EXHIBIT MLEC-201

MLEC
ENERGY ANALYSIS, REPORTING AND ADVOCACY

Midwest Large Energy Consumers
Direct Testimony of
Larry L. Schedin, PE

Before the
North Dakota Public Service Commission

In the Matter of Otter Tail Power Company 2017
Electric Rate Increase Application

CASE NO.: PU-17-398

Exhibit __

May 18, 2018

201 PU-17-398 Filed 07/11/2018 Pages: 50
Exhibit MLEC-201 – Prefiled Direct Testimony and Attachments of Larry L. Schedin, PE
Midwest Large Energy Consumers – Intervenors

Contents

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 332 Minnesota Street, Suite W2550, Saint Paul, MN 55101.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying as an expert witness on behalf of the Midwest Large Energy Consumers Group ("MLEC").

Q. PLEASE DESCRIBE THE BUSINESS OF THE MLEC AND THE LOCATION OF ITS OFFICES.

A. The MLEC is a group of Otter Tail's largest electric consumers in North Dakota and are among North Dakota's largest employers. The members include seven large industrial customers taking service from Otter Tail Power Company (OTP or Company) on its Large General Service rate schedules.

Q. PLEASE DESCRIBE THE BUSINESSES OR INSTITUTIONS REPRESENTED BY MLEC IN THIS PROCEEDING.

A. MLEC is comprised by business members that are high load factor customers, which are disproportionately affected by increases in rates. For these businesses, a large portion of their operating expenses are comprised of electric bills.

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

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

Q. HAVE YOU EVER TESTIFIED IN OTHER UTILITY PROCEEDINGS?

A. Yes, in numerous cases, including federal, state and local proceedings dealing in a wide range of topics from utility rates, service rules, certificates of need, and transmission routing permits to PPAs and Renewable Energy Credits (RECs).

Q. HAS ANY OF YOUR RECENT EXPERT WITNESS EXPERIENCE INVOLVED UTILITY ELECTRIC RATE PROCEEDINGS?

A. Yes. I was an expert witness before the North Dakota Public Service Commission representing the North Dakota Otter Tail Power Large Industrial Group ("Large Industrial Group" or "LIG") in Otter Tail Power Company's ("OTP" or "Otter Tail") 2007 Cost of Fuel Adjustment Clause Tariff, and in OTP's North Dakota Time of Day Tariff. In 2008, I represented the LIG group in Otter Tail's Minnesota general rate case, in 2008-2010. I represented the same group in Otter Tail's Renewable Energy Rider proceeding, and in 2010, I represented the LIG in the Big Stone II cost recovery proceeding.

I was an expert witness for the Minnesota Chamber of Commerce ("Chamber") in Xcel Energy's ("Xcel") general rate case, Minnesota Public Utilities Commission ("MPUC" or "Commission") Docket No. E-002/GR-15-826. I also represented the Chamber in front of the MPUC on Xcel's previous three rate cases and numerous rider proceedings, as well as Interstate Power and Light Company's last electric rate case.

In 2016, I represented the Chamber before the MPUC in OTP's proceeding under Docket No. E-017/GR-15-1033 to raise rates for electric service in Minnesota. Some of the same issues addressed in that proceeding are present in this case.

II. SERVICE QUALITY AND RELIABILITY – MAIFI

Q. MR. SCHEDIN, HAVE YOU REVIEWED OTP'S ANNUAL SAFETY, RELIABILITY, AND SERVICE QUALITY (SRSQ) REPORT?

A. Yes. In response to MLEC IR No. 200 (Exhibit __ (LLS-1), Attachment 2, partially included), OTP has provided a copy of its Minnesota 2017 report. As stated in its response to MLEC IR No. 200, OTP has filed its MN report with the ND Commission on the basis that it covers reliability for the total company.

Q. MR. SCHEDIN, WHAT ARE YOUR CONCERNS REGARDING OTP'S REPORTING OF SYSTEM RELIABILITY?

A. The rules and report place emphasis on three indices, all based on customer outages lasting 5 minutes or longer as follows:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)
- Customer Average Interruption Duration Index (CAIDI)

Q. PLEASE PROVIDE A BRIEF EXPLANATION OF EACH.

A. **SAIFI** is a measure of the number of sustained (greater than 5 minutes) outages the average customer experienced over the measured time frame. The formula for SAIFI is as follows:

- SAIFI = The Sum of the Total Customers Interrupted / Total Number of Customers Served.

CAIDI is a measure of the average duration of a sustained event (greater than 5 minutes) over the measured time frame. The formula for CAIDI is as follows:

- CAIDI = The Sum of the Total Customer Minutes of Interruptions / The Sum of The Total Number of Customers Interrupted

SAIDI is a measure of the total duration time an average customer was without power over the measured time frame and includes only sustained events greater than 5 minutes. The formula for SAIDI is as follows:

- SAIDI = The Sum of the Total Customer Minutes of Interruptions / Total Number of Customers Served

Q. IS MANAGEMENT PERFORMANCE TIED TO THE SAIDI, SAIFI, AND CAIDI INDICES?

A. Yes. Each measure has a specific goal.

Q. WHAT IMPORTANT ELEMENT OF SERVICE QUALITY IN THE RULE IS NOT PROPERLY INCLUDED AND TREATED?

A. An important reliability index called **MAIFI** (Momentary Average Interruption Frequency Index) is being disregarded and improperly treated in the MN rule because outages of 5 minutes or less are entirely ignored in the three foregoing adopted indices. MAIFI is referenced in some of the reliability reports but ignored as a KPI.

Q. WHAT IS MAIFI?

A. The MAIFI index is calculated similar to SAIFI, but reports customer outages lasting 5 minutes or less rather than more than 5 minutes.

Q. WHY IS MAIFI IMPORTANT TO LARGE COMMERCIAL AND INDUSTRIAL ("C&I") CUSTOMERS?

A. Unlike the three adopted indices most applicable to residential customers, MAIFI reports outages 5 minutes and less which are of greater concern to C&I customers. For example, an outage of 5 minutes or less can bring down a large industrial facility resulting in lost production, equipment damage, inferior product, and a big cleanup mess which may take several days to eliminate before re-starting production. The established indices in the MN rule entirely ignore problems like this one.

Q. HOW DOES OTP TREAT MAIFI IN ITS SERVICE POLICY REPORT FILED WITH THE MN AND ND COMMISSIONS?

A. I'm pleased to note that OTP has calculated and published a MAIFI index since 2012, but without the rigorous treatment and analyses given to SAIDI, SAIFI, and CAIDI. As presently reported an analyzed, the MAIFI index has limited usefulness. Although not required by a regulatory agency, OTP has set an internal minimum MAIFI performance goal of 6.5 outages per year which is the approximate MAIFI index achieved in 2016.

Q. WHAT IMPROVEMENTS IN TRACKING, MONITORING, AND REPORTING DO YOU RECOMMEND?

A. I recommend that:

a. OTP review on an area-by-area basis, the opportunities for improving MAIFI performance.
b. OTP state in its KPI planning that it will provide a plan including opportunities to improve the present 6.5 MAIFI performance index.
c. OTP relate the MAIFI index to outages per year for C&I customers.

III. TRANSMISSION COST CONTROL

Q. MR. SCHEDIN, HAS OTP GIVEN YOU AN OVERVIEW OF TRANSMISSION COSTS?

A. Yes. In its response to MLEC IR's 218, 219, 220, and 221 (Exhibit __ (LLS-1), Attachments 3, 4, 5 and 6), OTP provides the elements of transmission costs for the period 2014-2019.

Q. MR. SCHEDIN, PLEASE STATE YOUR CONCERNS REGARDING TRANSMISSION COSTS.

A. Transmission continues to be a major area of investment and revenue requirements. For example, in its response to MLEC IR's No. 218, 219, 220 and 221, OTP estimates the following (Table 1) historic and future expenditures and revenue requirements for transmission projects. Note that during the 4-year period 2014-2018, total transmission revenue requirements are increasing at more than 11% per year which is far greater than OTP's growth in peak demand.

TABLE 1. Growth in Transmission Revenue Requirements

		Revenue Requirements (1,000's)				
Year	Expenditures ($ millions)	Non-MISO	MISO NITS	Other (net)	MISO	Total
2014	42.9	5,653	20,343		1,065	27,061
2015	40.6	7,269	25,310		1,582	34,161
2016	82.1	7,585	28,776		1,858	38,219
2017	53.0	8,903	29,571		2,381	40,855
2018	35.6	7,467	29,946		2,054	39,467
2019	15.6	7,103	Not Avail		2,969	Not Avail

Q. ALSO, AS A PARTIAL RESULT OF THESE EXPENDITURES, WHAT HAS THIS DONE TO THE NETWORK INTEGRATION TRANSMISSION SERVICE (NITS) RATE, THE PRINCIPAL MISO TRANSMISSION RATES APPLICABLE TO ALL TRANSMISSION USERS IN OTP'S RATE ZONE?

A. OTP'S response to MLEC IR No. 217 (Exhibit __ (LLS-1), Attachment 7) shows that over the 5-year period 2014-2018 the NITS rate is expected to increase from $30.00 per KW-yr to $36.50 per KW-yr as shown below:

- 2014 $30.0 per KW-yr
- 2015 $35.4 per KW-yr

- 2016 $37.6 per KW-yr
- 2017 $39.2 per KW-yr
- 2018 $36.5 per KW-yr
- 2019 N/A

The foregoing represents an increase of 21.7% over the 2014-2018 4-year period, or 5.4% per year, again, greater than the annual growth in peak demand.

The foregoing data also indicates that control of transmission costs should be a major concern to C&I Customers.

Q. DID YOU REVIEW OTP'S COST CONTROL FOR TWO OF ITS LARGE TRANSMISSION PROJECTS?

A. Yes. In response to MLEC IR's No. 201 and 202 (Exhibit __ (LLS-1), Attachments 8 and 9), OTP provided cost control information for its Big Stone South to Brookings County 345 KV line (in service) and its Big Stone Ellendale 345 KV line (under construction).

Q. WHAT DID OTP'S RESPONSES SHOW?

A. OTP's responses indicate that OTP accepts its project manager's opinion regarding cost control with respect to an initial project cost estimate. Neither cost caps nor CN's were required by the SD PSC under its jurisdiction over most of the lines' routings. However, permission was received by the NDPSC to include the cost of both projects in the TCRR. MISO has accepted the projects into its Midwest ISO Transmission Expansion Plan ("MTEP").

Q. DOES MISO CONDUCT ANY COST CONTROL FOR MTEP, MVP, AND OTHER TRANSMISSION PROJECTS CONSTRUCTED BY ITS MEMBERS AND OTHER AGENTS?

A. In its response to MLEC IR No. 225 (Exhibit __ (LLS-1), Attachment 10), OTP states that MISO does cost-benefit analyses and provides notices of cost changes so that stakeholders can file comments.

Q. IN YOUR OPINION, IS THIS COST CONTROL?

A. Absolutely not. MISO, through FERC rules, merely exercises a monitoring and notification function based on data which the sponsoring utility provides. No ordinary stakeholder like a C&I customer has the capability to properly respond with an objection let alone conduct its own cost control investigation which would probably require retaining a qualified expert.

Q. WHAT DID OTP SAY IN ITS RESPONSE TO MLEC IR NO. 224 (EXHIBIT __ (LLS-1), ATTACHMENT 11) IN REGARD TO MISO RESPONSES TO SIGNIFICANT COST OVERRUNS?

A. According to OTP, MISO can re-assign or cancel projects with significant cost overruns. This merely encourages the responsible party to estimate high instead of examining options with lower costs. This procedure in no way encourages participants to search for cost decrease measures.

Q. WHAT DO YOU RECOMMEND IN THIS PROCEEDING REGARDING COST CONTROL OF LARGE TRANSMISSION PROJECTS?

A. I recommended that OTP's transmission VP be assigned a Key Performance Incentive ("KPI") at that level aimed at controlling costs of major transmission projects. A KPI is a program that evaluates performance of achieving material management objectives. I recommend that a firm, detailed, line-by-line project cost estimate be established for each major transmission project to serve as a cost cap prior to approval to include cost of any project in the TCRR, or if not in TCRR, prior to construction. The estimate should include all elements of cost and expense which will be booked into FERC accounts. These include a breakdown of engineering design, major materials, other materials, labor, labor overheads, ROW acquisition, transportation, permitting and permitting fees, AFUDC, and taxes on construction materials, plus a reasonable amount for contingencies. The resulting total project estimated cost, including the contingency amount, should serve as a cost cap, which cannot be exceeded for revenue requirement purposes without state regulatory approval. The transmission VP's KPI should be based on the final project cost under these cost caps, and any amounts exceeding cost caps (on a project-by-project basis) would require reasonable justification and Commission approval before being allowed into rate base and base rates.

I also recommend that a portion of the transmission VP's KPI be determined by comparing the achieved MAIFI index to stated MAIFI goals.

Q. DID OTP CITE AN EXAMPLE OF GOOD COST CONTROL?

A. Yes. OTP's top officers cite the Big Stone AQCS project savings based on innovation resulting in large cost underruns. Proper cost control appears to have worked well regarding the Big Stone AQCS project.

Q. DO YOU RECOMMEND TRANSMISSION VP LEVEL INCENTIVE PAYMENTS FOR GOOD COST CONTROL?

A. Yes.

IV. UNBUNDLING OF DISTRIBUTION COST ELEMENTS

Q. HOW DID OTP RESPOND TO MLEC IR'S NO. 210 AND 211 (EXHIBIT __ (LLS-1), ATTACHMENTS 12 AND 13) REQUESTING SEPARATION OF TRANSMISSION COSTS FROM DISTRIBUTION COSTS AND UNBUNDLING OF DISTRIBUTION COSTS BY VOLTAGE LEVEL?

A. OTP states in its responses that it separates transmission costs from distribution costs according to amounts booked into separate FERC accounts. However, it does not separate distribution costs according to voltage level on the basis of fully embedded costs, including the cost of losses. Instead, in this rate case, it makes this distribution cost separation by voltage level (primary vs. secondary) only on the basis of marginal costs.

Q. WHY IS THIS INSUFFICIENT?

A. Selection of the proper distribution voltage level is very important to C&I customers because the level of distribution, service can significantly impact a customer's total electric costs. In some cases, it is more economical for a customer to own and operate its own primary distribution system on site along with secondary distribution transformers in order to optimize its operations.

C&I Customers should therefore receive the proper fully embedded cost information in order to make the right distribution voltage level determination, both from the customer's viewpoint as well as the utility's viewpoint. Marginal costs as applied by OTP in this instance do not make sense and should be rejected if OTP can make fully embedded distribution costs available by voltage level available in this case.

Q. HOW DOES OTP DEFINE PRIMARY VS. SECONDARY DISTRIBUTION?

A. OTP states in its response to MLEC IR No. 211 (Exhibit __ (LLS-1), Attachment 13) that the voltage of primary distribution is in the range of 2.4 KV-25 KV while secondary distribution operates at 277/480 volts and below. Transmission starts at 41.6 KV.

Q. CAN OTP READILY MAKE THIS FULLY EMBEDDED COST SEPARATION?

A. OTP has not offered to do so. However, in response to MLEC IR No. 226 (Exhibit __ (LLS-1), Attachment 14), OTP provided data that separates its distribution investments into primary and secondary distribution and also separates peak demand data into these same two components.

Another important distinction is line-losses. OTP has provided no distribution loss information. Secondary customers utilize both primary and secondary distribution, incurring losses at two levels, while primary customers utilize only primary voltage facilities, therefore, incurring only primary losses. Also, distribution costs are size related and properly expressed in $ per KW-mos. rather than fixed monthly charges. If OTP cannot provide the necessary information to properly unbundle primary distribution from secondary distribution on the basis of fully embedded costs in this case, it should be ordered to do so as part of its next rate case.

V. WIND TURBINE MAINTENANCE

Q. MR. SCHEDIN, DID OTP PROVIDE COST DATA REGARDING ITS LANGDON, ASTUBULA, AND LUVERNE COMPANY OWNED WIND FARMS?

A. Yes. In its response to MLEC IR No. 203 (Exhibit __ (LLS-1), Attachment 15), OTP provided selected cost items.

Q. WHICH OF THESE ITEMS IS OF PARTICULAR CONCERN TO YOU?

A. Wind farm maintenance, unlikely to be disclosed, is seldom analyzed.

Q. WHAT DID OTP PROVIDE IN RESPONSE TO MLEC'S IR 203?

A. The response shows that maintenance is a major cost item which should be discussed and analyzed on a comparative basis.

Q. DID OTP PROVIDE ANY COMPARATIVE DATA?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. OTP should provide comparative data from other wind farms and also show how it is managing its wind farm maintenance costs.

VI. BASE LOAD GENERATOR PERFORMANCE

Q. MR. SCHEDIN, DID OTP PROVIDE RECENT INFORMATION REGARDING ITS BASELOAD GENERATION AVAILABILITY AND ITS RELATIONSHIP TO ESTABLISH KPI GOALS?

A. Yes. OTP responded to MLEC IR No. 207 (Exhibit __ (LLS-1), Attachment 16) with information regarding its baseload unit availability which it states were:

Year	**KPI Goals** (%available)	**Actual Achieved**
2015	73.09%	69.33%
2016	88.92%	88.62%
2017	88.92%	88.71%

Q. DID YOU EXAMINE THE PERFORMANCE OF INDIVIDUAL BASELOAD GENERATING UNITS?

A. Yes, in response to MLEC IR No. 112, OTP provided a list of the top 10 baseload outages for the period 2013-2017.

Q. WHAT DOES OTP'S RESPONSE SHOW?

A. In addition to unit outage causes and durations, it shows the cost of replacement power and energy. The most serious outages relate to the Coyote plant back in 2012-2013 when significant replacement power costs were incurred. Outages at the coyote plant subsequently appear to have been diminished.

Q. WHAT IS YOUR OPINION REGARDING THE FOREGOING AVAILABILITY GOALS AND ACHIEVEMENTS?

A. The procedure already in place of documenting individual unit outage cost impacts along with the setting of KPI goals and establishing management KPI incentives appears to be working.

Q. WHAT DO YOU FIND MISSING?

A. OTP should be documenting and making available to its large C&I customers, how excessive unit outage costs are treated by the Commission and what costs, if any, are denied recovery in OTP's FCA.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

General Resume of Larry L. Schedin PE

Firm Name: **LLS Resources, LLC**

Address: **332 Minnesota Street, Suite 2550** **Title:** President and Owner
St Paul, MN 55101
Phone: (651) 224-2222 **Total Professional Experience:** over 48 years

Education:

- Master's 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 No. 8470, State of Minnesota - current
- Lifetime Member of the Institute of Electrical and Electronics Engineers Inc.

Awards, publications, etc.:

- Member of University of Minnesota Department of Bioproducts and Biosystems Engineering project team, project title: Biomass Electricity Generation at Ethanol Plants - Achieving Maximum Impact. Numerous publications at project web site www.biomassCHPethanol.umn.edu.
- Currently publishes and edits energy bulletins for Midwest Large Energy Customer (MLEC) group
- Published and edited "Energy Bulletin" a monthly energy news update for largest 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
- Massachusetts Institute of Technology Thesis: "Strategic Planning in the Utility Industry," 1976

Other papers for businesses and institutions such as Rock-Tenn and U of M Morris

Previous Employment:

Larry L. Schedin started his own energy consulting business, Schedin & Associates Inc. in 1980 after 18 years with Northern States Power Company (NSP), a large electric and gas utility company serving over two million people in a four-state service area. His utility experience at NSP 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 as an expert witness. His current emphases include wind, solar, cogeneration and other alternative energy development projects along with negotiation of energy purchase and sales agreements. His clients have included large corporations such as General Mills, Inc., American Crystal Sugar Company, CITGO Petroleum, Coca-Cola, the Minnesota Chamber of Commerce, the University of Minnesota and others. He also serves as an expert witness in utility regulatory proceedings both at the federal and state levels. Besides starting several businesses, Mr. Schedin's achievements include:

- Introduced the concept of off-site renewable distributed generation in Minnesota to encourage customer ownership of wind farms and other forms of renewable generation in Minnesota, 2007.
- In cooperation with Caterpillar, CITGO Refining, General Mills Inc., Mobil Oil Refinery and others, Mr. Schedin helped form the Illinois Industrial and Institutional Customers for Electrical Restructuring (I^3CER) Group to help draft the Illinois electric restructuring law, 1996 & 1997.
- In 1985, Mr. Schedin assisted a nucleus group of industrial customers to organize the Chicago Area Energy Users (CAEU) group with the purpose of improving the rates and policies of Northern Illinois Gas Company, Peoples Gas Light & Coke Company, North Shore Gas Company and Commonwealth Edison Company. Throughout the 1980's and 1990's this group helped to develop the new guidelines for delivering deregulated natural gas to the Chicago area. Mr. Schedin has continued to act as technical support advisor, counselor, organizer, administrator and energy expert for groups of customers who come together with a common need to understand the changing energy environment.

- Selected as technical advisor to The Minnesota Energy Consumers (MEC) Group, including many of Minnesota's largest energy users in 1998. As follow-on to that group, he currently serves as an expert witness for the Minnesota Chamber of Commerce.

- 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.

Recent Expert Witness Experience

- Expert witness in approximately 15 recent and current electric utility rate case before the Minnesota Public Utilities Commission (MPUC) and the North Dakota Public Service Commission (NDPSC). A wide range of clients include businesses such as Cargill, ADM, the Minnesota Chamber of Commerce, and Bobcat as well as institutions such as the University of Minnesota, Twin Cities Metropolitan Council Environmental Services, Dakota County, Hennepin County, and others.

- Expert witness for the US Dept. of Transportation and Metro Council regarding relocation of 115 KV underground facilities for Hiawatha Light Rail System.

- Expert witness for environmental clients such as the Izaak Walton League regarding the first major approved 345 KV transmission outlets for Buffalo Ridge wind farms.

- Expert witness for environmental clients such as Wind on the Wires and Fresh Energy regarding three CapX 2020 345 KV projects each receiving a certificate of need.

- Expert witness for Minnesota Chamber of Commerce regarding utility requests to recover transmission facility costs and renewable resource investment costs via new automatic adjustment riders.

- Many others including studies and installation of CHP projects listed in separate document.

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

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/07/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please describe how OTP tracks and reports on electric system reliability. Does OTP file an annual reliability report with the ND Commission? If so, please explain how the report differs, if any, from the report made to the MN Commission. i.e., are the facilities and customers reported on the same for both jurisdictions?

a. Please provide a copy of the most recent reliability reports made to both Commissions.
b. Besides the standard reliability indices of CAIDI, SAIFI, and SAIDI, do the reports include the momentary outage index called MAIFI? If not, why not?
c. Does OTP have adequate SCADA facilities at its substations to provide the data necessary for reporting MAIFI? If not, please explain.
d. For the indices reported, does OTP have a minimum reliability index goal for each? If yes, please provide the goals. Please include the present goal or a proposed goal for MAIFI.

Attachments: 1

Attachment 1 to DR ND-MLEC-200.pdf

Response:

Otter Tail provides an annual Safety, Reliability, Service Quality (SRSQ) Report to the Minnesota Public Utilities Commission per Minn. Rules Ch. 7826. Otter Tail does not have a similar reporting obligation in North Dakota. Otter Tail includes in its North Dakota annual jurisdictional report annual CAIDI, SAIFI and SAIDI results for total company.

a. Attachment 1 to DR ND-MLEC-200 is the SRSQ Report filed March 31, 2017 reporting on calendar year 2016. The 2017 report will be filed with the Minnesota Public Utilities Commission on or before April 2, 2018.
b. Otter Tail includes MAIFI results in the annual SRSQ Report.
c. Otter Tail's SCADA facilities monitor our transmission systems, 115KV and above. Otter Tail monitors reliability and calculates MAIFI utilizing an interruption monitoring system (IMS). The IMS is used to monitor and calculate reliability indices at the feeder level and above.
d. Goals set and reported annually on the SRSQ Report to the Minnesota Public Utilities Commission, for 2017 reporting are as follows:
    a. CAIDI less than or equal to: 62 minutes/interruption
    b. SAIFI less than or equal to: 0.97 interruptions/customer
    c. SAIDI less than or equal to: 60 minutes/customer
    d. MAIFI: We are required to report MAIFI in our SRSQ report, but, to date, the Minnesota Public Utilities Commission has not established a minimum target index. Otter Tail does have internal system and Customer Service Center indices established for MAIFI which it tracks and reports on a monthly basis internally. Otter Tail's annual 2017 MAIFI target was less than or equal to 6.5 interruptions/customer.

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

March 31, 2017

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: In the Matter of Otter Tail Power Company 2016 Annual Safety, Reliability and Service Quality Report and Proposed SAIFI, SAIDI and CAIDI Reliability Standards for 2017
Docket No. E017/M-17-

Dear Mr. Wolf:

Otter Tail Power Company (Otter Tail) submits the enclosed Annual Report pursuant to Minn. Rules 7826.0400, 7826.0500, and 7826.1300. This Annual Report presents our safety, reliability, and service quality performance for the year 2016 and proposed reliability standards for 2017 pursuant to Minn. R. 7826.0600. Otter Tail's proposed reliability standards for 2017 are found in Table 1 in Section IV, of the attached 2016 Report and Proposed 2017 Reliability Standards Petition.

Otter Tail has electronically filed this document with the Commission. In compliance with Minn. Rule 7829.1300, subp. 2, Otter Tail is serving a copy of this filing on the Department of Commerce – Division of Energy Resources and Office of Attorney General – Antitrust & Utilities Division. A Summary of the filing has been served on all persons on Otter Tail's general service list. A Certificate of Service is also enclosed.

We are available to provide any additional information or respond to any questions you may have. Feel free to contact me at (218) 739-8395 or email me at jfyhrie@otpco.com.

Sincerely,

/s/ JESSICA FYHRIE
Jessica Fyhrie
Supervisor, Regulatory Proceedings

ljh
Enclosures
By electronic filing
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's 2016 Annual Safety, Reliability and Service Quality Report and Proposed SAIFI, SAIDI and CAIDI Reliability Standards for 2017	Docket No. E017/M-17-

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2016 REPORT AND PROPOSED 2017 RELIABILITY STANDARDS

Summary of Filing

Please take notice that on March 31, 2017, Otter Tail Power Company (Otter Tail or the Company), filed with the Minnesota Public Utilities Commission (Commission) its annual Safety, Reliability and Service Quality Report for 2016 pursuant to Minnesota Rules 7826.0400, 7826.0500 and 7826.1300. Pursuant to Minnesota Rule 7826.0600, subp. 1, Otter Tail proposes SAIFI, SAIDI and CAIDI reliability standards for 2017.

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Otter Tail Power Company's 2016 Annual Safety, Reliability and Service Quality Report and Proposed SAIFI, SAIDI and CAIDI Standards for 2017	Docket No. E017/M-17-

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2016 REPORT AND PROPOSED 2016 RELIABILITY STANDARDS

I. INTRODUCTION

Otter Tail Power Company (Otter Tail or the Company), submits this filing in compliance of Minnesota Rules 7826.0400, 7826.0500, 7826.0600, subp. 1, and 7826.1300.

II. GENERAL FILING INFORMATION

Pursuant to Minnesota Rule 7829.1300, subp. 4, Otter Tail provides the following general information.

A. Name, Address, and Telephone Number of Utility

Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8200

B. Name, Address, and Telephone Number of Utility Attorney

Bruce Gerhardson
Associate General Counsel
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8475

C. Date of Filing and Effective Date

This Report is being filed on March 31, 2017. The proposed reliability standards will be effective for the calendar year 2017.

D. Title of Utility Employee Responsible for Filing

Jessica Fyhrie
Supervisor, Regulatory Proceedings
Otter Tail Power Company
215 South Cascade Street
P. O. Box 496
Fergus Falls, MN 56538-0496
(218) 739-8395

III. MISCELLANEOUS INFORMATION

A. Service on Other Parties

Pursuant to Minn. Rule 7829.1300, subp. 2 and Minn., Stat. §216.17, subd. 3, Otter Tail has electronically filed this Report and Proposed 2017 Reliability Standards. A summary of the filing has been served on all parties on the attached service list.

B. Summary of Filing

A one-paragraph summary of the Report is attached pursuant to Minnesota Rule 7829.1300, subp. 1.

IV. DESCRIPTION AND PURPOSE OF FILING

A. Annual Reporting

Minnesota Commission Rules 7826.0400, 7826.0500 and 7826.1300 require electric utilities to file reports on safety, reliability, and service quality performance for the prior year. Otter Tail's 2016 Safety, Reliability, and Service Quality Report is attached.

B. Proposed reliability standards for 2017

Minnesota Commission Rules 7826.0600 subp. 1, requires electric utilities to propose reliability performance standards for each of its work centers. The rule requires the performance standards be filed on or before April 1 of each year. The utility is to propose standards for the following reliability indices:

1. System average interruption duration index or SAIDI
2. System average interruption frequency index or SAIFI
3. Customer average interruption duration index or CAIDI

In compliance with the Commission Rules 7826.0600 Subpart 1, Otter Tail's proposed 2017 reliability performance standards for each of Otter Tail's work centers. As ordered in **Docket No. E017/M-15-322 dated August 14, 2015**, Otter Tail's reliability standards have been frozen at 2013 levels until the Company has shown sufficient improvement in indices' performance. Otter Tail proposes to maintain the performance standards at the 2013 levels as shown in **Table 1** below.

Table 1

Proposed 2017 Standards by CSC			
Work Center	**SAIDI**	**SAIFI**	**CAIDI**
Bemidji	70.64	1.26	56.06
Crookston	69.33	1.19	58.26
Fergus Falls	66.97	1.11	60.33
Milbank	75.49	1.82	41.48
Morris	55.78	1.01	55.23
Wahpeton	57.24	1.13	50.65
All MN Customers	**64.95**	**1.13**	**57.48**

V. CONCLUSION

Otter Tail hereby submits its annual Safety, Reliability, and Service Quality Report for 2016, proposed reliability standards for 2017.

Date: March 31, 2017

Respectfully submitted,

By: /s/ JESSICA FYHRIE

Jessica Fyhrie
Supervisor, Regulatory Proceedings
Otter Tail Power Company
215 South Cascade St., PO Box 496
Fergus Falls, MN 56537
(218) 739-8395

BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Docket No. E017/M-17-

Otter Tail Power Company's
Safety, Reliability, and Service Quality
Report for 2016,
and
Proposed SAIFI, SAIDI, and CAIDI
Reliability Standards for 2017,

Including Additional Information Required
by Commission Orders

March 31, 2017

TABLE OF CONTENTS

I. OTTER TAIL EXECUTIVE MANAGEMENT'S VIEW OF RELIABILITY

This section provides the view of Otter Tail's executive management towards reliability and customer satisfaction.

Reliability at Otter Tail Power Company (Otter Tail) continues to be best summarized in the Company's mission statement:

"To produce and deliver electricity as reliably, economically, and environmentally responsibly as possible to the balanced benefit of customers, shareholders, and employees and to improve the quality of life in the areas in which we do business."

Otter Tail provides electricity to 422 communities and to rural areas in western Minnesota, northeastern South Dakota, and the eastern two-thirds of North Dakota. The average population of the communities we serve is approximately 630, and over one-half of the communities we serve have populations of fewer than 200. Only three of our communities have populations exceeding 10,000: Fergus Falls, Minnesota (pop. 13,138), Bemidji, Minnesota (pop. 13,431), and Jamestown, North Dakota (pop. 15,427). We operate 9 Customer Service Centers (CSC) throughout our service territory. Otter Tail is committed to utilizing proactive efforts to communicate, investigate, and resolve reliability issues across our approximately 70,000 square-mile service territory. This is roughly the size of Wisconsin.

The integrity of Otter Tail's entire transmission and distribution system is directly related to interruption frequency; thus, the accountability lies within our Asset Management area. Otter Tail's Asset Management area is accountable for the quality, availability and delivery of materials and engineering associated with providing electric service to Otter Tail customers. At Otter Tail, we employ a system of Key Performance Indicators (KPIs), for the purpose of providing additional focus on achievement in particular areas of our operations. Two of Asset Management's KPIs are reliability indices dealing with interruption frequency: the Momentary Average Interruption Frequency Index (MAIFI) and System Average Interruption Frequency Index (SAIFI).

Otter Tail's Customer Service area is accountable for responding to all interruptions. Thus, Otter Tail's Customer Service area is accountable for the cost effective and efficient deployment of field personnel, trucks, and equipment as quickly and safely as possible, necessary for restoring service to customers when interruptions occur. One of the Customer Service area's KPIs is Customer Average Interruption Duration Index (CAIDI.) Additionally, the Reliability indices, SAIDI, SAIFI, CAIDI, and MAIFI are companywide KPI's. These indices are communicated and reviewed with all employees, on a monthly basis, with the expectation that all employees remain cognizant of our company's reliability performance.

The Asset Management and Customer Service areas have a common goal, which is to improve the overall system reliability. Each area recognizes the overall system improvement cannot be accomplished without collaboratively working with the other area. Each area also recognizes system reliability improvements are based on cost effective decisions and overall system improvements over longer periods of time.

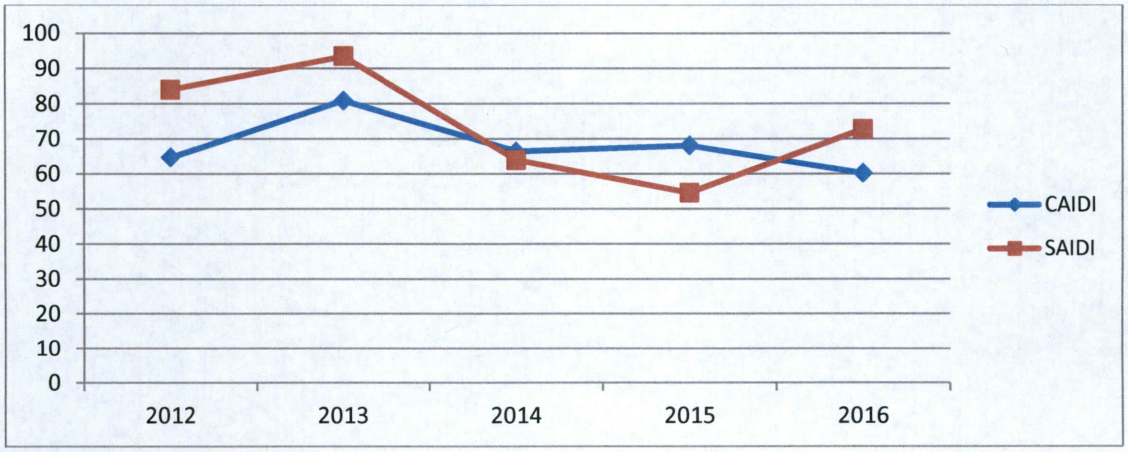
Our KPI's help us measure the success and effectiveness of our company. Through the efforts of our dedicated employees, in 2016 we achieved the lowest OSHA recordable injuries rate in company history and we maintained high customer satisfaction. With twelve recordable injuries we met our 2016 safety goal of no more than 15 OSHA recordable injuries. 2016 is the third time in nine years we've set new or tied past records for recordable injuries. Of note, several work groups finished the year with zero recordable injuries.

Customer experience (including service reliability) and satisfaction are among top priorities for our company. Otter Tail was the highest scoring utility among electric and gas-electric investor-owned utilities measured by the American Customer Satisfaction Index in 2016 with an overall Customer Satisfaction score of 84 (out of 100). The Reliability portion of the survey indicated a score of 91 compared to the average investor-owned utility score of 80. Survey results also show Otter Tail receiving the top scores from customers in Customer Restoration, Quality, Value, and Loyalty.

II. OTTER TAIL 2016 SUMMARY GRAPHS

As previously included Otter Tail provides a summary table that allows the reader to more easily assess the overall reliability of the system and identify the main factors that affect reliability. Figure 1 through **Figure 6** below provides a brief summary of Otter Tail's overall reliability and service quality for the years 2012 through 2016.

Figure 1 - Historic Minnesota SAIDI and CAIDI



Otter Tail Power MN Customers saw improvement in CAIDI and an increase in SAIDI for 2016 compared to 2015 results.

Figure 2 - Minnesota Historic SAIFI

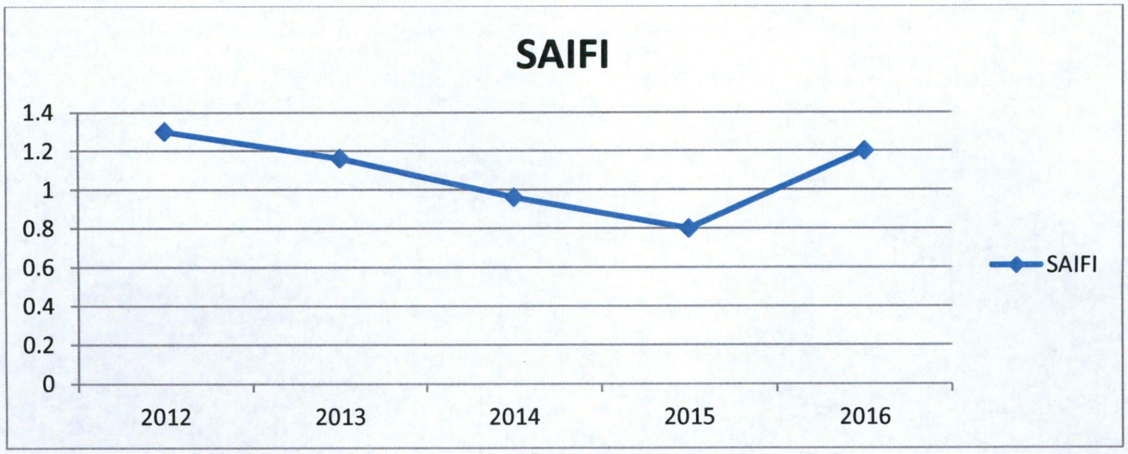


Figure 3 –Historic Expense of Major Critical System Infrastructure Items

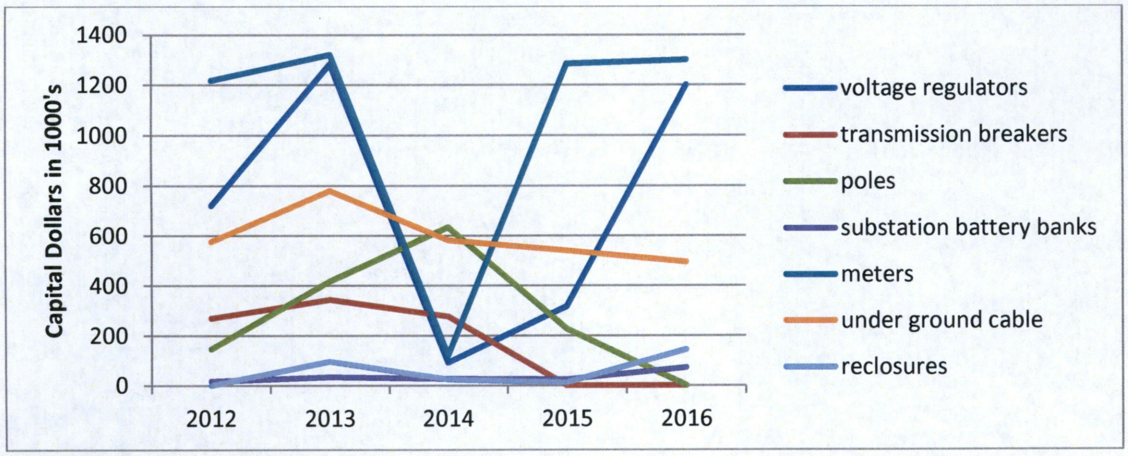


Figure 4 – Minnesota Historic MAIFI

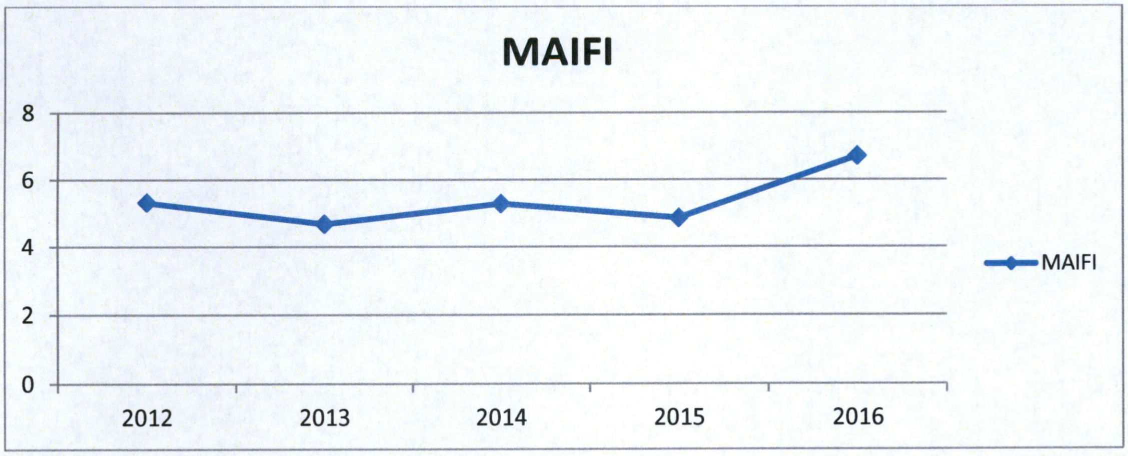


Table 1
MAIFI by Customer Service Center

CSC 2016	MAIFI
Bemidji	4.9
Crookston	6.1
Fergus Falls	6.2
Milbank	12.8
Morris	9.1
Wahpeton	8.9
MN Total	6.7

Figure 5 – Full Time Lineworkers available for trouble calls and for the operation and maintenance of Minnesota distribution lines

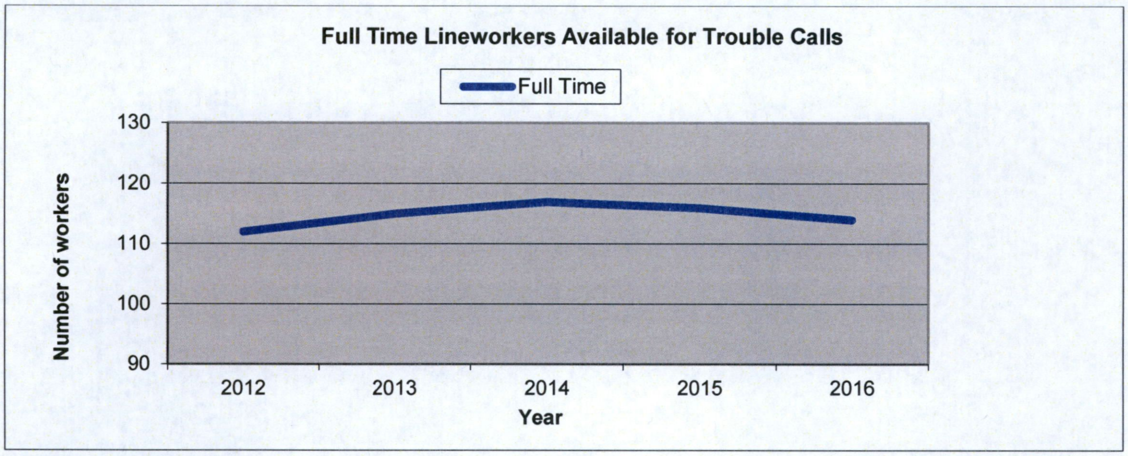
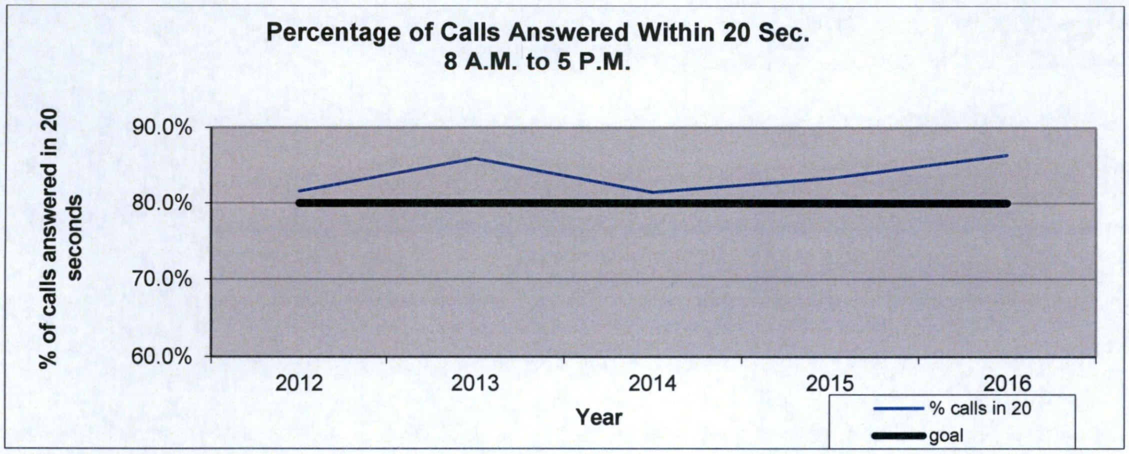


Figure 6 - Calls Answered within 20 Seconds



III. ANNUAL SAFETY REPORT 7826.0400

Pursuant to Minnesota Rule 7826.0400, ANNUAL SAFETY REPORT, each utility shall file a report on its safety performance during the last calendar year. This report shall include the following information.

A. Summary of all reports filed with the United States Occupational Safety and Health Administration and the Occupational Safety and Health Division of the Minnesota Department of Labor and Industry during the 2016 Calendar year.

Table 2

NUMBER OF CASES			
Total number of deaths	Total number of cases with days away from work	Total number of cases with job transfer or restriction	Total number of other recordable cases
0	3	1	8

NUMBER OF DAYS	
Total number of days of job transfer or restriction	Total number of days away from work
240	10

INJURY AND ILLNESS TYPES				
Injuries	Skin disorders	Respiratory conditions	Poisonings	All other illnesses
12	0	0	0	0

In 2016 we achieved the lowest OSHA recordable injuries rate in company history.

B. A description of all incidents during the calendar year in which an injury requiring medical attention or property damage resulting in compensation occurred as a result of downed wires or other electric system failures and all remedial action taken as a result of any injuries or property damage described.

Table 3

ANNUAL SAFETY REPORT				
Date	**Cause**	**Type**	**Action Taken**	**Expense**
7/28/2016	Faulty Secondary Wire	Property damage	Paid for damages	$277.50
There were no instances of personal injury due to system failures in 2016.				

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/26/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

---

Data Request:

Please provide revenue requirements for NITS services 2014-2019 and describe how such NITS costs are recovered by rate class.

Attachments: 0

Response:

Consistent with the approach taken in providing the data in OTP's response to ND-MLEC-217, OTP's revenue requirements for NITS services for 2014 – 2018 are shown in the table below. OTP's revenue requirement for NITS services during 2019 is not expected to be available until February of 2019.

Year	OTP's Net Annual Transmission Revenue Requirement
2014	$20,343,186
2015	$25,309,881
2016	$28,776,242
2017	$29,570,958
2018	$29,946,065
2019	Not Available

OTP's revenue requirements for the applicable transmission costs that derive OTP's NITS rate are recovered through OTP's respective state jurisdictions. Any NITS revenues received through MISO are allocated to each jurisdiction and credited against the overall jurisdictional revenue requirement, thereby reducing the revenue requirement recovered from retail customers in each of the three state jurisdictions. The 2018 Test Year filed as part of OTP's request to increase rates in North Dakota allocates OTP's NITS net revenue requirement based on the NEPIS[1] allocation factor as follows:

Rate Class	Allocation
Residential	35.564%
Farms	2.399%
General Service	24.963%
Large General Service	25.519%
Irrigation	0.089%
Outdoor Lighting	2.323%
OPA	0.920%
Controlled Water Heating	1.064%
Controlled Service Interrupt	6.253%
Controlled Service Deferred	0.906%

[1] OTP Initial Filing Volume 3, Part E, Schedule E-3, Page 16-2

OTTER TAIL POWER COMPANY
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Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

---

Data Request:

Please provide MISO transmission receipts, expenses and net amounts included in revenue requirements (other than NITS) for the years 2014-2019 and explain how these amounts are recovered by rate class.

Attachments: 0

Response:

The following table shows the MISO revenues and expenses included in the TCRR revenue requirement for the years 2014 through 2019. Actual revenues and expenses are included through July 2017 and estimates are included going forward. The estimates include the retail share of the MISO revenues and expenses.[1]

	2014	2015	2016	2017	2018	2019
MISO Schedule 26 Revenue	($4,061,349)	($4,937,859)	($5,075,208)	($4,529,787)	($4,963,718)	($4,488,192)
MISO Schedule 37 Revenue	($49,083)	($59,124)	($61,327)	($27,402)	($0)	($0)
MISO Schedule 38 Revenue	($69,796)	($80,844)	($77,625)	($30,826)	($0)	($0)
MISO Schedule 26A Revenue	($285,731)	($366,812)	($439,636)	($532,951)	($612,118)	($542,933)
MISO MVP ARR Revenue	($7,583)	($25,228)	($17,125)	($19,437)	($21,383)	($26,135)
Net MISO Revenue	($4,473,542)	($5,469,867)	($5,670,921)	($5,140,402)	($5,597,219)	($5,057,260)
MISO Schedule 26 Expense	$4,796,792	$5,703,989	$5,520,901	$4,845,426	$4,822,225	$4,748,111
MISO Schedule 26A Expense	$741,993	$1,348,209	$2,008,488	$2,676,321	$2,829,366	$3,278,198
Net MISO Expense	$5,538,785	$7,052,198	$7,529,389	$7,521,748	$7,651,591	$8,026,309
Net MISO	**$1,065,243**	**$1,582,331**	**$1,858,467**	**$2,381,345**	**$2,054,372**	**$2,969,049**

[1] Commission's April 25, 2012 Order Point 2 in Case Nos. PU-11-153 and PU-11-682 requiring OTP to use the Split Method for the treatment of OTP's investments in transmission projects eligible for regional cost allocation through the MISO Tariff.

OTP recovers MISO revenues and expenses as a part of the overall North Dakota TCRR Revenue Requirement which attributes approximately 27.77 percent to the Large General Service Class, 2.77 percent to Controlled Service classes, 0.96 percent to Lighting customers, and the remaining 68.50 percent to all other service classes. This can be seen on Exhibit_(BCH-1) Schedule 6, Page 1 of 2[2].

[2] Provided in OTP's February 15, 2018 filing in its Application for Authority to Increase Electric Rates in North Dakota Case No. PU-17-398.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/25/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

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Data Request:

Please provide total transmission expenditures by year 2014–2019.

Attachments: 0

Response:

OTP interprets "total transmission expenditures" to mean capital investment in transmission projects. The following table shows the total transmission expenditures (OTP Total) as shown in the TCRR for the years 2014 through 2019. Actual data is included through July 2017 and estimates are included going forward.

	2014	2015	2016	2017	2018	2019
Total Transmission Expenditures	$42,929,544	$40,641,070	$82,118,317	$52,969,932	$35,551,021	$15,582,456

OTTER TAIL POWER COMPANY
Case No: PU-17-398

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Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/25/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

Data Request:

Please provide transmission revenue requirements by year 2014 – 2019 net of MISO credits and charges and NITS costs.

Attachments: 0

Response:

The following table shows the net revenue requirement (OTP ND) as shown in the TCRR for the years 2014 through 2019. Actual data is included through July 2017 and estimates are included going forward.

	2014	2015	2016	2017	2018	2019
Net Revenue Requirement	$5,652,996	$7,268,555	$7,585,410	$8,902,594	$7,467,464	$7,103,150

OTTER TAIL POWER COMPANY
Case No: PU-17-398

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Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/27/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

Data Request:

Please provide the NITS transmission rate applicable to OTP's transmission rate zone for the years 2014-2019.

Attachments: 0

Response:

Due to constant changes and numerous updates occurring across all of MISO, the NITS transmission rate for each pricing zone (i.e. "rate zone") is updated by MISO almost every month. Utilizing the Attachment O worksheets that are publicly posted by MISO effective in January of each calendar year,[1] the following NITS transmission rates were applicable to OTP's pricing zone (Zone 18) between 2014 and 2018.

Year	NITS Rate ($/MW-Year)
2014	$30,071
2015	$35,438
2016	$37,580
2017	$39,219
2018	$36,493
2019	Not Available

The NITS transmission rate applicable to the OTP pricing zone for 2019 is not expected to be available until February of 2019.

[1] See MISO's Attachment O postings at:
https://www.misoenergy.org/markets-and-operations/ts-pricing/#nt=/tspricingtype:Attachment O Data

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

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Data Request:

Regarding the Big Stone South-to-Brookings County 345 KV transmission line completed in 2017:

a. Please provide the initial estimate of the cost of this project and the split among the participants.
b. Was this project approved under a CN proceeding. If not, what regulatory approvals were necessary?
c. Was there a budget or regulatory cost cap placed on the projected cost for this project when it was initially approved? How will the PMI system be used to control costs?
d. How did the final cost compare to the initial estimate?
e. Please explain any cost overruns after Completion.
f. Is this an MVP project? Why or why not?
g. Is the cost of this project currently being recovered in the TCRR or will it go directly into rate base.

Attachments: 0

Response:

a. The initial cost estimate for the BSAT-Brookings project was $226.7 million. OTP's share of the project was $134.5 million [OTP Total] and the project partner's share was $92.2 million. The MISO project ID is 2221.

b. No. This project did not require a CN. The BSAT-Brookings project was included in MISO's 2011 Transmission Expansion Plan and was approved for recovery in OTP's

TCRR in Case No. PU-12-702. The project obtained a Route Permit from the South Dakota Public Utilities Commission.[1]

c. No regulatory cost cap was placed on this project when it was approved for recovery in Case No. PU-12-702. Xcel Energy established a budget for the project and the budget was agreed to by both owners. The companies use Project Management Institute (PMI) process and specific Knowledge Areas of Scope, Time, Cost, Risk, and Procurement. To this end, the project came in on time and under budget.

d. The project went in-service in September 2017. OTP's final investment in the project of approximately $73 million (OTP Total) is lower than the initial estimate.

e. Not applicable.

f. Yes. It meets the criteria established by MISO for MVPs because it provides a combination of regional reliability and economic value with the cost of the project paid for by all MISO load serving entities.

g. The North Dakota retail share for the project is currently recovered according to the methods approved in the order in Case Nos. PU-11-153 and PU-11-682 which established OTP's North Dakota TCRR. OTP proposes that the North Dakota retail share be rolled into base rates at the time final rates are implemented.[2]

[1] Docket No. EL13-020.
[2] Haugen Direct Testimony, beginning at page 17, line 5 through page 25 line 17.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

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Data Request:

Regarding the Big Stone – Ellendale 345 KV line transmission project scheduled for operation in 2019:

a. Please provide a project description, the present estimated cost, and the cost split among the participants.
b. Will this project be requested for approval under CN proceeding. If not, what regulatory approvals are anticipated to be necessary?
c. Will there be a budget or regulatory cost cap placed on the projected cost for this project when it is initially approved? How will the PMI system be used to control costs?
d. Will the final cost compared to the initial estimate be calculated and reconciled?
e. Is this an MVP project? Why or why not?
f. Will the cost of this project be recovered in the TCRR or will it go directly into rate base.

Attachments: 0

Response:

a. This 345 kV MVP transmission project extends from OTP's Big Stone South substation to MDU's Ellendale substation, approximately 150 miles. The initial cost estimate for the BSAT-Ellendale project was $395.7 million. OTP's share of the project was $182.5 million [OTP Total] and the project partner's share was $193.2 million. The MISO project ID is 2220.

b. All regulatory approvals for the project have been secured. A Siting and Route permit and Certificate of Public Convenience and Necessity[1] from the North Dakota Commission has already been secured. The BSAT-Ellendale project was included in MISO's 2011 Transmission Expansion Plan and was approved for recovery in OTP's TCRR in Case No. PU-12-702. OTP and MDU also received a Route permit from the South Dakota Public Utilities Commission.[2] No other regulatory approvals were required.

c. No regulatory cost cap was placed on this project when it was approved for recovery in Case No. PU-12-702. OTP established a budget and schedule for the project that was agreed to by both owners and adopted by MISO. The companies use Project Management Institute (PMI) process and specific Knowledge Areas of Scope, Time, Cost, Risk, and Procurement to execute the project. To this end, the project continues to come in on time and under budget.

d. Yes. OTP proposes that the BSAT-Ellendale project remain in its active TCRR. Project investment updates will be included in future TCRR filings and OTP can provide the reconciliation in those proceedings upon request.

e. Yes. It meets the criteria established by MISO for MVPs because it provides a combination of regional reliability and economic value and the costs for the project are paid by all MISO load serving entities.

f. The North Dakota retail share of this project is currently recovered according to the methods approved in the order in Case Nos. PU-11-153 and PU-11-682 which established OTP's North Dakota TCRR. The BSAT-Ellendale project will go in-service after this rate case is completed. The North Dakota retail share will continue to be recovered in the TCRR until OTPs first rate case after completion of the BSSE project.[3]

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[1] North Dakota Case No. PU-13-840, PU-13-273
[2] South Dakota Docket No. EL13-028
[3] Haugen Direct Testimony, beginning at page 17, line 5 through page 25 line 17.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/27/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

Data Request:

Does MISO exercise any type of cost control for projects accepted into its MTEP, MVP, or other expansion plans other than the cost estimates provided by project participants? Please explain.

Attachments: 0

Response:

MISO exercises cost control for future projects after they are approved in the MISO Transmission Expansion Plan (MTEP). MISO generally relies upon its respective transmission owners to provide cost estimates for future projects. MISO's primary cost control for approved projects in MTEP (including MVPs) are the quarterly status reports. To the extent that a project has a cost variance or schedule variance, MISO requires the transmission owner to provide a variance explanation justifying each change. These quarterly status reports are publicly posted for interested stakeholders to review.[1]

Additionally, Section VII in Attachment FF of MISO's Tariff[2], requires detailed reporting of MVPs and includes the following information available on the MISO website[3]:

- Triennial report that includes a full MVP review of the benefits versus cost of the approved MVP portfolio;
- Annual report that includes a limited MVP review of the benefits versus cost of the approved MVP portfolio; and

[1] https://cdn.misoenergy.org/20180331%20MTEP%20Appendix%20A%20Status%20Report173773.xlsx
[2] https://cdn.misoenergy.org/Attachment%20FF90219.pdf
[3] https://www.misoenergy.org/planning/transmission-studies-and-reports/#nt=/report-study-analysistype:MTEP/mtepdoctype:MTEP Study/mtepstudytype:Multi Value Projects

- Quarterly MVP dashboard summarizing the status of each MVP with its respective cost and schedule variance.

The quarterly dashboard, as well as the annual and triennial reports, are available on MISO's public website for access by the appropriate stakeholders.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/30/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

Data Request:

What are the consequences of any significant cost overruns with respect to the initial estimates?

Attachments: 0

Response:

MISO Transmission Owners are required to provide quarterly status updates to MISO for all previously approved transmission projects under development. The quarterly status updates must include any material changes to a project's cost and the reasons or causes for such cost changes. MISO facilitates transparency by aggregating this information for all MTEP projects and posting it on MISO's website, where it may be reviewed by interested stakeholders.[1]

In response to FERC Order No. 1000 and the introduction of competitively bid projects, MISO now has approved procedures in place for cost-shared projects approved after 2014 that gives them the authority to take certain actions if an approved cost-shared project has a significant cost overrun from its initial estimate, such as, but not limited to: (1) cancellation of the approved project; (2) development of an alternative project or mitigation plan; (3) reassignment to another transmission developer; or (4) no action.[2]

[1] MISO's latest quarterly status report is available at https://cdn.misoenergy.org/20180331%20MTEP%20Appendix%20A%20Status%20Report173773.xlsx
[2] Additional information can be found in Section IX of Attachment FF, available at https://cdn.misoenergy.org/Attachment%20FF90219.pdf

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Gina Ice, Rate Analyst

Data Request:

Please explain how OTP separates (unbundles) distribution from transmission costs in its cost of service by voltage class studies.

Attachments: 0

Response:

OTP does not prepare a voltage class study. OTP follows the FERC Uniform System of Accounts so any transmission costs are included within FERC accounts 350-358 (Plant) and 560-573 (O&M) and properly classified as transmission costs in our cost of service study. Distribution costs are included within FERC accounts 360-373 (Plant) and 580-598 (O&M) and properly classified as distribution costs in our cost of service study.

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Responding Witness: Gina Ice, Rate Analyst

Data Request:

What levels by voltage are unbundled? E.g., primary distribution, secondary distribution, transmission transformed, transmission etc.?

Attachments: 0

Response:

OTP considers electrical lines with a voltage of 41.6 kV or greater as transmission lines. Typically, lines with a voltage less than 41.6 kV are designated as distribution lines. Specifically, for distribution, anything from the distribution substation transformer to the customer transformer is primary distribution and from the customer transformer to the meter is secondary distribution. Typical transmission level voltages for OTP are operated between 41.6 kV and 345 kV while primary distribution is usually operated between 2.4 kV and 25 kV and secondary distribution is operated below 480 Volts.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/30/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

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Data Request:

Please provide:

a. the peak load estimated in 2018 for all customers served at primary distribution (2.4 KV-25 KV) and separately for all customers served at secondary distribution (277/480 volts and less);

b. provide the 2018 net plant investment for each of the two foregoing groups.

Attachments: 0

Response:

a. The Company's peak demand at the primary distribution level, specifically the D3 factor, is 879 MW while the secondary distribution level, the D4 factor, is 1,168 MW for the test year, which can be seen on page 15-1 of the Jurisdictional Cost of Service Study (JCOSS).

b. Please see the table below for OTP's Total and North Dakota share of primary and secondary distribution system net plant.

	Net Plant	
	OTP-Total	**OTP-ND**
Primary Demand	$109,513,754	$50,143,286
Secondary Demand	$62,207,636	$29,825,344

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Witness Tommerdahl describes the OTP Langdon, Ashtubula, and Luverne owned wind projects. Regarding these projects:

a. Please state the annual increase in revenue requirements (2017-2020) as a result of the Langdon PTC's expiring in 2017 and the expected increase in 2018 when the Ashtabula PTC's expire.
b. Please quantify and provide the annual benefit toward revenue requirements of the federal grant in lieu of the PTC for the Luverne wind farm in 2009. Will this grant be paid back? Please explain.
c. Please provide for each wind farm the annual O&M costs ($ & $ per MWH) since each were placed in service.
d. Please provide any O&M analyses comparing the OTP-owned wind farms to other wind farms in MISO or any other O&M studies from other upper-midwest wind farms.

Attachments: 2

Attachment 1 to ND-MLEC-203.xlsx
Attachment 2 to ND-MLEC-203.xlsx

Response:

a. Please see Attachment 1 to DR ND-MLEC-203 for the information requested. Note that OTP had proposed levelizing the PTCs but the settlement in Case No. PU-08-862 with the Large Industrial Group and other parties required not levelizing the PTCs but flowing them through (page 15 of 21 of the amended Settlement Agreement).

b. The Federal grant reduced the plant in service balance for the Luverne wind farm. The annual benefit of the federal grant in lieu of PTC for the Luverne wind farm is a $348,614 decrease to revenue requirements. This assumption was based on the 2018 Test Year using the most recent three-year average output and assuming 50 percent of the PTCs would be used on the 2018 tax return. Also, the assumption does not consider any additional rate base revenue requirement that would have occurred due to accumulated deferred PTCs in effect since the in-service date. The grant does not have to be paid back.

c. Please see Attachment 2 to DR ND-MLEC-203.

d. OTP does not have the requested analysis comparing the OTP-owned wind farms to other wind farms in MISO or any other O&M studies from other upper-Midwest wind farms.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please provide OTP's actual base-load unit key performance indicator (KPI) goals for each year for the period 2015-2017. Describe and quantify the KPI explicitly aimed at base load generation availability. What were the consequences for OTP's management of the 2015 KPI being above or below OTP's goal?

Attachments: 0

Response:

The equivalent availability goals for 2015, 2016 and 2017 were 73.09%, 88.92%, and 88.92%. The 2015 KPI was lower due to the planned cutover of the AQCS projects at Big Stone Plant. If the equivalent availability goal was met, there was a financial incentive of 1% of annual pay in each of those years to qualified employees. The actual equivalent availability for 2015, 2016 and 2017 was 69.33%, 88.62%, and 88.71%. Each year for the last three years the goal was not achieved, and the 1% incentive was not awarded.