	10.55	18.55	8.00	8.00	8.00	8.00	8.00
(16)	With A&G Loading [(7)+(8)+(9)] x 1.1425 (Non-plant Related)	82.28	134.23	60.86	67.43	98.41	98.41	44.04
(17)	Customer-Related Costs (6) + (10)	121.26	200.63	84.45	93.08	129.29	129.29	44.04
	Working Capital							
(18)	Materials and Supplies (2) x 1.34%	1.02	5.03	3.45	3.75	4.52	4.52	0.00
(19)	Prepayments (2) x 0.130%	0.10	0.49	0.33	0.36	0.44	0.44	0.00
(20)	Cash Working Capital (10) x -0.31%	-0.26	-0.42	-0.19	-0.21	-0.31	-0.31	-0.14
(21)	Revenue Requirement for Working Capital [(12)+(13)+(14)] x 12.19%	0.11	0.62	0.44	0.48	0.57	0.57	-0.02
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$121.36	$201.25	$84.89	$93.55	$129.86	$129.86	$44.03

Table 30 (II). Derivation of Annual Meter, Service and Customer-Related Costs

		General Service < 20 kW	General Service >= 20 kW	GS (Control Dual)	Farm Service	Large Commercial Secondary	Large Commercial Primary
		(2009 Dollars per Customer)					
a) Investment - Meter Costs		(1)	(2)	(3)	(4)	(5)	(6)
(1)	Meter Cost Investment per Customer	$320.97	$320.97	$1,094.90	$330.69	$1,173.12	$6,831.12
(2)	With General Plant Loading (1) x 1.0000	320.97	320.97	1,094.90	330.69	1,173.12	6,831.12
(3)	Annual Economic Charge Related to Capital Investment	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
(4)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(5)	Total Carrying Charge Meters (3) + (4)	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%
(6)	Total Annualized Meter Costs (2) x (5)	29.39	29.39	100.27	30.28	107.43	625.59
b) Investment - Meter Service Drops							
(7)	Service Cost Investment per Customer	$562.07	$562.07	$492.60	$434.72	$25,837.94	$26,611.21
(8)	With General Plant Loading (1) x 1.0000	562.07	562.07	492.60	434.72	25,837.94	26,611.21
(9)	Annual Economic Charge Related to Capital Investment	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%
(10)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(11)	Total Carrying Charge Services (3) + (4)	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%
(12)	Total Annualized Service Costs (2) x (5)	44.30	44.30	38.82	34.26	2,036.40	2,097.35
c) O&M - Meter, Customer Accounts Expenses, Customer Service							
(13)	Meter and CT O&M Expenses	7.80	102.24	102.24	7.80	204.47	204.47
(14)	Customer Accounts Expenses	78.69	78.69	116.16	56.86	68.84	68.84
(15)	Customer Service and Informational Expenses	32.43	32.43	40.43	8.00	522.73	522.73
(16)	With A&G Loading [(7)+(8)+(9)] x 1.1425 (Non-plant Related)	135.87	243.76	295.71	83.01	909.48	909.48
(17)	Customer-Related Costs (6) + (10)	209.56	317.46	434.81	147.56	3,053.31	3,632.41
	Working Capital						
(18)	Materials and Supplies (2) x 1.34%	4.30	4.30	14.67	4.43	15.72	91.54
(19)	Prepayments (2) x 0.130%	0.42	0.42	1.42	0.43	1.53	8.88
(20)	Cash Working Capital (10) x -0.31%	-0.42	-0.76	-0.92	-0.26	-2.82	-2.82
(21)	Revenue Requirement for Working Capital [(12)+(13)+(14)] x 12.19%	0.52	0.48	1.85	0.56	0.00	11.90
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$210.08	$317.94	$436.66	$148.12	$3,053.31	$3,644.31

Table 30 (III). Derivation of Annual Meter, Service and Customer-Related Costs

		Large GS (Real Time Pricing) Secondary	Large GS (Real Time Pricing) Primary	Large GS (Off Peak Rider) Secondary	Large GS (Off Peak Rider) Primary	Large GS (TOU) Secondary	Large GS (TOU) Primary
		(2009 Dollars per Customer)					
a) Investment - Meter Costs		(1)	(2)	(3)	(4)	(5)	(6)
(1)	Meter Cost Investment per Customer	$1,173.12	$6,831.12	$1,173.12	$6,831.12	$1,173.12	$6,831.12
(2)	With General Plant Loading (1) x 1.0000	1,173.12	6,831.12	1,173.12	6,831.12	1,173.12	6,831.12
(3)	Annual Economic Charge Related to Capital Investment	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
(4)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(5)	Total Carrying Charge Meters (3) + (4)	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%
(6)	Total Annualized Meter Costs (2) x (5)	107.43	625.59	107.43	625.59	107.43	625.59
b) Investment - Meter Service Drops							
(7)	Service Cost Investment per Customer	$25,837.94	$26,611.21	$25,837.94	$26,611.21	$25,837.94	$26,611.21
(8)	With General Plant Loading (1) x 1.0000	25,837.94	26,611.21	25,837.94	26,611.21	25,837.94	26,611.21
(9)	Annual Economic Charge Related to Capital Investment	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%
(10)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(11)	Total Carrying Charge Services (3) + (4)	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%
(12)	Total Annualized Service Costs (2) x (5)	2,036.40	2,097.35	2,036.40	2,097.35	2,036.40	2,097.35
c) O&M - Meter, Customer Accounts Expenses, Customer Service							
(13)	Meter and CT O&M Expenses	1,226.82	1,226.82	1,226.82	1,226.82	1,226.82	1,226.82
(14)	Customer Accounts Expenses	68.84	68.84	68.84	68.84	68.84	68.84
(15)	Customer Service and Informational Expenses	522.73	522.73	522.73	522.73	522.73	522.73
(16)	With A&G Loading [(7)+(8)+(9)] x 1.1425 (Non-plant Related)	2,077.51	2,077.51	2,077.51	2,077.51	2,077.51	2,077.51
(17)	Customer-Related Costs (6) + (10)	4,221.34	4,800.45	4,221.34	4,800.45	4,221.34	4,800.45
	Working Capital						
(18)	Materials and Supplies (2) x 1.34%	15.72	91.54	15.72	91.54	15.72	91.54
(19)	Prepayments (2) x 0.130%	1.53	8.88	1.53	8.88	1.53	8.88
(20)	Cash Working Capital (10) x -0.31%	-6.44	-6.44	-6.44	-6.44	-6.44	-6.44
(21)	Revenue Requirement for Working Capital [(12)+(13)+(14)] x 12.19%	1.32	11.46	1.32	11.46	1.32	11.46
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$4,222.66	$4,811.90	$4,222.66	$4,811.90	$4,222.66	$4,811.90

Table 30 (IV). Derivation of Annual Meter, Service and Customer-Related Costs

		Commercial Water Heat Controlled	Large Com. Controlled Dual Fuel (I-01)	Small Com. Controlled Dual Fuel (I-02)	Small Com. Controlled Deferred Load (I-03)	Small Com. Fixed Time of Delivery (I-04)	Bulk Interruptible	Irrigation
				(2009 Dollars per Customer)				
a) Investment - Meter Costs		(1)	(4)	(2)	(3)	(5)	(6)	(7)
(1)	Meter Cost Investment per Customer	$257.57	$1,264.65	$280.05	$337.13	$337.13	$6,831.12	$906.77
(2)	With General Plant Loading (1) x 1.0000	257.57	1,264.65	280.05	337.13	337.13	6,831.12	906.77
(3)	Annual Economic Charge Related to Capital Investment	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
(4)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(5)	Total Carrying Charge Meters (3) + (4)	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%
(6)	Total Annualized Meter Costs (2) x (5)	23.59	115.82	25.65	30.87	30.87	625.59	83.04
b) Investment - Meter Service Drops								
(7)	Service Cost Investment per Customer	$0.00	$0.00	$0.00	$0.00	$0.00	$26,611.21	$406.10
(8)	With General Plant Loading (1) x 1.0000	0.00	0.00	0.00	0.00	0.00	26,611.21	406.10
(9)	Annual Economic Charge Related to Capital Investment	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%	7.72%
(10)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
(11)	Total Carrying Charge Services (3) + (4)	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%	7.88%
(12)	Total Annualized Service Costs (2) x (5)	0.00	0.00	0.00	0.00	0.00	2,097.35	32.01
c) O&M - Meter, Customer Accounts Expenses, Customer Service								
(13)	Meter and CT O&M Expenses	0.00	204.47	76.68	102.24	102.24	1,226.82	76.68
(14)	Customer Accounts Expenses	37.47	43.22	43.22	43.22	43.22	112.06	60.66
(15)	Customer Service and Informational Expenses	8.00	8.00	8.00	8.00	8.00	530.73	8.00
(16)	With A&G Loading [(7)+(8)+(9)] x 1.1425 (Non-plant Related)	51.95	292.13	146.13	175.33	175.33	2,136.03	166.05
(17)	Customer-Related Costs (6) + (10)	75.54	407.94	171.77	206.20	206.20	4,858.96	281.10
	Working Capital							
(18)	Materials and Supplies (2) x 1.34%	3.45	16.95	3.75	4.52	4.52	91.54	12.15
(19)	Prepayments (2) x 0.130%	0.33	1.64	0.36	0.44	0.44	8.88	1.18
(20)	Cash Working Capital (10) x -0.31%	-0.16	-0.91	-0.45	-0.54	-0.54	-6.62	-0.51
(21)	Revenue Requirement for Working Capital [(12)+(13)+(14)] x 12.19%	0.44	2.16	0.45	0.54	0.54	11.43	1.56
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$75.98	$410.10	$172.22	$206.74	$206.74	$4,870.40	$282.66

Table 30 (V). Derivation of Annual Meter, Service and Customer-Related Costs

		Commercial TOU	Flood-Athletic Field Lighting-South Dakota Only	Energy-Only Street & Area Lighting - Metered	Street & Area, Flood and Sign Lighting	Other Public Authority
		(2009 Dollars per Customer)				
a) Investment - Meter Costs		(1)	(2)	(3)	(4)	(5)
(1)	Meter Cost Investment per Customer	$1,094.90	$335.26	$76.08		$292.01
(2)	With General Plant Loading (1) x 1.0000	1,094.90	335.26	76.08		292.01
(3)	Annual Economic Charge Related to Capital Investment	9.00%	9.00%	9.00%		9.00%
(4)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%		0.16%
(5)	Total Carrying Charge Meters (3) + (4)	9.16%	9.16%	9.16%		9.16%
(6)	Total Annualized Meter Costs (2) x (5)	100.27	30.70	6.97		26.74
b) Investment - Meter Service Drops						
(7)	Service Cost Investment per Customer	$26,611.21	$0.00	$0.00		$687.11
(8)	With General Plant Loading (1) x 1.0000	26,611.21	0.00	0.00		687.11
(9)	Annual Economic Charge Related to Capital Investment	7.72%	7.72%	7.72%		7.72%
(10)	A&G Loading (Plant Related)	0.16%	0.16%	0.16%		0.16%
(11)	Total Carrying Charge Services (3) + (4)	7.88%	7.88%	7.88%		7.88%
(12)	Total Annualized Service Costs (2) x (5)	2,097.35	0.00	0.00		54.15
c) O&M - Meter, Customer Accounts Expenses, Customer Service						
(13)	Meter and CT O&M Expenses	204.47	7.80	0.00	0.00	102.24
(14)	Customer Accounts Expenses	68.84	30.55	30.55	30.55	83.37
(15)	Customer Service and Informational Expenses	522.73	8.00	8.00	8.00	8.00
(16)	With A&G Loading [(7)+(8)+(9)] x 1.1425 (Non-plant Related)	909.48	52.95	44.04	44.04	221.20
(17)	Customer-Related Costs (6) + (10)	3,107.09	83.66	51.01	44.04	302.10
	Working Capital					
(18)	Materials and Supplies (2) x 1.34%	14.67	4.49	1.02	0.00	3.91
(19)	Prepayments (2) x 0.130%	1.42	0.44	0.10	0.00	0.38
(20)	Cash Working Capital (10) x -0.31%	-2.82	-0.16	-0.14	-0.14	-0.69
(21)	Revenue Requirement for Working Capital [(12)+(13)+(14)] x 12.19%	1.62	0.58	0.12	-0.02	0.44
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$3,108.71	$84.24	$51.13	$44.03	$302.54

IX. 2009 SUMMARY TABLES

Marginal energy costs, as well as generation capacity, transmission and distribution substation costs, were estimated on an hourly basis, which means they can be expressed in terms of cost per kWh. This section shows all the 2009 time-differentiated costs (including energy) on a per-kWh basis, averaged over the hours in the period. Capacity costs are often expressed on a per-kW basis. Converting hourly marginal costs per kW to period costs per kW requires making an assumption about how consumers' consumption changes throughout a costing period when their peak demand in that period changes. For purposes of these summary tables, we summed the hourly capacity costs within each period. This is consistent with the assumption that a customer who used an additional kW at the time of his peak within a costing period also uses an additional kW in all other hours of that period. Finally, we summarized the time-varying marginal costs with generation capacity, transmission and distribution substation costs stated on a per-kW basis, and marginal energy costs on a per-kWh basis.

Table 31. 2009 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 32. 2009 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 32 summarizes monthly marginal local distribution facilities costs per kW of design demand and on a per customer basis, by class.

Table 33: 2009 Summary of Monthly Marginal Local Distribution Facilities (and Lighting) Costs per kW of Design Demand and Per Customer or per Fixture

	Customer Class	Monthly Facility Cost per kW of Design Demand	Estimate of Typical Design Demand by Customer	Monthly Facility Cost per Customer
		(\$/kW)	kW	(\$/customer/mo.)
				(1)*(2)
		(1)	(2)	(3)
	Residential			
(1)	Urban	$1.37	8	$11.38
(2)	Rural	2.17	21	44.92
(3)	Apartment, Gas	1.39	9	12.65
(4)	Apartment, Electric	0.85	5	3.85
(5)	**Farm**	2.67	21	55.38
	Small Commercial			
(6)	Stand-Alone customer, overhead	0.64	50	32.10
(7)	Stand-Alone customer 3ph, overhead	0.82	75	61.57
(8)	Shared-customer 3ph, overhead	0.87	75	65.50
(9)	Stand-Alone customer, underground	1.06	50	52.91
(10)	Shared-customer 3ph, underground	1.50	75	112.47
	Large Commercial (Secondary Only)			
(11)	101-150kVa, 3ph	1.07	150	160.76
(12)	151-300kVa, 3ph	0.78	300	234.54
(13)	301-500kVa, 3ph	0.65	500	327.01
(14)	>501 kVa, 3ph	0.54	2,600	1,395.86
(15)	**Very Large Commercial (Secondary TOU)**			
	3000 kVa (LGS)	0.54	3,000	1,616.30
	Large Commercial (Primary)			
(16)	3000 kVa (LGS)	0.27	3,000	819.34
(17)	5000 kVa (LGS TOU)	0.29	5,000	1,459.13
	Lighting			$/Fixture
(18)	Area Light 1 HPS 9 (no pole), underground			11.60
(19)	Area Light 1 HPS 9 (no pole), overhead			10.74
(20)	Street Light - (no light, no pole), underground			7.69
(21)	Street Light - (no light, no pole), overhead			6.84

Table 33 summarizes the monthly marginal customer cost by customer class.

Table 34. 2009 Summary of Monthly Marginal Customer Costs

		Monthly Marginal Customer Cost per Customer (2009$ /mo.)
	Residential	
R-01	Residential	$10.11
R-03	Residential Controlled Demand	16.77
R-91	Residential Water Heat Controlled	7.07
I-02	Residential Controlled Dual Fuel	7.80
I-03	Residential Controlled Deferred Load	10.82
I-04	Residential Fixed Time Of Delivery	10.82
M-42	Street Lighting	3.67
	Flood Lighting	3.67
	Sign Lighting	3.67
	Energy-Only Street & Area Lighting - Metered	4.26
	Energy-Only Street & Area Lighting - Non-Metered	3.67
	Athletic Field Lighting- South Dakota Only	7.02
	Commercial and Industrial	
G-01	General Service < 20 kW	17.51
G-01	General Service >= 20 kW	26.50
G-02	General Service (Control Demand)	36.39
F-61	Farm Service	12.34
C-02	Large Commercial Service	
	Secondary	254.44
	Primary	303.69
C-03	Large General Service (Real Time Pricing)	
	Secondary	351.89
	Primary	400.99
C-04	Large General Service (Off Peak Rider)	
	Secondary	351.89
	Primary	400.99
C-09	Large General Service (Time Of Use)	
	Secondary	351.89
	Primary	400.99
R-91	Commercial Water Heat Controlled	6.33
I-01	Large Commercial Controlled Dual Fuel	34.17
I-02	Small Commercial Controlled Dual Fuel	14.35
I-03	Small Commercial Controlled Deferred Load	17.23
I-04	Small Commercial Fixed Time Of Delivery	17.23
I-06	Bulk Interruptible	405.87
M-03	Irrigation Service	23.56
M-04	Commercial Time Of Use	259.06
	Street Lighting	3.67
	Flood Lighting	3.67
	Sign & Area Lighting	3.67
	Energy-Only Street & Area Lighting - Metered	4.26
	Energy-Only Street & Area Lighting - Non-Metered	3.67
	Miscellaneous	
	Streetlighting	3.67
	Other Public Authority	25.21

APPENDIX

Marginal Generation and Transmission Costs, 2008, 2010 – 2012

Table 35. 2008 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 36. 2008 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 37. 2010 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 38. 2010 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 39. 2011 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 40. 2011 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)						
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 41. 2012 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2009 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Energy	[TRADE SECRET DATA HAS BEEN EXCISED]					
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

Table 42. 2012 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(2) Primary						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
(3) Transmission						
Monthly Costs per Kilowatt (2009 Dollars per Kilowatt)						
Generation Capacity	[TRADE SECRET DATA HAS BEEN EXCISED]					
Transmission	[TRADE SECRET DATA HAS BEEN EXCISED]					
Distribution Substation	[TRADE SECRET DATA HAS BEEN EXCISED]					
Total	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					
Energy Costs (2009 Cents per kWh)	[TRADE SECRET DATA HAS BEEN EXCISED]					
Seasonal	[TRADE SECRET DATA HAS BEEN EXCISED]					
Annual	[TRADE SECRET DATA HAS BEEN EXCISED]					

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