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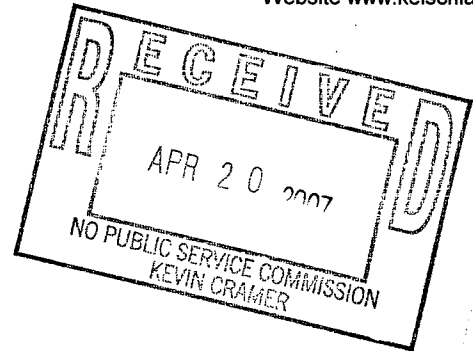
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April 20, 2007

ILLONA JEFFCOAT-SACCO  
ND PUBLIC SERVICE COMMISSION  
600 E BOULEVARD AVE  
BISMARCK ND 58505-0480

RE: Case No. PU-05-131  
NDPSC  
Otter Tail Corporation  
Cost of Fuel Adjustment Clause Tariff  
Direct Testimony of Larry L. Schedin PE & Direct Testimony of Kavita Maini  
Our File No. 12039

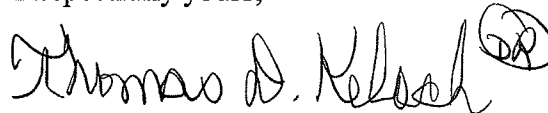


Dear Ms. Jeffcoat-Sacco:

I am enclosing an original and 7 copies of the Direct Testimony of Larry L. Schedin PE with Resume of Larry L. Schedin & Direct Testimony of Kavita Maini with Exhibits 1, 2 & 3 and Resume of Kavita Maini in the above case no. PU-05-131 on behalf of ND OTP Large Industrial Energy Group and an Affidavit of Service by Mail and Facsimile.

If you have any questions, please give me a call.

Respectfully yours,



Thomas D. Kelsch

TDK:dr

Enclosures

cc: Eric Hoegger, Cargill, Incorporated  
Steve Otto, Imation  
Larry Schedin  
Kavita Maini  
Chuck McFarlane, Otter Tail Corporation  
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BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF NORTH DAKOTA

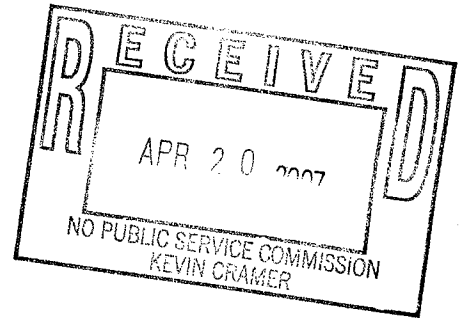
IN THE MATTER OF THE PUBLIC SERVICE )  
COMMISSION OTTER TAIL CORPORATION )  
COST OF FUEL ADJUSTMENT CLAUSE )  
TARIFF )

Docket No. PU-05-131

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DIRECT TESTIMONY OF LARRY L. SCHEDIN PE

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I. Introduction

Q. Please state your name and occupation

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

Q. Please state your business address.

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

Q. Please state your educational and professional background.

A. Please see the summary of my educational and professional experience attached as LIG Exhibit (or Attachment?) No.1.

Q. Have you ever testified in other utility proceedings?

A. Yes, in numerous cases, in Federal, state and local proceedings.

Q. Has any of your recent experience been closely related to this current case before the NDPSC?

A. Yes. I was recently an expert witness for the Minnesota Chamber of Commerce (MN Chamber) in Xcel Energy's general rate case, MPUC Docket No. E-002/GR-05-1428, in which I analyzed the impact of the MISO Day 2 market on Xcel's retail Fuel Cost Adjustment (FCA). As a participant in this case I assisted the MN Chamber in reaching a settlement on this issues and others, including the sharing of wholesale margins.

Q. Has any of your recent work included participation with OTP?

A. Yes. As follow-on to my work on the Xcel Rate case, I participated as a MN Chamber representative in the MISO Stakeholder Group set up as an attempt to reach a settlement in MPUC Docket No. E-002/M-04-1970. OTP was a member of the Stakeholder Group along with the three other Minnesota IOU's all impacted by MISO related FCA issues.

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

A. Yes. Much of the settlement was patterned after my rate case settlement with Xcel Energy

Q. Did the settlement include a sharing of wholesale margins?

A. No. However, both Xcel Energy and Alliant Energy had settled their wholesale margin sharing issue in their respective rate cases, and the MPUC has noted that wholesale

margin sharing will be an issue for OTP in their general rate case to be filed with the MPUC by October 1, 2007.

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

A. My testimony examines OTP's request to recover all of its MISO Day 2 Market costs via OTP's FCA along with its current practice of sharing its wholesale trading margins. My testimony includes analysis, conclusions and recommendations regarding OTP's request and related practices impacting OTP's FCA and treatment of its retail customers.

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

A. Yes, I worked with Kavita Maini, an associate in Oconomowoc, Wisconsin. She is a senior rate economist who has an extensive analytic background and knowledge of the MISO Day 2 Market.

Q. Has Ms Maini also submitted direct testimony in this case?

A. Yes. Her testimony is submitted as a separate exhibit. Her testimony includes analytic analyses upon which some of my conclusions and recommendations are based.

## II. Background of Proceeding

Q. Please state your understanding of the background of this proceeding.

A. The proceeding background is as follows:

1. On March 1, 2005 OTP filed requested revisions to its FCA which would allow OTP to recover its MISO Day 2 Market costs via the revised FCA. The Commission suspended the requested tariff revisions on March 9, 2005. The new market began operations on April 1, 2005. OTP has participated in the market since its startup.
2. On April 6, 2005 the Commission issued its Interim Order temporarily authorizing the recovery of costs from the Midwest ISO's new Day-2 energy market through fuel cost adjustments (FCA). The Commission's consolidated order states that sufficient Day-2 operational experience and market maturity would be necessary before adopting any permanent accounting treatment.
3. The Commission order states that FCA recovery of Day-2 Market costs is authorized on an interim basis and that the recovery of net Day-2 costs will be subject to refund plus interest if the Commission ultimately orders different accounting practices. Compliance tariff changes to standardize language in FCA tariff schedules were approved on an interim basis for all three North Dakota IOU's during July, 2005.

4. (Larry, I got this observation by reviewing the staff report..First page summary..Please review the first page and let me know if you agree with this observation)During August, 2006, the Commission Staff began reviewing the first three months of

MISO Day 2 Market costs according to the 32 cost categories as well as following re-settlement of certain MISO charge types. A Staff report regarding OTP was presented on December 8, 2006.

5. At present, Schedule 16 & 17 charges (market administration) as well as other uplift and RSG charges are all recovered via the FCA.

### III Summary and Recommendations

Q. Please state your summary and recommendations.

A. My summary and recommendations are as follows:

#### A. Base Load Fuel Costs

The load duration curve and base load fuel cost analysis in Kavita Maini's testimony shows that OTP's base-load units supply about 85% of OTP's retail customer energy requirements at coal costs that have remained quite stable. OTP's 2006 coal costs expressed in cents per KWH are only 4.3% higher than in 2005 thereby eliminating coal cost changes as major factors in FCA volatility.

#### B. FCA Volatility

OTP's use of a four-month average FCA covers up true month-to-month variations in the FCA via smoothing. Our de-averaged FCA analysis shows extreme volatility in monthly FCA's with respect to the 1.65 cents per KWH base fuel cost embedded in base rates. Our analysis shows swings in the monthly FCA as high as 300% or more of the base embedded fuel cost even though OTP's base-load coal-fired units provide about 85% of OTP's retail energy requirements. Kavita Maini's use of hourly interval data to test the retail sales volumes used in the FCA also shows great disparities. This indicates that the market is not working properly for OTP's retail customers either because OTP is not properly managing its market participation or because OTP is charging costs without offsetting benefits to its retail customers.

OTP essentially entered the Day 2 market unprepared because it did not conduct any of its own impact studies prior to market startup. If OTP is unable to manage its market participation and accounting to eliminate these unreasonable swings and retail customer impacts, the Commission select a major accounting firm with no connection to OTP to review and correct OTP's market strategy and accounting (at OTP's expense) in order to ensure the lowest possible market-related FCA costs to OTP's retail customers. An outside accounting firm could also check for possible pass-through of hidden capacity costs which the FCA does not allow.

### C. Wholesale margin sharing

OTP used wholesale trading margins of \$29.9 million in 2005 and \$16.0 million in 2006 to increase shareholder earnings (apparently the result of an astute and effective trading staff) to increase shareholder earnings. It is the opinion of the Large Industrials that keeping the margins to boost ROE completely contradicts good management practice. OTP took advantage of a new market with virtual trades and other trading practices and used the profits to boost shareholder earnings at the expense of its retail customers while claiming good management. Retail customers were forced to pay all of the out-of control FCA cost swings while receiving no credits. The opinion of the Large Industrials is that this is bad management. While good performing traders should be rewarded via salaries and other incentives, OTP's asset-based margins are made possible by selling output from generation paid for by OTP's retail ratepayers. Non-asset based margins are made possible by OTP trading staff members whose salaries and benefits are paid for by retail customers. Therefore, all the margins since market startup should be refunded to OTP's retail customers via the FCA rather than used to increase earnings. Additionally, all future wholesale margins should be passed on to retail ratepayers via the FCA. Because the present proceeding makes major changes to OTP's FCA, the Settlement Agreement and Revised Performance-Based Ratemaking (PBR) Plan in NDPSC Case No. PU-401-00-36 should not be used as a basis for utilizing trading margins for increasing OTP's ROE. That earlier Agreement clearly states in Sec 10(A), entitled "Fuel Clause Adjustment":

"This Agreement and the Company's revised PBR does not change the Company's existing fuel clause adjustment (FCA) mechanism in its North Dakota Electric Rate Book tariff schedules"

This clearly indicates that the FCA change which OTP has filed was not anticipated in the PBR Plan.

### D. MISO Market Management Transparency to Retail Customers

OTP's management should be held accountable for reporting and controlling its FCA costs. As part of this responsibility, OTP should provide to its Large Industrial customers and the Commission FCA projections to which it can be held accountable. For example, as OTP relates in its response to Large Industrial Interrogatory No. 25, it has not hedged any natural gas purchases even though it consumes large volumes in its Solway combustion turbine plant. When actual FCA's vary significantly from forecasted FCA's, deviations from forecast should be explained, and re-forecasts should be submitted. OTP should therefore conform to the same FCA reporting and MISO pass-through requirements to which they are now held responsible in MN. Since OTP already prepares the reports for its MN jurisdiction, no additional report preparation would be involved. (Note: If the MN consensus is not adopted in ND, the ND Commission could order a similar stakeholder process in ND). If the PBR Ratemaking plan is continued, OTP's

proper management and control of fuel and purchased energy costs, as expressed via the FCA, should be one of the most important performance criteria.

#### E. Staff report

The Large Industrials agree with the staff report conclusion that OTP should file a general rate case in North Dakota as soon as practicable, but we disagree that OTP should be allowed to recover MISO Administrative costs, charge types 16 and 17, via the FCA. Like other utility administrative costs, these charges are not part of energy costs and should be recovered in base rates via a rate case. The Large Industrials agree with the staff report that wholesale margin sharing should be given prompt attention, but we disagree that this important issue should be put off until OTP's next rate case. Margin sharing should begin as a result of the Commission's order in this present case. We also agree with the staff report conclusion that on a marginal cost basis that wind energy is substantially less expensive than energy from gas-fired turbines. However, wind turbines have a capacity factor of only 35-40% thereby requiring gas-fired combustion turbines and other generating units to be constructed in any event as back-up power sources. Although wind turbines have great benefits with respect to air emissions and should be constructed in any event, wind turbines are not necessarily a lower cost alternative on a total cost basis and are unlikely to reduce natural gas use during peak load periods. Therefore, natural gas cost hedging remains an important part of fuel cost management.

#### IV. Analysis of Issues

##### A. How the MISO Day 2 Market Works.

Q. Please explain briefly how the MISO Day 2 Market works.

A. A brief overview of the MISO Day 2 Market is as follows:

1. ND IOU's (OTP, NSP and MDU) as well as its municipal and cooperative Generation and Transmission (G&T) providers are fully engaged in the Midwest Independent System Operator (MISO) Day 2 Day-Ahead Market run out MISO's headquarters at Carmel, Indiana. The market is an energy-only spot market. Prior to 10:00 AM central standard time each day, each participating utility separately offers each of its generators each hour into tomorrow's market (at the generator's cost to start up, run and shut down) along with its request for bids to meet its hourly load forecast.
2. All the offers from all the utilities in the MISO Day 2 Market footprint are then stacked each hour in merit order (order of cost). A clearing price is established hourly at the price of the lowest marginal cost resource (plus losses) necessary to meet the hourly load consistent with reliability and deliverability constraints (security constrained dispatch with market clearing price based on marginal cost of last unit placed in service). The entire day-ahead market is cleared hourly, and ALL generators are paid the price of the market clearing price necessary to serve

the market load for that hour and for that location regardless of the actual cost to run. Similarly, each utility which serves load, called a Load-Serving Entity (LSE) must bid their load into the market and must pay the market clearing price for that hour for receiving all of its energy needs to serve load from the market. Hourly market clearing prices, called Locational Market Prices (LMP's) are set separately at each load point and at each generator location.

3. Prior to 3:00 PM on the day bids are submitted, each utility is notified which units it must run tomorrow. With few exceptions, each utility must bid ALL of its load and ALL of its generation into the Day 2 Market. Because of losses incurred by shipping power around the grid and because of security (deliverability) constraints, MISO posts the separate nodal LMP's at approximately 1300 locations around the grid. The LMP's change every 5 minutes and are averaged hourly. As the following day unfolds, the Day 2 Market prices are replaced by the real-time prices, and utilities pay penalties based on the difference between their bids and offers and actual performance. Market participants can play the Day 2 Market against the Real-Time Market via virtual (dummy) bids and offers.
  4. The Real-Time Energy Market dispatch is also supported by a Reliability Assessment Commitment (RAC) process to ensure that sufficient generating capacity is on line for regulating and contingency spinning reserves as well as for load, all to meet real-time, security-constrained operating conditions.
  5. Market participants can hedge against transmission congestion cost penalties by purchasing Financial Transmission Rights (FTR's) in advance.
4. MISO Accounting
- a. MISO credits each generating market participant each hour with an amount equal to the market clearing price at each of its generating locations (the LMP) times the generator output at each location.
  - b. For an LSE participant, such as an IOU which also must serve its customer load, MISO charges an offsetting amount for the load cost each hour equal to the MWH of load times the market clearing price at the load location (the load LMP). Because of location differences, the load LMP is typically different from the generation LMP. The generating offer revenues and the load bid costs for the Day 2 Market are cleared and netted in the Day Ahead Asset Energy Account.
  - c. The net Day-Ahead cost is then billed to the market participant as one of the 32 MISO charge types.
  - d. As the Real-Time Market unfolds and to the extent that actual loads and generation differ from the corresponding bids and offers into the Day-2 Market, MISO records and nets the differences in the Real Time Asset Energy Account as one of the 32 MISO charge types.

- e. Beyond this basic accounting and because all utility resources and loads must be offered and bid into the market, the corresponding Market Participant is also billed or credited via other of the 32 MISO charge types. MISO accounting then becomes quite complicated as reflected in charge types such as Revenue Sufficiency Guarantees (RSG's), Uplift Charges, FTR charges and Account 16 and 17 administrative charges, etc. The Commission Staff Report includes a definition of each of the 32 MISO charge types.

## 5. Utility Accounting

- a. Since a utility cannot distinguish from hour to hour whether any of its generators is generating for the needs of its own retail customers or the needs of other market participants, each utility must create a supplemental accounting based on "what if" principles which allocates its lowest cost generation first to the needs of its retail customers.

### B. OTP's Cost of Energy Adjustment Clause – commonly called OTP's Fuel Cost Adjustment ( FCA) and Volatility.

Q. Please describe OTP's Cost of Energy Adjustment Clause and its volatility.

A. The Clause and its volatility are described as follows:

1. FCA Volatility. OTP's FCA is based on a 4-month moving average of fuel and purchased energy costs with the immediate preceding month excluded from the calculations. The 4-month average hides true monthly variations and volatility of the FCA, especially since startup of the MISO Day 2 Market in April, 2005. Our de-averaged analysis of the monthly FCA's prepared by Kavita Maini in her testimony shows a sharp increase in FCA volatility beginning with the MISO Day 2 Market startup. The analysis shows month-to-month swings as high as 5.25 cents per KWH which is over 200% of the embedded cost of fuel. The analysis also shows discrepancies in OTP's KWH and cost data. Both the volatility and the discrepancies are being hidden by the FCA averaging.

2. Volatility Conclusions. FCA volatility since MISO Day 2 Market startup clearly indicates that the market is not working properly for OTP either because OTP is not properly managing its market participation or because OTP is charging costs without offsetting benefits to its retail customers. OTP essentially entered the MISO Day 2 Market unprepared. OTP did not conduct any of its own impact studies prior to entering the market (see OTP response to Large Industrial Interrogatory No. 7)

3. Monthly Retail Sales Volume Discrepancies. The month-to-month changes in energy use do not compare consistently with energy derived from OTP's interval load data thereby indicating possible FCA numerical errors.

4. FCA Wording Error. Because of an error in the description of the months averaged, OTP has not been following their authorized FCA. Their correction request to the

Commission under this Case ( prompted by Large Industrial interrogatories) decreases the months averaged from 5 to 4 with the immediate preceding month excluded. The long time period with incorrect interpretation concerns the Large Industrial Group. This will decrease the recovery lag time.

5. Hidden Capacity Costs . OTP's FCA allows pass through of purchased energy costs but does not allow pass-through of capacity costs. As OTP admits in its response to Large Industrial Interrogatory No. 4, the MISO market is a spot market based on marginal energy costs which in some cases may include hidden capacity costs. Before FCA pass through is allowed, capacity costs should be removed from MISO's marginal energy costs. OTP admits in its response to Large Industrial Interrogatory No. 5 that it does not know if other participants recover their capacity costs via market energy charges.

6. Impact on Large Industrials. Even when averaged, the hidden volatility and the likelihood of OTP's questionable market management means a loss of confidence by the Large Industrials accompanied by a strong likelihood of unnecessary added costs.

7. FCA Conclusions and Recommendations . OTP must be held accountable for their FCA which is out of control. MISO costs as well as fuel procurement, unit maintenance and fuel transportation costs should no longer be considered as costs beyond OTP's control and automatically passed through to its retail customers via the FCA. OTP must also be held accountable for the discrepancies and errors in its monthly FCA reports. We recommend that OTP be required to disclose its MISO Market strategy along with its management of fuel costs, capacity costs, and unit maintenance for Commission and Large Industrial scrutiny. Further accounting review may be necessary by an outside accounting firm.

### C. Wholesale Trading Margins

Q. Please describe OTP's wholesale trading margins.

A. Based on OTP's response to our interrogatories, their wholesale margins are as follows:

#### 1. Types of Margins and Amounts.

OTP separates its wholesale trading margins (profits) into two types: 1) asset based and 2) non-asset based. Asset-based margins are derived from selling excess capacity and energy from OTP's owned generating plants. Non-asset based margins are derived from buying and selling capacity and energy which is not related to OTP's owned generating plants. OTP's response to Large Industrial Interrogatory No. 20 shows the following wholesale margins for 2005 and 2006:

|                 | <u>2005</u>  | <u>2006</u>  |
|-----------------|--------------|--------------|
| Asset-Based     | \$11,571,416 | \$11,046,158 |
| Non Asset-Based | \$18,353,356 | \$5,002,751  |
| Total           | \$29,924,772 | \$16,048,908 |

## 2. Present Application of Margins

In its response to Large Industrial Interrogatory No.24, OTP states that ND retail customers benefited from OTP's wholesale margins because the margins boosted OTP's ROE as allowed under PBR ratemaking and avoided a retail rate increase which would otherwise have been necessary. None of the margins were applied to reduce retail rates via the FCA.

## 3. Recommendation on Margins

It is the opinion of the Large Industrials that keeping the margins to boost ROE completely contradicts good management practice. OTP's traders took advantage of the new market via virtual trades and other trading practices and used the profits to boost earnings at the expense of its retail customers while claiming good management. Retail customers were forced to pay all of the out-of control FCA cost swings while receiving no credits. The opinion of the Large Industrials is that this is bad management, and all the margins since market startup should be refunded to OTP's retail customers via the FCA. Additionally, all future wholesale margins should be passed on to retail ratepayers via the FCA.

D. MISO Stakeholder Procedure in MN (See MPUC Order for Combined Dockets for the four IOU's) OTP's MN Docket No. is E-017/M-05-284

Q. Please describe the MISO Stakeholder process used in Minnesota and the outcome.

A. The process and its outcome are as follows:

1. Procedure and Participation. The procedure in MN went beyond the typical Case procedure. After the Commission combined the four dockets, the four impacted IOU's, the industrial customers, the MN Chamber of Commerce, the Dept of Commerce, the AG's office and MISO all participated in a stakeholder process aimed at reaching a settlement. The process also included a tutorial session for the MPUC Commissioners and their staffs. After many meetings and much dialog the Stakeholder Group reached a consensus with only one exception being the AG's office concern regarding state vs federal jurisdiction. The Commission essentially adopted the Stakeholder Group's consensus settlement over the objection of the AG's office.

2. Basis for Consensus. The MN Stakeholder Group Basically adopted a settlement relating to MISO costs agreed upon by Xcel and interveners in Xcel's retail rate case as initially proposed by the MN Chamber of Commerce. The consensus deals with all the MISO issues including ultimate sharing of wholesale margins.

3. The Agreement and MPUC Order.

a. Because most of the MISO costs in question are either fuel, purchased energy or

generator operating cost related, the order allows the pass-through of 30 of MISO's 32 charge types via the utility FCA's PROVIDED THAT THE COSTS ARE PRUDENTLY INCURRED. Also, definition of the 32 charge types are FERC approved.

- b. For the first time, commercial and industrial customers are given access to very important utility confidential information along with a process allowing them to challenge utility prudence regarding management of FCA costs and allowing them to budget for changes in FCA costs. THE ORDER EFFECTIVELY CONTRADICTS THE TRADITIONAL UTILITY POSITION THAT FCA COSTS ARE BEYOND MANAGEMENT CONTROL. Each IOU must greatly expand its annual FCA filing (called the AAA Report) and its monthly filings to include:
  - i. management strategy (quantified) to show how use of the MISO Day 2 Market, fuel procurement, fuel transportation and other related aspects of energy costs are being managed so as to minimize FCA costs.
  - ii. FCA forecasts to allow C&I customers the opportunity to better budget for FCA cost increases and decreases.
  - iii. Deviation explanation reports when actual FCA's exceed a threshold above forecast information.
  - iv. Re-forecasts of FCA's when deviations from forecasts (above a set threshold) significantly impact forecasts.
- c. IOU's must conform to a uniform supplemental accounting system to ensure that lowest-cost generation is first used to meet retail customer load.
- d. IOU's are limited regarding their risk in utilizing certain MISO Day 2 market transactions such as "virtual" transactions
- e. MISO administrative costs as reported under charge types 16 and 17 cannot be passed through the FCA. However, these costs can be accrued and deferred to the IOU's next rate case for possible future amortization to accounts recoverable from future retail ratepayers.
- f. At a time no later than their next rate case, MP&L and OTP must propose a plan for sharing their wholesale trading margins with their retail customers. Note: Under a separate order, OTP must file its next rate case in MN no later than October 1, 2007. Alliant Energy and Xcel's sharing plans have already been approved.

**4. Conclusions and Recommendations.** OTP should be held accountable for reporting and controlling its FCA costs. As part of this responsibility, OTP should provide to its Large Industrial customers and the Commission FCA projections to which it can be held accountable. For example, as OTP relates in its response to Large Industrial Interrogatory

No. 25, it has not hedged any natural gas purchases even though it consumes large volumes in its Solway combustion turbine plant. When actual FCA's vary significantly from forecasted FCA's, deviations from forecast should be explained, and re-forecasts should be submitted. OTP should therefore conform to the same FCA reporting and MISO pass-through requirements to which they are now held responsible in MN. Since OTP already prepares the reports for its MN jurisdiction, no additional report preparation would be involved. (Note: If the MN consensus is not adopted in ND, the ND Commission could order a similar stakeholder process in ND).

E. ND Commission Staff Report.

Q. Please explain your review and opinions regarding the North Dakota Staff report.

A. My review and opinions are as follows:

1. Timing

The ND Staff issued its Staff Report in OTP's Case No. PU-05-131 on December 8, 2006.

2. Recommendations

After displaying 17 graphs and figures showing OTP's MISO transactions and related materials, the ND Staff provided four recommendations as follows:

- a. Otter Tail should commit to a schedule for filing a general rate case as soon as practicable.
- b. Staff recommends continuing with the current FCA recovery process for Midwest ISO Day-2 market costs at this time. Staff does not recommend refunding and deferring schedule 16 and 17 charges for later rate case recovery because the money would have to be collected again through increased base rates, and then with a return on the deferral. The total amount of schedule 16 and 17 charges collected from North Dakota customers for the period under consideration in the staff report is approximately \$340,000.
- c. In Otter Tail's next general rate case, a sharing of wholesale margins through the fuel clause should be investigated. The Commission has addressed this issue with other utilities in the context of a general rate case.
- d. Otter Tail should continue to investigate cost-effective opportunities to displace purchases of energy produced from natural gas with less expensive wind energy.

3. Large Industrial Group Comments on Staff's Recommendations.

- a. The Large Industrial group agrees with the Staff's first recommendation that OTP should commit to a rate case as soon as practicable. Preparation can be consistent with

the upcoming MN rate case. However, we disagree with the remaining three recommendations.

b. The schedule 16 and 17 charges are not directly related to fuel and purchased energy and in that regard are no different from OTP's internal administrative costs which are not recovered via the FCA. Therefore the schedule 16 and 17 charges should be recovered in base rates during a general rate case.

c. The asset based wholesale margins are derived from assets included in OTP's rate base and paid for by retail customers. Therefore any margins derived from use of customer assets should be directly flowed through to retail customers beginning immediately (or retroactively?)

d. Wind turbines certainly have a place in OTP's generation mix, but wind turbines are not likely to reduce natural gas use which occurs during peak hours when wind output is likely to be low. Wind energy is more likely to reduce coal use. Also, when standby power and capital costs are considered, wind generation in total is likely to be more costly than natural gas fueled combustion turbines. Wind turbines will, however, always have lower marginal costs than gas-fired combustion turbines and are necessary to reduce air emissions.

e. The Staff report also indicates in Figures 4 and 5 that because of its extensive use of bilateral contracts, OTP has little Market exposure to MISO purchases. This conclusion is clearly misleading because all of OTP's resources are essentially cleared through the MISO Market even though bilateral settlements occur in parallel with the Market. As a result, bilateral contracts as well as OTP generation gather all types of MISO charges merely by being cleared through the MISO Market. See OTP response to Large Industrial Interrogatory No. 9.

## Resume of Larry L. Schedin PE

**Firm Name:** LLS Resources, LLC

**Address:** 12 South 6<sup>th</sup> Street, Suite 1137  
Minneapolis, MN 55402  
**Phone:** (612) 343-8188

**Title:** Owner

**Total Professional Experience:** 44 years

### **Education:**

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

### **Professional registrations and licenses:**

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

### **Awards, publications, etc:**

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

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

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

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

### **Previous Employment:**

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

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

In 1998, Alliant Energy of Madison, Wisconsin purchased Schedin & Associates Inc. and operated the business as part of their non-regulated consulting business subsidiary named Alliant Energy Integrated Services, LLC. Mr. Schedin continued to manage the Minneapolis office for Alliant Energy until early 2004. In March, 2004 Mr. Schedin began a new business named LLS Resources, LLC where he continues to serve a broad range of commercial, industrial, institutional and utility clients.

### **Brief Summary of Relevant Experience, including Special Achievements:**

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

- Introduced the concept of contract renewable service in Minnesota to encourage customer ownership of wind farms in Minnesota, 2006.
- In cooperation with Caterpillar, CITGO Refining, General Mills Inc., Mobil Oil Refinery and others, Mr. Schedin helped form the Illinois Industrial and Institutional Customers for Electrical Restructuring (I<sup>3</sup>CER) Group to help draft the Illinois electric restructuring law, 1996 & 1997.
- In 1985, Mr. Schedin assisted a nucleus group of industrial customers to organize the Chicago Area Energy Users (CAEU) group with the purpose of improving the rates and policies of Northern Illinois Gas Company, Peoples Gas Light & Coke Company, North Shore Gas Company and Commonwealth Edison Company. Throughout the 1980's and 1990's this group helped to develop the new guidelines for delivering deregulated natural gas to the Chicago area. Mr. Schedin has continued to act as technical support advisor, counselor, organizer, administrator and energy expert for groups of customers who come together with a common need to understand the changing energy environment.
- Selected as technical advisor to The Minnesota Energy Consumers (MEC) Group, Minnesota's largest energy users in 1998.
- Testified before U.S. Congress House of Representatives.
- Testified before the Atomic Energy Commission (AEC), now the Nuclear Regulatory Commission (NRC).
- Testified before many state agencies regarding gas and electric utility rates, all on behalf of large energy users.

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



1           **A. The purpose of my testimony is to describe the various tests that I**  
2           **conducted in order to determine the reasonability of OTP's FCA**  
3           **subsequent to OTP's participation in the MISO Day 2 market.**

4           **Specifically, I conducted the following tests:**

5           **1. The extent to which OTP's retail electric requirements are being supplied**  
6           **by OTP's base-load generating units including Big Stone, Coyote and**  
7           **Hoot Lake along with base-load coal costs expressed as \$ per KWH.**

8           **2. The extent to which OTP's remaining retail electric requirements are**  
9           **being supplied by non base-load generation and the relationship of these**  
10           **costs to OTP's FCA.**

11           **3. An analysis of de-averaged monthly incremental FCAs to identify the**  
12           **level of volatility that is smoothed by averaging the FCAs over 4 months.**

13           **4. Comparison of monthly net generation applied in OTP's FCA**  
14           **calculations to these same requirements developed from OTP's hourly**  
15           **interval system load data.**

16           **5. Determination of whether all MISO related charges should be included in**  
17           **the FCA**

18  
19           **Q. What are your conclusions from these analytical tests?**

20           **A. My conclusions are as follows:**

21                   **1. For the months and years tested in 2005 and 2006, OTP supplied**  
22                   **over 85% of its retail requirements from its base-load generation.**  
23                   **Fuel costs from these coal-fired, base-load resources have been**  
24                   **very stable.**

25                   **2. Of its 2005 and 2006 annual requirements, OTP would have**  
26                   **needed 14% and 13% respectively to fulfill system load**  
27                   **requirements through non base load generation, either from its**

1 own peaking generation, purchased power from bilateral contracts  
2 and/or purchases from the MISO Market.

3 3. My load duration curve analysis serves as a credibility check on  
4 base-load generation costs. However, there is limited ability to  
5 stack up the purchased power as well as purchases from MISO  
6 under the load duration curve since the data provided by OTP for  
7 non base-load resources does not lend itself to “cleanly” stacking  
8 these other resources.

9 4. OTP has only limited ability to assure the Commission that its  
10 retail system load requirements are being met with least cost  
11 resources.

12 5. The current method of calculating FCAs over a 4-month period  
13 significantly covers the underlying excessive monthly volatility.

14 6. Given the differential in OTP’s extensive base-load generation  
15 costs and non base-load generation costs, it maybe appropriate to  
16 differentiate day-time costs from night-time costs in the FCA.

17 7. There appears to be no consistent relationship between monthly  
18 retail system energy requirements when measured from interval  
19 load data load and from net generation shown on OTP’s FCA  
20 calculations.

21 8. Schedule 16 and 17 charges are administrative charges and should  
22 not be included in the FCA

23 9. Uplift charges such as Revenue Sufficiency Guarantee and  
24 Revenue Neutrality Uplift should carefully analyzed and justified  
25 before being be included in the FCA

26 Q. What was the method used to assess the percentage of system load  
27 requirements to be met with resources other than OTP’s base-load  
28 generation?

29 A. I used the following steps to make a credibility check on the amounts  
30 of base-load generation used to supply OTP’s retail customer load:



| BASELOAD GENERATION, WEIGHTED COST AND % SYSTEM ENERGY REQUIREMENTS TO BE FULFILLED BY PURCHASED POWER/MISO |                     |                                 |               |  |             |              |
|---|---------------------|---------------------------------|---------------|--|-------------|--------------|
| Annual  | 2005 Net Generation | Excess over load duration curve | Net Amt.      | FERC 1 Fuel Cost                         | with Losses |              |
| Coyote  | 1,043,019,952       | 106,300                         | 1,042,913,652 | \$0.0101                                 | \$0.0115    | \$11,993,507 |
| Big Stone   | 1,479,741,361       | -                               | 1,479,741,361 | \$0.0161                                 | \$0.0183    | \$27,079,267 |
| Hoot Lake   | 930,997,900         | -                               | 930,997,900   | \$0.0189                                 | \$0.0215    | \$20,016,455 |
| Total Baseload Gen. (KWH)   | 3,453,759,213       |                                 | 3,453,652,913 | Weighted Unit cost for baseload (\$/KWh) |             | \$0.01711    |
| System Energy Requirements (KWH)  |                     |                                 | 4,030,235,000 |  |             |              |
| System Energy Requirements to be fulfilled through purchased power/ MISO (KWH)                              |                     |                                 | 576,582,087   | Base Cost of Energy (embedded in rates)  |             | \$0.01647    |
| %System Energy Requirements to be fulfilled through purchased power/ MISO (KWH)                             |                     |                                 | 14.3%         | Amount to be recovered from FCA          |             | \$0.00064    |
| <b>2006 Net Gen.</b>  |                     |                                 |               |  |             |              |
| Annual  | 2006 Net Gen.       |                                 |               |  |             |              |
| Coyote  | 981,477,885         | 124,000.00                      | 981,353,885   | 0.0116                                   | \$0.01318   | \$12,936,028 |
| Big Stone   | 1,669,980,759       | -                               | 1,669,980,759 | 0.0161                                   | \$0.01830   | \$30,553,057 |
| Hoot Lake   | 869,741,600         | -                               | 869,741,600   | 0.0196                                   | \$0.02227   | \$19,371,517 |
| Total Baseload Gen. (KWH)   | 3,521,200,244       |                                 | 3,521,076,244 | Weighted Unit cost for baseload (\$/KWh) |             | \$0.01785    |
| System Energy Requirements (KWH)  |                     |                                 | 4,060,037,000 |  |             |              |
| System Energy Requirements to be fulfilled through purchased power/ MISO (KWH)                              |                     |                                 | 538,960,756   | Base Cost of Energy (embedded in rates)  |             | \$0.01647    |
| %System Energy Requirements to be fulfilled through purchased power/ MISO (KWH)                             |                     |                                 | 13.3%         | Amount to be recovered from FCA          |             | \$0.00138    |

Source: FERC Form 1, OTP System Hourly Data

Q. What major assumption is used in this analysis?

A. This analysis assumes that the base load generation is the least cost dispatch as opposed to procuring net amounts from MISO during the majority of the hours. However, it is important to note that if it were cheaper to procure from MISO, then the majority of the load assumed to be fulfilled by the OTP's base load generation would be satisfied by resources whose weighted average costs would be less than those calculated in Table 1.

Q. Why did you have to make this assumption?

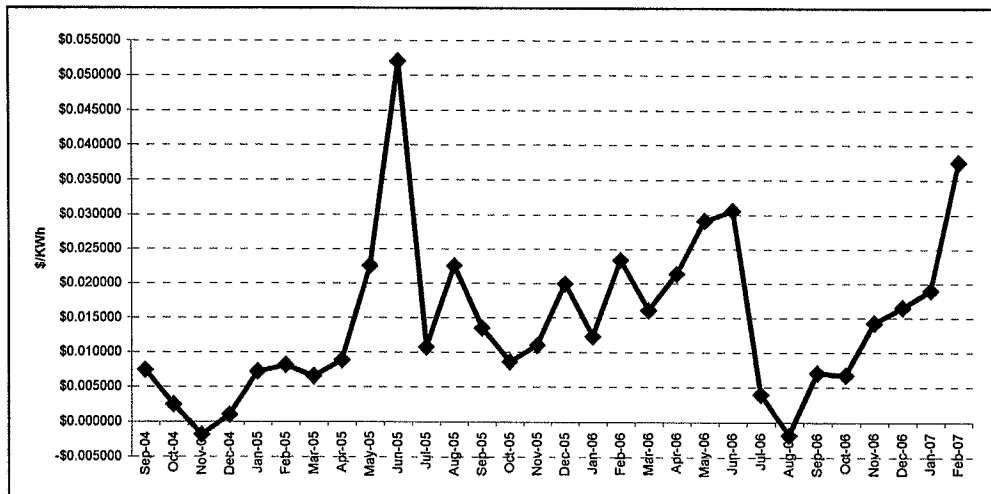
A. I had to make this assumption since there was no other discernable way to develop the stack without it. Pre-Day 2, it was relatively easy to

1 stack up resources through generation and cost figures available from  
 2 FERC Form 1. However, since OTP's participation in the Day 2  
 3 market and the complicated accounting associating with (a) procuring  
 4 all native load requirements, (b) selling all energy from owned  
 5 generation and (c) handling of purchased power deals, it has become  
 6 extremely challenging to decouple and avoid double counting the  
 7 trading activity and be able to discern whether OTP is serving its  
 8 native load requirements with least cost resources.

9 Q. What method was used to test and examine the 4-month cost of energy  
 10 adjustments provided by OTP?

11 A. I first de-averaged the cost of energy adjustments. By de-averaged, I  
 12 mean calculating the fuel adjustments on a monthly basis. Using the  
 13 information provided in Attachment 13-A (response to interrogatory #13  
 14 by OTP), the true up amount for each month was added to the energy  
 15 charges and this total was divided by the net energy adjusted for losses.  
 16 The base cost of \$0.016473/kWh was subtracted from the resulting  
 17 number to arrive at the monthly *incremental* FCA. Exhibit 3 (KMEXH 3  
 18 entitled "Tabulation of de-averaged monthly FCAs) shows the monthly  
 19 FCA numbers that were calculated.

20 Figure 2: De-Averaged Monthly Incremental FCAs



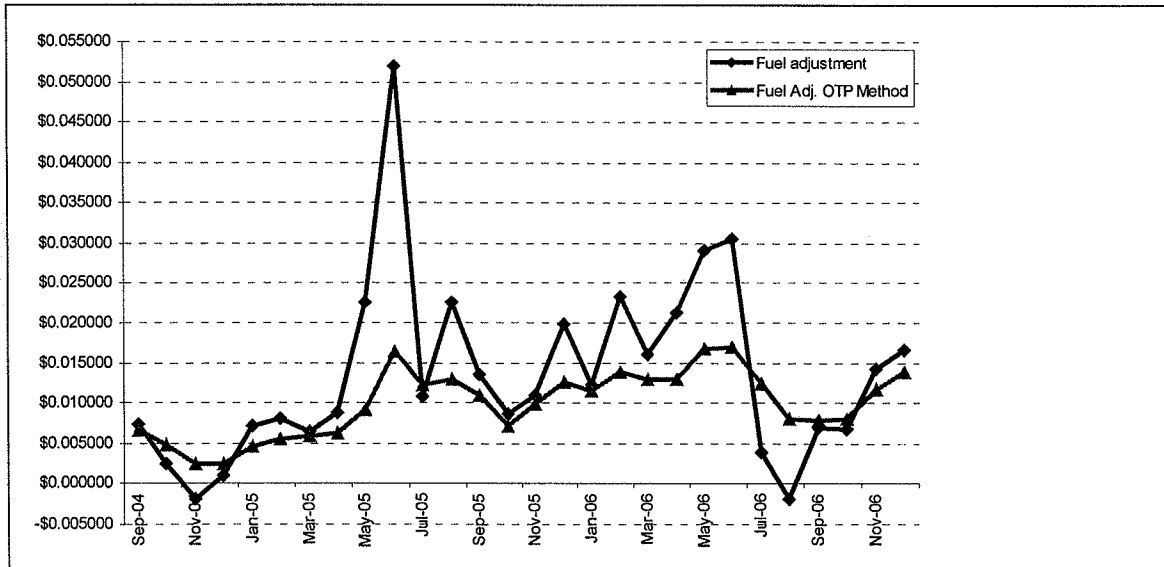
21 Q. What are your observations regarding this analysis?

22 A. The following are my observations regarding this analysis:

- 23 1. *High volatility gets hidden in the OTP FCA charges.* As is apparent from  
 24 Figure 2, there has been high volatility in the monthly incremental FCAs  
 25 that get smoothed by averaging over a 4-month period. Note the jump in  
 26  
 27  
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1 June 2005 at 5.2 cents/kWh, which results after subtracting the base  
 2 amount of \$0.016473/KWh. Figure 3 compares the de-averaged monthly  
 3 FCA with the 4-month adjusted OTP FCA. This reinforces the  
 4 observation that the volatility gets hidden and smoothed out when using a  
 5 4-month average. Data for 2007 indicates that the excessive volatility is  
 6 still present and has not settled down.

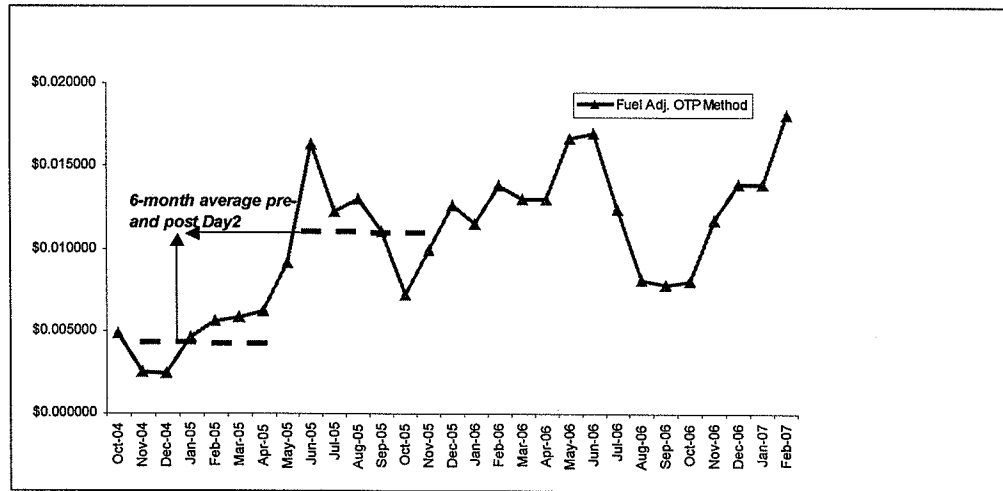
7  
 8 **Figure 3: Comparison of De-Averaged Monthly Incremental FCA**  
 9 **And OTP's FCA**  
 10



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 12  
 13 **2. OTP's FCA indicates a significant increase beginning with The Company's**  
 14 **participation in MISO Day 2 markets. Figure 4 shows OTP's FCA trend**  
 15 **and indicates 2 blue dashed lines that indicate the 6-month OTP's FCA**  
 16 **average pre and post Day 2 markets. The average 6-month FCA goes up**  
 17 **from \$0.004/KWh to \$0.0113/KWh, a 182% increase.**  
 18

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**Figure 4: OTP's FCA and 6-month Average FCA  
Pre- and Post-Day 2 MSIO Market**



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**Q. Was there a significant change in fuel costs associated with base-load generation?**

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**10. No. Figure 5 indicates the total monthly de-averaged FCA (i.e., include base cost of fuel @ \$0.016473/KWh) and shows dashed lines indicating average annual fuel costs associated with coal fired generation for 2004, 2005 and 2006 respectively. As the figure indicates, these fuel costs (obtained from FERC Form 1 data) did not change that significantly and do not appear to be the major driver for the high jump in the FCA. From 2004 to 2005, coal contract costs increased by 8.9% and from 2005 to 2006, the increase was 4.3%. Given the differential in OTP's extensive base-load generation costs and non base-load generation costs, it maybe appropriate to differentiate day-time costs from night-time costs in the FCA.**

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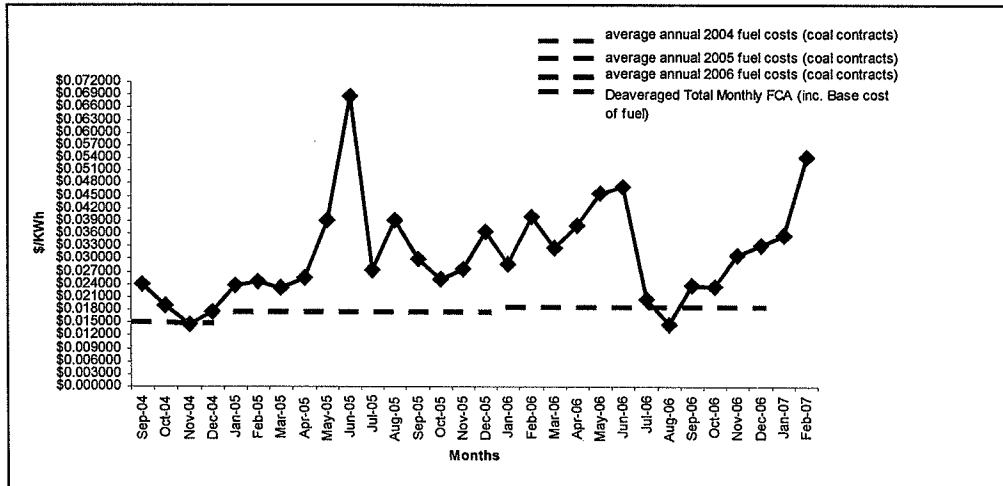
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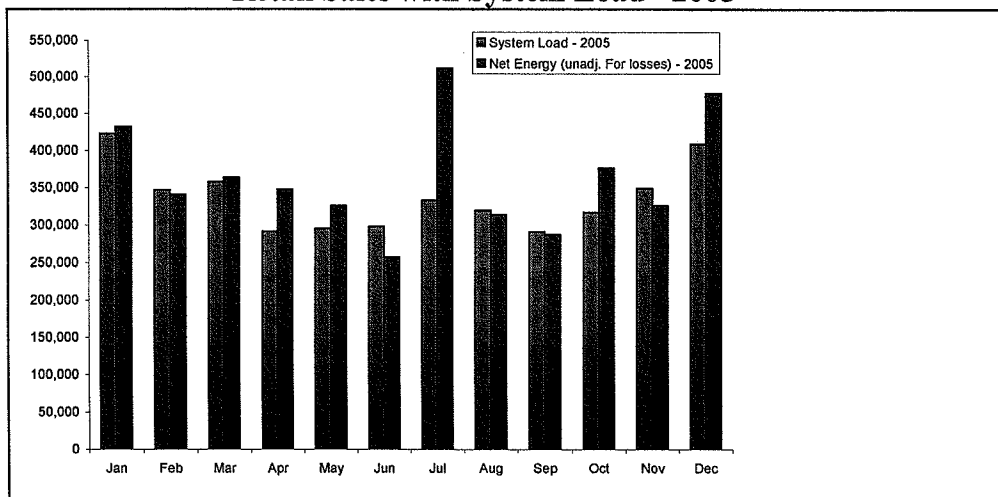
**Figure 5: Average Base-load Fuel Costs and Total  
Monthly De-averaged FCA (include base cost of fuel)**



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3 **Q. What data reasonability check did you perform regarding the net energy**  
4 **sales and system load data?**

5  
6 **A. I compared net retail energy sales obtained from the FCA reports in**  
7 **Attachment 13-A (OTP interrogatory response) to the system load data**  
8 **obtained from Attachment 18 A and B (OTP interrogatory response). I**  
9 **found large differentials between the system load data and net retail sales**  
10 **in some months of the year. I expected that the net retail energy sales**  
11 **(unadjusted for losses and after accounting for intersystem sales) to serve**  
12 **load should more or less equal the system load. However, as Figure 6**  
13 **indicates for 2005 and Table 7 indicates for 2005 & 2006, this is not the**  
14 **case. Note that there are several months each year where the differentials**  
15 **are 10% or higher in 2005 and 2006**

16  
17 **Figure 6: Comparison of Monthly Net Energy**  
18 **Retail Sales with System Load - 2005**



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21 **Table 7: Comparison of Monthly Net Energy**  
22 **Retail Sales with System Load**

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|     | SYSTEM LOAD- MWH |         | NET ENERGY (UNADJ. FOR LOSSES) |         | % Difference (Net Retail Energy Sales - Sys. Load)/ Sys. Load |      |
|-----|------------------|---------|--------------------------------|---------|---|------|
|     | 2005             | 2006    | 2005                           | 2006    | 2005  | 2006 |
| Jan | 422,538          | 390,328 | 431,586                        | 375,602 | 2%  | -4%  |
| Feb | 346,769          | 380,025 | 340,595                        | 381,558 | -2%   | 0%   |
| Mar | 357,869          | 369,855 | 363,635                        | 361,730 | 2%  | -2%  |
| Apr | 291,114          | 284,629 | 347,466                        | 316,567 | 19%   | 11%  |
| May | 295,261          | 297,409 | 325,878                        | 326,110 | 10%   | 10%  |
| Jun | 298,122          | 288,064 | 257,512                        | 260,428 | -14%  | -10% |
| Jul | 333,094          | 339,260 | 511,933                        | 307,227 | 54%   | -9%  |
| Aug | 319,479          | 318,642 | 314,236                        | 330,882 | -2%   | 4%   |
| Sep | 291,373          | 285,260 | 287,737                        | 295,938 | -1%   | 4%   |
| Oct | 316,918          | 342,054 | 376,204                        | 360,683 | 19%   | 5%   |
| Nov | 349,216          | 361,856 | 326,439                        | 336,390 | -7%   | -7%  |
| Dec | 408,482          | 402,655 | 477,572                        | 442,076 | 17%   | 10%  |

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There appears to be no consistent pattern/relationship in the differentials. This could perhaps be a symptom of deeper numerical errors in FCA calculations. Commission staff report refers to the large discrepancy in July 2005 as improper load accounting in April and May by OTP's own admission. However, there appear to be unsystematic differentials aside from the three months that were not explained.

**Q. What MISO charges administrative or non-fuel related in nature appear to be passed through the FCA?**

**A. The following charges are administrative or non-fuel related in nature and appear to be passed through OTP's FCA:**

**1. Schedules 16 & 17. Schedules 16, and 17 associated with administrative costs related to ISO cost recovery for day ahead and real time markets as well as implementation of FTRs should be addressed under base rates as none of these costs are directly associated with "fuel". All MISO related costs that are non-transaction specific -- and, thus, not directly related to providing ratepayers with energy including, but not limited to charges under Schedules 16 and 17 should be addressed under the base rate. Under MISO related charge types, this would include the costs associated with:**

- Day-Ahead Market Administration Amount.
- Financial Transmission Rights Market Administration Amount
- Real-Time Market Administration Amount

**2. Day ahead and real time sufficiency guarantee and make whole payments - While the fuel component of the day ahead and real time revenue sufficiency guarantee payments could pass through in the FCA, the no-load and start-up costs should be addressed in a base rate case. Since a portion of the start-up costs are designed to recover maintenance expense, these costs -- no matter how minimal -- should be addressed in the base rate case.**

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3. ***Real-Time Revenue Neutrality Uplift Amount.*** - This uplift amount is a balancing mechanism to assess costs or distribute revenues for which the MISO has no other method of assessing or distributing. These charges could have non-fuel components and should be addressed as part of a base rate proceeding.

EXHIBIT 1: Calendar Year 2005 - Stacked Load Duration Curve

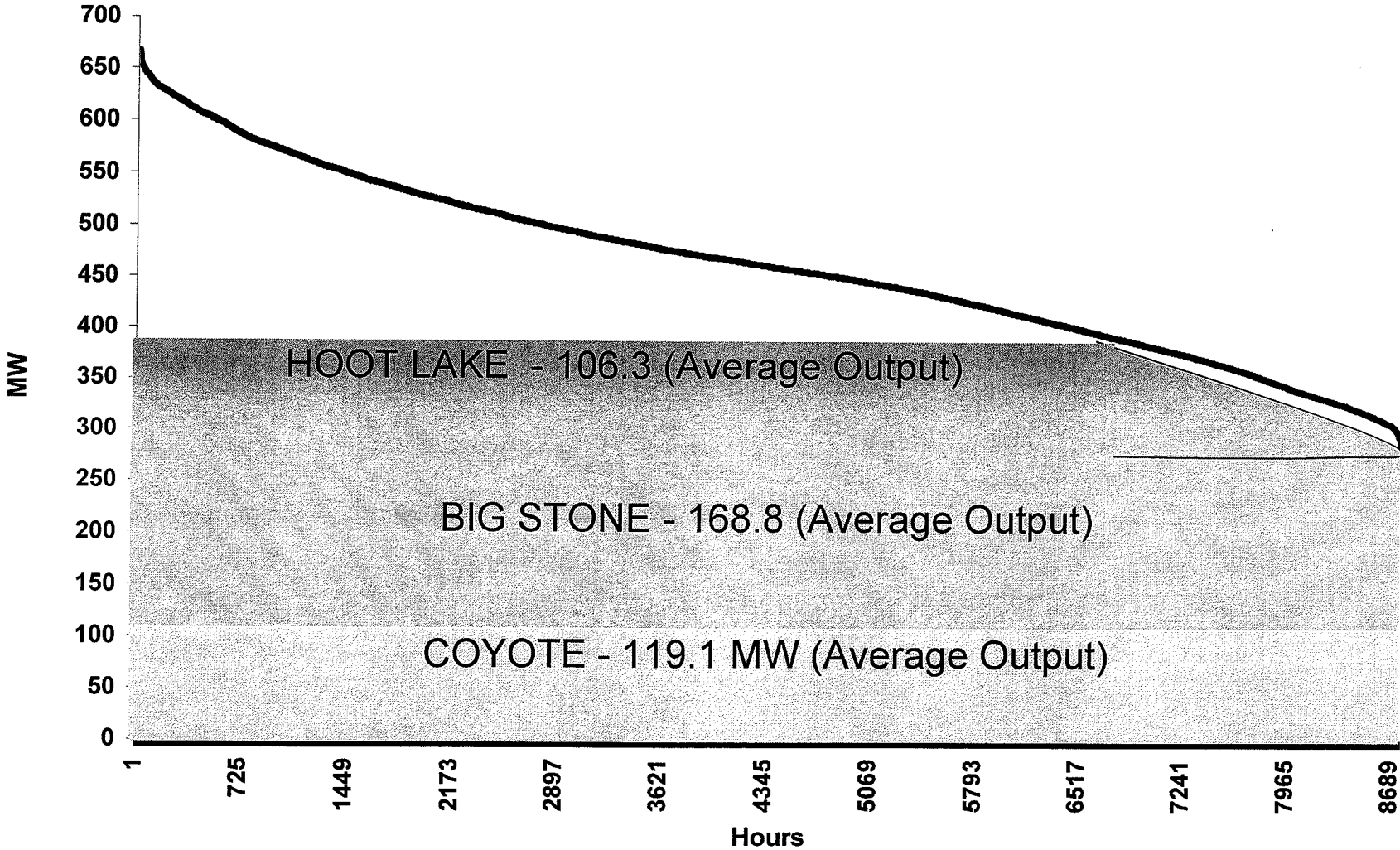
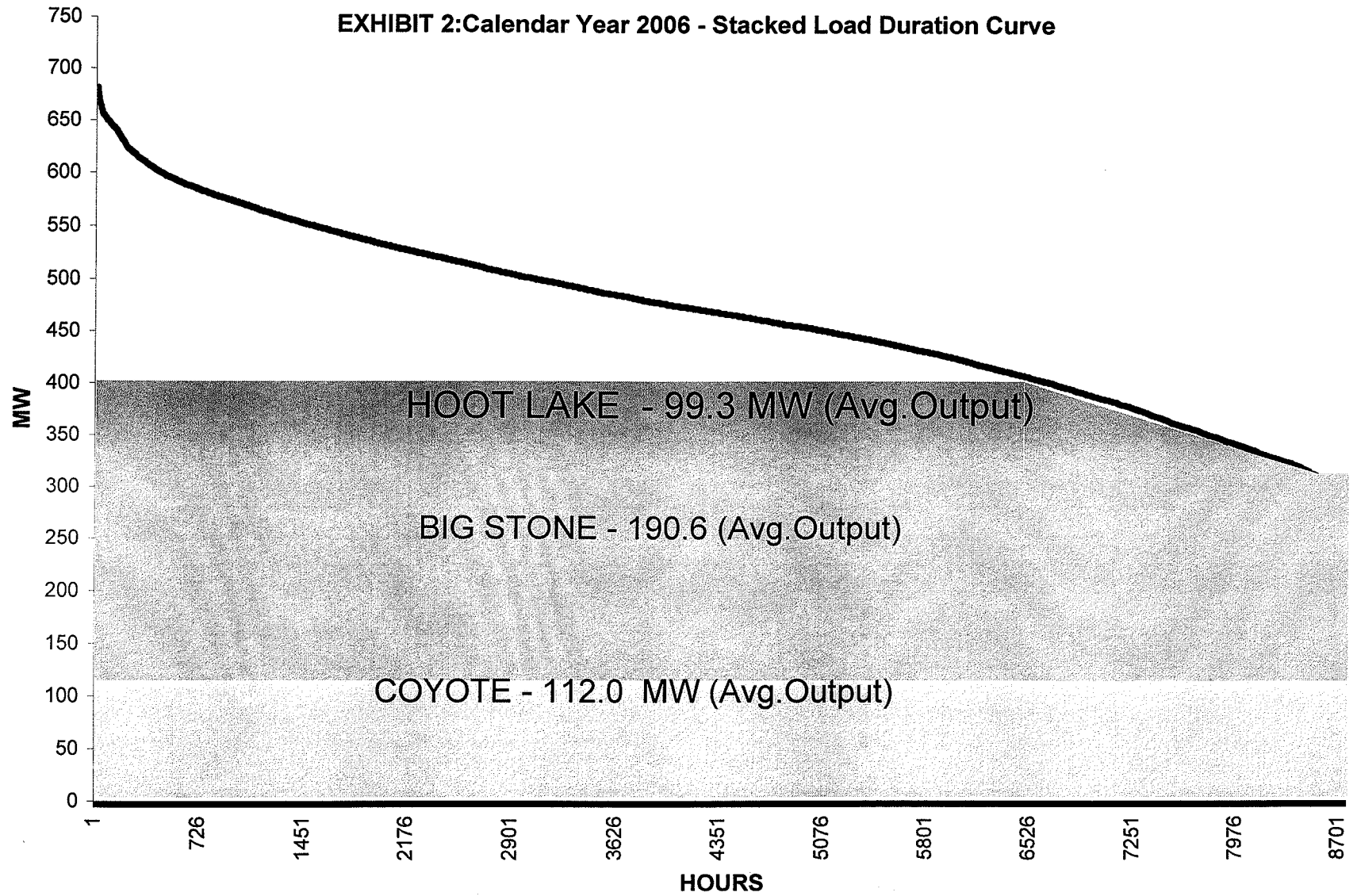


EXHIBIT 2:Calendar Year 2006 - Stacked Load Duration Curve



### EXHIBIT - 3: Tabulation of De-Averaged Monthly FCA

|                                  | Sep-04       | Oct-04       | Nov-04       | Dec-04       | Jan-05       | Feb-05       | Mar-05       | Apr-05      |
|----------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|-------------|
| <b>Net Energy Costs</b>          | \$5,061,181  | \$5,595,430  | \$5,927,403  | \$7,973,034  | 8,809,034    | 6,427,776    | 6,576,718    | 6,852,342   |
| Prior (over) under recovery      | 1,114,768    | (220,932)    | (1,420,619)  | (1,431,412)  | 171,757      | 942,847      | 776,229      | 879,303     |
| <b>Adjusted Net Energy Costs</b> | \$6,175,949  | \$5,374,498  | \$4,506,784  | \$6,541,622  | 8,980,791    | 7,370,623    | 7,352,947    | 7,731,645   |
| <b>Energy Usage (KWH)</b>        |              |              |              |              |              |              |              |             |
| Total Energy                     | 436,240,494  | 443,355,134  | 500,261,890  | 614,110,991  | 561,112,118  | 481,965,062  | 501,755,045  | 373,738,470 |
| Less Intersystem Sales           | -141,963,000 | -120,199,000 | -149,247,000 | -187,630,000 | -129,526,000 | -141,370,000 | -138,120,000 | -95,113,000 |
| Net Retail MISO Day 2            |              |              |              |              |              |              |              | 68,840,842  |
| Net Energy - KW Hs               | 294,277,494  | 323,156,134  | 351,014,890  | 426,480,991  | 431,586,118  | 340,595,062  | 363,635,045  | 347,466,312 |
| Adjusted for Losses              | 258,964,195  | 284,377,398  | 308,893,103  | 375,303,272  | 379,795,784  | 299,723,655  | 319,998,840  | 305,770,355 |
| De-Averaged Total Monthly        |              |              |              |              |              |              |              |             |
| Fuel Adj                         | \$0.023849   | \$0.018899   | \$0.014590   | \$0.017430   | \$0.023646   | \$0.024591   | \$0.022978   | \$0.025286  |
| Base Cost \$/KWh                 | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473  |
| De-Averaged Fuel Adj.            | \$0.007376   | \$0.002426   | -\$0.001883  | \$0.000957   | \$0.007173   | \$0.008118   | \$0.006505   | \$0.008813  |

**EXHIBIT - 3: Tabula**

|                                  | May-05       | Jun-05       | Jul-05       | Aug-05       | Sep-05       | Oct-05       | Nov-05       |
|----------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| <b>Net Energy Costs</b>          | 8,338,142    | 8,909,886    | 8,581,245    | 8,088,312    | 6,073,931    | 8,281,197    | 7,875,151    |
| Prior (over) under recovery      | 2,830,165    | 6,602,111    | 3,662,696    | 2,688,364    | 1,502,041    | 25,913       | 8,998        |
| <b>Adjusted Net Energy Costs</b> | 11,168,307   | 15,511,997   | 12,243,941   | 10,776,676   | 7,575,972    | 8,307,110    | 7,884,149    |
| <b>Energy Usage (KWH)</b>        |              |              |              |              |              |              |              |
| Total Energy                     | 380,502,392  | 467,226,557  | 526,543,694  | 465,629,853  | 437,731,807  | 600,232,516  | 545,500,472  |
| Less Intersystem Sales           | -106,829,000 | -264,691,000 | -173,071,000 | -201,016,000 | -196,985,000 | -245,879,000 | -282,733,000 |
| Net Retail MISO Day 2            | 52,204,199   | 54,976,412   | 158,460,166  | 49,622,207   | 46,990,343   | 21,850,790   | 63,671,452   |
| Net Energy - KW Hs               | 325,877,591  | 257,511,969  | 511,932,860  | 314,236,060  | 287,737,150  | 376,204,306  | 326,438,924  |
| Adjusted for Losses              | 286,772,280  | 226,610,533  | 450,500,917  | 276,527,733  | 253,208,692  | 331,059,789  | 287,266,253  |
| De-Averaged Total Monthly        |              |              |              |              |              |              |              |
| Fuel Adj                         | \$0.038945   | \$0.068452   | \$0.027179   | \$0.038971   | \$0.029920   | \$0.025092   | \$0.027445   |
| Base Cost \$/KWh                 | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   |
| De-Averaged Fuel Adj.            | \$0.022472   | \$0.051979   | \$0.010706   | \$0.022498   | \$0.013447   | \$0.008619   | \$0.010972   |

### EXHIBIT - 3: Tabula

|  | Dec-05       | Jan-06       | Feb-06       | Mar-06       | Apr-06       | May-06       | Jun-06       | Jul-06       |
|--|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| <b>Net Energy Costs</b>                          | 12,610,541   | 7,767,539    | 10,689,884   | 8,289,472    | 8,451,774    | 9,726,701    | 7,090,183    | 5,397,050    |
| Prior (over) under recovery                      | 2,670,635    | 1,721,114    | 2,682,703    | 2,067,748    | 2,086,102    | 3,354,738    | 3,690,404    | 118,799      |
| <b>Adjusted Net Energy Costs</b>                 | 15,281,176   | 9,488,653    | 13,372,587   | 10,357,220   | 10,537,876   | 13,081,439   | 10,780,587   | 5,515,849    |
| <b>Energy Usage (KWH)</b>                        |              |              |              |              |              |              |              |              |
| Total Energy                                     | 568,058,969  | 716,878,348  | 622,977,589  | 516,991,930  | 430,684,369  | 551,862,967  | 529,745,607  | 568,332,716  |
| Less Intersystem Sales                           | -172,631,646 | -364,215,889 | -293,174,737 | -203,169,398 | -181,771,184 | -253,976,985 | -281,580,388 | -227,131,932 |
| Net Retail MISO Day 2                            | 82,145,117   | 22,939,511   | 51,755,183   | 47,907,185   | 67,653,787   | 28,223,935   | 12,262,492   | -33,973,410  |
| Net Energy - KW Hs                               | 477,572,440  | 375,601,970  | 381,558,035  | 361,729,717  | 316,566,972  | 326,109,917  | 260,427,711  | 307,227,374  |
| Adjusted for Losses<br>De-Averaged Total Monthly | 420,263,747  | 330,529,734  | 335,771,071  | 318,322,151  | 278,578,935  | 286,976,727  | 229,176,386  | 270,360,089  |
| Fuel Adj   | \$0.036361   | \$0.028707   | \$0.039827   | \$0.032537   | \$0.037827   | \$0.045584   | \$0.047041   | \$0.020402   |
| Base Cost \$/KWh                                 | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   |
| De-Averaged Fuel Adj.                            | \$0.019888   | \$0.012234   | \$0.023354   | \$0.016064   | \$0.021354   | \$0.029111   | \$0.030568   | \$0.003929   |

### EXHIBIT - 3: Tabula

|                                  | Aug-06       | Sep-06       | Oct-06       | Nov-06       | Dec-06       | Jan-07       | Feb-07       |
|----------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| <b>Net Energy Costs</b>          | 6,920,541    | 8,156,381    | 8,599,860    | 8,759,833    | 10,983,875   | 12,339,525   | 11,937,784   |
| Prior (over) under recovery      | -2,678,081   | -2,040,973   | -1,240,605   | 333,858      | 1,835,970    | 2,450,763    | 4,929,577    |
| <b>Adjusted Net Energy Costs</b> | 4,242,460    | 6,115,408    | 7,359,255    | 9,093,691    | 12,819,845   | 14,790,288   | 16,867,362   |
| <b>Energy Usage (KWH)</b>        |              |              |              |              |              |              |              |
| Total Energy                     | 638,154,126  | 510,923,962  | 667,052,322  | 482,231,589  | 870,121,872  | 549,546,724  | 388,786,400  |
| Less Intersystem Sales           | -298,826,865 | -254,784,076 | -340,048,851 | -172,610,687 | -479,628,604 | -161,756,277 | -103,506,006 |
| Net Retail MISO Day 2            | -8,445,300   | 39,798,529   | 33,679,371   | 26,769,020   | 51,583,215   | 86,813,595   | 69,782,848   |
| Net Energy - KW Hs               | 330,881,961  | 295,938,415  | 360,682,842  | 336,389,922  | 442,076,483  | 474,604,042  | 355,063,242  |
| Adjusted for Losses              | 291,176,126  | 260,425,805  | 317,400,901  | 296,023,131  | 389,027,305  | 417,651,557  | 312,455,653  |
| De-Averaged Total Monthly        |              |              |              |              |              |              |              |
| Fuel Adj                         | \$0.014570   | \$0.023482   | \$0.023186   | \$0.030720   | \$0.032954   | \$0.035413   | \$0.053983   |
| Base Cost \$/KWh                 | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   | \$0.016473   |
| De-Averaged Fuel Adj.            | -\$0.001903  | \$0.007009   | \$0.006713   | \$0.014247   | \$0.016481   | \$0.018940   | \$0.037510   |



*Protecting Your Bottom Line*

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**KAVITA MAINI**  
Principal, KM Energy Consulting, LLC  
Certified as a Minority Business Enterprise in Wisconsin

**Core Competency:** *Economist and extensive experience in electricity and natural gas pricing, market dynamics, procurement, regulatory and policy issues; Independent consultant working on behalf of retail customers*

**2002 – Present: Independent Energy Consultant**

***Areas of Expertise***

- RTO, Regulatory & Policy Issues
- Rate analyses, rate design
- Energy policy advising
- Energy price forecasting
- Energy procurement advising & contract negotiations
- Fuel and asset optimization studies, on-site generation feasibility
- Risk management & hedging strategies
- Strategic energy planning and best practices
- Educational workshops
- Due Diligence, Business/Strategic Plans & Market Research
- Support to Energy User Groups

**Alliant Energy Integrated Services, WI, Energy Consulting Division, 1998 - 2002**

***Title: Senior Economist – Responsibilities***

- Regulatory & rate analyses, rate design
- Energy policy advising
- Energy price forecasting
- Energy procurement advising & contract negotiations
- Fuel and asset optimization, on-site generation feasibility
- Risk management & hedging strategies
- Strategic energy planning and best practices
- Educational workshops
- Due Diligence on Acquisitions, Business/Strategic Planning & Market Research
- Support to Energy User Groups

**Regional Economic Research, Inc., CA, 1997 – 1998**

***Title: Senior Analyst – Responsibilities***

- Energy Market Profiles
- Various DSM Evaluations
- Forecasting using Neural Network Models

## **Wisconsin Power & Light Co., WI, 1991-1997**

### ***Title: Research & Senior Research Analyst -Responsibilities***

- Impact evaluations for the commercial, industrial and residential programs
- Process evaluations for the commercial, industrial and residential programs
- Forward price curve and asset valuation analyses
- Market transformation analysis
- Market research, target market and segmentation analyses
- Monitoring and verification protocols for energy efficiency initiatives
- Merger related strategic planning & research

### **Education**

- Bachelor of Arts Degree in English Literature and French from Sacred Heart College, Dalhousie, India, 1982
- Masters in Business Administration, Marquette University, Milwaukee, WI, 1986
- Masters of Science in Applied Economics, Marquette University, Milwaukee, WI, 1991
- Risk Management Workshops, Due Diligence for Mergers and Acquisitions Workshops

### **Recent Publications/Other**

*Energy Round Table, Expert Speaker, Corporate Report Wisconsin, November 2003.*

*Comments on PSC's Strategic Energy Assessment (Shaping Wisconsin's Energy Policy & Regulatory Process), July 2004 (One of the primary authors)*

Participant, Workshops on Post 2006 Initiative in Illinois, 2004

*Joint Comments on Strategic Energy Assessment – ATC long term expansion plan”, March 2005, Submitted to PSC - WI*

Maini, Kavita et al, “*Joint Comments on PSCW's own investigation regarding Cost of Service and Rate Design Issues*”, August 2005 (*One of the primary authors*)

Maini, Kavita et al, “*Joint Comments on ATC's Access Initiative*”, September 2005, Submitted to PSC – WI

Maini, Kavita et al, “*Joint Comments on PSCW's draft report on ATC's Access Initiative*”, September 2005, Submitted to PSC – WI

Maini, Kavita et al, “*Comments on PSCW's Notice of Investigation on MISO Cost Categorization*”, November 2005, Submitted to PSC – WI

Maini, Kavita et al, “*Comments on PSCW's draft Strategic Energy Assessment Report*”, 2006 Submitted to PSC – WI

Joint Comments with Midwest Industrials to FERC on MISO's proposed Ancillary Services Market, March 2007

### **Received 2005 Energy Engineer of the Year by the AEE Regional Chapter, Chicago, IL**

#### **Select Presentations/Workshops**

CLASEC (Illinois) – Energy Deregulation and Pricing Trends

Association of Energy Engineers - Electricity Deregulation Options in Illinois

Corporate Report Wisconsin – Roundtable Discussion on Energy Related Issues

Wisconsin Public Utility Institute – Workshops on Integrated Natural Gas Planning, Energy Utility Basics

University of MN – Workshops on Energy Deregulation

Wisconsin Industrial Energy Group – Several Presentations

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE PUBLIC SERVICE )  
COMMISSION OTTER TAIL CORPORATION ) Docket No. PU-05-131  
COST OF FUEL ADJUSTMENT CLAUSE )  
TARIFF )

STATE OF NORTH DAKOTA )  
) ss. **AFFIDAVIT OF SERVICE**  
COUNTY OF MORTON ) **BY MAIL & FACSIMILE**

DEBRA K. ROEHRICH being first duly sworn, on oath, deposes and says: That she is a citizen of the United States, over the age of eighteen and not a party to the above-entitled action.

That on the 20th day of April, 2007, this affiant deposited in the United States Post Office at Mandan, North Dakota, and faxed a true and correct copy of the following document(s) in the above-captioned action:

1. Direct Testimony of Larry L. Schedin PE with Resume of Larry L. Schedin PE;
2. Direct Testimony of Kavita Maini with Exhibits 1, 2 & 3 and Resume of Kavita Maini.


That a copy of the above document(s) was securely enclosed in an envelope with postage duly prepaid, and addressed as follows:

CHUCK MCFARLANE  
OTTERTAIL CORPORATION  
215 S CASCADE STREET  
FERGUS FALLS MN 56538  
FAX NO.: 218-739-8218

BRUCE GERHARDSON  
OTTERTAIL CORPORATION  
215 S CASCADE STREET  
FERGUS FALLS MN 58538  
FAX NO.: 218-739-8218

  
DEBRA K. ROEHRICH

Subscribed and sworn to before me this 20 day of April, 2007.

  
Notary Public, State of North Dakota

(SEAL)

