

**BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

**In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota**

Case No. PU-17-398

PUBLIC DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY Staff

May 18, 2018

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I. INTRODUCTION

Q. Please state your name, position, and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction

1 with maintaining my accountancy license. I am a licensed Certified Public
2 Accountant and attorney in the State of Michigan. I am also a Certified Financial
3 Planner™ professional and a Certified Rate of Return Analyst (“CRRA”). Since
4 1981, I have been a member of the Michigan Association of Certified Public
5 Accountants. I am also a member of the Michigan Bar Association and the
6 Society of Utility and Regulatory Financial Analysts (“SURFA”). I have also been
7 a member of the American Bar Association (“ABA”), and the ABA sections on
8 Public Utility Law and Taxation.

9
10 **Q. Please summarize your professional experience.**

11 A. Subsequent to graduation from the University of Michigan, and after a short
12 period of installing a computerized accounting system for a Southfield, Michigan
13 realty management firm, I accepted a position as an auditor with the predecessor
14 CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility
15 regulation, where the majority of my time for the past 38 years has been spent, I
16 performed audit, accounting, and tax work for a wide variety of businesses that
17 were clients of the firm.

18
19 During my service in the regulatory section of our firm, I have been involved in
20 rate cases and other regulatory matters concerning numerous electric, gas,
21 telephone, water, and sewer utility companies. My present work consists
22 primarily of analyzing rate case and regulatory filings of public utility companies
23 before various regulatory commissions and where appropriate, preparing

1 testimony and schedules relating to the issues for presentation before these
2 regulatory agencies.

3
4 I have performed work in the field of utility regulation on behalf of industry, state
5 attorneys general, consumer groups, municipalities, and public service
6 commission staffs concerning regulatory matters before regulatory agencies in
7 Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida,
8 Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland,
9 Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico,
10 New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, Puerto
11 Rico, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah,
12 Vermont, Virginia, Washington, Washington D.C., West Virginia, and Canada as
13 well as the Federal Energy Regulatory Commission and various state and federal
14 courts of law. My prior testimonies have included evaluations of numerous utility
15 rate case filings and revenue requirement determinations.

16

17 **Q. Have you previously testified before the North Dakota Public Service**
18 **Commission?**

19 A. Yes. For example, I testified before the Commission in the following dockets:
20 Application for Transfer of Local Exchanges, Case No. PU-314-94-688; US West
21 Communications, Inc. Cost Studies, Case No. PU-314-97-12; US West Universal
22 Service Cost Model, Case No. PU-314-97-465; and US West, Inc. Toll and
23 Access Rebalancing, Case No. 99-419/420.

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Q. Have you previously testified before other state public utility regulatory commissions?

A. Yes, I have testified before other state public utility regulatory commissions on many occasions.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Appendix A provides details concerning my experience and qualifications.

Q. Have you prepared any exhibits to accompany your testimony?

A. Yes. I have prepared Exhibit RCS-1, which presents the Staff's Accounting and Revenue Requirement Schedules. Exhibit RCS-2 presents selected non-confidential material, such as responses to discovery, which is referenced in my testimony and schedules. Exhibit RCS-3 presents selected confidential material, such as responses to discovery, which is referenced in my testimony and schedules.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. On whose behalf are you appearing?

A. Larkin & Associates, PLLC, was retained by the North Dakota Public Service Commission Advocacy Staff ("Staff") to review the revenue increase request of

1 Otter Tail Power Company ("OTP" or "Company"). Accordingly, I am appearing
2 on behalf of Staff.

3

4 **Q. What amount of revenue increase is the Company requesting?**

5 A. On November 2, 2017, OTP filed testimony, in which it requested an increase in
6 its base rates for electric utility service in North Dakota of
7 \$15,715,320. Specifically, as discussed on page 2 of the Direct Testimony of
8 Company witness Gerhardson, the Company is proposing to revise its
9 Environmental Cost Recovery Rider ("ECRR"), Transmission Cost Recovery
10 Rider ("TCRR") and Renewable Resource Adjustment Rider ("RRAR") to (1)
11 incorporate OTP's proposed rate of return, (2) incorporate changes in allocation
12 factors, and (3) transfer the recoveries for each rider to base rates at the end of
13 this proceeding. Mr. Gerhardson goes on to state that the Company's proposed
14 increase and revisions results in an annual increase of non-fuel base electric
15 revenues of \$13,138,372, or 8.72 percent. However, Mr. Gerhardson also states
16 that if the rate of return and allocation factor revisions to the ECRR, TCRR, and
17 RRAR are not made, then the increase to non-fuel base revenue would be
18 \$15,715,320, or 10.61 percent.

19

20 **Q. What is the Company proposing for fuel and purchased power costs?**

21 A. As discussed on page 2 of Mr. Gerhardson's direct testimony, the Company is
22 also proposing to transfer \$50,727,914 of fuel and purchased power costs,
23 currently being recovered in base rates, to the Energy Adjustment Rider, which is

1 also referred to as the Fuel Clause Agreement ("FCA"). This Company proposal
2 is made pursuant to being in compliance with the Stipulation that was approved
3 by the Commission's Order on Settlement in Case Nos. PU-08-862 and PU-08-
4 742. Specifically, on page 8 of the Stipulation at Section II, subsection B, it
5 states:

6 Energy Costs Separate from Base Rates - The Parties agree that in
7 its next rate case OTP will separate its energy costs from base
8 rates. It is understood that this will give the appearance of much
9 larger rate increases in future rate cases than is reflected in the
10 overall change in customer bills.
11

12 **Q. Did the Company make a supplemental filing to address the impacts of the**
13 **Tax Cuts and Jobs Act that was signed into law on December 22, 2017?**

14 A. Yes. In order to address the impacts of the Tax Cuts and Jobs Act ("TCJA") that
15 was signed into law on December 22, 2017, on March 23, 2018, the Company
16 filed a supplemental filing, which reflects (1) the impacts of tax reform, and (2)
17 corrections and/or updates to information identified by OTP subsequent to its
18 original filing that was made on November 2, 2017. As discussed on page 1 of
19 the supplemental direct testimony of Company witness Gerhardson, the overall
20 impacts of the updates to the Company's original request is a reduction to the
21 Company's requested revenue deficiency of \$6,005,205. Mr. Gerhardson states
22 that of this amount, \$4,772,552 relates to tax reform while the remaining
23 \$1,232,653 relates to other updates made in the Company's supplemental filing.
24 In other words, OTP's original requested increase of \$15,715,320 has been
25 reduced to \$9,710,119 in the Company's March 23, 2018 supplemental filing.
26

1 **Q. What is the purpose of your testimony?**

2 A. The purpose of my testimony is to present to the Commission an appropriate test
3 period rate base, overall rate of return and utility operating income, as well as an
4 overall revenue requirement.

5
6 **Q. Are you relying upon the testimony and recommendations of other Staff
7 witnesses?**

8 A. Yes. In the determination of the Staff's recommended overall revenue
9 requirement and revenue increase, I have relied on and incorporated the
10 recommendations of Mr. Aaron Rothschild concerning cost of capital and rate of
11 return.

12
13 **Q. Are other witnesses submitting testimony on behalf of Staff?**

14 A. Yes. Dr. David Dismukes is filing testimony concerning the class cost of service
15 study, jurisdictional allocation, revenue allocation to the classes, and rate design.

16
17 **Q. What tasks did you perform in preparing your testimony in this matter?**

18 A. In developing this testimony, I have reviewed and analyzed the Company's
19 November 2, 2017 filing, March 23, 2018 supplemental filing, supporting
20 testimonies, exhibits, filing requirements, and workpapers; the Company's
21 responses to data requests issued by the PSC Staff, and other intervenors; and
22 other relevant financial documents and data. I also reviewed prior case material
23 and prior Commission Orders.

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III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. Please summarize your findings and conclusions in this case.

A. I have reached the following findings and conclusions in this case, which is based on Staff's adjustments to the Company's supplemental filing dated March 23, 2018. This reflects the impact of the lower 21% corporate federal income tax rate that is in effect beginning in 2018 pursuant to the TCJA:

1. The appropriate jurisdictional test year rate base amounts to approximately \$359.77 million, which is \$253,865 lower than the Company's proposed test year rate base of \$360.03 million, as shown on Exhibit RCS-1, Schedule B, line 14.
2. The Staff's expert rate of return witness, Mr. Rothschild, has recommended a return on equity of 8.31%, and an overall rate of return of 6.88% for OTP's North Dakota electric operations. In contrast, OTP has requested an overall rate of return of 7.92%, including a return on equity of 10.30%, as shown on Exhibit RCS-1, Schedule A, line 2 and on Schedule D.
3. The appropriate test year utility operating income for OTP's North Dakota electric operations amounts to approximately \$24.08 million, which is approximately \$2.90 million higher than the Company's proposed test year utility operating income of \$21.17 million, as shown on Exhibit RCS-1, Schedule A, line 4 and on Schedule C.

- 1 4. To calculate the base rate revenue increase, I used a gross revenue
2 conversion factor ("GRCF") of 1.322837, as shown on Exhibit RCS-1,
3 Schedule A-1. This is the same GRCF used by OTP in its March 23,
4 2018 supplemental filing and reflects the new 21% federal income tax
5 rate.
- 6 5. The application of the recommended overall rate of return of 6.88% to
7 the recommended jurisdictional rate base of approximately \$359.77
8 million produces a required return of approximately \$24.75 million, as
9 shown on Exhibit RCS-1, Schedule A, column C, line 3. Compared to
10 the adjusted net operating income of approximately \$24.08 million, this
11 represents a deficiency of \$675,391, as shown on Exhibit RCS-1,
12 Schedule A, column C, line 5. Applying the GRCF of 1.322837
13 indicates that the Company has an annual base rate revenue
14 requirement deficiency of \$893,432, as shown on Exhibit RCS-1,
15 Schedule A, column C, line 7. As shown on Exhibit RCS-1, Schedule
16 A, column D, line 7, this represents a difference of approximately \$8.82
17 million versus the Company's proposed annual base rate revenue
18 deficiency of \$9.71 million that was presented in the Company's March
19 23, 2018 supplemental filing.
- 20 6. The total base rate revenue increase of \$893,432 is an overall
21 increase of 0.61 percent over adjusted revenue at current rates of
22 approximately \$146.27 million, as shown on Exhibit RCS-1, Schedule
23 A, line 11.

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IV. ORGANIZATION OF ACCOUNTING SCHEDULES FOR BASE RATE
REVENUE REQUIREMENT

Q. How are Staff’s accounting schedules organized?

A. The Staff’s accounting schedules used to determine OTP’s base rate revenue requirement are presented in Exhibit RCS-1. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Exhibit RCS-1 also contains rate base adjustment Schedules B-1 and B-2 and net operating income adjustment Schedules C-1 through C-13.

Q. What is shown on Schedule A, page 1, of Exhibit RCS-1?

A. As noted above, Exhibit RCS-1 presents the Staff’s Accounting Schedules and Revenue Requirement determination. Schedule A, page 1, presents the overall financial summary, giving effect to all of Staff’s adjustments and Mr. Rothschild’s recommended rate of return. Schedule A, page 1, presents the change in the Company’s gross revenue requirement needed for the Company to have the opportunity to earn Staff’s recommended rate of return on the adjusted rate base. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on rate base, as presented in the direct testimony of Staff witness Aaron Rothschild, is shown on Exhibit RCS-1, Schedule D, page 1, for convenience.

1 Exhibit RCS-1, Schedule A, page 1, column A, replicates OTP's proposed
2 calculations of its overall revenue deficiency, consisting of (1) the base rate
3 revenue deficiency; and (2) the revenue requirement for each of the Company's
4 proposed surcharges. Schedule A, page 1, column B, presents OTP's updated
5 revenue requirement as presented in the Company's March 23, 2018
6 supplemental filing. Staff used the OTP updated revenue requirement as the
7 starting point for making adjustments. Column C of Schedule A presents Staff's
8 determination of the base rate revenue deficiency. Column D shows the
9 differences between OTP's updated request and Staff's recommendation.

10
11 The operating income deficiency shown on line 5 of Schedule A, page 1, is
12 obtained by subtracting the adjusted operating income on line 4 (operating
13 income as adjusted) from the required operating income on line 3. Line 7
14 represents the gross revenue deficiency, which is obtained by multiplying the
15 operating income deficiency by the GRCF.

16
17 **Q. What is shown on Exhibit RCS-1, Schedule A, page 2?**

18 A. Exhibit RCS-1, Schedule A, page 2, presents a reconciliation of the base rate
19 revenue requirement and shows the approximate impact of each Staff
20 adjustment, incorporating the adjustment of income taxes using the new 21%
21 federal income tax rate.

22
23 **Q. What is shown on Schedule A-1 of Exhibit RCS-1?**

1 A. Schedule A-1 shows the GRCF that OTP used to convert the net operating
2 income deficiency into a revenue deficiency amount under both the 35 percent
3 federal income tax rate and the new 21 percent rate, which produced GRCFs of
4 1.607756 and 1.322837, respectively. For purposes of this case, I used the
5 GRCF of 1.322837, which includes components for state and federal income
6 taxes as shown on Exhibit RCS-1, Schedule A-1, column D.

7

8 **Q. What is shown on Exhibit RCS-1, Schedule B, page 1?**

9 A. Schedule B presents OTP's proposed adjusted test year rate base and Staff's
10 proposed adjusted test year rate base. The beginning rate base amounts
11 presented on Schedule B are taken from the Company's filing for the test year,
12 specifically Exhibit____(TAA-2), Schedule 3 from OTP's March 23, 2018
13 supplemental filing. My recommended adjustments to rate base are summarized
14 on Schedule B.1, and shown on Schedule B, column E. My adjusted rate base
15 for OTP is shown on Schedule B in column F.

16

17 **Q. What is shown on Schedule B.1 and Schedules B-1 and B-2?**

18 A. Exhibit RCS-1, Schedule B.1 presents a summary of my recommended rate base
19 adjustments. Schedules B-1 and B-2 provide further support and calculations for
20 the rate base adjustments that I am recommending.

21

22 **Q. What is shown on Exhibit RCS-1, Schedule C?**

1 A. The starting point on Schedule C is OTP's adjusted test year net operating
2 income, as provided on Schedule C-1 from the Company's Exhibit____(TAA-1)
3 from its original filing. I then reflect the adjustments and tax reform impacts
4 proposed by OTP to arrive at the Company's revised net operating income that is
5 reflected in OTP's supplemental filing dated March 23, 2018, which is the starting
6 point for my recommended adjustments to net operating income. My
7 recommended adjustments to OTP's adjusted test year revenues and expenses
8 are summarized on Schedule C.1.
9 Schedules C-1 through C-13 provide further support and calculations for the net
10 operating income adjustments that I am recommending. Each of the adjustments
11 is discussed in my testimony.

12

13 **Q. What is shown on Exhibit RCS-1, Schedule D?**

14 A. Schedule D summarizes the capital structure and cost of capital that is being
15 proposed by OTP and the capital structure and cost of capital that is
16 recommended by Staff witness Aaron Rothschild. Using Mr. Rothschild's
17 recommended return on equity of 8.31%, and the other capital structure
18 components and cost rates he recommends, produces an overall cost of capital
19 of 6.88%, which is 1.04% lower than OTP's proposed cost of capital of 7.92%
20 from its supplemental filing dated March 23, 2018.

21

22 **Q. What is shown on Exhibit RCS-1, adjustment Schedules B-1 and B-2 and C-**
23 **1 through C-13?**

1 A. Those schedules present calculations of each rate base and operating income
2 adjustment that I am recommending.

3

4 **V. RATE BASE**

5 **Q. What adjustments are you recommending to OTP's requested rate base?**

6 A. I am recommending three adjustments to OTP's rate base, as discussed below.

7

8 **B-1, Construction Work in Progress**

9 **Q. Did the Company include Construction Work in Progress ("CWIP") in its**
10 **North Dakota jurisdictional rate base?**

11 A. Yes. As shown on Exhibit__(TAA-2), Schedule 2, which was filed in conjunction
12 with the supplemental direct testimony of Company witness Akerman in the
13 Company's supplemental filing dated March 23, 2018, OTP included CWIP
14 totaling \$271,747 in its North Dakota jurisdictional rate base.¹

15

16 **Q. What capital projects are included in the \$271,747 of CWIP?**

17 A. According to the response to data request ND-PSC-15.37, the \$271,747 of CWIP
18 relates to one project, which OTP identified as Project No. 105245 - Winger Thief
19 River Falls 230kV Line ("Winger Thief River Falls"), which the Company stated
20 has an in-service date of December 2023.

21

22 **Q. Does any portion of the \$271,747 of CWIP accrue AFUDC?**

¹ OTP also included the \$271,747 of CWIP in rate base in its original filing dated November 2, 2017.

1 A. No. In its response to data request ND-PSC-15.37, OTP stated that no AFUDC
2 was taken on the Winger Thief River Falls project due to uncertainty related to
3 this project going forward. In addition, the Company stated that long-term CWIP
4 and AFUDC are recorded on a total Company level and are not allocated to
5 North Dakota jurisdictional operations.

6

7 **Q. Since the \$271,747 of CWIP related to the Winger Thief River Falls project is**
8 **included in OTP's North Dakota jurisdictional rate base, does OTP consider**
9 **this project to be short-term CWIP?**

10 A. Apparently not. In its response to data request ND-PSC-15.37, the Company
11 stated:

12 In completing this Data Request, we inadvertently found that OTP's
13 short-term CWIP should not have included the above Project
14 105245-Winger Thief River. Short-term CWIP will be corrected in
15 the final compliance filing.
16

17 Based on the passage above, the Winger Thief River Falls is a long-term CWIP
18 project and, as noted above, OTP does not allocate long-term CWIP to North
19 Dakota jurisdictional operations. In addition, the expected in-service date for this
20 project is not until December 2023, which would appear to support the contention
21 that this is a long-term CWIP project. Therefore, the \$271,747 should be
22 removed from the Company's North Dakota jurisdictional rate base.

23

24 **Q. Please explain your adjustment.**

1 A. As shown on Exhibit RCS-1, Schedule B-1, I have removed the \$271,747 of
2 CWIP from OTP's North Dakota jurisdictional rate base as the Winger Thief River
3 Falls project is a long-term CWIP project.
4

5 **B-2, Cash Working Capital**

6 **Q. What is Cash Working Capital?**

7 A. Cash working capital ("CWC") is the cash needed by the Company to cover its
8 day-to-day operations. If the Company's cash expenditures, on an aggregate
9 basis, precede the cash recovery of expenses, investors must provide cash
10 working capital. In that situation, a positive cash working capital requirement
11 exists. On the other hand, if revenues are typically received prior to when
12 expenditures are made, on average, then ratepayers provide the cash working
13 capital to the utility, and the negative cash working capital allowance is reflected
14 as a reduction to rate base. In this case, the cash working capital requirement is
15 an increase to rate base as investors are essentially supplying these funds.
16

17 **Q. Does OTP's supplemental filing reflect a positive or negative cash working
18 capital requirement?**

19 A. OTP's Exhibit__(TAA-2), Schedule 2, which was filed with its supplemental filing
20 dated March 23, 2018, shows a net positive cash working capital requirement of
21 approximately \$3.455 million.
22

1 **Q. What is indicated by a positive or negative cash working capital**
2 **requirement?**

3 A. A negative CWC requirement occurs when the results of a lead-lag study indicate
4 that ratepayers are supplying the funds used for the day-to-day operations of the
5 Company. On average, revenues from ratepayers are received prior to the time
6 when the utility pays the associated expenditures. Conversely, a positive CWC
7 requirement indicates that utility investors have supplied funds used for the day-
8 to-day operations of the Company.

9
10 **Q. Did OTP present a lead/lag study in support of its cash working capital**
11 **requirement?**

12 A. Yes, as discussed in the direct testimony of Company witness Gina OTP
13 performed a lead/lag study to calculate the cash working capital requirement in
14 this case. The Company has provided its lead/lag study calculations with its
15 work papers.

16
17 **Q. Are you recommending any revisions to OTP's cash working capital**
18 **request?**

19 A. Yes. I have reflected the impact of my adjustments to OTP's cash working
20 capital request on Exhibit RCS-1, Schedule B-2. As shown on Schedule B-2, my
21 recommended adjustments to expense increase OTP's claim for CWC by
22 \$17,882.

23

1 **VI. ADJUSTMENTS TO OPERATING INCOME**

2 **Q. Please describe how you have summarized Staff's proposed adjustments**
3 **to operating income.**

4 A. Exhibit RCS-1, Schedule C summarizes Staff's recommended net operating
5 income. As shown on Exhibit RCS-1, Schedule C, page 1, column A, OTP's
6 proposed adjusted test year net operating income at current rates is \$21.17
7 million, whereas Staff's recommended adjusted net operating income at current
8 rates is \$24.08 million.

9
10 Schedule C.1 presents Staff's recommended adjustments to test year revenues
11 and expenses. The impact on state and federal income taxes associated with
12 each of the recommended adjustments to operating income is also reflected on
13 Schedule C.1. The recommended adjustments to operating income are
14 discussed below in the same order as they appear on Schedule C.1.

15
16 **C-1, Employee Gifts and Recognition Expense**

17 **Q. Please explain your adjustment on Schedule C-1.**

18 A. My adjustment on Schedule C-1 removes the costs associated with employee
19 gifts and recognition. In its response to data request ND-PSC-06.28, the
20 Company stated that it has reflected employee gift expense of \$12,346 and
21 employee recognition expense of \$19,349 (both on a North Dakota jurisdictional
22 basis) in its 2018 test year cost of service.

23

1 **Q. Did OTP explain its rationale for including these costs in its 2018 test year**
2 **cost of service?**

3 A. Yes. In its response to data request ND-PSC-06.29, the Company stated that
4 the items given for employee recognition are modest, reasonable, and prudent,
5 and should therefore be eligible for recovery insofar as they help build employee
6 morale and promote retention.

7
8 **Q. Do you agree with the Company's rationale for including these costs in**
9 **2018 test year cost of service?**

10 A. No, I do not. While these types of costs may build employee morale and/or
11 promote retention, they are not necessary for the provision of safe and reliable
12 electric utility service. Therefore, ratepayers should not be responsible for paying
13 for these types of costs.

14
15 **Q. Were costs related to employee gifts and recognition disallowed for**
16 **recovery in OTP's recent Minnesota base rate case?**

17 A. Yes. OTP's employee gifts and recognition expenses were disallowed for
18 recovery in OTP's recent Minnesota base rate case. Specifically, in its Findings
19 of Facts, Conclusions and Order dated May 1, 2017 in Docket No. E-017/GR-15-
20 1033 at page 48, the Minnesota Commission stated in part:

21 The Commission concurs with the Administrative Law Judge and
22 will disallow recovery of the Company's proposed employee gift and
23 recognition expenses...The ALJ reasoned that the hearing record in
24 this matter, and the legal arguments for approving the proposed
25 expenses, are akin to those in the Company's last rate case, in
26 which the Commission denied recovery. Therefore, absent a

1 willingness by the Commission to revisit its decision in the 2010
2 case, Otter Tail's proposed employee recognition and employee gift
3 expenses should be denied.
4

5 The Commission finds that the evidence adduced and the
6 arguments presented in this rate case are similar to those of the
7 last rate case. The Commission finds that the proposed employee
8 gift and recognition expenses are not reasonable and necessary for
9 the provision of utility services. The Commission will deny recovery
10 for these items.
11

12 **Q. Is your recommended adjustment consistent with the Minnesota**
13 **Commission's ruling as it relates to employee gift and recognition**
14 **expenses in OTP's recent Minnesota base rate case?**

15 A. Yes.
16

17 **Q. What is the impact of this adjustment?**

18 A. As shown on Exhibit RCS-1, Schedule C-1, my adjustment to remove employee
19 gift and recognition expenses reduces O&M expense by \$31,695 on a North
20 Dakota jurisdictional basis
21

22 **C-2, Investor Relations Expense**

23 **Q. Has the Company requested recovery of investor relations expense in its**
24 **2018 test year cost of service?**

25 A. Yes. In its response to data request ND-PSC-06.27, the Company indicated that
26 it is requesting recovery of forecasted investor relations expense in its 2018 test
27 year cost of service in the amount of \$167,148 on a North Dakota jurisdictional
28 basis.

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Q. What are investor relations?

A. Investor relations is a term which describes the division of a company that is devoted to responding to inquiries from shareholders and investors (or others) who may be interested in a company's stock price or financial stability. In the case of OTP, investor relations are a means by which the Company's shareholders can receive and review information about the Company for things such as capital spending and OTP's ability to access debt and/or equity markets to finance such capital spending. As such, a significant portion of OTP's investor relations expenses are for the benefit of the Company's shareholders.

Q. What is your recommendation with regard to investor relations expense?

A. I recommend that 50 percent of the Company's forecasted investor relations expense be removed from 2018 test year cost of service. The removal of 50 percent of the investor relations expense, in essence, provides an equal sharing of such costs, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers.

Q. Was a 50/50 sharing of investor relations expense ordered by the Minnesota Commission in OTP's recent Minnesota base rate case?

A. Yes. Fifty percent of OTP's proposed investor relations expense was disallowed for recovery in OTP's recent Minnesota base rate case. Specifically, in its

1 Findings of Facts, Conclusions and Order dated May 1, 2017 in Docket No. E-
2 017/GR-15-1033 at page 43, the Minnesota Commission stated in part:

3 The Commission agrees with the Department that a significant
4 portion of the investor relations costs identified by the Company
5 appear principally to benefit shareholders. The Company has not
6 met its burden to show that 100% of these costs benefit ratepayers.
7 Accordingly, to resolve doubt in favor of ratepayers and reasonably
8 and equitably share such expenses between shareholders and
9 ratepayers, the Commission will disallow half of the proposed test
10 year investor relations expenses.
11

12 **Q. What is the impact of this adjustment?**

13 A. As shown on Exhibit RCS-1, Schedule C-2, my recommended adjustment to
14 exclude 50 percent of the Company's forecasted investor relations expense from
15 2018 test year cost of service reduces OTP's requested O&M expense by
16 \$83,574 on a North Dakota jurisdictional basis.

17

18 **C-3, Corporate Aircraft Expense**

19 **Q. Does OTP own its own aircraft?**

20 A. Yes. According to the response to data request ND-PSC-06.06, the Company
21 owns a 1987 322 King Air turboprop aircraft. Despite being owned by OTP, the
22 pilots who fly the plane are employees of Otter Tail Corporation and use of the
23 plane is scheduled by Otter Tail Corporation's administrative staff. In addition,
24 the response to ND-PSC-06.06 states that the plane is used by both OTP and
25 Otter Tail Corporation for business purposes. At the end of each year, the
26 associated fixed costs of using the plane are divided between OTP and Otter Tail
27 Corporation on a pro-rata share.

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Q. How were the aircraft costs charged to OTP in 2017?

A. According to the response to data request ND-PSC-06.07, the entity using the plane (i.e., OTP or Otter Tail Corporation) was charged a variable cost that was based on the distance of the trip. At year's end, aircraft costs that were not specifically invoiced were allocated between OTP and Otter Tail Corporation on a pro rata basis, based on the number of flights. Specifically, for 2017, OTP was allocated fixed costs totaling \$246,945 on a total Company basis based on 71 flights. The Company then removes flight costs associated with capital projects and below-the-line lobbying activities, to derive the amount of corporate aircraft costs reflected in test year O&M expense. After removing the capitalized and below-the-line costs, the amount included in 2017 cost of service was \$329,240 on a total Company basis and \$133,374 on a North Dakota jurisdictional basis. This amount includes the North Dakota jurisdictional portion of the \$246,945 as shown in the following table:

FERC Account	Description	Amount
1070	Construction Work in Progress	\$ 57,107
4264	Expenditures for Civil & Political	\$ 6,026
5000	Steam Power Generation - Operations	\$ 3,405
5060	Steam Power Generation - Miscellaneous	\$ 3,855
5570	Other Power Supply Expenses	\$ 202
5880	Distribution Expenses	\$ 1,337
9080	Customer Service and Information	\$ 4,978
9210	Office Supplies and Expenses	\$ 54,672
9280	Regulatory Commission Expenses	\$ 12,269
9302	Miscellaneous General Expenses	\$ 1,577
	Subtotal	\$ 145,429
1070	Less: Construction Work in Progress	\$ (57,107)
4264	Less: Expenditures for Civil & Political	\$ (6,026)
	O&M Related Aircraft Expense	\$ 82,296
	Allocation from Corporate	\$ 246,945
	Total Aircraft Expense Included in Cost of Service	\$ 329,240
	North Dakota Jurisdictional Allocation Factor	40.5096%
	Total North Dakota Jurisdictional Aircraft Expense	\$ 133,374
Source: ND-PSC-06.07		

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Q. How was the "Allocation from "Corporate amount of \$246,945 that was charged to OTP calculated?

A. According to the response to data request ND-PSC-16.05, the total costs are determined at the corporate (Otter Tail Corporation) level with a direct bill being created (per flight) for the party using the plane (Otter Tail Corporation or OTP). The remaining unbilled costs at year-end are then assigned to each entity based on the percentage of each entity's total flights for the year. The Company provided the following breakout showing how the \$246,945 of costs that were allocated to OTP in 2017 was derived:

Description	Amount
Pilot Salaries	\$ 301,868
Plane Repairs	\$ 74,238
Fuel	\$ 106,889
Rental of Hanger	\$ 10,800
Pilot Education	\$ 24,710
Miscellaneous	\$ 7,834
Subtotal	\$ 526,339
Less: Billings for Direct Usage of Plane	\$ (174,224)
Total Costs of Plane	\$ 352,115
Less: Non-Utility Usage	\$ (105,170)
Billed to OTP	\$ 246,945

Source: ND-PSC-16.05

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Q. What amount of corporate aircraft expense has OTP included in 2018 test year cost of service?

A. OTP has not identified a specific amount of corporate aircraft expense that is included in 2018 test year cost of service. Specifically, Staff requested this information in two separate data requests, including ND-PSC-06.07 and ND-PSC-16.05. In each response, OTP stated the following:

The 2018 allocation is included in the general allocator from Otter Tail Corporation and is expected to be similar to actual 2017 results.

The response to ND-PSC-16.05 also states that the 2018 budgeted amount is not itemized to the level of actual results.

Q. Did OTP prepare a cost-benefit analysis which compared aircraft costs to other transportation alternatives?

A. Yes. In its response to data request ND-PSC-06.08, the Company provided an attachment, which the Company stated was a cost-benefit analysis that was

1 based on 2017 flight data and which compared the total 2017 flight costs against
2 the costs associated with driving to those same destinations. The Company
3 stated that this analysis excludes flights for which the costs were recorded below-
4 the-line, or for costs related to capital projects.

5

6 **Q. What does OTP's cost-benefit analysis purport to show?**

7 A. According to the Company's attachment to ND-PSC-06.08, the cost-benefit
8 analysis shows that the equivalent driving costs for the 71 flights in 2017 would
9 have totaled \$417,470 and the total flight costs in 2017 for the 71 flights totaled
10 \$400,872. This amount includes the aforementioned amount of \$246,945, which
11 the Company described as being a corporate allocation. The Company's claims
12 that its cost-benefit analysis shows that flying versus driving resulted in a savings
13 of \$16,598 based on the 71 flights from 2017.

14

15 **Q. Do you agree with the results of the Company's cost-benefit analysis?**

16 A. Not necessarily. There are certain aspects of the Company's cost-benefit
17 analysis which are questionable. The study itself appears to be conceptually
18 flawed. For example, in its response to data request ND-PSC-19.01, OTP stated
19 that for salaried employees, the difference in the time it takes to drive to a
20 destination versus flying does not result in savings of any incremental costs. Yet,
21 the estimated labor costs for both salaried and hourly travelers is the primary
22 basis for the "driving cost" and "flying cost" comparisons upon which the study is
23 based. Removing the costs for salaried employees in the OTP study could

1 potentially produce a much different result. The fact that the study assumed cost
2 savings for salaried employees when there are no incremental costs or
3 incremental payroll cost savings for salaried employees appears to be a severe
4 conceptual flaw with the design of the study, and one that could have skewed the
5 results significantly to show a higher cost of driving versus flying. In addition,
6 Staff requested that OTP explain whether any comparison is made between the
7 costs of flying the Company plane versus the cost of commercial flights, and if
8 so, to identify and provide supporting documentation. In its response to ND-
9 PSC-19.01, OTP stated that whenever a commercial flight is available, an
10 analysis is performed similar to that of comparing the costs of driving, but without
11 the use of a model and that such analysis is performed within cost centers but
12 not retained in a central repository. Failure to include a comparison of the cost of
13 commercial flights available at the time versus using the corporate aircraft is
14 another serious concern with OTP's cost-benefit analysis.

15
16 **Q. Does it appear that using commercial flights would be more economical**
17 **than using the Company plane on some long distance trips?**

18 A. Yes. Staff had requested supporting documentation for the costs of several long
19 distance flights that were identified in Attachment 1 to the response to data
20 request ND-PSC-06.08. For example, one such flight from OTP's headquarters
21 in Fergus Falls, Minnesota to Vancouver, British Columbia reflected an "invoiced
22 flight amount" of \$10,176.43. Upon reviewing the supporting documentation for
23 this flight, which was provided in response to data request ND-PSC-16.06, of the

1 \$10,176.43, \$6,375 was related to the cost of the flight crew, which bills at the
2 rate of \$750 per hour, and in this instance billed for an 8.5 hour flight ($\$750 \times 8.5$
3 = \$6,375). In addition, an additional \$3,258.11 was for "crew expense." So, in
4 summary, of the invoiced amount of \$10,176.43 for this particular flight, \$9,633 of
5 that amount was related to the flight crew with the balance of the invoiced
6 amount (\$543) being related to catering, parking and for a landing fee at the
7 Vancouver airport. In contrast, a commercial flight would tend to be at a price per
8 round trip ticket per passenger. If purchased in advance and by price shopping
9 (e.g., using airline sites and travel sites such as Expedia) sometimes very
10 economic commercial flight arrangements can be obtained. Yet OTP provided
11 no comparable documentation of advanced-purchased commercial flights.

12

13 **Q. Were the costs of using the Company plane for long distance trips charged**
14 **to OTP?**

15 A. Yes. Attachment 1 to the response to ND-PSC-06.08 indicated that during 2017,
16 there were various long distance trips to destinations including (1) Denver,
17 Colorado; (2) Marshall Texas; (3) Vancouver, British Columbia (two trips); (4)
18 Greenville, South Carolina; and (5) Shreveport, Louisiana. The table below
19 identifies the invoiced amounts for these flights as well as the cost of the crew
20 associated with these flights:

Date	Destination	Total Invoiced Amount	Flight Crew Expense	Percentage of Flight Crew Expense
1/16/2017	Denver, CO	\$ 4,068	\$ 3,958	97.29%
3/27/2017	Marshall, TX	\$ 5,787	\$ 5,640	97.47%
4/3/2017	Vancouver, BC	\$ 8,740	\$ 8,038	91.97%
5/2/2017	Greenville, SC	\$ 6,585	\$ 6,489	98.55%
8/21/2017	Vancouver, BC	\$ 10,176	\$ 9,633	94.66%
11/15/2017	Shreveport, LA	\$ 5,783	\$ 5,694	98.46%
		\$ 41,139	\$ 39,452	95.90%

Source: ND-PSC-06.08

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 2 As shown in the table above, of these six illustrative flights in 2017, in each
 3 instance, over 90% of the costs relate to the expense of the crew flying the plane.
 4 By comparison, and using the August 21, 2017 trip to Vancouver, British
 5 Columbia as an example, I checked to see how much a similar trip would cost
 6 using commercial airlines. Specifically, I checked airfares for five passengers
 7 (the number of passengers on the August 21, 2017 flight to Vancouver,) from the
 8 four closest airports to Fergus Falls, Minnesota and using Vancouver, BC as the
 9 destination.² The results are summarized in the table below:

Departing Airport	Airfare to Vancouver, BC	No. of Passengers	Total Airfare	Cost of OTP's 8/21/2017 Trip to Vancouver	Difference
Bemidji, MN	\$ 1,325	5	\$ 6,627	\$ 10,176	\$ (3,549)
Brainerd, MN	\$ 789	5	\$ 3,947	\$ 10,176	\$ (6,229)
Deluth, MN	\$ 604	5	\$ 3,022	\$ 10,176	\$ (7,155)
Hibbing, MN	\$ 935	5	\$ 4,676	\$ 10,176	\$ (5,500)

10
 11 As shown in the table, the cost of flying to Vancouver, BC using commercial
 12 airlines for five passengers could be substantially less than using the corporate
 13 aircraft and incurring the flight crew expenses associated with traveling on the
 14 Company's plane.

² This analysis was done using the Delta Airlines website and current pricing.

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Q. What is the total amount from which the corporate allocation of \$246,945 was derived and how was it allocated between OTP and Otter Tail Corporation?

A. It is not clear what the total amount from which the corporate allocation of \$246,945 is nor how it was allocated between OTP and Otter Tail Corporation. In its response to data request ND-PSC-19.01, the Company merely stated:

The allocation from corporate of \$246,945 is the amount of the fixed costs allocated to OTP based on a percentage of flights taken by OTP compared to other subsidiaries.

Q. Are you recommending that an adjustment be made to the corporate aircraft expense included in 2018 test year cost of service?

A. Yes. As previously noted, OTP has not identified a specific amount of corporate aircraft expense that is included in 2018 test year cost of service, except to say that such costs are expected to be similar to actual 2017 results. In addition, as explained above, OTP's cost-benefit analysis of using the Company plane versus driving is highly flawed and the results extremely questionable, especially as it relates to long distance trips, and to OTP assumed labor cost savings from salaried employees. OTP conceded in its response to DR ND-PSC-19.01 that there are no incremental labor cost savings from salaried employees driving versus flying, yet that comparison was a major component of OTP's cost-benefit study. Moreover, OTP has not sufficiently explained nor provided the source amount from which the 2017 corporate allocation to OTP of \$246,945 was derived. Furthermore, some of the corporate aircraft travel costs could be

1 excessive compared with commercial air travel. An adjustment to reduce the
2 amount of corporate aircraft expense being requested by OTP is therefore
3 needed. To calculate such an adjustment, I removed the North Dakota
4 jurisdictional portion of the \$246,945 that was allocated from Otter Tail
5 Corporation in 2017 from the 2018 test year cost of service. As shown on Exhibit
6 RCS-1, Schedule C-3, this adjustment reduces OTP's requested O&M expense
7 by \$100,037 on a North Dakota jurisdictional basis.

8
9 **C-4, Payroll Expense**

10 **Q. How was the budgeted amount of payroll expense that OTP is requesting**
11 **for the 2018 test year determined?**

12 A. As discussed on page 4 of the direct testimony of Company witness Christine
13 Petersen, OTP's budgeted payroll costs were developed based on individual
14 employees within each department within each business area and then
15 culminated at the business area level. The Business Planning Department
16 provided Full-Time Equivalent ("FTE") employee projections to each
17 department's manager during the second quarter of the year prior to the budget
18 year. Ms. Petersen stated that the 2018 O&M budget was based primarily on
19 2016 employee levels.

20
21 **Q. How many FTE's did OTP include for its 2018 budgeted payroll expense?**

22 A. According to the response to data request ND-PSC-15.02, Attachment 2, OTP
23 budgeted for a total of 767.1 FTE's.

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Q. How does that compare to OTP's actual FTE count for 2016?

A. According to the response to data request ND-PSC-15.02, Attachment 1, OTP had 779.1 actual FTE's in 2016 or 12 more FTE's than OPT has budgeted for 2018.

Q. Please continue describing how the Company developed its budgeted payroll costs for the 2018 test year.

A. As further discussed in Ms. Petersen's direct testimony, a composite labor rate is determined for each business area, which is based on total employee salaries in each department within the business area. The Company then determines an inflation rate based on existing contracts and estimated costs increases, which are applied in order to increase basic labor costs to the budget year level. In addition, overtime projections are factored and a labor loading rate is applied to basic labor costs.

Q. What amount of payroll cost is the Company requesting for the 2018 test year?

A. As shown in the response to data request ND-PSC-15.03, the Company is requesting payroll expense, which is broken out by FERC account, totaling \$70.503 million on a total Company basis and \$28.1 million on a North Dakota jurisdictional basis.

1 **Q. Did you review historical data which compares the Company's budgeted to**
2 **actual payroll costs?**

3 A. Yes. I reviewed historical data which compares the Company's budgeted to
4 actual payroll costs. Specifically, I initially reviewed the Company's budgeted
5 and actual payroll costs for 2016 and 2017, which is summarized in the table
6 below.

Description	Actual Payroll Expense	Budgeted Payroll Expense	Variance	Percentage Difference
OTP Total Company 2016 Payroll Expense	\$ 63,329,041	\$ 65,897,249	\$ (2,568,208)	-3.90%
OTP Total Company 2017 Payroll Expense	\$ 65,265,663	\$ 69,119,559	\$ (3,853,896)	-5.58%
Average Variance Percentage				-4.74%

7 Source: ND-PSC-15.02 and ND-PSC-15.04

8 As shown in the table above, for both 2016 and 2017, OTP's actual payroll costs
9 were less than OTP had budgeted for by the amounts and percentages shown
10 and results in an average variance percentage of -4.74% for the two-year period.

11
12 **Q. Did you also review budgeted to actual payroll costs for 2018?**

13 A. Yes. The Company provided this data in its response to data request ND-PSC-
14 15.07, which is summarized in the following table: In reviewing this data, I noted
15 that, similar to 2016 and 2017, OTP's actual payroll costs in each month of the
16 first quarter of 2018 were less than OTP's budgeted amounts:

Description	Actual Payroll Expense	Budgeted Payroll Expense	Variance	Percentage Difference
OTP Total Company Payroll Expense - January 2018	\$ 5,211,656	\$ 5,391,402	\$ (179,746)	-3.33%
OTP Total Company Payroll Expense - February 2018	\$ 5,689,745	\$ 6,227,437	\$ (537,692)	-8.63%
OTP Total Company Payroll Expense - March 2018	\$ 5,939,477	\$ 6,077,170	\$ (137,693)	-2.27%
Total 2018 First Quarter	\$ 16,840,878	\$ 17,696,009	\$ (855,131)	-4.83%

1 Source: ND-PSC-15.07

2 As shown in the table above, similar to 2016 and 2017, OTP's actual payroll
3 costs in each month of the first quarter of 2018 were less than budgeted amounts
4 by the amounts and percentage shown. It is notable that the average variance
5 percentage between budgeted actual payroll costs for the first three months of
6 2018 is also -4.74%, which is similar to the average budget variance percentage
7 for 2016 and 2017.

8
9 **Q. What did you conclude from your review of the Company's historical**
10 **payroll cost data?**

11 A. Based on my review of the Company's historical payroll cost data for 2016, 2017
12 and the first quarter of 2018, I concluded that OTP has a recent history of over-
13 budgeting payroll expense. The Company's 2018 test year payroll expense
14 should be adjusted to address the over-budgeting tendency and thus accurately
15 reflect the Company's actual 2018 test year payroll expense.

16
17 **Q. Please explain your recommended adjustment to payroll expense.**

18 A. As shown on Exhibit RCS-1, Schedule C-4, I applied the -4.74% variance
19 percentage discussed above to each component (i.e., by FERC account) of the
20 Company's projected payroll expense. This reduced OTP's 2018 test year

1 payroll expense by \$3.339 million on a total Company basis. After applying the
2 North Dakota jurisdictional allocator factors on a FERC account basis, my
3 recommended adjustment reduces 2018 test year payroll expense by \$1.332
4 million on a North Dakota jurisdictional basis.

5

6 **Q. Is there a related adjustment to payroll tax expense?**

7 A. Yes. As discussed below, my recommended adjustment to payroll expense
8 results in a related adjustment to payroll tax expense as shown on Exhibit RCS-
9 1, Schedule C-8.

10

11 **C-5, Incentive Compensation**

12 **Q. Does the Company have incentive compensation plans available to its**
13 **employees?**

14 A. Yes. As discussed in the direct testimony of Company witness Peter Wasberg,
15 the Company has an annual incentive plan ("AIP") which is available to its non-
16 union employees. Specifically, the AIP consists of two separate plans, including
17 (1) the OTP Key Performance Award Plan ("OTP KPA Plan"), which is available
18 to non-union employees, and (2) the Utility Management Incentive Plan ("OTP
19 Management Plan"), which is available to key management employees. In
20 addition, as discussed on page 5 of his direct testimony, Mr. Wasberg states that
21 OTP's President is under the Otter Tail Corporation Executive Annual Incentive
22 Plan ("OTC Executive Annual Plan"). The Company provided copies of all three
23 plans in its confidential response to data request ND-PSC-15.17. The focus of

1 my discussion will be on (1) the OTP Management Plan, and (2) the OTC
2 Executive Annual Plan.

3

4 **A. OTP Management Plan**

5 **Q. What are the OTP Management Incentive Plan's key objectives?**

6 A. As discussed in the Background section, the OTP Management Plan states:

7 **[BEGIN CONFIDENTIAL]**

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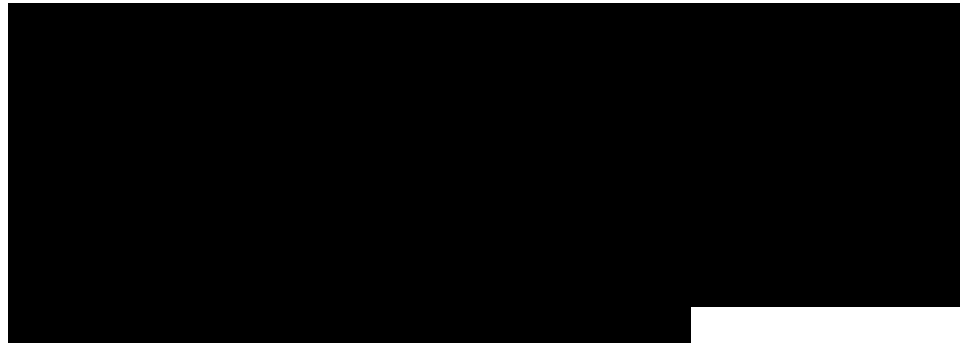
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[END CONFIDENTIAL]

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21 **Q. Please briefly describe the OTP Management Incentive Plan.**

22 A. As discussed on page 4 of Mr. Wasberg's direct testimony, the OTP
23 Management Plan covers 19 OTP management employees (not including the
24 President as noted above). In addition, the OTP Management Plan is comprised
25 of the following criteria: (1) safety; (2) a number of individual criteria that vary by
26 employees' job and responsibilities; and (3) two overall financial criteria, including
27 OTP's earnings and ROE. Mr. Wasberg states that the safety and individual
28 criteria have a cumulative weighting of 50% and the two financial criteria also

1 have a weighting of 50%. A table on page 2 of the OTP Management Plan
2 indicates that [BEGIN CONFIDENTIAL] [REDACTED]
3 [REDACTED] [END CONFIDENTIAL] totaling the 50% referenced by Mr.
4 Wasberg in his testimony.

5
6 **Q. Has OTP included incentive compensation expense related to the OTP**
7 **Management Plan in its 2018 test year cost of service?**

8 A. Yes. The confidential response to data request ND-PSC-15.18 states that the
9 Company included incentive compensation expense related to the OTP
10 Management Plan of [BEGIN CONFIDENTIAL] [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED] [END CONFIDENTIAL]

14
15 **Q. Are you recommending an adjustment to the level of incentive**
16 **compensation related to the OTP Management Plan that is included in the**
17 **2018 test year cost of service?**

18 A. Yes. I recommend that 50% of the incentive compensation related to the OTP
19 Management Plan that is included in the 2018 test year be borne by
20 shareholders.

21
22 **B. OTC Executive Annual Plan**

23 **Q. What are the OTC Executive Annual Plan's key objectives?**

1 A. As discussed in the Background section, the OTC Executive Annual Plan states:

2 **[BEGIN CONFIDENTIAL]**

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13 **[END CONFIDENTIAL]**

14

15 **Q. Please briefly describe the OTC Executive Annual Plan.**

16 A. As discussed on page 5 of Mr. Wasberg's direct testimony, the criteria and target
17 incentives of the OTC Executive Annual Plan are determined by the
18 Compensation Committee of the Otter Tail Corporation Board of Directors. In
19 addition, the criteria under the OTC Executive Annual Plan includes the following:
20 (1) OTP net income; (2) OTP return on equity; (3) Otter Tail Corporation's
21 earnings per share; (4) individual performance; and (5) OTP OSHA safety case
22 rate.

23

24 **Q. What is the component weighting of the foregoing criteria under the OTC**
25 **Executive Annual Plan?**

26 A. Page E-1 of the OTC Executive Annual Plan, which was provided in the
27 confidential response to data request ND-PSC-15.17 contains a chart with the
28 heading "Otter Tail Corporation Executive Annual Incentive Plan 2018

1 Performance Objectives and Targets", which indicates that **[BEGIN**

2 **CONFIDENTIAL]** [REDACTED]

3 [REDACTED]

4 [REDACTED]

5 [REDACTED]

6 [REDACTED]

7 **[END CONFIDENTIAL]**

8

9 **Q. Has OTP included incentive compensation expense related to the OTC**
10 **Executive Annual Plan in its 2018 test year cost of service?**

11 A. Yes. The response to data request ND-PSC-15.19 states that the 2018 test year
12 cost of service includes budgeted incentive compensation expense allocated
13 from Otter Tail Corporation in the amount of \$834,429. In an email to Staff dated
14 May 10, 2018, OTP stated that the OTC Executive Annual Plan is the plan that
15 relates to incentive compensation allocated to OTP from Otter Tail Corporation.

16

17 **Q. Are you also recommending an adjustment to the level of incentive**
18 **compensation related to the OTC Executive Annual Plan that is allocated to**
19 **OTP and included in the 2018 test year cost of service?**

³Varistar Corporation, which is a wholly owned subsidiary of Otter Tail Corporation, owns the Company's manufacturing and plastic pipe businesses.

⁴ Page 17 of Otter Tail Corporation's 2018 Proxy Statement indicates that the measure for workplace safety is the OTC Executive Annual Plan's non-financial related measure.

1 A. Yes. I recommend that 90% of the incentive compensation related to the OTC
2 Executive Annual Plan that is allocated to OTP and included in the 2018 test year
3 be borne by shareholders.

4

5 **Q. What is the basis for your recommendations to (1) remove 50% of incentive**
6 **compensation related to the OTP Management Plan, and (2) 90% of**
7 **incentive compensation related to the OTC Executive Annual Plan?**

8 A. The basis for my recommendations is that incentive compensation expense that
9 is tied to a utility's financial performance should not be borne by ratepayers.
10 Specifically, the portion of incentive compensation expense that is directly
11 attributable to meeting financial performance goals is not properly recoverable
12 from ratepayers for several reasons. First, if the financial goals are set properly,
13 achieving the necessary performance should be self-supporting. That is,
14 measures that achieve additional cost savings, improve sales, or otherwise
15 improve the financial results of the Company should provide the income
16 necessary to fund the awards. Second, the payouts for financial goal
17 achievement can be distinguished from incentive compensation that is measured
18 for improving the quality of service, efficiency, or safety goals. Finally, the
19 incentive to improve financial performance is not necessarily consistent with
20 ratepayers' interests.

21

22 **Q. Please explain your recommended adjustment for Incentive Compensation**
23 **expense related to the OTP Management Plan.**

1 A. As shown on Exhibit RCS-1, Schedule C-5, this adjustment reduces 2018 test
2 year expense by \$437,805 on a North Dakota jurisdictional basis to reflect the
3 removal of (1) 50% of directly charged incentive compensation expense that
4 relates to the OTP Management Plan pursuant to the earnings and ROE related
5 financial criteria discussed above, and (2) 90% of incentive compensation
6 expense allocated to OTP from Otter Tail Corporation that relates to the financial
7 goals associated with the OTC Executive Annual Plan.

8

9 **Q. Is there a related adjustment to payroll tax expense?**

10 A. Yes. As discussed below, my recommended adjustment to incentive
11 compensation expense results in a related adjustment to payroll tax expense as
12 shown on Exhibit RCS-1, Schedule C-8.

13

14 **C-6, Stock-Based Compensation Expense**

15 **Q. Please explain your adjustment to stock-based compensation expense.**

16 A. As shown on Exhibit RCS-1, Schedule C-7, I have removed all stock-based
17 compensation expense. This adjustment reduces OTP's 2018 test year cost of
18 service by \$1.297 million on a total Company basis and by \$525,567 on a North
19 Dakota jurisdictional basis for stock-based compensation directly charged to
20 OTP. In addition, my recommended adjustment reduces 2018 test year cost of
21 service by an additional \$299,282 on a total Company basis and \$121,481 on a

1 North Dakota jurisdictional basis for stock-based compensation allocated to OTP
2 from Otter Tail Corporation.⁵

3

4 **Q. What types of stock-based compensation costs did OTP include in its 2018**
5 **test year cost of service?**

6 A. In its response to data request ND-PSC-15.20, the Company stated:

7 Both Restricted Stock Units and Performance Share Awards were
8 included in the charges to OTP for test year ending December 31,
9 2018.
10

11 **Q. Did the Company provide a copy of its stock-based compensation plan**
12 **documents?**

13 A. Yes. In its response to data request ND-PSC-15.20, the Company provided a
14 copy of the Otter Tail Corporation 2014 Stock Incentive Plan ("2014 Stock
15 Incentive Plan").

16

17 **Q. What is the stated purpose of the 2014 Stock Incentive Plan?**

18 A. The purpose of the 2014 Stock Incentive Plan is to provide stock-based
19 compensation to benefit Otter Tail Corporation's shareholders by aligning the
20 interests of the participants with those of the shareholders. Specifically, page 1
21 of the 2014 Stock Incentive Plan under "Purpose" states as follows:

22 The purpose of the Plan is to **promote the interests of the**
23 **Company and its shareholders** by aiding the Company in
24 attracting and retaining employees, officers, consultants,
25 independent contractors, advisors and non-employee Directors
26 capable of assuring the future success of the Company, to offer

⁵ The total Company amounts of stock-based compensation included in 2018 cost of service were provided in response to data request ND-PSC-15.20.

1 such persons incentives to put forth maximum efforts for the
2 success of the Company's business and to compensate such
3 persons through various stock-based arrangements and provide
4 them with opportunities for stock ownership in the Company,
5 **thereby aligning the interests of such persons with the**
6 **Company's shareholders.**

7
8 (Emphasis supplied)
9

10 **Q. Has OTP provided any studies that demonstrate a quantitative benefit to**
11 **ratepayers from the provision of stock-based compensation to OTP and**
12 **Otter Tail Corporation executives?**

13 A. No.

14
15 **Q. Please discuss the reasons for removing stock-based compensation from**
16 **OTP's 2018 test year cost of service.**

17 A. Ratepayers should not be required to pay executive or management
18 compensation that is based on the performance of the Company's (or its parent
19 company's) stock price, or that has the primary purpose of benefitting the parent
20 company's shareholders and aligning the interests of participants with those of
21 such shareholders.

22
23 Charging a shareholder-oriented expense to OTP's revenue requirement would
24 not be good regulatory policy.

25

1 OTP has failed to provide any studies that demonstrate a quantitative benefit to
2 OTP ratepayers from the provision of stock-based compensation directly charged
3 to OTP and/or allocated to OTP from Otter Tail Corporation.

4 Additionally, prior to being required to expense stock options for financial
5 reporting purposes under Statement of Financial Accounting Standards No. 123
6 Revised (SFAS 123R)⁶, the cost of stock-option based compensation was
7 typically treated as a dilution of shareholders' investments, i.e., it was a cost
8 borne by shareholders. While SFAS 123R now requires stock-option based
9 compensation cost to be expensed on a company's financial statements, this
10 does not provide a reason for shifting the cost responsibility for stock-based
11 compensation from shareholders to utility ratepayers.

12
13 **Q. Please explain your recommended adjustment for Stock-Based**
14 **Compensation expense.**

15 A. As shown on Exhibit RCS-1, Schedule C-6, OTP's 2018 test year cost of service
16 is reduced by \$525,567 on a North Dakota jurisdictional basis to remove all
17 identified stock-based compensation directly charged to OPT and by \$121,481
18 on a North Dakota jurisdictional basis for charges allocated to OTP from Otter
19 Tail Corporation for stock-based compensation. The total reduction to expense
20 to remove stock-based compensation is \$647,048 on a North Dakota
21 jurisdictional basis.

22
23 **Q. Is there a related adjustment to payroll tax expense?**

⁶ This is now known as Accounting Standards Codification (ASC) 718.

1 A. Yes. As discussed below, my recommended adjustment to stock-based
2 compensation expense results in a related adjustment to payroll tax expense as
3 shown on Exhibit RCS-1, Schedule C-8.

4

5 **C-7, Non-Employee Director Restricted Stock Grants**

6 **Q. Do the non-employee members of the Company's Board of Directors**
7 **receive stock-based compensation?**

8 A. Yes. In its response to data request ND-PSC-06.23, the Company stated that
9 the Board of Directors is comprised of officers from Otter Tail Corporation. As
10 members of Otter Tail Corporation's Board of Directors, each non-employee
11 member receives combination of an annual retainer and annual grants of
12 restricted stock. With regard to the grants of restricted stock, the response to
13 ND-PSC-06.23 states:

14 Each non-employee Director receives an annual grant of restricted
15 stock with an approximate value of \$80,000 granted under the
16 terms of the 2014 Stock Incentive Plan on the date of the Annual
17 Meeting. The amount is fixed and is not defined as incentive
18 compensation as it is not tied to individual performance or Otter Tail
19 Corporation's financial performance. The shares of restricted stock
20 vest over a period of four years at the rate of 25% per year and are
21 eligible for full dividend and voting rights. Starting in April 2018, on
22 the date of the Annual Meeting, each non-employee Director will
23 receive an additional grant of restricted stock with an approximate
24 value of \$10,000 for each committee on which they serve, and the
25 Board Chair will receive an additional grant of restricted stock with
26 an approximate value of \$25,000. All shares of restricted stock
27 awarded to non-employee Directors will vest over a period of three
28 years at the rate of 33.3% per year and will be eligible for full
29 dividend and voting rights.

30

1 **Q. Does the Company's 2018 test year include costs associated with grants of**
2 **restricted stock issued to OTP's Board of Directors?**

3 A. Yes. In its response to data request ND-PSC-18.01, the Company included an
4 attachment which provided a breakout of the 2018 allocation of non-employee
5 Director compensation to OTP on a total Company and North Dakota
6 jurisdictional basis. Specifically, this breakout included the costs associated with
7 (1) the retainers per Director, Board Chair, and Committee Chairs, and (2)
8 restricted stock grants per Director and Board Chair.

9
10 **Q. Do the costs that are included in the breakout of non-employee Director**
11 **retainers and restricted stock grants reflect what is included in the 2018**
12 **test year?**

13 A. No. With regard to what is included in the 2018 test year, the response to ND-
14 PSC-18.01 states in part:

15 At the time OTP's Test Year was developed, the estimated allocation
16 of Director Compensation was \$710,704 (OTP Total) / \$287,903
17 (OTP ND), as shown on line 21.⁷ These estimates were based on
18 previous assumptions associated with Director Compensation. No
19 adjustments were made to the Test Year amounts in the
20 Supplemental Filing.

21

22 **Q. Has the Company explained the purpose of the annual grants of restricted**
23 **stock to the non-employee Directors?**

24 A. Yes. In its response to ND-PSC-18.01(f), OTP stated in part:

⁷ The reference to "line 21" refers to Attachment 1 to the response to ND-PSC-18.01.

1 The use of stock grants is based on a combination of competitive
2 practice and a desire to align the interests of the Directors with the
3 long-term performance and success of the organization.
4

5 **Q. What are you recommending with regard to non-employee Director**
6 **compensation?**

7 A. For the reasons discussed above as it relates to my recommendation to remove
8 stock-based compensation, I am recommending that the cost of the non-
9 employee Director restricted stock grants be removed from 2018 test year cost of
10 service. Specifically, and as stated above with regard to stock-based
11 compensation, ratepayers should not be required to pay executive or
12 management compensation that is based on the performance of Otter Tail
13 Corporation's stock price, or that has the primary purpose of benefitting the
14 parent company's shareholders and aligning the interests of participants with
15 those of such shareholders

16
17 **Q. Please explain your adjustment.**

18 A. The attachment to the response to ND-PSC-18.01 did not provide a breakout of
19 the categories of non-employee Director compensation that are included in the
20 2018 test year filing, the totals of which are summarized in the following table:

Total Per Plan Per 2018 Test Year Filing	OTP Total Per 2018 Test Year Filing	North Dakota Jurisdictional Portion Per 2018 Test Year Filing
\$ 1,184,507	\$ 710,704	\$ 287,903
Source: ND-PSC-18.01		

21

1 However, in an email dated May 14, 2018, OTP stated that of the total amount of
2 \$1.185 million, \$485,856 was related to restricted stock grants and that the OTP
3 portion of the restricted stock grants totaled \$291,514. Therefore, as shown on
4 Exhibit RCS-1, Schedule C-7, I have removed the North Dakota jurisdictional
5 portion of the restricted stock grants included in the Company's 2018 test year by
6 applying the blended North Dakota jurisdictional allocator to the \$291,514 of
7 restricted stock grants that was allocated to OTP. Applying this allocator to
8 remove the non-employee Director restricted stock grants reduces 2018 test year
9 cost of service by \$118,091 on a North Dakota jurisdictional basis.

10
11 **Q. Is there a related adjustment to payroll tax expense?**

12 A. Yes. As discussed below, my recommended adjustment to remove non-
13 employee Director restricted stock grants results in a related adjustment to
14 payroll tax expense as shown on Exhibit RCS-1, Schedule C-8.

15
16 **C-8, Payroll Tax Expense**

17 **Q. Please explain your adjustment to OTP's payroll tax expense.**

18 A. My recommended adjustment to OTP's payroll tax expense is made in
19 conjunction with the adjustments that I am recommending related to (1) payroll
20 expense; (2) incentive compensation expense; (3) stock-based compensation
21 expense; and (4) non-employee Director restricted stock grants. Based upon
22 those recommended adjustments, as shown on Exhibit RCS-1, Schedule C-8, I

1 have reduced OTP's payroll tax expense by \$193,910 on a North Dakota
2 jurisdictional basis.

3

4 **Q. Did the Social Security Administration update the threshold on the wage**
5 **levels that are subject to the 6.20% Social Security Taxes?**

6 A. Yes. On November 27, 2017, the Social Security Administration increased the
7 maximum amount of wages in 2018 that are subject to the 6.20% Social Security
8 Tax (i.e., FICA tax) to \$128,400. Staff acknowledges that to the extent that the
9 salaries of certain individuals are included in the adjustments to which my
10 adjustment to payroll tax expense applies are above the threshold of \$128,400, it
11 will be necessary to modify my recommended adjustment to payroll tax expense.

12

13 **C-9, Executive Survivor and Supplemental Retirement Plan ("ESSRP")**

14 **Q. What is the Company's ESSRP?**

15 A. The Company referred to the ESSRP as being the equivalent of a Supplemental
16 Executive Retirement Plan ("SERP").⁸ A SERP, or in OTP's case, an ESSRP,
17 provides supplemental retirement benefits for highly compensated executives.
18 Generally, SERPs are implemented for executives to provide retirement benefits
19 that exceed amounts limited by qualified plans by Internal Revenue Service
20 ("IRS") limitations. Companies usually maintain that providing such
21 supplemental retirement benefits to executives is necessary in order to ensure
22 attraction and retention of qualified employees. Typically, SERPs provide for
23 retirement benefits in excess of limits placed by IRS regulations on pension plan

⁸ See the confidential response to data request ND-PSC-15.21, which inquired about OTP's SERP expense.

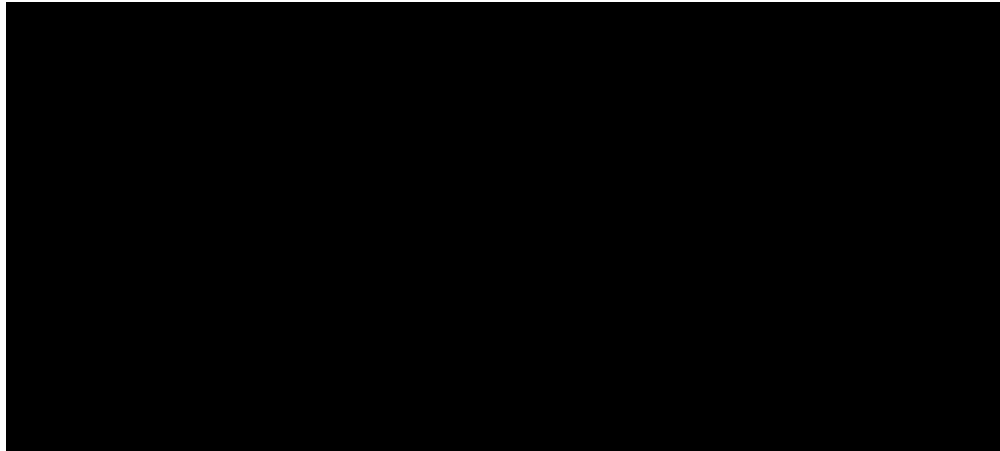
1 calculations for salaries in excess of specified amounts. IRS restrictions can also
2 limit the Company 401(k) contributions such that the Company 401(k)
3 contribution as a percent of salary may be smaller for a highly paid executive
4 than for other employees.

5

6 **Q. Does OTP's ESSRP include any current OTP or Otter Tail Corporation**
7 **employees and executives?**

8 A. Yes. In its confidential response to data request ND-PSC-15.21, the Company
9 provided Attachment 5, which listed ten active employees and executives with
10 the job titles summarized in the following table:

11 **[BEGIN CONFIDENTIAL]**



12

13 **[END CONFIDENTIAL]**

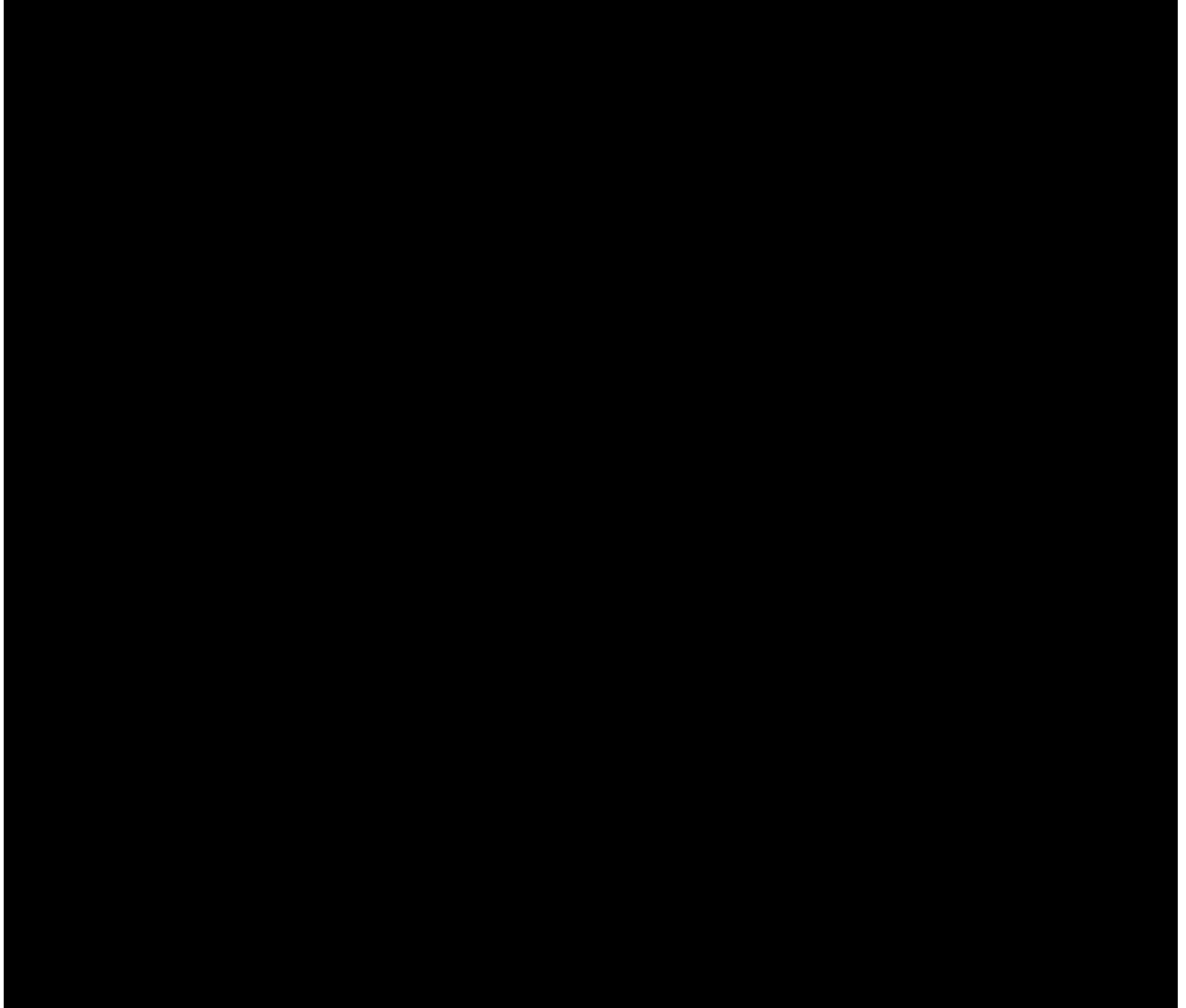
14

15 **Q. Does OTP's ESSRP include any retired OTP or Otter Tail Corporation**
16 **employees and executives?**

1 A. Yes. In its confidential response to data request ND-PSC-15.21, the Company
2 provided Attachment 6, which listed 31 retired and/or vested employees and
3 executives with the job titles summarized in the following table:

4 **[BEGIN CONFIDENTIAL]**

5



6

7 **[END CONFIDENTIAL]**

8

9 **Q. Should ratepayers be responsible for OTP's ESSRP expense?**

1 A. No. The provision of additional retirement compensation to the Company's
2 current and former highest paid executives is not a reasonable expense that
3 should be recovered in rates.

4

5 **Q. Please explain your adjustment for ESSRP expense.**

6 A. This adjustment removes 100% of the expense for ESSRP expense included in
7 the Company's 2018 test year cost of service. As shown on Exhibit RCS-1,
8 Schedule C-9, my adjustment reduces 2018 test year cost of service by \$1.426
9 million on a total Company basis and by \$577,665 on a North Dakota
10 jurisdictional basis.

11

12 **C-10, Rate Case Expense**

13 **Q. What is the Company requesting for rate case expense?**

14 A. As discussed on pages 45-46 of the direct testimony of Company witness
15 Tommerdahl, the Company has estimated rate case expense totaling \$775,000,
16 which is comprised of external legal fees, administrative costs, costs of
17 consultants and PSC filing costs, which is summarized in the table below:

Description	Per OTP
External Attorney Fees	\$ 400,000
Administrative Costs, Consultants, etc.	\$ 200,000
PSC Costs	\$ 175,000
Estimated Rate Case Expense	\$ 775,000

18

19 After allocating a portion of its estimated rate case expense to unregulated
20 activities based on the ratio of OTP's unregulated revenues to regulated
21 revenues, the Company proposes to amortize the regulated portion of rate case
22 expense over a three-year period. As shown on Company workpaper TY-02

1 from Volume 4a of its filing, the Company's proposed 2018 test year rate case
2 expense is \$257,871 on a North Dakota jurisdictional basis.

3

4 **Q. Do you agree with the Company's requested level of rate case expense?**

5 A. No. I do not agree with the Company's requested level of rate case expense.

6 First of all, on its face, the estimate for external legal fees of \$400,000 seems
7 excessive. OTP's confidential response to data request ND-PSC-15.26 indicates
8 that [BEGIN CONFIDENTIAL] [REDACTED]

9 [REDACTED] [END CONFIDENTIAL] It is my understanding from Staff that the
10 attorney representing the Company in this proceeding is an OTP employee, not
11 an external law firm, thus there should be no need for external legal counsel. In
12 addition, the amount of \$200,000 that the Company has estimated for
13 administrative and consulting fees also appears to be excessive.

14

15 **Q. How many outside consultants has OTP engaged for this proceeding?**

16 A. OTP has engaged only one outside consultant in this proceeding and that relates
17 to issues associated with the Company's proposed rate of return and ROE.

18

19 **Q. Who is the outside consultant engaged by OTP in this proceeding?**

20 A. OTP's outside consultant in this proceeding is Robert Hevert, a partner in the firm
21 ScottMadden, Inc.

22

1 **Q. Did Mr. Hevert address OTP's rate of return and ROE in its last rate case in**
2 **Case No. PU-08-862?**

3 A. Yes. It is my understanding that Mr. Hevert, who was with the firm Concentric
4 Energy Advisors at the time, addressed OTP's rate of return and ROE issues in
5 OTP's last rate case in Case No. PU-08-862. In its response to data request ND-
6 PSC-01.16, OTP stated that Mr. Hevert's fees are included in its rate case
7 expense request at a set amount along with other consultants, such as for the
8 Marginal Cost Study and other administrative expenses.

9
10 **Q. Did the Company hire an outside consultant to perform its class cost of**
11 **service study in this proceeding?**

12 A. No. The Company's class cost of service study in this proceeding was performed
13 by Company witness Gina Ice, who is an employee of OTP. As noted above, Mr.
14 Hevert is the only outside consultant hired by OTP for this proceeding. The
15 response to ND-PSC-01.16 states that the amount of administrative costs and
16 consulting fees included in this proceeding are the same amount that was
17 included in OTP's last North Dakota rate case in Case No. PU-08-862.

18
19 **Q. What amount of expense did OTP incur in its last rate case for Mr. Hevert's**
20 **rate of return and ROE analysis?**

21 A. According to the confidential response to data request ND-PSC-15.26, Mr.
22 Hevert's fees while with Concentric Energy Advisors totaled **[BEGIN**

1 **CONFIDENTIAL]** [REDACTED]

2 [REDACTED] **[END CONFIDENTIAL]**

3
4 **Q. Based on the foregoing, are you recommending an adjustment to rate case**
5 **expense?**

6 A. Yes. I have removed the external legal fees of \$400,000 and reduced the
7 estimate for administrative costs and consulting fees to \$75,000, which results in
8 estimated rate case expense of \$250,000. After allocating a portion of the
9 recommended rate case expense to unregulated activities based on the ratio of
10 OTP's unregulated revenues to regulated revenues, similar to OTP, I amortized
11 the regulated portion of my recommended rate case expense over a three-year
12 period. As shown on Exhibit RCS-1, Schedule C-10, my recommended
13 adjustment reduces OTP's requested O&M expense by \$174,687 on a North
14 Dakota jurisdictional basis.

15
16 **C-11, Interest Synchronization**

17 **Q. Please explain the adjustment to Interest Synchronization.**

18 A. This adjustment modifies the Company's interest synchronization adjustment to
19 reflect my recommended rate base and the weighted cost of debt recommended
20 by Staff witness Rothschild. As shown on Exhibit RCS-1, Schedule C-14, state
21 and federal income tax expense is increased by \$2,890 for interest
22 synchronization.

23

1 **VII. TAX CUTS AND JOBS ACT**

2 **Q. Has OTP identified the impact of the TCJA on its requested revenue**
3 **requirement?**

4 A. Yes, to some extent. On March 23, 2018, OTP filed the Supplemental Direct
5 Testimony of Mr. Akerman, which utilized the new 21 percent federal corporate
6 income tax rate to compute income tax expense. Additionally, in response to
7 discovery, OTP has indicated that its original filing had included in its calculation
8 of federal income tax expense the impact of the Domestic Production Activities
9 Deduction ("DPAD") which was discontinued by the TCJA, and the Company
10 removed that impact in its supplemental filing and for purposes of interim rates.
11 Additionally, the Company's supplemental filing included updated amounts for
12 2017 bonus tax depreciation. The Company's supplemental filing also reflected a
13 recalculation of the Gross Revenue Conversion Factor ("GRCF") to reflect the
14 new 21 percent federal corporate income tax rate.

15
16 However, it does not appear that the Company has reflected the amortization of
17 excess federal ADIT as an adjustment to 2018 deferred federal income tax
18 expense. Nor does it appear that the Company has reflected the return to
19 customers of TCJA-based revenue requirement savings that occurred in 2018 in
20 the months before OTP's interim rates and rider-based rates were reset, which
21 apparently occurred on March 1, 2018. I address these two aspects of the TCJA
22 in the following sections of my testimony.

23

1 **C-12, Amortization of Excess Accumulated Deferred Income Taxes (ADIT)**

2 **Q. Has the Company identified the amount of Accumulated Deferred Income**
3 **Taxes ("ADIT") that it had recorded as of December 31, 2017?**

4 A. Yes. The Company's response to Staff data requests ND-PSC-03.04 and ND-
5 PSC-03.06 indicate that as of December 31, 2017, OTP had ADIT of \$321.359
6 million, consisting of federal ADIT of \$271.829 million, Minnesota ADIT of
7 \$33.865 million, and North Dakota ADIT of \$15.664 million. The Company's
8 response to Staff data request ND-PSC-03.06 indicates that the amount of
9 excess federal ADIT at December 31, 2017 is \$108.732 million.

10

11 **Q. What is your current understanding of how excess federal ADIT for**
12 **regulated public utilities can be addressed?**

13 A. My current understanding is that regulated public utilities will be required to
14 identify the portions of their ADIT balances that represent "excess" ADIT based
15 on recalculations using the difference between the old federal income tax rate
16 ("FIT") (typically 35%) under which the ADIT was accumulated and the new
17 federal corporate rate of 21%. Basically, utility ADIT must be revalued at the new
18 FIT rate. All *non-plant* related ADIT (FERC account 190 and 283 for electric
19 utilities) will be reduced. To ensure that these benefits are passed to customers,
20 the regulator should require that the reduction be deferred in a net regulatory
21 liability. *Plant* related ADIT (FERC accounts 281 and 282 for electric utilities) will
22 also need to be revalued at the new FIT rate. IRS normalization requirements
23 will apply to the portion of the property related ADIT that relates to the use of

1 accelerated tax depreciation (including federal bonus tax depreciation).
2 Regulated public utilities (as do other business taxpayers) typically compute tax
3 depreciation using the Modified Accelerated Cost Recovery System ("MACRS"),
4 which is the current tax depreciation system in the United States. Under this
5 system, the capitalized cost (basis) of tangible property is recovered over a
6 specified life by annual deductions for depreciation. The differences between the
7 use of accelerated tax depreciation to produce depreciation deductions for
8 federal income tax purposes and the use of book depreciation (typically some
9 form of straight-line depreciation) are accounted for, and the tax impacts are
10 accumulated as ADIT for accounting and ratemaking purposes. It is expected
11 that the excess ADIT related to the use of accelerated tax depreciation will result
12 in "protected" excess ADIT balances for at least a portion of the utility's property
13 related ADIT, e.g., the ADIT recorded in account 282. That "protected" ADIT will
14 be subject to normalization requirements which will govern how it can be flowed
15 back to ratepayers. The TCJA specifically provides that the average rate
16 assumption method ("ARAM") must be used for the protected portion of excess
17 ADIT, although an alternative method is permitted if adequate records are not
18 available to compute the ARAM.

19
20 In contrast, the flow back of the "unprotected" portion of the excess ADIT will be
21 up to the discretion of the regulatory authority. Unprotected ADIT is not subject
22 to normalization requirements and will be revalued at the lower 21% FIT rate. A

1 regulatory liability may need to be established to ensure that the un-protected
2 excess ADITs are captured and can be passed back to customers.

3

4 **Q. Please elaborate on the normalization requirement for protected excess**
5 **ADIT.**

6 A. As described above, the TCJA reduced the federal corporate income tax rate to a
7 flat 21%. Public utilities are required, as a condition of using MACRS
8 (accelerated tax depreciation) to use normalization accounting under which
9 depreciation for ratemaking purposes does not reflect the accelerated tax
10 depreciation under MACRS. The normalization requirements address how the
11 "excess" ADIT balances related to the use of accelerated tax depreciation on
12 utility property can be flowed back. Generally, the flow-back of such "protected"
13 excess ADIT balances must occur over the remaining life of the related utility
14 property. The TCJA provides for a specific method, the ARAM, for assuring
15 compliance with the normalization requirements as they relate to protected
16 excess ADIT.

17

18 Specifically, the TCJA provides that public utilities subject to the normalization
19 method of accounting are not treated as applying the normalization method for
20 any public utility property for purposes of Code Sec. 167 or Code Sec. 168 if they
21 reduce their excess tax reserves resulting from the lower tax rate in computing
22 their cost of service for ratemaking purposes and for purposes of reflecting
23 operating results in their regulated books of account, more rapidly or to a greater

1 extent than the amount the reserve would be reduced under the ARAM. (See
2 TCJA §13001(d)(1)). For this purpose, the excess tax reserve is the reserve for
3 deferred taxes, described in Code Sec. 168(i)(9)(A)(ii) as in effect on the day
4 before the FIT rate reductions take effect (TCJA §13001(d)(3)(A)(i)), minus the
5 amount that would be the balance in the reserve if the amount of the reserve
6 were determined by assuming that the TCJA corporate rate reductions were in
7 effect for all prior periods. (See TCJA §13001(d)(3)(A)(ii)).

8
9 **Q. Has OTP identified the amount of "protected" excess federal ADIT that it**
10 **has as of December 31, 2017?**

11 A. Yes. The Company's response to Staff data request ND-PSC-03.06 indicates
12 that out of a total excess federal ADIT as of December 31, 2017 of \$108.732
13 million, two items relate to excess ADIT balances which were created due to the
14 Company using accelerated tax depreciation. The two items are:

- 15 1. Excess tax over book depreciation (in FERC account 282), for which OTP
16 shows an excess ADIT amount of \$106.178 million, and
- 17 2. Excess tax over book depreciation - AQCS AL7 (in FERC account 281),
18 for which OTP shows an excess ADIT amount of \$1.624 million.

19 The Company's response to DR ND-PSC-18.02(e) explains that:

20 In FERC account 282, the only protected timing difference is "Excess
21 Tax over Book Depreciation", all others are unprotected. OTP also
22 has ADIT in FERC account 281 which is based on the timing
23 differences between book and tax depreciation which we've
24 (meaning OTP) labeled as being protected, similar to FERC 282."

25

1 The Company's response to DR ND-PSC-16.02 shows a similar breakout of the
 2 excess ADIT, and includes an additional column showing OTP's North Dakota
 3 allocated amounts of excess ADIT.

4
 5 The following table uses that OTP-provided information to summarize the
 6 Company's excess ADIT balance as of December 31, 2017 into the "protected"
 7 and "non-protected" portions:

8

Otter Tail Power Company				
Excess Federal Accumulated Deferred Income Taxes				
As of December 31, 2017				
		FERC	Total OTP	North Dakota
Description		Account	Amount	OTP Allocated
			(A)	(B)
Protected Excess ADIT				
Excess Tax Over Book Depreciation	282		\$ (106,177,537)	\$ (38,312,502)
Excess Tax Over Book Depreciation - AQCS SL 7	281		\$ (1,623,952)	\$ (585,977)
Subtotal - Protected Excess ADIT			\$ (107,801,489)	\$ (38,898,479)
Non-Protected Excess ADIT				
	190		\$ 13,835,519	\$ 4,992,331
	282		\$ (6,480,550)	\$ (2,338,405)
	283		\$ (8,285,172)	\$ (2,989,575)
Subtotal - Non-Protected Excess ADIT			\$ (930,203)	\$ (335,649)
Total Excess Federal ADIT at December 31, 2017			\$ (108,731,692)	\$ (39,234,128)
Source: OTP's response to DR ND-PSC-03.06, Attachment 1 and ND-PSC-16.02, Attachment 1				

9

10

11 **Q. Did the Company record a journal entry to reflect the transfer of its excess**
 12 **federal ADIT at December 31, 2017 into a regulatory liability account?**

13 A. Yes. The Company's response to DR ND-PSC-18-11 includes an attachment
 14 which provides a detailed summary workpaper of the Company's calculation of

1 excess ADIT performed at year-end 2017 and the related journal entries made to
2 adjust the ADIT balances. As shown on Attachment 1 to that response, the
3 Company transferred the \$108,731,692 amount of excess federal ADIT, grossed-
4 up for income taxes using a factor of 1.3556 (for a gross-up amount of
5 \$38,785,895), out of the ADIT accounts and into a regulatory liability account
6 (FERC account 254) in the net amount of \$147,857,589, of which \$39,356,813 is
7 allocable to OTP North Dakota.

8
9 **Q. Has OTP stated how it proposes to amortize the Protected portion of its**
10 **excess ADIT?**

11 A. Yes. OTP's response to DR ND-PSC-05.02 indicates that to be in compliance
12 with the normalization requirements of the Internal Revenue Service, the
13 Company will be applying the ARAM to the protected portions of its excess
14 federal ADIT balances that relate to the use of accelerated tax depreciation for
15 federal income tax purposes.

16
17 **Q. Please explain your current understanding of the ARAM that is specified in**
18 **the TCJA for compliance with normalization requirements on the**
19 **"protected" excess ADIT.**

20 A. The ARAM is the method under which the "protected" excess in the reserve for
21 deferred taxes is reduced over the remaining lives of the property as recorded in
22 the utility's regulated books of account which gave rise to the reserve for deferred
23 taxes. Under this method, if timing differences for the property reverse, the

1 amount of the adjustment to the reserve for the deferred taxes is calculated by
2 multiplying (1) the ratio of the aggregate deferred taxes for the property to the
3 aggregate timing differences for the property as of the beginning of the period in
4 question (TCJA §13001(d)(3)(B)(i)) by (2) the amount of the timing differences
5 that reverse during the period. (See, TCJA §13001(d)(3)(B)(ii)).
6

7 The reversal of timing differences generally occurs when the cumulative amount
8 of the tax depreciation taken on the asset is less than the cumulative amount of
9 the regulatory (book) depreciation taken on the asset. To ensure that the
10 deferred tax reserve, including the excess tax reserve, is reduced to zero at the
11 end of the regulatory life of the asset that generated the reserve, the amount of
12 the timing difference which reverses during a tax year is multiplied by the ratio of
13 (1) the aggregate deferred taxes as of the beginning of the period in question to
14 (2) the aggregate timing differences for the property as of the beginning of the
15 period in question.
16

17 **Q. Has OTP stated how it will apply the ARAM to the Protected portion of its**
18 **excess federal ADIT?**

19 A. Yes. OTP's response to DR ND-PSC-05.02 states that the Company uses the
20 software PowerTax to track and calculate the obligation and reversal of ADIT
21 balances, and provided an illustrative example from the PowerTax system of how
22 the system tracks each jurisdiction, vintage, and tax class and computes an
23 ARAM for each. Additional explanation of the ARAM was provided by OTP in

1 response to DR ND-PSC-05.05. The Company's response to DR ND-PSC-18.03
2 and DR ND-PSC-18.04 contain additional explanations of how the PowerTax
3 modules of the PowerPlan software is used to track tax depreciation and
4 compute the ARAM and how the PowerPlan module tracks the Company's book
5 plant activity. The systems maintain the information by tax account per each
6 vintage year. The Company's response to DR ND-PSC-18.04 explains that the
7 PowerPlan system fixed asset software tracks the utility plant in service assets
8 by plant account and at their book cost and in-service vintage, and indicates that
9 the associated accumulated book depreciation for these assets is allocated to the
10 individual plant assets within that plant account by vintage. OTP's response to
11 DR ND-PSC-18.07 similarly explains that the Company will be using the
12 PowerTax module of the PowerPlan software system to calculate the reversal of
13 the protected portion of the excess federal ADIT balance that related to the use
14 of accelerated tax depreciation for federal income tax purposes.

15

16 **Q. Do you agree with OTP's proposal to apply the ARAM to the Protected**
17 **portion of its excess federal ADIT?**

18 A. Yes. The TCJA requires that the ARAM be applied to the Protected portion of a
19 utility's excess federal ADIT. I therefore agree with OTP's proposal to apply the
20 ARAM to the Protected portion of its excess federal ADIT.

21

22 **Q. How has OTP identified and reflected the 2018 ARAM based amortization of**
23 **the protected excess federal ADIT?**

1 A. It appears that OTP has not yet identified, or reflected the 2018 ARAM-based
2 amortization of the protected excess federal ADIT.

3

4 **Q. How should the 2018 test year impact of the ARAM-based amortization of**
5 **the protected excess federal ADIT be reflected in OTP's rate case?**

6 A. The 2018 test year impact of the ARAM-based amortization of the protected
7 excess federal ADIT at December 2017 should be reflected as an adjustment to
8 deferred federal income tax expense; however, it does not appear that OTP
9 included this impact in their supplemental filing or specifically identified the 2018
10 ARAM-based amount. I have not been able to compute the 2018 ARAM-based
11 amount using information provided by the Company. I recommend that OTP
12 provide the impact of the 2018 ARAM-based amortization of protected excess
13 federal ADIT in its rebuttal filing, so that impact on deferred federal income tax
14 expense can be reflected in calculating OTP's North Dakota jurisdictional
15 revenue requirement in this rate case.

16

17 **Q. Has OTP stated how it intends to amortize the Non-Protected portion of its**
18 **excess federal ADIT?**

19 A. Yes. OTP's response to DR ND-MLEC-141 states that, due to the non-protected
20 items total of only \$930,203 out of total excess ADIT of \$108,731,692, OTP
21 suggests that the non-protected items be treated the same as the protected
22 balances, with the same amortization schedule, to be reversed using ARAM.
23 OTP's response to DR ND-MLEC-141 estimates that this would approximate a

1 25-year amortization period, which if done on a straight-line basis, would produce
2 an annual amortization of the non-protected excess ADIT of approximately
3 \$37,208 annually (\$930,203 divided by 25 years).

4
5 OTP's response to DR ND-MLEC-141 states further that the revenue
6 requirement for the non-protected excess ADIT amortization would include a
7 gross-up amount. OTP indicates that the gross-up factor subsequent to tax
8 reform equals 1.32284 resulting in a total revenue requirement impact of
9 \$1,203,510, or \$49,220 annually (1,230,510 divided by 25 years).

10
11 OTP's response to DR ND-MLEC-141 also identifies the North Dakota portion of
12 the non-protected balance of \$930,203 to be \$335,674, based on OTP's current
13 North Dakota allocation factor of 0.36086122.

14
15 **Q. Do you agree with OTP's proposal to apply the ARAM to the Non-Protected**
16 **excess federal ADIT balances?**

17 A. No. The "non-protected" excess federal ADIT liability balance for OTP should be
18 amortized on a straight-line basis over a relatively short period, rather than being
19 subject to the Average Rate Assumption Method ("ARAM"). The "non-protected"
20 excess ADIT balances are not subject to normalization requirements, and the
21 amortization of such balances is up to the regulatory commission. A three-year
22 straight-line amortization period approximates the period being recommended for
23 amortization of the Company's rate case expense. A straight-line method

1 produces a consistent amount of amortization each year. This contrasts with the
2 ARAM, which would produce a different amount of amortization each year.
3 Because OTP has relatively small amounts of "non-protected" excess ADIT net
4 liability balances, the annual amortization would modestly decrease deferred
5 income tax expense. There is benefit to utility customers during the amortization
6 period from reduced deferred federal income tax expense from amortizing those
7 "non-protected" excess ADIT liability balances over a relatively shorter period, as
8 is the case with some other utilities, who also, like OTP, have excess ADIT
9 liabilities. For OTP, my recommendation is to amortize their "non-protected"
10 excess ADIT asset balances on a straight-line basis over a three-year period,
11 coinciding with the estimated rate case filing cycle, as reflected in the
12 amortization period being used for rate case expense.

13

14 **Q. What adjustment does that produce?**

15 A. As shown on Exhibit RCS-1, Schedule C-12, amortizing the December 31, 2017
16 non-protected excess ADIT over a three-year period on a straight-line basis
17 reduces 2018 test year deferred income tax expense by \$111,883.

18

19 **Q. Have you identified an amount of reduction to 2018 test year deferred**
20 **income tax expense in OTP's filing that was associated with the Company's**
21 **proposal to apply the ARAM to either the Protected or the Non-Protected**
22 **excess ADIT balances?**

1 A. No. I have not identified an amount of reduction to 2018 test year deferred
2 income tax expense in OTP's filing that was associated with the Company's
3 proposal to apply the ARAM to both the Protected and Non-Protected excess
4 ADIT balances, and it appears that there is none. If the Company had reduced
5 2018 test year deferred income tax expense related to its proposal to apply the
6 ARAM to the Non-Protected excess ADIT balances, that amount of deferred
7 income tax expense reduction would need to be netted against the \$111,883
8 reduction to deferred income tax expense. However, as noted, it does not
9 appear that any reduction to 2018 test year deferred income tax expense related
10 to OTP's proposal to apply the ARAM to Non-Protected (or Protected) excess
11 ADIT was reflected in the Company's supplemental filing.

12

13 **C-13, 2018 TCJA-Based Income Tax Savings Occurring Prior to Reflection in**
14 **Rates**

15 **Q. Has OTP experienced savings in income tax expense associated with the**
16 **TCJA in the early months of 2018 before its interim rates and riders were**
17 **adjusted for TCJA-related impacts?**

18 A. Yes. OTP's response to DR ND-PSC-19.03 indicates that the Company
19 experienced the impacts of the TCJA effective January 1, 2018, and the
20 Company has been provisioning an estimated amount of interim rate refund for
21 January and February 2018. During those months the Company had interim
22 rates in effect which did not yet include the impacts of the TCJA.

23

1 **Q. Has OTP suggested how the TCJA savings in January and February 2018**
2 **could be calculated?**

3 A. Yes. OTP's response to DR ND-PSC-19.03(b) states that:

4 The estimated impact of the TCJA on January and February could
5 be calculated using method noted of allocating the \$4.5 million
6 annual income tax reduction equally by month for the year. Given the
7 Cost of Service Study (COSS) used to calculate the impact on the
8 TCJA is based on a 2018 annual Test Year, it seems to be
9 appropriate to use this approach. The Company does not calculate
10 COSS results on a monthly basis but rather on a calendar year.

11

12 OTP witness Akerman's Supplemental Direct Testimony states at page 2, lines 6-
13 10 states that:

14 Effective March 1, 2018, OTP's revenue requirement for interim rates
15 were reduced from \$12.8 million to \$8.3 million, a total reduction in
16 interim rates of approximately \$4.5 million. This decrease is the
17 result of OTP's preliminary assessment of the tax rate reduction
18 components of the TCJA. OTP's revenue requirement for its
19 Transmission, Renewable and Environmental riders will be reduced
20 by approximately \$1.7 million.

21

22 OTP's response to DR ND-PSC-19.03(c) state that:

23 The table below identifies the amount of revenue requirement from
24 the Transmission, Renewable, and Environmental riders. The
25 amounts in the supplemental filing were modeled in Utilities
26 International. The modeling in the supplemental filing reflects the
27 lower federal income tax rate and lower tax gross-up factor for each
28 of the three riders. The total difference amount below is also shown
29 in Exhibit__(TAA-2), Schedule 7.

30

Rider Revenue Requirements	Supplemental Filing	Initial Filing	Difference
Transmission	\$ 7,391,542	\$ 7,913,280	\$ (521,738)
Renewable	\$ 8,868,053	\$ 9,211,881	\$ (343,828)
Environmental	\$ 7,581,594	\$ 8,357,519	\$ (775,925)
Total	\$ 23,841,189	\$ 25,482,680	\$ (1,641,491)

Source: ND-PSC-19.03

1
2 As shown in the above table, the difference is a total revenue requirement
3 reduction of \$1,641,491 for the three riders.

4 OTP's response to ND-PSC-19.03(d) states that:

5 The effective rate change date for the Transmission, Renewable,
6 and Environmental riders was March 1, 2018.

7
8
9 **Q. Using the information provided by OTP, have you calculated the estimated
10 revenue requirement savings for January and February of 2018 from the
11 TCJA?**

12 A. Yes. This is shown on Exhibit RCS-1, Schedule C-13. To compute the
13 estimated January and February 2018 revenue requirement savings from the
14 TCJA, I used 2/12ths (i.e., two months of the 12 months) of the \$4.5 million
15 interim rate reduction and 2/12ths of the \$1,641,491 amount of revenue
16 requirement reduction for the three riders. That produced a combined annual
17 revenue requirement reduction of approximately \$6.14 million, and a two-month
18 revenue requirement savings amount of approximately \$1.024 million.

19
20 **Q. What is your recommendation for handling that January and February 2018
21 revenue requirement savings from the TCJA for ratemaking purposes?**

1 A. As noted above, OTP's response to DR ND-PSC-19.03(a) has indicated that the
2 Company has been provisioning an estimated amount of interim rate refund.
3 Having a refund, or a one-time customer bill credit, would therefore be one way
4 of passing the January and February 2018 revenue requirement savings from the
5 TCJA onto customers. A refund would probably also be the most direct way of
6 returning these revenue requirement savings to OTP's customers. Having a
7 refund of the January and February 2018 TCJA related revenue requirement
8 savings would be acceptable to Staff.

9

10 **Q. Have you also seen this issue of 2018 TCJA related revenue requirement**
11 **savings handled in a different manner?**

12 A. Yes. An alternative would be to have the estimated TCJA related revenue
13 requirement savings that occurred in 2018 before being reflected in rates (for
14 OTP that would be for January and February, since interim rates and the three
15 riders were apparently adjusted on March 1, 2018), be quantified and recorded
16 as a regulatory liability and amortized back as a reduction to the utility's revenue
17 requirement over an appropriate period, such as the period being used for the
18 amortization of rate case expense. As shown on Exhibit RCS-1, Schedule C-13
19 amortizing the estimated January and February 2018 revenue requirement
20 savings from the TCJA over a three-year period would reduce OTP's North
21 Dakota jurisdictional revenue requirement by approximately \$341,000 per year.

22

1 **VIII. RIDER ROLL-INS TO BASE RATES**

2 **Q. Is the Company proposing to transfer certain capital costs currently**
3 **recovered in various riders to base rates at the conclusion of this case?**

4 A. Yes. As discussed in the direct testimony of Company witness Haugen, OTP
5 proposes to transfer into base rates the recovery of certain capital costs currently
6 recovered in the Environmental Cost Recovery Rider ("ECRR"), Transmission
7 Cost Recovery Rider ("TCRR"), and the Renewable Resource Adjustment Rider
8 ("RRAR"). I discuss each Company proposal below.

9

10 **A. Environmental Cost Recovery Rider**

11 **Q. When was the ECRR established?**

12 A. The ECRR was established in Case Nos. PU-13-79 and PU-13-84 and went into
13 effect on January 1, 2014. The basis for the ECRR is N.D.C.C. § 49-05-04.2,
14 which allows electric utilities to recover jurisdictional capital costs and related
15 operating expenses in order to be in compliance with federal environmental
16 requirements on existing electric generating stations.

17

18 **Q. What capital projects is OTP proposing to transfer to base rates from the**
19 **ECRR?**

20 A. OTP is proposing to transfer two projects currently being recovered through the
21 ECRR into base rates: (1) the Big Stone Plant Air Quality Control System
22 ("AQCS") project, and (2) the Hoot Lake Plant Mercury and Air Toxics Standards
23 ("HLP MATS") project.

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Q. Are the AQCS and HLP MATS projects currently in service?

A. Yes. The AQCS project was placed into service in December 2015, and the HLP MATS project was placed into service in August 2014.

Q. Did the Company include projected ECRR revenues in the 2018 test year?

A. Yes. On page 4 of his testimony, Mr. Haugen states that the 2018 test year present revenue includes the projected 2018 ECRR revenues. Mr. Haugen stated that transferring the projects from the ECRR to base rates is merely a change in how the costs of the projects are recovered and that including the ECRR revenue in 2018 test year present revenues provides a more accurate measurement of the overall impact on ratepayers.

Q. Does the Company's 2018 test year rate base include the AQCS and HLP MATS projects?

A. Yes. On page 4 of his testimony, Mr. Haugen states that these investments are part of the rate base that OTP used to determine the 2018 test year revenue requirement in this proceeding.

Q. What amounts associated with the AQCS and HLP MATS projects are reflected in the 2018 test year rate base?

A.. As discussed on page 5 of Mr. Haugen's testimony, for the AQCS project, the 2018 test year rate base reflects a 13-month average balance of \$193.0 million

1 on a total Company basis and \$70.3 million on a North Dakota jurisdictional
2 basis. For the HLP MATS project, the 2018 test year rate base reflects a 13-
3 month average balance of \$6.5 million on a total Company basis and \$2.4 million
4 on a North Dakota jurisdictional basis. Both of these projects are summarized in
5 the table below:

Description	Total Company Amount	North Dakota Jurisdictional Amount
ECRR Projects		
Big Stone Plant AQCS	\$ 192,985,866	\$ 70,290,056
HLP MATS	\$ 6,460,514	\$ 2,353,073
Total	\$ 199,446,380	\$ 72,643,129
Source: Exhibit__(BCH-1), Schedule 2		

6

7

8 **Q. When does OTP propose to transfer the projects out of the ECRR and into**
9 **base rates?**

10 A. OTP is proposing to transfer the two projects out of the ECRR and into base
11 rates when the final rates determined at the end of this case go into effect, and
12 that such rates reflect the net plant-in-service balances of both projects at that
13 time. In its response to data request ND-MLEC-214, OTP stated that it is
14 proposing that any over/under collection remaining in the ECRR at the time the
15 two projects are rolled into base rates be recovered through the ECRR over the
16 subsequent 12 months.

17

18 **Q. Has the Company provided information regarding its actual and projected**
19 **over/under recovered ECRR balances as well as actual and projected ECRR**
20 **revenue?**

1 A. Yes. In its response to data request ND-PSC-15.39, the Company provided
2 information regarding its actual and projected over/under recovered ECRR
3 balances as well as actual and projected ECRR revenue. Specifically, the table
4 below summarizes (1) the Company's actual monthly over/under recovered
5 ECRR balances and ECRR revenue for the period January 2016 through March
6 2018, and (2) the Company's actual monthly over/under recovered ECRR
7 balances and ECRR revenue for the period April 2018 through September 2018.
8 The Company did not provide projected ECRR costs for the period October
9 through December 2018 as OTP anticipates final rates in the current proceeding
10 will be effective as of October 1, 2018.

Date	Net Revenue Requirement*	Actual Billed Revenue	(Over)/Under
Actuals			
January 2016	\$ 905,592	\$ 1,166,949	\$ (261,357)
February 2016	\$ 914,655	\$ 1,096,483	\$ (181,828)
March 2016	\$ 915,115	\$ 1,013,479	\$ (98,364)
April 2016	\$ 906,725	\$ 928,957	\$ (22,232)
May 2016	\$ 907,344	\$ 799,999	\$ 107,345
June 2016	\$ 910,009	\$ 864,022	\$ 45,987
July 2016	\$ 909,344	\$ 775,660	\$ 133,684
August 2016	\$ 914,579	\$ 815,428	\$ 99,151
September 2016	\$ 915,568	\$ 818,015	\$ 97,553
October 2016	\$ 908,135	\$ 697,332	\$ 210,803
November 2016	\$ 907,716	\$ 791,732	\$ 115,984
December 2016	\$ 914,977	\$ 887,681	\$ 27,296
January 2017	\$ 839,194	\$ 1,046,843	\$ (207,649)
February 2017	\$ 837,353	\$ 977,658	\$ (140,305)
March 2017	\$ 838,631	\$ 875,488	\$ (36,857)
April 2017	\$ 844,605	\$ 818,150	\$ 26,455
May 2017	\$ 838,090	\$ 692,819	\$ 145,271
June 2017	\$ 838,558	\$ 745,184	\$ 93,374
July 2017	\$ 837,617	\$ 754,671	\$ 82,946
August 2017	\$ 842,045	\$ 762,314	\$ 79,731
September 2017	\$ 840,624	\$ 755,308	\$ 85,316
October 2017	\$ 834,381	\$ 635,599	\$ 198,782
November 2017	\$ 833,904	\$ 818,528	\$ 15,376
December 2017	\$ 846,084	\$ 860,255	\$ (14,171)
January 2018	\$ 623,417	\$ 852,776	\$ (229,359)
February 2018	\$ 626,329	\$ 806,825	\$ (180,496)
March 2018	\$ 622,317	\$ 664,037	\$ (41,720)
Forecast			
April 2018	\$ 624,999	\$ 647,823	\$ (22,824)
May 2018	\$ 624,999	\$ 553,488	\$ 71,511
June 2018	\$ 624,999	\$ 571,204	\$ 53,795
July 2018	\$ 624,999	\$ 592,253	\$ 32,746
August 2018	\$ 624,999	\$ 614,465	\$ 10,534
September 2018	\$ 624,999	\$ 608,968	\$ 16,031
October 2018**	-	-	-
November 2018**	-	-	-
December 2018**	-	-	-

* Revenue requirement does not include carrying charge/credit.

** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.

Source: ND-PSC-15.39

1 **Q. Has the Company provided information regarding its actual and projected**
2 **ECRR costs?**

3 A. Yes. In its response to data request ND-PSC-15.39, the Company provided
4 information regarding its actual and projected ECRR costs. Specifically, the table
5 below summarizes (1) the Company's actual monthly ECRR costs for the period
6 January 2016 through March 2018, and (2) the Company's projected monthly
7 ECRR costs for the period April 2018 through September 2018. Similar to the
8 ECRR over/under recovered balances and ECRR revenue, the Company did not
9 provide projected ECRR costs for the period October through December 2018 as
10 OTP anticipates final rates in the current proceeding will be effective as of
11 October 1, 2018.

1

Date	Return on Rate Base	O&M Costs	Property Taxes	Depreciation	Interest	Income Taxes	Net Revenue Requirement*
Actuals							
January 2016	\$ 323,708	\$ 9,249	\$ 3,430	\$ 229,178	\$ 148,990	\$ 191,038	\$ 905,593
February 2016	\$ 323,708	\$ 18,188	\$ 3,430	\$ 229,302	\$ 148,990	\$ 191,038	\$ 914,656
March 2016	\$ 323,708	\$ 18,455	\$ 3,430	\$ 229,494	\$ 148,990	\$ 191,038	\$ 915,115
April 2016	\$ 323,708	\$ 10,234	\$ 3,430	\$ 229,326	\$ 148,990	\$ 191,038	\$ 906,726
May 2016	\$ 323,708	\$ 10,794	\$ 3,430	\$ 229,384	\$ 148,990	\$ 191,038	\$ 907,344
June 2016	\$ 323,708	\$ 13,466	\$ 3,430	\$ 229,376	\$ 148,990	\$ 191,038	\$ 910,008
July 2016	\$ 323,708	\$ 12,487	\$ 3,430	\$ 229,690	\$ 148,990	\$ 191,038	\$ 909,343
August 2016	\$ 323,708	\$ 14,852	\$ 3,430	\$ 232,560	\$ 148,990	\$ 191,038	\$ 914,578
September 2016	\$ 323,708	\$ 15,607	\$ 3,430	\$ 232,795	\$ 148,990	\$ 191,038	\$ 915,568
October 2016	\$ 323,708	\$ 11,087	\$ 3,430	\$ 229,882	\$ 148,990	\$ 191,038	\$ 908,135
November 2016	\$ 323,708	\$ 10,236	\$ 3,430	\$ 230,314	\$ 148,990	\$ 191,038	\$ 907,716
December 2016	\$ 323,708	\$ 17,483	\$ 3,430	\$ 230,327	\$ 148,990	\$ 191,038	\$ 914,976
January 2017	\$ 293,210	\$ 16,949	\$ 4,022	\$ 217,020	\$ 134,953	\$ 173,040	\$ 839,194
February 2017	\$ 293,210	\$ 15,105	\$ 4,022	\$ 217,023	\$ 134,953	\$ 173,040	\$ 837,353
March 2017	\$ 293,210	\$ 16,350	\$ 4,022	\$ 217,056	\$ 134,953	\$ 173,040	\$ 838,631
April 2017	\$ 293,210	\$ 23,867	\$ 4,022	\$ 215,513	\$ 134,953	\$ 173,040	\$ 844,605
May 2017	\$ 293,210	\$ 17,352	\$ 4,022	\$ 215,513	\$ 134,953	\$ 173,040	\$ 838,090
June 2017	\$ 293,210	\$ 17,700	\$ 4,022	\$ 215,634	\$ 134,953	\$ 173,040	\$ 838,559
July 2017	\$ 293,210	\$ 16,758	\$ 4,022	\$ 215,634	\$ 134,953	\$ 173,040	\$ 837,617
August 2017	\$ 293,210	\$ 21,186	\$ 4,022	\$ 215,634	\$ 134,953	\$ 173,040	\$ 842,045
September 2017	\$ 293,210	\$ 19,766	\$ 4,022	\$ 215,634	\$ 134,953	\$ 173,040	\$ 840,625
October 2017	\$ 293,210	\$ 13,522	\$ 4,022	\$ 215,634	\$ 134,953	\$ 173,040	\$ 834,381
November 2017	\$ 293,210	\$ 12,960	\$ 4,022	\$ 215,718	\$ 134,953	\$ 173,040	\$ 833,903
December 2017	\$ 293,210	\$ 25,140	\$ 4,022	\$ 215,718	\$ 134,953	\$ 173,040	\$ 846,083
January 2018	\$ 226,836	\$ 17,311	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 623,417
February 2018	\$ 226,836	\$ 20,224	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 626,330
March 2018	\$ 226,836	\$ 16,211	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 622,317
Forecast							
April 2018	\$ 226,836	\$ 18,393	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 624,499
May 2018	\$ 226,836	\$ 18,393	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 624,499
June 2018	\$ 226,836	\$ 18,393	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 624,499
July 2018	\$ 226,836	\$ 18,393	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 624,499
August 2018	\$ 226,836	\$ 18,393	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 624,499
September 2018	\$ 226,836	\$ 18,393	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 624,499
October 2018**	-	-	-	-	-	-	-
November 2018**	-	-	-	-	-	-	-
December 2018**	-	-	-	-	-	-	-

* Revenue requirement does not include carrying charge/credit.
 ** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.

Source: ND-PSC-15.39

2

3

4

1 **Q. Do you agree with the Company's proposal to transfer the costs of these**
2 **two projects out of the ECRR and into base rates?**

3 A. Conceptually, I agree with the Company's proposal to transfer the costs of the
4 two projects out of the ECRR and into base rates at the conclusion of this rate
5 case, provided that when the two projects are transferred into base rates from
6 the ECRR at the conclusion of this proceeding, the amounts are updated to
7 reflect current plant balances at that time so as to minimize the impacts of the
8 true-up that will occur when the two projects are transferred from the ECRR into
9 base rates and that OTP demonstrates this by filing a compliance filing.

10

11 **B. Transmission Cost Recovery Rider**

12 **Q. When was the TCRR established?**

13 A. The TCRR was established in Case Nos. PU-11-153 and PU-11-682 and went
14 into effect on May 1, 2012. The basis for the TCRR is N.D.C.C. § 49-05-04.3,
15 which allows OTP to recover transmission related capital costs and to recover
16 costs assigned by regional transmission organizations ("RTOs") for projects that
17 are subject to cost sharing.

18

19 **Q. What capital projects is OTP proposing to transfer to base rates from the**
20 **TCRR?**

21 A. OTP is proposing to transfer the 16 projects listed in the table below, which are
22 currently being recovered through the TCRR, to base rates at the conclusion of
23 this proceeding.

Line No.	TCRR Projects Proposed for Transfer to Base Rates	In Service Date
1	CAPX 2020: Fargo	April 2015
2	CAPX 2020: Bemidji	August 2012
3	Cass Lake-Nary-Helga-Bemidji	August 2012
4	Rugby Wind Interconnection	August 2011
5	Casselton – Buffalo 115 kV Project	October 2017
6	CAPX 2020: Brookings - Hampton	March 2015
7	MVP: Big Stone Area Transmission	September 2017
8	Ramsey 230/115 kW Transformer Upgrade	December 2013
9	Karlstad, MN Capacitor Bank Project	December 2012
10	Oakes Area Transmission Improvements	October 2015
11	Hankinson Transformer Addition	December 2012
12	NERC Compliance	September 2016
13	Summit Transformer	May 2016
14	Spiritwood Station Interconnection	August 2015
15	Rugby Breaker Station	July 2017
16	Granville Jct Breaker Station	July 2017

1

2

3 **Q. Did the Company include projected TCRR revenues in the 2018 test year?**

4 A. Yes. On page 19 of his testimony, Mr. Haugen states that the 2018 test year
 5 present revenue includes the projected 2018 TCRR revenues. Mr. Haugen
 6 stated that, similar to the proposed treatment of the projects in the ECRR,
 7 transferring the projects from the TCRR to base rates is merely a change in how
 8 the costs of the projects are recovered and that including the TCRR revenue in
 9 2018 test year present revenues provides a more accurate measurement of the
 10 overall impact on ratepayers.

11

12 **Q. Does the Company's 2018 test year rate base include the 16 TCRR projects
 13 listed above?**

14 A. Yes. On page 19 of his testimony, Mr. Haugen states that these investments are
 15 part of the rate base used to determine the 2018 test year revenue requirement
 16 in this proceeding.

1
 2 **Q. What amounts associated with the 16 TCRR projects are reflected in the**
 3 **2018 test year rate base?**

4 A. As discussed on page 20 of Mr. Haugen's testimony, the 2018 test year rate
 5 base reflects a 13-month average balances totaling \$246.5 million on a total
 6 Company basis and \$47.2 million on a North Dakota jurisdictional basis for the
 7 16 projects that OTP proposes be transferred from the TCRR and into base rates
 8 at the conclusion of this proceeding. A breakout of the amounts by project is
 9 summarized in the table below:

10

Line No.	Description	Total Company Amount	North Dakota Jurisdictional Amount
	TCRR Projects		
1	CAPX 2020: Fargo	\$81,428,592	\$23,856,947
2	CAPX 2020: Bemidji	16,331,201	\$5,885,328
3	Cass Lake-Nary-Helga-Bemidji	7,039,948	\$975,736
4	Rugby Wind Interconnection	394,399	\$26,613
5	Casselton – Buffalo 115 kV Project	13,509,407	\$2,743,099
6	CAPX 2020: Brookings - Hampton	26,322,129	\$2,114,671
7	MVP: Big Stone Area Transmission	73,597,018	\$565,385
8	Ramsey 230/115 kW Transformer Upgrade	416,398	\$164,889
9	Karlstad, MN Capacitor Bank Project	1,103,974	\$437,161
10	Oakes Area Transmission Improvements	7,010,020	\$2,775,887
11	Hankinson Transformer Addition	828,844	\$328,213
12	NERC Compliance	14,078,440	\$5,574,900
13	Summit Transformer	853,991	\$338,171
14	Spiritwood Station Interconnection	720,137	\$285,166
15	Rugby Breaker Station	1,824,862	\$722,624
16	Granville Jct Breaker Station	1,015,655	\$402,188
17	Total Plant In Service	\$246,475,014	\$47,196,977
Source: Exhibit__(BCH-1), Schedule 2			

11

12

1 **Q. When does OTP propose to transfer the 16 projects out of the TCRR and**
2 **into base rates?**

3 A. OTP is proposing to transfer the 16 projects out of the TCRR and into base rates
4 when the final rates determined at the end of this case go into effect. In its
5 response to data request ND-MLEC-214, OTP stated that it is proposing that any
6 over/under collection remaining in the TCRR at the time the two projects are
7 rolled into base rates be recovered through the TCRR over the subsequent 12
8 months.

9
10 **Q. Has the Company provided information regarding its actual and projected**
11 **over/under recovered TCRR balances as well as actual and projected TCRR**
12 **revenue?**

13 A. Yes. In its response to data request ND-PSC-15.40, the Company provided
14 information regarding its actual and projected over/under recovered TCRR
15 balances as well as actual and projected TCRR revenue. Specifically, the table
16 below summarizes (1) the Company's actual monthly over/under recovered
17 TCRR balances and TCRR revenue for the period January 2016 through March
18 2018, and (2) the Company's actual monthly over/under recovered TCRR
19 balances and TCRR revenue for the period April 2018 through December 2018.
20 The Company anticipates that final rates in the current proceeding will be
21 effective as of October 1, 2018.

Date	Net Revenue Requirement*	Actual Billed Revenue	(Over)/Under
Actuals			
January 2016	\$ 699,540	\$ 973,403	\$ (273,863)
February 2016	\$ 646,344	\$ 912,173	\$ (265,829)
March 2016	\$ 612,028	\$ 845,906	\$ (233,878)
April 2016	\$ 580,292	\$ 769,063	\$ (188,771)
May 2016	\$ 866,078	\$ 674,565	\$ 191,513
June 2016	\$ 473,260	\$ 678,025	\$ (204,765)
July 2016	\$ 513,692	\$ 706,896	\$ (193,204)
August 2016	\$ 579,524	\$ 744,122	\$ (164,598)
September 2016	\$ 490,732	\$ 746,452	\$ (255,720)
October 2016	\$ 630,113	\$ 695,897	\$ (65,784)
November 2016	\$ 662,720	\$ 776,811	\$ (114,091)
December 2016	\$ 799,076	\$ 878,623	\$ (79,547)
January 2017	\$ 947,052	\$ 713,189	\$ 233,863
February 2017	\$ 971,246	\$ 663,351	\$ 307,895
March 2017	\$ 476,327	\$ 598,526	\$ (122,199)
April 2017	\$ 700,027	\$ 551,200	\$ 148,827
May 2017	\$ 604,594	\$ 476,867	\$ 127,727
June 2017	\$ 571,546	\$ 474,824	\$ 96,722
July 2017	\$ 630,097	\$ 481,209	\$ 148,888
August 2017	\$ 646,559	\$ 502,412	\$ 144,147
September 2017	\$ 630,060	\$ 498,794	\$ 131,266
October 2017	\$ 666,308	\$ 459,887	\$ 206,421
November 2017	\$ 897,306	\$ 580,165	\$ 317,141
December 2017	\$ 799,840	\$ 609,614	\$ 190,226
January 2018	\$ 655,061	\$ 865,720	\$ (210,659)
February 2018	\$ 1,579,695	\$ 806,154	\$ 773,541
March 2018	\$ 670,787	\$ 693,188	\$ (22,401)
Forecast			
April 2018	\$ 620,670	\$ 784,698	\$ (164,028)
May 2018	\$ 478,787	\$ 636,902	\$ (158,115)
June 2018	\$ 450,091	\$ 602,064	\$ (151,973)
July 2018	\$ 478,301	\$ 625,933	\$ (147,632)
August 2018	\$ 480,730	\$ 647,468	\$ (166,738)
September 2018	\$ 484,761	\$ 645,353	\$ (160,592)
October 2018**	\$ 219,994	\$ 625,380	\$ (405,386)
November 2018**	\$ 248,604	\$ 742,485	\$ (493,881)
December 2018**	\$ 324,662	\$ 836,546	\$ (511,884)
<p>* Revenue requirement includes projects and RTO revenue and expenses. Does not include carrying charge/credit. ** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.</p>			
Source: ND-PSC-15.40			

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Q. Has the Company provided information regarding its actual and projected TCRR costs?

A. Yes. In its response to data request ND-PSC-15.40, the Company provided information regarding its actual and projected TCRR costs. Specifically, the table below summarizes (1) the Company's actual monthly TCRR costs for the period January 2016 through March 2018, and (2) the Company's projected monthly TCRR costs for the period April 2018 through December 2018. The Company anticipates that final rates in the current proceeding will be effective as of October 1, 2018.

Date	Return on Rate Base	O&M Costs	Property Taxes	Depreciation	Interest	Income Taxes	Net MISO & SPP Rev/Exp	Wholesale Revenue Credit	Net Revenue Requirement*
Actuals									
January 2016	\$ 180,031	\$ 14,933	\$ 58,873	\$ 59,328	\$ 82,862	\$ 106,247	\$ 208,057	\$ (10,791)	\$ 699,540
February 2016	\$ 180,031	\$ 26,884	\$ 58,888	\$ 60,791	\$ 82,862	\$ 106,247	\$ 141,573	\$ (10,932)	\$ 646,344
March 2016	\$ 180,031	\$ 148	\$ 58,888	\$ 61,143	\$ 82,862	\$ 106,247	\$ 133,674	\$ (10,965)	\$ 612,028
April 2016	\$ 180,031	\$ 291	\$ 58,887	\$ 61,371	\$ 82,862	\$ 106,247	\$ 101,391	\$ (10,988)	\$ 580,092
May 2016	\$ 180,031	\$ 22,430	\$ 58,879	\$ 61,355	\$ 82,862	\$ 99,305	\$ 365,277	\$ (11,003)	\$ 859,136
June 2016	\$ 180,031	\$ 90	\$ 58,878	\$ 62,061	\$ 82,862	\$ 99,460	\$ (5,840)	\$ (11,068)	\$ 466,474
July 2016	\$ 180,031	\$ 7,829	\$ 58,878	\$ 62,184	\$ 82,862	\$ 106,427	\$ 26,745	\$ (11,084)	\$ 513,872
August 2016	\$ 180,031	\$ 603	\$ 58,878	\$ 62,282	\$ 82,862	\$ 106,427	\$ 99,716	\$ (11,095)	\$ 579,704
September 2016	\$ 180,031	\$ 14,131	\$ 58,878	\$ 62,401	\$ 82,862	\$ 106,427	\$ (2,714)	\$ (11,104)	\$ 490,912
October 2016	\$ 180,031	\$ 75	\$ 58,878	\$ 63,785	\$ 82,862	\$ 106,427	\$ 149,499	\$ (11,254)	\$ 630,303
November 2016	\$ 180,031	\$ 4,665	\$ 58,931	\$ 63,915	\$ 82,862	\$ 106,427	\$ 177,344	\$ (11,275)	\$ 662,900
December 2016	\$ 180,031	\$ 75	\$ 58,931	\$ 63,889	\$ 82,862	\$ 106,427	\$ 318,320	\$ (11,279)	\$ 799,256
January 2017	\$ 184,545	\$ 76	\$ 60,316	\$ 64,144	\$ 84,939	\$ 108,910	\$ 452,943	\$ (8,821)	\$ 947,052
February 2017	\$ 184,545	\$ 10,577	\$ 60,316	\$ 64,133	\$ 84,939	\$ 108,910	\$ 464,268	\$ (6,442)	\$ 971,246
March 2017	\$ 184,545	\$ 76	\$ 60,316	\$ 64,227	\$ 84,939	\$ 108,910	\$ (17,856)	\$ (8,830)	\$ 476,327
April 2017	\$ 184,545	\$ 75	\$ 60,316	\$ 64,229	\$ 84,939	\$ 108,910	\$ 205,849	\$ (8,836)	\$ 700,027
May 2017	\$ 184,545	\$ 2,155	\$ 60,316	\$ 64,263	\$ 84,939	\$ 108,920	\$ 110,645	\$ (11,179)	\$ 604,604
June 2017	\$ 184,545	\$ 75	\$ 60,316	\$ 64,259	\$ 84,939	\$ 108,916	\$ 77,341	\$ (8,839)	\$ 571,552
July 2017	\$ 184,545	\$ 863	\$ 60,316	\$ 64,274	\$ 84,939	\$ 108,910	\$ 135,090	\$ (8,840)	\$ 630,097
August 2017	\$ 184,545	\$ 1,612	\$ 60,316	\$ 65,793	\$ 84,939	\$ 108,910	\$ 149,397	\$ (8,953)	\$ 646,559
September 2017	\$ 184,545	\$ 75	\$ 60,316	\$ 65,816	\$ 84,939	\$ 108,910	\$ 134,411	\$ (8,952)	\$ 630,060
October 2017	\$ 184,545	\$ 75	\$ 60,317	\$ 66,480	\$ 84,939	\$ 108,910	\$ 169,995	\$ (8,953)	\$ 666,308
November 2017	\$ 184,545	\$ 633	\$ 60,317	\$ 66,492	\$ 84,939	\$ 108,910	\$ 400,425	\$ (8,955)	\$ 897,306
December 2017	\$ 184,545	\$ 215	\$ 60,317	\$ 68,420	\$ 84,939	\$ 108,910	\$ 301,469	\$ (8,975)	\$ 799,840
January 2018	\$ 162,196	\$ 1,328	\$ 59,551	\$ 65,646	\$ 76,794	\$ 52,363	\$ 256,049	\$ (18,866)	\$ 655,061
February 2018	\$ 162,196	\$ 1,675	\$ 59,551	\$ 65,643	\$ 76,794	\$ 52,363	\$ 1,180,338	\$ (18,865)	\$ 1,579,695
March 2018	\$ 162,196	\$ 202	\$ 59,551	\$ 65,649	\$ 76,794	\$ 52,363	\$ 272,897	\$ (18,865)	\$ 670,787
Forecast									
April 2018	\$ 162,196	\$ 88	\$ 59,551	\$ 65,640	\$ 76,794	\$ 52,363	\$ 222,904	\$ (18,866)	\$ 620,670
May 2018	\$ 162,196	\$ 88	\$ 59,551	\$ 65,682	\$ 76,794	\$ 52,363	\$ 80,986	\$ (18,873)	\$ 478,787
June 2018	\$ 162,196	\$ 5,688	\$ 59,551	\$ 65,723	\$ 76,794	\$ 52,363	\$ 46,658	\$ (18,882)	\$ 450,091
July 2018	\$ 162,196	\$ 88	\$ 59,551	\$ 65,763	\$ 76,794	\$ 52,363	\$ 80,434	\$ (18,888)	\$ 478,301
August 2018	\$ 162,196	\$ 88	\$ 59,551	\$ 65,804	\$ 76,794	\$ 52,363	\$ 82,829	\$ (18,895)	\$ 480,730
September 2018	\$ 162,196	\$ 5,688	\$ 59,551	\$ 65,845	\$ 76,794	\$ 52,363	\$ 81,228	\$ (18,904)	\$ 484,761
October 2018**	\$ 9,705	-	\$ 570	\$ 1,037	\$ 4,595	\$ 3,133	\$ 203,324	\$ (2,370)	\$ 219,994
November 2018**	\$ 9,705	-	\$ 570	\$ 2,505	\$ 4,595	\$ 3,133	\$ 230,740	\$ (2,644)	\$ 248,604
December 2018**	\$ 9,705	-	\$ 570	\$ 2,546	\$ 4,595	\$ 3,133	\$ 306,765	\$ (2,652)	\$ 324,662
* Revenue requirement includes projects and RTO revenue and expenses Does not include carrying charge/credit									
** Implementation of final rates Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider									
Source: ND-PSC-15 40									

- 1
- 2
- 3 **Q. Do you agree with the Company's proposal to transfer the costs of these 16**
- 4 **projects out of the TCRR and into base rates?**
- 5 **A. Conceptually, I agree with the Company's proposal to transfer the costs of the 16**
- 6 **projects out of the TCRR and into base rates at the conclusion of this rate case**
- 7 **provided that when the two projects are transferred into base rates from the**

1 TCRR at the conclusion of this proceeding, the amounts are updated to reflect
2 current plant balances at that time so as to minimize the impacts of the true-up
3 that will occur when the two projects are transferred from the TCRR into base
4 rates and that OTP demonstrates this by filing a compliance filing.

5

6 **C. Renewable Resource Adjustment Rider**

7 **Q. When was the RRAR established?**

8 A. The RRAR was established in Case No. PU-06-466 and went into effect on May
9 21, 2008. The RRAR allows public utilities to recover jurisdictional capital costs
10 and related operating expenses of certain renewable resource additions outside
11 of rate cases.

12

13 **Q. What capital projects is OTP proposing to transfer to base rates from the**
14 **RRAR?**

15 A. OTP is proposing to transfer three projects currently being recovered through the
16 RRAR to base rates, including (1) the Ashtabula Wind Project ("Ashtabula"), (2)
17 the Langdon Wind Project ("Langdon"), and (3) the Luverne Wind Project
18 ("Luverne").

19

20 **Q. Were any of these three wind projects to be included in base rates**
21 **pursuant to the Stipulation from the Company's last rate case in Case Nos.**
22 **PU-08-742 and PU-08-862?**

1 A. Yes. The Stipulation in OTP's last rate case, identified four issues that the
2 Company was to address in the current proceeding. As it relates to the RRAR,
3 page 8 of the Stipulation at Section II, subsection D states:

4 Wind Farm Cost Recovery - the Parties agree that in its next rate
5 case OTP shall propose including the Ashtabula and Langdon wind
6 farm costs in base rates.

7

8 **Q. Did the Company include projected RRAR revenues in the 2018 test year?**

9 A. Yes. On page 11 of his testimony, Mr. Haugen states that the 2018 test year
10 present revenue includes the projected 2018 RRAR revenues. Mr. Haugen
11 stated that, similar to the proposed treatment of the projects in the ECRR and
12 TCRR, transferring the projects from the RRAR to base rates is merely a change
13 in how the costs of the projects are recovered and that including the RRAR
14 revenue in 2018 test year present revenues provides a more accurate
15 measurement of the overall impact on ratepayers.

16

17 **Q. Does the Company's 2018 test year rate base include the three RRAR
18 projects listed above?**

19 A. Yes. On page 11 of his testimony, Mr. Haugen states that these investments are
20 part of the rate base used to determine the 2018 test year revenue requirement
21 in this proceeding.

22

23 **Q. What amounts associated with the three RRAR projects are reflected in the
24 2018 test year rate base?**

1 A. As discussed on page 11 of Mr. Haugen's testimony, the 2018 test year rate base
2 reflects a 13-month average balances totaling \$268.7 million on a total Company
3 basis and \$101.0 million on a North Dakota jurisdictional basis for the three
4 projects that OTP proposes be transferred from the RRAR and into base rates at
5 the conclusion of this proceeding. A breakout of the amounts by project is
6 summarized in the table below:

Description	Total Company Amount	North Dakota Jurisdictional Amount
RRAR Projects		
Langdon Wind Project	\$79,417,900	\$29,843,126
Ashtabula Wind Project	\$116,261,976	\$43,688,146
Luverne Wind Project	72,996,881	\$27,430,280
Total	\$268,676,757	\$100,961,553
Source: Exhibit (BCH-1), Schedule 2		

7

8 **Q. When does OTP propose to transfer the three projects out of the RRAR and**
9 **into base rates?**

10 A. OTP is proposing to transfer the three projects out of the RRAR and into base
11 rates when the final rates determined at the end of this case go into effect. In its
12 response to data request ND-MLEC-214, OTP stated that it is proposing that any
13 over/under collection remaining in the RRAR at the time the two projects are
14 rolled into base rates be recovered through the RRAR over the subsequent 12
15 months.

16

17 **Q. Has the Company provided information regarding its actual and projected**
18 **over/under recovered RRAR balances as well as actual and projected**
19 **RRAR revenue?**

1 A. Yes. In its response to data request ND-PSC-15.41, the Company provided
2 information regarding its actual and projected over/under recovered RRAR
3 balances as well as actual and projected RRAR revenue. Specifically, the table
4 below summarizes (1) the Company's actual monthly over/under recovered
5 RRAR balances and RRAR revenue for the period January 2016 through March
6 2018, and (2) the Company's projected monthly over/under recovered RRAR
7 balances and RRAR revenue for the period April 2018 through September 2018.
8 The Company did not provide projected RRAR costs for the period October
9 through December 2018 as OTP anticipates final rates in the current proceeding
10 will be effective as of October 1, 2018.

Date	Net Revenue Requirement*	Actual Billed Revenue	REC Sales	(Over)/Under
Actuals				
January 2016	\$ 744,774	\$ 516,648		\$ 228,126
February 2016	\$ 745,499	\$ 485,484		\$ 260,015
March 2016	\$ 674,947	\$ 449,057		\$ 225,890
April 2016	\$ 563,269	\$ 411,857		\$ 151,412
May 2016	\$ 620,627	\$ 354,330	\$ 60,333	\$ 205,964
June 2016	\$ 665,848	\$ 383,086		\$ 282,762
July 2016	\$ 758,056	\$ 745,371		\$ 12,685
August 2016	\$ 766,873	\$ 782,917		\$ (16,044)
September 2016	\$ 650,634	\$ 785,386		\$ (134,752)
October 2016	\$ 554,432	\$ 669,901		\$ (115,469)
November 2016	\$ 605,070	\$ 760,163	\$ 105,957	\$ (261,050)
December 2016	\$ 532,204	\$ 851,869		\$ (319,665)
January 2017	\$ 574,125	\$ 1,004,180		\$ (430,055)
February 2017	\$ 626,273	\$ 938,383		\$ (312,110)
March 2017	\$ 586,659	\$ 839,470		\$ (252,811)
April 2017	\$ 593,223	\$ 726,454		\$ (133,231)
May 2017	\$ 578,772	\$ 615,527	\$ 34,800	\$ (71,555)
June 2017	\$ 647,587	\$ 661,159		\$ (13,572)
July 2017	\$ 792,202	\$ 669,828		\$ 122,374
August 2017	\$ 820,720	\$ 700,559		\$ 120,161
September 2017	\$ 609,242	\$ 694,255		\$ (85,013)
October 2017	\$ 455,878	\$ 585,016		\$ (129,138)
November 2017	\$ 525,111	\$ 752,888		\$ (227,777)
December 2017	\$ 780,587	\$ 791,465		\$ (10,878)
January 2018	\$ 672,030	\$ 999,685		\$ (327,655)
February 2018	\$ 667,566	\$ 948,576		\$ (281,010)
March 2018	\$ 691,490	\$ 832,161		\$ (140,671)
Forecast				
April 2018	\$ 757,792	\$ 753,624		\$ 4,168
May 2018	\$ 681,705	\$ 685,258		\$ (3,553)
June 2018	\$ 739,787	\$ 732,116		\$ 7,671
July 2018	\$ 766,676	\$ 800,440		\$ (33,764)
August 2018	\$ 782,345	\$ 798,582		\$ (16,237)
September 2018	\$ 739,257	\$ 775,339		\$ (36,082)
October 2018**	-	-	-	-
November 2018**	-	-	-	-
December 2018**	-	-	-	-
* Revenue requirement does not include carrying charge/credit or REC sales ** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.				
Source: ND-PSC-15.41				

1 **Q. Has the Company provided information regarding its actual and projected**
2 **RRAR costs?**

3 A. Yes. In its response to data request ND-PSC-15.41, the Company provided
4 information regarding its actual and projected RRAR costs. Specifically, the table
5 below summarizes (1) the Company's actual monthly RRAR costs for the period
6 January 2016 through March 2018, and (2) the Company's projected monthly
7 RRAR costs for the period April 2018 through September 2018. The Company
8 did not provide projected RRAR costs for the period October through December
9 2018 as OTP anticipates final rates in the current proceeding will be effective as
10 of October 1, 2018.

Date	Net Income	O&M Costs	Depreciation	Property Taxes	Interest Expense	Income Taxes	PTCs	ITCs	Net Revenue Requirement*
Actuals									
January 2016	\$ 303,945	\$ 117,686	\$ 378,447	\$ 14,243	\$ 139,864	\$ 32,406	\$ (212,781)	\$ (29,035)	\$ 744,775
February 2016	\$ 303,945	\$ 109,097	\$ 378,447	\$ 14,243	\$ 139,864	\$ 35,927	\$ (206,988)	\$ (29,035)	\$ 745,500
March 2016	\$ 303,945	\$ 96,534	\$ 378,447	\$ 14,243	\$ 139,864	\$ 14,006	\$ (243,056)	\$ (29,035)	\$ 674,948
April 2016	\$ 303,945	\$ 116,402	\$ 378,447	\$ 14,243	\$ 139,864	\$ (35,721)	\$ (324,876)	\$ (29,035)	\$ 563,269
May 2016	\$ 283,981	\$ 90,871	\$ 361,760	\$ 13,615	\$ 133,697	\$ 4,636	\$ (240,178)	\$ (27,755)	\$ 620,627
June 2016	\$ 283,981	\$ 97,104	\$ 361,744	\$ 13,615	\$ 133,697	\$ 19,380	\$ (215,919)	\$ (27,755)	\$ 665,847
July 2016	\$ 283,981	\$ 105,970	\$ 361,715	\$ 13,615	\$ 133,697	\$ 50,896	\$ (164,062)	\$ (27,755)	\$ 758,057
August 2016	\$ 283,981	\$ 111,285	\$ 361,715	\$ 13,615	\$ 133,697	\$ 52,220	\$ (161,884)	\$ (27,755)	\$ 766,874
September 2016	\$ 283,981	\$ 107,773	\$ 361,715	\$ 13,615	\$ 133,697	\$ 9,607	\$ (231,999)	\$ (27,755)	\$ 650,634
October 2016	\$ 283,981	\$ 80,866	\$ 361,324	\$ 13,615	\$ 133,697	\$ (16,439)	\$ (274,856)	\$ (27,755)	\$ 554,433
November 2016	\$ 283,981	\$ 136,026	\$ 361,326	\$ 13,615	\$ 133,697	\$ (18,149)	\$ (277,670)	\$ (27,755)	\$ 605,071
December 2016	\$ 283,981	\$ 102,628	\$ 361,844	\$ 13,615	\$ 133,697	\$ (33,265)	\$ (302,541)	\$ (27,755)	\$ 532,204
January 2017	\$ 286,907	\$ 94,123	\$ 362,525	\$ 13,615	\$ 135,074	\$ (15,014)	\$ (275,350)	\$ (27,755)	\$ 574,125
February 2017	\$ 286,907	\$ 132,720	\$ 362,525	\$ 13,615	\$ 135,074	\$ (9,891)	\$ (266,921)	\$ (27,755)	\$ 626,274
March 2017	\$ 286,907	\$ 85,922	\$ 362,525	\$ 13,615	\$ 135,074	\$ (7,176)	\$ (262,454)	\$ (27,755)	\$ 586,658
April 2017	\$ 286,907	\$ 123,984	\$ 362,525	\$ 13,615	\$ 135,074	\$ (19,083)	\$ (282,044)	\$ (27,755)	\$ 593,223
May 2017	\$ 286,907	\$ 97,173	\$ 362,525	\$ 13,615	\$ 135,074	\$ (14,410)	\$ (274,357)	\$ (27,755)	\$ 578,772
June 2017	\$ 286,907	\$ 97,313	\$ 362,269	\$ 13,615	\$ 135,074	\$ 11,647	\$ (231,483)	\$ (27,755)	\$ 647,587
July 2017	\$ 286,907	\$ 116,846	\$ 362,269	\$ 13,615	\$ 135,074	\$ 58,930	\$ (153,683)	\$ (27,755)	\$ 792,203
August 2017	\$ 286,907	\$ 86,885	\$ 362,268	\$ 13,615	\$ 135,074	\$ 81,036	\$ (117,310)	\$ (27,755)	\$ 820,720
September 2017	\$ 286,907	\$ 101,665	\$ 362,273	\$ 13,615	\$ 135,074	\$ (4,495)	\$ (258,042)	\$ (27,755)	\$ 609,242
October 2017	\$ 286,907	\$ 102,554	\$ 362,273	\$ 13,615	\$ 135,074	\$ (62,805)	\$ (353,985)	\$ (27,755)	\$ 455,878
November 2017	\$ 286,907	\$ 108,744	\$ 362,165	\$ 13,615	\$ 135,074	\$ (38,933)	\$ (314,706)	\$ (27,755)	\$ 525,111
December 2017	\$ 286,907	\$ 116,718	\$ 362,345	\$ 13,615	\$ 135,074	\$ 54,558	\$ (160,876)	\$ (27,755)	\$ 780,586
January 2018	\$ 248,401	\$ 98,438	\$ 347,499	\$ 13,048	\$ 117,609	\$ 23,291	\$ (149,657)	\$ (26,600)	\$ 672,029
February 2018	\$ 248,401	\$ 90,109	\$ 347,499	\$ 13,048	\$ 117,609	\$ 24,234	\$ (146,735)	\$ (26,600)	\$ 667,565
March 2018	\$ 248,401	\$ 84,544	\$ 347,499	\$ 13,048	\$ 117,609	\$ 31,431	\$ (124,442)	\$ (26,600)	\$ 691,490
Forecast									
April 2018	\$ 248,401	\$ 162,928	\$ 347,499	\$ 13,048	\$ 117,609	\$ 28,482	\$ (130,769)	\$ (29,406)	\$ 757,792
May 2018	\$ 248,401	\$ 104,663	\$ 347,573	\$ 13,048	\$ 117,609	\$ 24,115	\$ (144,297)	\$ (29,406)	\$ 681,706
June 2018	\$ 248,401	\$ 101,901	\$ 347,573	\$ 13,048	\$ 117,609	\$ 38,964	\$ (98,302)	\$ (29,406)	\$ 739,788
July 2018	\$ 248,401	\$ 102,396	\$ 347,721	\$ 13,048	\$ 117,609	\$ 45,369	\$ (78,461)	\$ (29,406)	\$ 766,677
August 2018	\$ 248,401	\$ 112,100	\$ 347,721	\$ 13,048	\$ 117,609	\$ 46,825	\$ (73,952)	\$ (29,406)	\$ 782,346
September 2018	\$ 248,401	\$ 120,311	\$ 347,721	\$ 13,048	\$ 117,609	\$ 34,306	\$ (112,732)	\$ (29,406)	\$ 739,258
October 2018**	-	-	-	-	-	-	-	-	-
November 2018**	-	-	-	-	-	-	-	-	-
December 2018**	-	-	-	-	-	-	-	-	-

* Revenue requirement does not include carrying charge/credit or REC sales

** Implementation of final rates Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider

Source: ND-PSC-15 41

- 1
- 2
- 3 **Q. Do you agree with the Company's proposal to transfer the costs of these**
- 4 **three projects out of the RRAR and into base rates?**
- 5 **A. Conceptually, I agree with the Company's proposal to transfer the costs of the**
- 6 **three projects out of the RRAR and into base rates at the conclusion of this rate**
- 7 **case provided that when the three projects are transferred into base rates from**
- 8 **the RRAR at the conclusion of this proceeding, the amounts are updated to**

1 reflect current plant balances at that time so as to minimize the impacts of the
2 true-up that will occur when the two projects are transferred from the RRAR into
3 base rates and that OTP demonstrates this by filing a compliance filing. As
4 noted above, the Stipulation in OTP's last rate case included the provision that
5 OTP shall propose including the Ashtabula and Langdon wind farm costs in base
6 rates in its next rate case, which it has done in the current proceeding.

7
8 **IX. CUSTOMER INFORMATION SYSTEM**

9 **Q. Is OTP replacing its existing customer information system?**

10 A. Yes. As discussed on page 14 of the direct testimony of Company witness
11 Gerhardson, the Company is in the process of replacing its internally built
12 customer information system, which has been in service for over 30 years. Mr.
13 Gerhardson states that the capabilities of its existing system have limited OTP's
14 ability to implement complex rates and provide services expected from its
15 customers. As a result, the Company selected Cayenta Utilities as the vendor for
16 a new customer information system.

17
18 **Q. Please describe the new customer information system that OTP is in the
19 process of implementing.**

20 A. As discussed on pages 17-18 of the direct testimony of Company witness
21 Tommerdahl, the new customer information system, which the Company refers
22 to as "CISone", will provide many benefits once fully implemented. including the
23 ability to allow data to flow in real time as opposed to overnight batches and file

1 transfers, which is the process being used for the existing system. In addition,
2 Mr. Tommerdahl lists benefits that OTP believes that CISone will be able to
3 provide, which I have summarized below:

- 4 • Ease of new or updated rate implementation
- 5 • Customer Self Service ("CSS")
- 6 • Mobile Work Management ("MWM")
- 7 • A new system will be able to support future initiatives
- 8 • Less reliance on CIS programmers and technicians
- 9 • Improved Automation
- 10 • Elimination of reusing data fields
- 11 • Easier detection and correction of billing issues
- 12 • Advanced ad-hoc reporting
- 13 • More advanced "Checkout and Lock" features
- 14 • A more robust primary/secondary failover system
- 15 • Better ability to drive consistent business processes across all jurisdictions

16

17 **Q. Was the CISone project approved by OTP's Board of Directors?**

18 A. Yes. In response to ND-PSC-19.04, The Company provided OTP's Board of
19 Directors meeting minutes dated August 17, 2015 in which the CISone project
20 was discussed and approved.

21

22 **Q. When does OTP anticipate CISone will be placed into service?**

1 A. According to the response to data request ND-PSC-19.04, the current project
2 schedule indicates CISone being placed into service (i.e., "go live") at the end of
3 September 2018 with operations commencing on October 1, 2018. On page 19
4 of his direct testimony, Mr. Tommerdahl states that implementing CISone will
5 only occur after it has been thoroughly tested to ensure that customer billings
6 "will be accurately and correctly computed and accounted for."

7
8 **Q. What was the original approved budget for the CISone project?**

9 A. According to the response to ND-PSC-19.04, the original budget for the CISone
10 project was approximately \$16 million (in 2015 dollars). The components of the
11 project that comprise this amount are discussed in the aforementioned OTP
12 Board of Directors meeting minutes dated August 17, 2015 and summarized in
13 the table below:

Description	Amount
CISone Project Development Costs	\$ 620,000
CISone Project Development Costs - Forecasted Additional Spend	\$ 350,000
Conversion, Installation and Implementation of CISone Project (through 2018)	\$ 14,900,000
Total CISone Project Budget Per OTP Board of Directors Meeting Minutes	\$ 15,870,000

14 Source: ND-PSC-19.04, Attachment 2

15
16 **Q. Is the total amount indicated in the table above the amount that is reflected
17 in the 2018 test year?**

18 A. No. On page 17 of his direct testimony, Company witness Tommerdahl initially
19 stated that OTP's current estimated cost of the CISone system was \$15.8 million
20 on a total Company basis and \$6.5 million on a North Dakota jurisdictional basis.
21 However, on page 5 of his supplemental testimony, Mr. Tommerdahl states that

1 the amounts indicated in his direct testimony were incorrect and that the actual
2 total cost of the CISone project included in the 2018 test year is \$14.8 million on
3 a total Company basis and \$6.1 million on a North Dakota jurisdictional basis.
4 The \$14.8 million total Company amount is reflected on Company workpaper TY-
5 01 from the workpapers contained in Volume 4A from OTP's original filing.

6

7 **Q. Has OTP experienced any cost overruns on the CISone project?**

8 A. Not through March 2018. However, OTP indicated that the project could go over
9 budget for costs related to integration and testing. Specifically, the Company's
10 response to DR ND-PSC-19.04 states in part:

11 Through March 2018, \$11.851 million has been spent on the project.
12 The total amount spent on the project will depend on the duration
13 required to complete the integration of the Cayenta system with
14 OTP's original estimate associated with the time needed to complete
15 integration and testing. This is largely due to the archaic architecture
16 of the 30-year old legacy customer information system that is being
17 replaced. The current estimated cost to complete integration, testing
18 and post-go-live activities is an amount up to \$17,850,000. The
19 amount could be less depending on integration testing outcomes.

20

21 **Q. Has OTP included the CISone system in its 2018 test year rate base?**

22 A. Yes. OTP has included an adjustment to annualize the costs associated with the
23 CISone project in the 2018 test year rate base. Specifically, as discussed on
24 page 26 of Company witness Akerman's direct testimony, the Company's
25 adjustment to annualize the CISone project included: (1) an increase to
26 intangible plant in service in the amount of \$3,272,488; (2) an increase to
27 intangible accumulated depreciation in the amount of \$557,102, which results in

1 an increase to intangible net plant in service in the amount of \$2,715,386. These
2 adjustments are shown on Exhibit__(TAA-1), Schedules 5B and 7.

3

4 **Q. Has OTP reflected the corresponding impacts of the CISone project to its**
5 **2018 test year operating income?**

6 A. Yes. OTP has reflected the corresponding impacts of the CISone project to its
7 2018 test year operating income. Specifically, as discussed on page 39 of Mr.
8 Akerman's direct testimony, the Company adjustment to operating income
9 increases depreciation expense by \$709,039 and decreases income tax expense
10 by \$268,027 resulting in net decrease to operating income of \$441,012. This
11 adjustment is shown on Exhibit__(TAA-1), Schedule 10.

12

13 **Q. Do the Company's adjustments to annualize the costs associated with the**
14 **CISone project tie back to the \$14.8 million amount discussed on page 5 of**
15 **Mr. Tommerdahl's supplemental testimony?**

16 A. Yes. OTP workpaper TY-01 from Volume 4A (pages 55-57) from the Company's
17 original filing shows that the Company's adjustments to annualize the costs
18 associated with the CISone project were derived from the \$14.8 million total
19 Company amount discussed on page 5 of Mr. Tommerdahl's supplemental
20 testimony.

21

22 **Q. Does the Company anticipate any cost savings associated with the CISone**
23 **project, and if so, are such savings reflected in the 2018 test year?**

1 A. OTP has not reflected any anticipated cost savings associated with the CISone
2 project in the 2018 test year. In its response to ND-PSC-19.04, OTP stated in
3 part:

4 OTP does not anticipate immediate cost savings from the system. In
5 the future we anticipate that the automation of many of the functions
6 by the new system will result in time savings over manual processes
7 that exist today. However, the system will add tasks for functions
8 that the current 30-year old legacy system cannot perform today.
9 Rather than drive cost savings, the CISone project is intended to
10 provide a modern platform for services and conveniences that
11 customers have grown to expect from their service providers. For
12 example, in the future, customers will realize more options with rates,
13 as the system is capable of interfacing with future automated meter
14 infrastructure (AMI). The system will also provide a platform for an
15 outage management system (OMS) to assist with outage information
16 and restoration times.

17 OTP has not yet seen the impacts of any cost changes with the
18 implementation of Cayenta Utilities. As described above, it is
19 expected that future technology projects, that are made possible by
20 adding the CISone platform, will give OTP the ability to drive
21 organizational change and subsequently provide efficiencies that
22 don't exist today.

23

24 **Q. What is the anticipated useful life of the CISone project?**

25 A. According to the response to ND-PSC-19.04, the anticipated useful life for the
26 CISone project is 10 years.

27

28 **Q. Are you recommending any adjustments related to the CISone project?**

29 A. No. I am not recommending any adjustments related to the CISone project at
30 this time.

31

1 **Q. Are you recommending any reporting requirements related to the CISone**
2 **project going into service, which is currently projected by OTP to be by the**
3 **end of September 2018?**

4 A. Yes. I recommend that OTP be required to report to Staff and the Commission
5 on the actual cost of the CISone project when it is placed into service, and to
6 explain the reasons for any actual costs that are different than the \$14.8 million
7 amount (on a total Company basis) that OTP has used as the basis for its 2018
8 rate base and operating expenses related to CISone.

9
10 **X. ISSUES CARRIED OVER FROM LAST RATE CASE**

11 **Q. Were there certain issues identified in the Settlement reached between the**
12 **parties in OTP's last rate case in Case Nos. PU-08-742 and PU-08-862 that**
13 **are to be addressed by the Company in the current proceeding?**

14 A. Yes. There were certain issues identified in the Settlement reached between the
15 parties in OTP's last rate case in Case Nos. PU-08-742 and PU-08-862 that are
16 to be addressed by the Company in the current proceeding. Specifically, page 8
17 of the Stipulation in OTP's last rate case, identified the following four issues that
18 the Company is addressing in the current proceeding:

- 19
- 20 • **Benefits from Renewable Energy Credits** - The Parties agree that in
21 future rate cases OTP will credit the North Dakota jurisdiction with its
22 proportionate share of the value from Renewable Energy Credits (RECs)
23 based on the North Dakota allocated share of the costs of the assets used
24 to produce the RECs.
 - 25 • **Energy Costs Separate from Base Rates** - The Parties agree that in its
26 next rate case OTP will separate its energy costs from base rates. It is
27 understood that this will give the appearance of much larger rate

1 increases in future rate cases than is reflected in the overall change in
2 customer bills.
3

- 4 • **Use of an E8760 Allocator** - The Parties agree that OTP should use an
5 E8760 allocator in its next rate case for class cost of service study
6 development purposes, and for the purpose of allocating fuel costs
7 between classes.
8

- 9 • **Wind Farm Cost Recovery** - The Parties agree that in its next rate case
10 OTP shall propose including the Ashtabula and Langdon wind farm costs
11 in base rates.
12

13 **Q. Are you addressing these issues in your testimony?**

14 A. I am addressing the first, second and fourth bullet points noted above in my
15 testimony. Staff witness Dismukes addresses the use of an E8760 Allocator in
16 the class cost of service.
17

18 **A. Renewable Energy Credits**

19 **Q. Does OTP maintain an inventory of Renewable Energy Credits ("RECs")?**

20 A. Yes. In its response to data request ND-PSC-15.45, OTP stated that it primarily
21 generates wind RECs which are tracked through the Midwest Renewable Energy
22 Tracking System ("M-RETS") and that it allocates RECs to each of its
23 jurisdictions (Minnesota, North Dakota and South Dakota) based on a monthly
24 load-ratio calculation. In addition, the Company maintains its North Dakota
25 allocated RECs through the Renewable Resource Adjustment Rider.
26

27 **Q. Has OTP been crediting its North Dakota jurisdiction with its proportionate**
28 **share of the value of RECs based on the North Dakota share of the costs of**

1 **the assets pursuant to the Stipulation from Case Nos. PU-08-862 and PU-**
2 **08-742?**

3 A. Yes, but apparently only from April 2016 and forward. Specifically, in its
4 response to data request ND-PSC-15.46, which asked OTP whether it retired
5 any RECs between January 2015 and March 2018, the Company stated:

6 In April 2016, Otter Tail retired 176,948 RECs in the Midwest
7 Renewable Energy Tracking System to demonstrate compliance with
8 the ND Renewable Energy Objective for the year 2015 (10% of ND
9 retail load). The retired RECs were wind RECs generated in the
10 year 2014 and prior. Upon the direction of the ND PSC, Otter Tail
11 has not retired any ND allocated RECs since April 2016. Rather,
12 Otter Tail has sold ND allocated RECs and returned the proceeds to
13 ND customers.

14

15 In addition, in its response to data request ND-PSC-15.45, the Company stated
16 that it sells its North Dakota allocated RECs and returns the proceeds to its North
17 Dakota customers in accordance with the expectations of the Commission and
18 that it sells RECs once or twice a year.

19

20 **Q. Does OTP purchase RECs?**

21 A. No. According to the response to ND-PSC-15.45, OTP does not purchase
22 RECs, but rather it generates them, but that it does not allocate any costs to the
23 RECs it generates nor does it allocate costs to RECs sold.

24

25 **Q. Has OTP provided a schedule which shows the North Dakota allocated**
26 **RECs it has sold and the proceeds it has credited to its North Dakota**
27 **customers?**

1 A. Yes. In its response to data request ND-PSC-15.45, OTP provided a schedule,
 2 which I have replicated below, that shows the North Dakota allocated RECs it
 3 has sold and the proceeds it has credited to its North Dakota customers.

Date	REC Inventory North Dakota Allocation	RECs Generated North Dakota Allocation	RECs Sold North Dakota Allocation	REC Proceeds North Dakota Allocation
January 2015	0	35,994		
February 2015	35,994	28,307		
March 2015	64,301	37,608		
April 2015	101,909	33,377		
May 2015	135,286	27,661		
June 2015	162,947	16,454		
July 2015	179,401	20,220		
August 2015	199,621	17,536		
September 2015	217,157	22,127		
October 2015	239,284	29,977		
November 2015	269,261	27,017		
December 2015	296,278	24,133		
January 2016	320,411	25,302		
February 2016	345,713	23,064		
March 2016	368,777	27,242		
April 2016	396,019	35,049		
May 2016	431,068	23,774	320,381	\$ 104,957
June 2016	134,461	23,319		
July 2016	157,780	17,571		
August 2016	175,351	17,147		
September 2016	192,498	25,491		
October 2016	217,989	29,038		
November 2016	247,027	31,386	197,926	\$ 166,372
December 2016	80,487	34,837		
January 2017	115,324	32,832		
February 2017	148,156	31,345		
March 2017	179,501	29,219		
April 2017	208,720	25,307		
May 2017	234,027	26,975	115,296	\$ 69,178
June 2017	145,706	22,242		
July 2017	167,948	15,269		
August 2017	183,217	12,533		
September 2017	195,750	25,034		
October 2017	220,784	34,659		
November 2017	255,443	32,840		
December 2017	288,283	33,863		
Total RECs Sold and Related Proceeds			633,603	\$ 340,507
Source: ND-PSC-15.45				

1 As shown in the table, OTP sold 633,603 RECs in May and November of 2016
2 and in May 2017 with proceeds credited to North Dakota customers totaling
3 \$340,507.

4

5 **Q. What is your conclusion regarding whether OTP is crediting its North**
6 **Dakota customers with its proportionate share of the value of the RECs it**
7 **sells pursuant the Stipulation from OTP's last rate case in Case Nos. PU-08-**
8 **862 and PU-08-742?**

9 A. Based on the information I reviewed, it appears that OTP is crediting its North
10 Dakota customers with its proportionate share of the value of the RECs it sells
11 pursuant to the Stipulation from OTP's last rate case in Case Nos. PU-08-862
12 and PU-08-742.

13

14 **B. Separating Energy Costs from Base Rates**

15 **Q. Pursuant to the Stipulation from Case Nos. PU-08-862 and PU-08-742, has**
16 **OTP addressed separating its energy costs from base rates in the current**
17 **proceeding?**

18 A. Yes. As discussed on page 2 of his direct testimony, Company witness
19 Gerhardson states that in compliance with the Commission's Order in Case Nos.
20 PU-08-862 and PU-08-742, the Company is proposing to transfer fuel and
21 purchase power costs totaling \$50.728 million on a North Dakota jurisdictional
22 basis that is currently being recovered in base rates to the Energy Adjustment

1 Rider⁹ ("EAR"), which while reducing the base rate revenue, requirement will
2 increase the EAR revenue requirement by a like amount. On page 2 of his
3 testimony, Mr. Gerhardson states that: "This transition to fuel revenue recovery is
4 merely a change to how these fuel costs are recovered, and OTP's overall
5 revenues will not change as a result of this proposal."
6

7 **Q. How does OTP propose to transfer recovery of its fuel and purchase power
8 costs into the EAR?**

9 A. As discussed on pages 24-25 of the direct testimony of Company witness
10 Tommerdahl, the Company's current base rates include a base cost of fuel that
11 was established at the conclusion of its last rate case in Case Nos. PU-08-862
12 and PU-08-742. The Company is proposing that at the conclusion of the current
13 proceeding, that base fuel cost be removed from the new base rates and all
14 eligible costs be recovered through the EAR. The current base cost of fuel is
15 \$0.02803 per kWh and is part of current base rates and which amounts to the
16 \$50.728 million amount referenced above. Mr. Tommerdahl states that under the
17 Company's proposed rates, base rates would decrease by the \$50.728 million
18 and recovery under the EAR would increase by the same amount.
19

20 **Q. Did the Company calculate a new base cost of energy for the interim rate
21 period?**

22 A. Yes. As discussed on page 25 of Mr. Tommerdahl's direct testimony, the
23 Company calculated a base cost of energy of \$0.024327 per kWh that is based

⁹ OTP also refers to the Energy Adjustment Rider as the Fuel Clause Adjustment ("FCA").

1 on energy costs totaling \$118.245 million and energy retail sales of 4.861 billion
2 kWh.¹⁰ OTP proposes that the \$0.024327 per kWh base cost of energy would be
3 used when interim rates go into effect and the monthly fuel clause will be based
4 on this rate during the interim period.

5
6 **Q. Is OTP proposing that the \$0.024327 per kWh base cost of energy that was**
7 **developed for the interim period be used when all of the Company's fuel**
8 **and purchase power costs are transferred to the EAR at the conclusion of**
9 **this proceeding?**

10 A. No. On page 25 of his testimony, Mr. Tommerdahl states that OTP anticipates
11 calculating a new base cost of energy, which will be incorporated into the new
12 monthly EAR rates at the conclusion of this case and that the EAR will include
13 the base cost of energy as well as any amounts needed to true-up actual fuel
14 costs to the base cost of energy. In addition, the Company proposes to continue
15 calculating the monthly fuel clause based on a trailing four-month average as it
16 has it as done previously. Mr. Tommerdahl states that the only difference going
17 forward will be that the entire cost of fuel will be included in the EAR. Historically,
18 the base cost of fuel has been included in base rates and the difference between
19 the current month's rate and the base cost of fuel has been included in the fuel
20 clause adjustor.

21
22 **Q. What fuel and purchase power costs does OTP propose to transfer into the**
23 **EAR?**

¹⁰ See Volume 1, Part E, Schedule 1 from OTP's Interim Rate Petition.

- 1 A. The Company provided this information in Attachment 1 to its corrected response
 2 to data request ND-PSC-15.42, which I have replicated in the following table:

Components of Company's Base Cost of Energy - 2018 Interim Test Year						
FERC Acct.	Description	Purchased Power	Generation Costs	MISO Schedules 16 & 17	Reagent & Emissions Allowances	Total
447	Net Ancillary Services Market Revenue/Expenses	\$ 98,147				
501	Steam Power Generation - Fuel - Coyote-Lignite		\$ 21,745,748			
501	Steam Power Generation - Fuel - Coyote-Oil		\$ 294,766			
501	Steam Power Generation - Fuel - Big Stone-Subbituminous		\$ 24,654,643			
501	Steam Power Generation - Fuel -Big Stone-oil		\$ 257,985			
501	Steam Power Generation - Fuel - Hoot Lake-Subbituminous		\$ 6,786,500			
501	Steam Power Generation - Hoot Lake-Oil		\$ 30,590			
502	Steam Power Generation - Steam Expenses				\$ -	
509	Steam Power Generation - Allowances				\$ -	
547	Other Power Generation - Fuel - Jamestown CT					
547	Other Power Generation - Fuel - Lake Preston CT					
547	Other Power Generation - Fuel - Solway CT -LM6000		\$ 301,429			
501 or 547	Fuel Costs for Intersystem Sales		\$ (103,690)			
555	Purchased Power for System Use	\$ 46,732,600				
555	Other Energy Purchaes	\$ 16,589,327				
555	Schedule 16			\$ 21,830		
555	Schedule 17			\$ 627,783		
	TOTALS	\$ 63,420,074	\$ 53,967,971	\$ 649,613	\$ -	\$ 118,037,658

3 Source: OTP response to DR ND-PSC-15.42

4 As shown in the table above, in addition to its fuel and purchase power costs,
 5 OTP also proposes to include Net Ancillary Services Market Revenue/Expenses
 6 and Fuel Costs for Intersystem Sales, which are shown as a credit against
 7 Generation Costs in the EAR.

8
 9 **Q. Does OTP propose to include the costs associated with environmental
 10 reagents and emission allowances in the EAR?**

11 A. Yes. OTP proposes to include the costs associated with environmental reagents
 12 and emission allowances in the EAR. Specifically, in its response to data
 13 request ND-PSC-15.42, the Company stated in part:

14 For administrative efficiency, OTP proposes to include the cost of
 15 reagents and emission allowances, which are currently being
 16 recovered under the separate Reagents and Emissions Allowance
 17 Adjustment (REAA) Rider as detailed in Electric Rate Schedule

1 13.08, into the Energy Adjustment Rider. The REAA is computed
2 using the exact same mechanism as the Energy Adjustment Rider
3 and so the consolidation of these costs from two identical recovery
4 mechanisms to one will have no bill impact.

5
6 In addition, as discussed on pages 5-6 of Mr. Tommerdahl's supplemental direct
7 testimony, OTP is also proposing that the pebble lime reagent costs at the
8 Coyote Station also be transferred out of base rates and recovered through the
9 EAR.

10
11 **Q. Based on the foregoing, in your opinion, does OTP's proposed**
12 **methodology for transferring all of its fuel and purchase power costs from**
13 **base rates in to the EAR comply with the provision stated Section II,**
14 **subsection B, page 8 of the Stipulation in Case Nos. PU-08-862 and PU-08-**
15 **742 whereby OTP is to separate energy costs from base rates?**

16 **A.** Yes. The Company's proposed methodology for transferring all of its fuel and
17 purchase power costs from base rates to the EAR appears to be reasonable and
18 complies with the provision in Section II, subsection B of the Stipulation in Case
19 Nos. PU-08-862 and PU-08-742. In addition, Staff is agreeable to OTP
20 transferring the recovery of costs associated with environmental reagents and
21 emission allowances out of base rates (and out of the REAA Rider) and into the
22 EAR at the conclusion of this case.

23

1 **C. Wind Farm Cost Recovery**

2 **Q. Pursuant to the Stipulation from Case Nos. PU-08-862 and PU-08-742, has**
3 **OTP addressed including the Ashtabula and Langdon wind farm costs in**
4 **base rates?**

5 A. Yes. As discussed in more detail in Section VIII - C of my testimony, OTP is
6 proposing to move the Ashtabula and Langdon wind farms from the RRAR and
7 into base rates at the conclusion of this case.¹¹

8
9 **Q. In your opinion, does OTP's proposal for transferring the Astabula and**
10 **Langdon Wind Farms from the RRAR and into base rates comply with the**
11 **provision stated in Section II, subsection D, page 8 of the Stipulation in**
12 **Case Nos. PU-08-862 and PU-08-742?**

13 A. Yes. The Company's proposal for transferring the Astabula and Langdon Wind
14 Farms from the RRAR and into base rates complies with the provision in Section
15 II, subsection D of the Stipulation in Case Nos. PU-08-862 and PU-08-742.

16
17 **XI. CAPITAL EXPENDITURES**

18 **Q. Is there a potential issue with the level of capital expenditures included in OTP's**
19 **2018 test year rate base. A. Yes. There is a potential issue with the level of**
20 **capital expenditures included as plant additions in OTP's 2018 test year rate**
21 **base. Specifically, on page 6 of his direct testimony, Company witness**
22 **Gerhardson states that the Company expects to invest an additional \$821 million**

¹¹ OTP is also proposing moving the Luverne Wind Project out of the RRAR and into base rates at the conclusion of this case.

1 on a total Company basis between 2017 and 2021. Pursuant to Mr.
2 Gerhardson's statement, data request ND-PSC-15.34 asked the following:

3 Capital Additions. Refer to the direct testimony of Company witness
4 Bruce Gerhardson. On page 6 of his testimony, Mr. Gerhardson
5 states that OTP expects to have capital expenditures of \$821 million
6 on a total Company basis between 2017 and 2021.

7 a. Of the \$821 million of expected capital expenditures between
8 2017-2021, please quantify and explain the amount of capital
9 expenditures included in the Company's 2018 test year filing.

10 b. Provide a breakout by plant account, amount, and expected
11 in-service date of the capital expenditures included in the
12 Company's 2018 test year filing.

13

14 In its response to DR ND-PSC-15.34, OTP provided Attachment 1, which listed
15 numerous capital additions by functional classification that totaled \$172.72 million
16 on a total Company basis.

17

18 **Q. Do all of the estimated in-service dates for the capital expenditures listed**
19 **on Attachment 1 fall within the 2018 test year?**

20 A. No. Upon reviewing Attachment 1, I noted that nearly three dozen of the capital
21 projects listed have an in-service date that is beyond the 2018 test year. In fact,
22 some of the capital projects have estimated in-service dates as far out as 2023.

23

24 **Q. Are the capital projects with estimated in-service dates that are beyond the**
25 **2018 test year included in OTP's 2018 test year rate base?**

26 A. It is unclear from the response to DR ND-PSC-15.34 whether the capital projects
27 with estimated in-service dates that are beyond the 2018 test year are included in
28 OTP's 2018 test year rate base. Staff informally requested that OTP clarify its

1 response to DR ND-PSC-15.34 to indicate whether the capital projects with
2 estimated in-service dates beyond 2018 are included in its 2018 test year rate
3 base. As of the morning of May 17, 2018, the day before my direct testimony is
4 being filed, Staff had not received a response from the Company regarding this
5 issue. Depending on the Company's response to Staff's informal inquiry, it may
6 be necessary to make an adjustment to remove some of the listed capital
7 projects with in-service dates beyond 2018 from OTP's 2018 test year rate base.

8

9 **Q. Does this conclude your testimony?**

10 A. Yes, it does.

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

**Otter Tail Power Company
2017 Electric Rate Increase
Application**

Case No. PU-17-398

VERIFICATION


STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

RALPH C. SMITH, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matter under his name, that they prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.



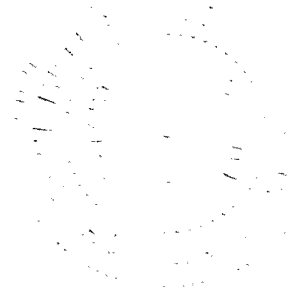
Ralph C. Smith, CPA

Subscribed and sworn to before me this 18th day of May, 2018.



Notary Public
My Commission Expires 11/8/2021

CHRISTINE MILLER
NOTARY PUBLIC, STATE OF MI
COUNTY OF WAYNE
MY COMMISSION EXPIRES Nov 8, 2021
ACTING IN COUNTY OF Wayne



Appendix A

QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA	
&76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA	
& 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001	
& ER-85647001	New England Power Company (FERC)
850782-EI &	
850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU	
& 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
T E-1032-88-102	Illinois Bell Telephone Company (Illinois CC)
89-0033	Puget Sound Power & Light Company (Washington UTC))
U-89-2688-T	Philadelphia Electric Company (Pennsylvania PUC)
R-891364	Potomac Electric Power Company (District of Columbia PSC)
F.C. 889	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
Case No. 88/546	
87-11628	Duquesne Light Company, et al, plaintiffs, against Gulf+Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
& U-1551-89-103	
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and	Intrastate Access Charge Methodology, Pool and Rates
TC-91-040B	Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS &	General Development Utilities - Port Malabar and
911-67-WS	West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314	
& M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 &	
U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC)
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 &	Citizens Utilities Company - Gas Division
U-1032-93-193	(Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/	Sale of Assets CC&N from Contel of the West, Inc. to
E-1032-93-169	Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation E-1032-95-473 E-1032-95-433	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission) Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC) Citizens Utility Co. - Arizona Electric Division (Arizona CC) Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285 94-10-45 A.96-08-001 et al.	Missouri Gas Energy (Missouri PSC) Southern New England Telephone Company (Connecticut PUC) California Utilities' Applications to Identify Sunk Costs of Non- Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324 96-08-070, et al.	Bell Atlantic - Delaware, Inc. (Delaware PSC) Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12 R-00973953	Connecticut Light & Power (Connecticut PUC) Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power & Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705 E-1072-97-067 Non-Docketed Staff Investigation PU-314-97-12 97-0351 97-8001	Entergy Gulf States, Inc. (Cities Steering Committee) Southwestern Telephone Co. (Arizona Corporation Commission) Delaware - Estimate Impact of Universal Services Issues (Delaware PSC) US West Communications, Inc. Cost Studies (North Dakota PSC) Consumer Illinois Water Company (Illinois CC) Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I 9355-U 97-12-020 - Phase I U-98-56, U-98-60, U-98-65, U-98-67 (U-99-66, U-99-65, U-99-56, U-99-52) Phase II of 97-SCCC-149-GIT PU-314-97-465 Non-docketed Assistance Contract Dispute	San Diego Gas & Electric Co., Section 386 costs (California PUC) Georgia Power Company Rate Case (Georgia PUC) Pacific Gas & Electric Company (California PUC) Investigation of 1998 Intrastate Access charge filings (Alaska PUC) Investigation of 1999 Intrastate Access Charge filing (Alaska PUC) Southwestern Bell Telephone Company Cost Studies (Kansas CC) US West Universal Service Cost Model (North Dakota PSC) Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC) City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL) Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC)
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No.	
98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No.	Post-Transition Ratemaking Mechanisms for the Electric Industry
99-01-016,	Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT- 1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT- 607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT- 060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)

Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA,	
06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
U-06-134	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208,	
R-2010-2166210,	
R-2010-2166212, &	
R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)

Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
Cause No. 43114-IGCC-11	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
E-04230A-14-0011 & E-01933A-14-0011	Reorganization of UNS Energy Corporation with Fortis, Inc. (Arizona CC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
U-14-002	Alaska Power Company (The Regulatory Commission of Alaska)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
Formal Case No. 1119	Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC (District of Columbia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)
Cause No. 43114-IGCC-12/13	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
14-1152-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
WS-01303A-14-0010	EPCOR Water Arizona, Inc. (Arizona CC)
2014-000396	Kentucky Power Company (Kentucky PSC)
15-03-45 [^]	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003	San Diego Gas & Electric Company (California PUC)
U-14-111	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)

2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)
PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
Docket No. 2015-0022	Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company Limited, and NextEra Energy, Inc. (Hawaii PUC)
15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-07-38 ^{^^}	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
15-26 ^{^^}	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Massachusetts DPU)
15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
2015-UN-0080	Mississippi Power Company (Mississippi PSC)
Docket No. 15-00042	B&W Pipeline, LLC (Tennessee Regulatory Authority)
WR-2015-0301/SR-2015-0302	Missouri American Water Company (Missouri PSC)
U-15-089, U-15-091, & U-15-092	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 16-00001	Kingsport Power Company d/b/a AEP Appalachian Power (Tennessee Regulatory Authority)
PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
P-15-014	PTE Pipeline LLC (Regulatory Commission of Alaska)
P-15-020	Swanson River Oil Pipeline, LLC (Regulatory Commission of Alaska)
Docket No. 40161	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
Formal Case No. 1137	Washington Gas Light Company (District of Columbia PSC)
160021-EI, et al.	Florida Power Company (Florida PSC)
R-2016-2537349	Metropolitan Edison Company (Pennsylvania PUC)
R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P	
(Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)
E-01345A-16-0036	Arizona Public Service Company (Arizona CC)
Docket No. 4618	Providence Water Supply Board (Rhode Island PUC)
Docket No. 46238	Joint Report and Application of Oncor Electric Delivery Company LLC and NextEra Energy Inc. (Texas State Office of Administrative Hearings; Texas PUC)
U-16-066	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Case No. 2016-00370	Kentucky Utilities Company (Kentucky PSC)
Case No. 2016-00371	Louisville Gas and Electric Company (Kentucky PSC)
P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142*	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322*	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034*	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
Case No. U-18248	DTE Electric Company (Michigan PSC)

Case No. 9449	Merger of AltaGas Ltd. and WGL Holdings (Maryland PSC)
Formal Case No. 1142	Merger of AltaGas Ltd. and WGL Holdings (District of Columbia PSC)
Case No. 2017-00179	Kentucky Power Company (Kentucky PSC)
Docket No. 29849	Georgia Power Plant Vogtle Units 3 and 4, VCM 17 (Georgia PSC)
Docket No. 2017-AD-112	Mississippi Power Company (Mississippi PSC)
Docket No. D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)

* Testimony filed, examination not completed

** Issues stipulated

*** Company withdrew case

^ Testimony filed, case withdrawn after proposed decision issued

^^ Issues stipulated before testimony was filed

Otter Tail Power Company
Case No. PU-17-398
Exhibit RCS-1

Accompanying the Direct Testimony of Ralph Smith

Number	Description	No. of Pages	Confidential	Exhibit Page No.
	Revenue Requirement Summary Schedules			
A	Calculation of Revenue Deficiency (Sufficiency)	2	No	2-3
A-1	Gross Revenue Conversion Factor	1	No	4
B	Adjusted Rate Base	1	No	5
B.1	Summary of Rate Base Adjustments	1	No	6
C	Adjusted Net Operating Income	1	No	7
C.1	Summary of Net Operating Income Adjustments	2	No	8-9
D	Capital Structure and Cost Rates	1	No	10
	Rate Base Adjustments			
B-1	Construction Work in Progress	1	No	11
B-2	Cash Working Capital	3	No	12-14
	Net Operating Income Adjustments			
C-1	Employee Gifts and Recognition Expense	1	No	15
C-2	Investor Relations Expense	1	No	16
C-3	Corporate Aircraft Expense	1	No	17
C-4	Payroll Expense	1	No	18
C-5	Incentive Compensation Expense	1	Yes	19
C-6	Stock-Based Compensation	1	No	20
C-7	Non-Employee Director Restricted Stock Grants	1	No	21
C-8	Payroll Taxes	1	No	22
C-9	Executive Survivor and Supplemental Retirement Plan	1	No	23
C-10	Rate Case Expense	1	No	24
C-11	Interest Synchronization	1	No	25
C-12	Deferred Income Tax Expense Adjustment for Excess Federal Accumulated Deferred Income Taxes Amortization	1	No	26
C-13	TCJA Related Revenue Requirement Savings in 2018 Before Rate Adjustments Occurred	1	No	27
	Total Pages (Including Contents Page)	27		

Otter Tail Power Company
Calculation of Revenue Deficiency (Sufficiency)

Exhibit RCS-1
Schedule A
Case No. PU-17-398
Page 1 of 2

Test Year Ending December 31, 2018

Line No.	Description	Reference	Per Company As Originally Filed (A)	Per Company Reflecting Supplemental & Tax Reform (B)	Per Staff (C)	Difference (D=C-B)
1	Adjusted Capitalization	Sch B	\$ 354,191,794	\$ 360,026,156	\$ 359,772,291	\$ (253,865)
2	Rate of return	Sch D	7.97%	7.92%	6.88%	
3	Net operating income required		\$ 28,229,086	\$ 28,514,072	\$ 24,752,334	\$ (3,761,738)
4	Adjusted net operating income	Sch C	\$ 18,454,394	\$ 21,173,697	\$ 24,076,943	\$ 2,903,246
5	Net operating income deficiency (Sufficiency)		\$ 9,774,692	\$ 7,340,375	\$ 675,391	\$ (6,664,984)
6	Gross revenue conversion factor	Sch A-1	1.607756	1.322837	1.322837	
7	Revenue deficiency (Sufficiency)		\$ 15,715,320	\$ 9,710,119	\$ 893,432	\$ (8,816,687)
8	Total Increase		\$ 15,715,320	\$ 9,710,119	\$ 893,432	\$ (8,816,687)
9	Adjusted operating revenues	Sch C	\$ 148,071,951	\$ 146,273,726	\$ 146,273,726	\$ -
10	Revenue requirement	Sch C	\$ 163,787,271	\$ 155,983,845	\$ 147,167,158	\$ (16,620,113)
11	Revenue increase, percent		10.61%	6.64%	0.61%	

Notes and Source

- Col. A: Exhibit (TAA-1), Schedule A-1 from the Company's filing
Col. B: Exhibit (TAA-2), Schedule 1 from the Company's March 23, 2018 supplemental filing
Col. C: See referenced schedules
Col. D: Col C - Col. B

Otter Tail Power Company
Revenue Requirement Reconciliation

Test Year Ending December 31, 2018

Exhibit RCS-1
Schedule A
Case No. PU-17-398
Page 2 of 2

Line No	Description	Exhibit RCS-1 Schedule Reference	Component	Staff Adjustments (A)	Staff Multiplier (B)	Staff Revenue Requirement Amount (C)
1		D	ROR Difference		-1.04%	
2	Jurisdictional Rate Base	A-1	GRCF		x 1.322837	
3	Rate Base per Otter Tail's Supplemental Filing	B		\$ 360,026,156	-1.376%	\$ (4,953,062)
4		D	Rate of Return		6.88%	
5	Effect of Staff Adjustments to Rate Base	A-1	GRCF		x 1.322837	
6	Construction Work in Progress	B-1		\$ (271,747)	9.10%	\$ (24,732)
7	Cash Working Capital	B-2		\$ 17,882	9.10%	\$ 1,627
8				\$ -	9.10%	\$ -
9	Total Staff Rate Base Adjustments			<u>\$ (253,865)</u>		
10	Staff Adjusted Rate Base	B		<u>\$ 359,772,291</u>		
11	Net Operating Income					
	Effect of Staff Adjustments on NOI					
12	Employee Gifts and Recognition Expense	C-1	Pre-Tax Operating Income Amount	\$ (31,695)	NOI Amount Sch C 1	Staff GRCF Sch A-1
13	Investor Relations Expense	C-2		\$ (83,574)	\$ 23,960	1.322837
14	Corporate Aircraft Expense	C-3		\$ 100,037	\$ 63,178	1.322837
15	Payroll Expense	C-4		\$ 1,331,830	\$ 75,623	1.322837
16	Incentive Compensation Expense	C-5		\$ 437,805	\$ 1,006,798	1.322837
17	Stock-Based Compensation	C-6		\$ 647,048	\$ 330,959	1.322837
18	Non-Employee Director Restricted Stock Grants	C-7		\$ 118,091	\$ 489,137	1.322837
19	Payroll Taxes	C-8		\$ 193,910	\$ 89,271	1.322837
20	Executive Survivor and Supplemental Retirement Plan	C-9		\$ 577,665	\$ 146,586	1.322837
21	Rate Case Expense	C-10		\$ 174,687	\$ 436,686	1.322837
22	Interest Synchronization	C-11		\$ -	\$ 132,055	1.322837
23	Deferred Income Tax Expense Adjustment for Excess Federal Accrual	C-12		\$ -	\$ (2,890)	1.322837
24	TCJA Related Revenue Requirement Savings in 2018 Before Rate	C-13		\$ -	\$ 111,883	1.322837
25	Total Staff Adjustments to Operating Income	C 1		<u>\$ 3,465,804</u>	\$ -	1.322837
26	Net Operating Income per Company Filing	C			\$ 2,903,246	
27	Staff Adjusted Net Operating Income	C			<u>\$ 21,173,697</u>	<u>\$ 24,076,943</u>
	Gross Revenue Conversion Factor Difference:					
28	Per Staff	A-1			1.322837	
29	Per Company Supplemental Filing	A-1			1.322837	
30	Difference				0.000000	
31	Company Adjusted NOI Deficiency	A			\$7,340,375	
32	GRCF Difference				\$ -	
33	Staff REVENUE REQUIREMENT ADJUSTMENTS ABOVE				\$ (8,816,687)	
34	Company Requested Base Rate Revenue Increase (Decrease)	A			\$ 9,710,119	
35	Reconciled Revenue Requirement				\$ 893,432	
36	Revenue Requirement Calculated on Schedule A	A			\$ 893,432	
37	Difference Not Accounted for Above	A			<u>\$ -</u>	

Notes and Source

Pre-tax return computed using Gross Revenue Conversion Factor

Test Year Ending December 31, 2018

Line No.	Description	Reference	Tax Rates	Per Company As Originally Filed (A)	Revised Tax Rates (B)	Per Company Reflecting Supplemental & Tax Reform (C)	Per Staff (D)
1	Operating Revenues			100.00%		100.00%	100.00%
2	Less: State Income Taxes		4.31%	4.31%	4.31%	4.31%	4.31%
3	Income Before Federal Income Taxes			95.69%		95.69%	95.69%
4	Less: Federal Income Taxes		35.00%	33.49%	21.00%	20.09%	20.09%
5	Operating Income Percentage			62.20%		75.60%	75.60%
6	Gross Revenue Conversion Factor	L1/L5		1.607756		1.322837	1.322837

Notes and Source

Col A: Exhibit (TAA-1), Schedule F-2 from the Company's filing

Components of Revenue Requirement Increase

	Percent (E)	Amount (F)
7	75.60%	\$ 675,391
8	20.09%	\$ 179,534
9	4.31%	\$ 38,507
10	100.00%	\$ 893,432
11		\$ 893,432

Total Revenue Increase per Schedule A

Calculation of Current Federal and State Income Tax Rate

	Per OTP Using 35% Federal Rate	Per OTP & Staff Using 21% Federal Rate
Federal Income Tax Rate	33.49%	20.09%
State Income Tax Rate	4.31%	4.31%
Combined Federal and State Income Tax Rate	37.80%	24.40%

Test Year Ending December 31, 2018

Line No.	Description	Company Proposed As Originally Filed (A)	Per Company Supplemental Filing Adjustments (B)	Per Company Supplemental Filing Adjustments for Tax Reform (C)	Company Proposed Reflecting Supplemental & Tax Reform (D)	Staff Adjustments (E)	Staff Proposed (F)
RATE BASE							
Electric Utility Plant							
1	Electric Plant in Service - Original Cost	\$ 758,395,144	\$ (82)		\$ 758,395,062	\$ -	\$ 758,395,062
2	Total Electric Utility Plant	\$ 758,395,144	\$ (82)	\$ -	\$ 758,395,062	\$ -	\$ 758,395,062
3	Accumulated Provision for Depreciation & Amortization	\$ (304,752,302)	\$ 278,578		\$ (304,473,724)	\$ -	\$ (304,473,724)
4	Net Electric Utility Plant	\$ 453,642,842	\$ 278,496	\$ -	\$ 453,921,338	\$ -	\$ 453,921,338
Other Rate Base Components:							
5	Plant Held for Future Use	\$ 13,044			\$ 13,044	\$ -	\$ 13,044
6	Construction Work in Progress	\$ 271,747			\$ 271,747	\$ (271,747)	\$ -
7	Materials & Supplies	\$ 8,275,549			\$ 8,275,549	\$ -	\$ 8,275,549
8	Fuel Stocks	\$ 4,430,805			\$ 4,430,805	\$ -	\$ 4,430,805
9	Prepayments	\$ (13,199,141)	\$ 7,216,241		\$ (5,982,900)	\$ -	\$ (5,982,900)
10	Customer Advances	\$ (365,882)	\$ (27)		\$ (365,909)	\$ -	\$ (365,909)
11	Cash Working Capital	\$ 3,602,273	\$ (37,689)	\$ (109,653)	\$ 3,454,931	\$ 17,882	\$ 3,472,813
12	Accumulated Deferred Income Taxes	\$ (102,479,443)	\$ (3,564,593)	\$ 2,051,587	\$ (103,992,449)	\$ -	\$ (103,992,449)
13	Total Other Rate Base Components	\$ (99,451,048)	\$ 3,613,932	\$ 1,941,934	\$ (93,895,182)	\$ (253,865)	\$ (94,149,047)
14	Total Rate Base	\$ 354,191,794	\$ 3,892,428	\$ 1,941,934	\$ 360,026,156	\$ (253,865)	\$ 359,772,291

Notes and Source

- Col. A: Amounts from Exhibit (TAA-1), Schedule B-1 of the Company's original filing
- Col. B: Amounts from Exhibit (TAA-2), Schedule 3 from the Company's supplemental filing
- Col. C: Amounts from Exhibit (TAA-2), Schedule 4 from the Company's supplemental filing
- Col. D: Col. A + Col. B + Col. C
- Col. E: See Schedule B-1

Line No.	Description	Staff Adjustments	Construction	
			Work in Progress B-1	Cash Working Capital B-2
Electric Utility Plant				
1	Electric Plant in Service - Original Cost	\$ -		
2	Total Electric Utility Plant	\$ -	\$ -	\$ -
3	Accumulated Provision for Depreciation & Amortization	\$ -		
4	Net Electric Utility Plant	\$ -	\$ -	\$ -
Other Rate Base Components:				
5	Plant Held for Future Use	\$ -		
6	Construction Work in Progress	\$ (271,747)	\$ (271,747)	
7	Materials & Supplies	\$ -		
8	Fuel Stocks	\$ -		
9	Prepayments	\$ -		
10	Customer Advances	\$ -		
11	Cash Working Capital	\$ 17,882		\$ 17,882
12	Accumulated Deferred Income Taxes	\$ -		
13	Total Other Rate Base Components	\$ (253,865)	\$ (271,747)	\$ 17,882
21	Total Rate Base	\$ (253,865)	\$ (271,747)	\$ 17,882

Notes and Source

See referenced schedule for each adjustment

Test Year Ending December 31, 2018

Line No.	Description	Company Proposed As Originally Filed (A)	Per Company Supplemental Filing Adjustments (B)	Per Company Supplemental Filing Adjustments for Tax Reform (C)	Company Proposed Supplemental & Tax Reform (D)	Staff Adjustments (E)	Per Staff (F)
Operating Revenue							
1	Retail Revenue	\$ 148,071,951	\$ (156,734)	\$ (1,641,491)	\$ 146,273,726	\$ -	\$ 146,273,726
2	Other Electric Operating Revenue	\$ 10,047,294	\$ 717		\$ 10,048,011	\$ -	\$ 10,048,011
3	Total Operating Revenues	\$ 158,119,245	\$ (156,017)	\$ (1,641,491)	\$ 156,321,737	\$ -	\$ 156,321,737
Operating Expenses							
4	Production Expenses	\$ 59,756,799	\$ (263,646)		\$ 59,493,153	\$ (305,698)	\$ 59,187,455
5	Transmission Expenses	\$ 13,507,453	\$ (117,874)		\$ 13,389,579	\$ (152,202)	\$ 13,237,377
6	Distribution Expenses	\$ 7,680,921	\$ (246,486)		\$ 7,434,435	\$ (277,390)	\$ 7,157,045
7	Customer Accounting Expenses	\$ 6,091,579	\$ (154,841)		\$ 5,936,738	\$ (204,216)	\$ 5,732,522
8	Customer Service and Information Expenses	\$ 1,382,509	\$ (8,784)		\$ 1,373,725	\$ (38,678)	\$ 1,335,047
9	Sales Expenses	\$ 222,472			\$ 222,472	\$ (6,330)	\$ 216,142
10	Administration and General Expenses	\$ 19,596,616	\$ (501,953)		\$ 19,094,663	\$ (2,516,580)	\$ 16,578,083
11	Charitable Contributions	\$ -			\$ -	\$ -	\$ -
12	Depreciation Expense	\$ 21,425,301	\$ (354,522)		\$ 21,070,779	\$ -	\$ 21,070,779
13	General Taxes	\$ 4,905,891	\$ 365		\$ 4,906,256	\$ (195,248)	\$ 4,711,008
14	Total Operating Expenses	\$ 134,569,541	\$ (1,647,741)	\$ -	\$ 132,921,800	\$ (3,696,342)	\$ 129,225,458
15	Net Electric Operating Income	\$ 23,549,704	\$ 1,491,724	\$ (1,641,491)	\$ 23,399,937	\$ 3,696,342	\$ 27,096,279
Income Tax Expense							
16	Investment Tax Credit	\$ (526,207)			\$ (526,207)	\$ -	\$ (526,207)
17	Deferred Income Taxes	\$ 1,317,383	\$ 67,699	\$ (2,750,449)	\$ (1,365,367)	\$ (111,883)	\$ (1,477,250)
18	Federal and State Income Taxes	\$ 4,304,134	\$ 526,152	\$ (712,472)	\$ 4,117,814	\$ 904,979	\$ 5,022,793
19	Total Income Tax Expense	\$ 5,095,310	\$ 593,851	\$ (3,462,921)	\$ 2,226,240	\$ 793,096	\$ 3,019,336
20	Net Operating Income	\$ 18,454,394	\$ 897,873	\$ 1,821,430	\$ 21,173,697	\$ 2,903,246	\$ 24,076,943
	Allowance for Funds Used During Construction	\$ -			\$ -	\$ -	\$ -
21	Total Available for Return	\$ 18,454,394	\$ 897,873	\$ 1,821,430	\$ 21,173,697	\$ 2,903,246	\$ 24,076,943

Notes and Source

- Col.A: Exhibit_(TAA-1), Schedule C-1 from the Company's original filing
- Col. B: Amounts from Exhibit_(TAA-2), Schedule 6 from the Company's supplemental filing
- Col. C: Amounts from Exhibit_(TAA-2), Schedule 7 from the Company's supplemental filing
- Col. D: Col. A + Col. B + Col. C
- Col. E: See Schedule C.1

Otter Tail Power Company
 Summary of Net Operating Income Adjustments

Exhibit RCS-1
 Schedule C.1
 Case No. PU-17-398
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Test Year Ending December 31, 2018

Line No.	Description	Staff Adjustments	Employee Gifts & Recognition Expense		Investor Relations Expense		Corporate Aircraft Expense		Payroll Expense		Incentive Compensation	
			C-1	C-2	C-3	C-4	C-5					
Operating Revenue												
1	Retail Revenue	\$ -										
2	Other Electric Operating Revenue	\$ -										
3	Total Operating Revenues	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Operating Expenses												
4	Production Expenses	\$ (305,698)										\$ (305,698)
5	Transmission Expenses	\$ (152,202)										\$ (152,202)
6	Distribution Expenses	\$ (277,390)										\$ (277,390)
7	Customer Accounting Expenses	\$ (204,216)										\$ (204,216)
8	Customer Service and Information Expenses	\$ (38,678)										\$ (38,678)
9	Sales Expenses	\$ (6,330)										\$ (6,330)
10	Administration and General Expenses	\$ (2,516,580)	\$ (82,236)	\$ (100,037)	\$ (31,695)	\$ (347,316)	\$ (437,805)					\$ (437,805)
11	Charitable Contributions	\$ -										
12	Depreciation Expense	\$ -										
13	General Taxes	\$ (195,248)	\$ (1,338)									
14	Pre-Tax Operating Expenses	\$ (3,696,342)	\$ (83,574)	\$ (100,037)	\$ (31,695)	\$ (1,331,830)	\$ (437,805)					\$ (437,805)
15	Pre-Tax Operating Income	\$ 3,696,342	\$ 83,574	\$ 100,037	\$ 31,695	\$ 1,331,830	\$ 437,805					\$ 437,805
16	Federal and State Income Taxes	\$ 904,979	\$ 20,396	\$ 24,414	\$ 7,735	\$ 325,032	\$ 106,846					\$ 106,846
17	Investment Tax Credit	\$ -										
18	Deferred Income Taxes	\$ (111,883)										
19	Total Income Tax Expense	\$ 793,096	\$ 20,396	\$ 24,414	\$ 7,735	\$ 325,032	\$ 106,846					\$ 106,846
20	Total Operating Expenses	\$ (2,903,246)	\$ (63,178)	\$ (75,623)	\$ (23,960)	\$ (1,006,798)	\$ (330,959)					\$ (330,959)
21	Net Operating Income	\$ 2,903,246	\$ 63,178	\$ 75,623	\$ 23,960	\$ 1,006,798	\$ 330,959					\$ 330,959
22	Allowance for Funds Used During Construction	\$ -										
23	Total Available for Return	\$ 2,903,246	\$ 63,178	\$ 75,623	\$ 23,960	\$ 1,006,798	\$ 330,959					\$ 330,959

Notes and Source

Line 19 Federal and State Income Tax Rate (using 21%) 24.40%

Otter Tail Power Company
 Summary of Net Operating Income Adjustments

Exhibit RCS-1
 Schedule C.1
 Case No. PU-17-398

Test Year Ending December 31, 2018

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Line No.	Description	Non-Employee Director Compensation		Payroll Tax Expense		Retirement Plan		Rate Case Expense		Interest Synchronization		Excess Federal Accumulated Deferred Income Taxes	
		C-6	C-7	C-8	C-9	C-10	C-11	C-12					
Operating Revenue													
1	Retail Revenue												
2	Other Electric Operating Revenue												
3	Total Operating Revenues	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Operating Expenses													
4	Production Expenses												
5	Transmission Expenses												
6	Distribution Expenses												
7	Customer Accounting Expenses												
8	Customer Service and Information Expenses												
9	Sales Expenses												
10	Administration and General Expenses												
11	Charitable Contributions												
12	Depreciation Expense												
13	General Taxes												
14	Pre-Tax Operating Expenses												
15	Pre-Tax Operating Income												
16	Federal and State Income Taxes												
17	Investment Tax Credit												
18	Deferred Income Taxes												
19	Total Income Tax Expense												
20	Total Operating Expenses												
21	Net Operating Income												
22	Allowance for Funds Used During Construction												
23	Total Available for Return												

Notes and Source
 Line 19 Federal and State Income Tax Rate (using 21%) 24.40%

Test Year Ending December 31, 2018

Line No.	Description	Amount (A)	Capital Structure Ratio (B)	Cost Rate (C)	Weighted Cost (D)
<u>I. Per Company as Originally Filed</u>					
1	Long Term Debt	\$ 492,672,120	46.01%	5.43%	2.50%
2	Short Term Debt	\$ 15,979,875	1.49%	4.02%	0.06%
3	Common Equity	\$ 562,251,832	52.50%	10.30%	5.41%
4	Total	<u>\$ 1,070,903,827</u>	<u>100.00%</u>		<u>7.97%</u>
<u>II. Per Company Supplemental & Tax Reform</u>					
5	Long Term Debt	\$ 493,131,053	45.86%	5.35%	2.45%
6	Short Term Debt	\$ 17,612,301	1.64%	3.84%	0.06%
7	Common Equity	\$ 564,530,097	52.50%	10.30%	5.41%
8	Total	<u>\$ 1,075,273,451</u>	<u>100.00%</u>		<u>7.92%</u>
<u>III. Per Staff</u>					
9	Long Term Debt	\$ 493,131,053	45.86%	5.35%	2.45%
10	Short Term Debt	\$ 17,612,301	1.64%	3.84%	0.06%
11	Common Equity	\$ 564,530,097	52.50%	8.31%	4.36%
12	Total	<u>\$ 1,075,273,451</u>	<u>100.00%</u>		<u>6.88%</u>
13	Difference		L.12 - L.8		-1.04%
14	Weighted Cost of Debt per Staff		Sum of Lines 9&10		<u>2.52%</u>

Notes

Lines 1-4: Exhibit__ (KGM-1), Schedule D-1 from OTP's filing
 Lines 5-8: Exhibit__ (KGM-2) - Updated Schedule 2 from OTP's Supplemental filing
 Lines 9-12: Cost rates and Return on Equity as recommended by Staff witness Aaron Rothchild

Line No.	Description	North Dakota Jurisdictional Amount	Reference
1	Adjustment to Remove Project 105245 - Winger Thief River Falls 230kV Line from CWIP	\$ <u>(271,747)</u>	A

Notes and Source

A: The response to ND-PSC-15.37 states that OTP's short-term CWIP should not have included Project 105245 - Winger Thief River Falls 230kV Line

Line No.	Description	NORTH DAKOTA JURISDICTION										TOTAL	
		Operating Expense		Staff Adjustments		Staff Adjusted		Expense/day at 365 day/year		Lead Days of 39.9		Net Revenue Lag Dollars	Net Revenue Lag Dollars
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)				
1	FUEL - COAL	\$ 19,990,895	\$ 19,990,895	\$ 54,770	15.5	24.4	\$ 1,335,830	\$ 4,081,316					
2	FUEL - OIL	\$ 21,698	\$ 21,698	\$ 59	11.2	28.7	\$ 1,705	\$ 5,403					
3	PURCHASED POWER	\$ 26,355,139	\$ 26,355,139	\$ 72,206	31.6	8.3	\$ 600,753	\$ 2,297,585					
4	LABOR AND ASSOC PAYROLL EXPENSE	\$ 2,286,135	\$ (1,331,830)	\$ 954,306	15.1	24.8	\$ 64,814	\$ 463,994					
5	ALL OTHER O&M EXPENSE	\$ 59,584,480	\$ (1,925,369)	\$ 57,659,111	13.1	26.8	\$ 4,234,501	\$ 13,153,685					
6	PROPERTY TAX (EXCL COAL CONV TAX)	\$ 4,665,439	\$ 4,665,439	\$ 12,782	299.5	(259.6)	\$ (3,317,757)	\$ (9,120,550)					
7	COAL CONVERSION TAXES	\$ 240,452	\$ 240,452	\$ 659	33.3	6.6	\$ 4,335	\$ 15,834					
8	FEDERAL INCOME TAXES	\$ 4,304,133	\$ 936,700	\$ 14,358	0.0	39.9	\$ 572,902	\$ 1,886,533					
9	STATE INCOME TAXES	-	-	-	0.0	39.9	-	\$ 229,009					
10	INCREMENTAL FEDERAL INCOME TAXES	-	-	-	0.0	39.9	-	-					
11	INCREMENTAL STATE INCOME TAXES	-	-	-	0.0	39.9	-	-					
12	BANK BALANCES	-	-	-	0.0	-	-	-					
13	SPECIAL DEPOSITS	-	-	-	0.0	-	-	-					
14	WORKING FUNDS	-	-	-	0.0	-	-	-					
15	TAX COLLECTIONS AVAILABLE	-	-	-	0.0	-	-	-					
16	FICA WITHHOLDING	\$ (1,964,003)	\$ (439,143)	\$ (6,584)	0.0	-	-	-					
17	FEDERAL WITHHOLDING	\$ (3,196,553)	\$ (3,196,553)	\$ (8,758)	0.0	-	-	-					
18	STATE WITHHOLDING- MN	-	-	-	1.9	-	-	\$ (9,942)					
19	STATE WITHHOLDING- ND	\$ (185,000)	\$ (185,000)	\$ (507)	69.1	-	\$ (34,998)	\$ (34,998)					
20	STATE SALES TAX	\$ (143)	\$ (143)	\$ (0)	23.8	-	\$ (9)	\$ (374,899)					
21	FRANCHISE TAXES	-	-	-	27.6	-	-	\$ (124,520)					
22	Total Cash Working Capital Requirement Per Staff	\$ 112,102,674	\$ (2,759,642)	\$ 109,343,032	\$ 299,570		\$ 3,472,813	\$ 12,498,212					
23	Total Cash Working Capital Requirement Per Company Supplemental Filing						\$ 3,454,931						
24	Staff Adjustment						\$ 17,882						

Line No	Description	Adjustment No	O&M Expense Adjustment (A)	Fuel (B)	Purchased Power (C)	Labor & Associated Labor Expense (D)	Property Taxes (E)	Payroll Taxes (F)	All Other O&M Expense (G)
1	Employee Gifts and Recognition Expense	C-1	\$ (31,695)						\$ (31,695)
2	Investor Relations Expense	C-2	\$ (83,574)					\$ (1,338)	\$ (82,236)
3	Corporate Aircraft Expense	C-3	\$ (100,037)						\$ (100,037)
4	Payroll Expense	C-4	\$ (1,331,830)			\$ (1,331,830)			
5	Incentive Compensation Expense	C-5	\$ (437,805)					\$ (437,805)	
6	Stock-Based Compensation	C-6	\$ (647,048)						\$ (647,048)
7	Non-Employee Director Restricted Stock Grants	C-7	\$ (118,091)						\$ (118,091)
8	Payroll Taxes	C-8	\$ (193,910)						\$ (193,910)
9	Executive Survivor and Supplemental Retirement Plan	C-9	\$ (577,665)						\$ (577,665)
10	Rate Case Expense	C-10	\$ (174,687)						\$ (174,687)
11	Interest Synchronization	C-11	\$ -						\$ -
12	Deferred Income Tax Expense Adjustment for Excess Federal Accumulated Deferred Income Taxes Amortization	C-12	\$ -						\$ -
13	TCJA Related Revenue Requirement Savings in 2018 Before Rate Adjustments Occurred	C-13	\$ -						\$ -
14									
15	TOTAL		\$ (3,696,342)	\$ -	\$ -	\$ (1,331,830)	\$ -	\$ (439,143)	\$ (1,925,369)
16	Total per Schedule C 1, line 14		\$ (3,696,342)						\$ (3,696,342)
17	Difference		\$ -						\$ -
18	Total Income Taxes from Schedule C 1		\$ 793,096						
19	Total operating expense adjustments (L17 +L20)		\$ (2,903,246)						
20	Total operating expense adjustments from Sch C 1, line 20		\$ (2,903,246)						
21	Difference		\$ -						\$ -

This worksheet shows how the Staff adjustments to operating expenses from Schedule C 1 are posted for CWC purposes

Line No.	Description	Amount (A)	Reference
Federal & State Income Taxes			
1	Per Company Filing - Cash Working Capital	\$ 4,304,133	Schedule B-3, Col.A, L8
2	Per Company Supplemental Filing Adjustments	\$ 526,152	Schedule C, Col. B, L18
3	Per Company Supplemental Filing Adjustments for Tax Reform	\$ (712,472)	Schedule C, Col. C, L18
4	Federal & State Income Taxes Per Company Supplemental Filing	\$ 4,117,813	
5	Staff Adjustments - at Current Rates	\$ 904,979	Schedule C.1, L16
6	Staff Rate Increase - Federal Income Taxes	\$ 179,534	Schedule A-1
7	Staff Rate Increase - State Income Taxes	\$ 38,507	Schedule A-1
8	Adjusted Current Federal & State Income Tax Expense	\$ 5,240,833	To Sch B-3, pg 1, Col. C, L8

Test Year Ending December 31, 2018

Line No.	Description	North Dakota Jurisdictional Amount (A)	Reference
1	Adjustment to Remove Employee Recognition and Gift Expenses	\$ (31,695)	A

Notes and Source

A: Amount from the response to ND-PSC-06.28 and calculated below:

Description	Amount
2 Employee Recognition Expense	\$ 19,349
3 Employee Gift Expense	\$ 12,346
4 Total Employee Recognition and Gift Expense	\$ 31,695

Test Year Ending December 31, 2018

Line No.	Description	Amount (A)	Reference
1	Adjustment to Remove 50% of Investor Relations Expense from O&M	\$ (82,236)	A
2	Adjustment to Remove 50% of Investor Relations Expense from Payroll Taxes	\$ (1,338)	
3	Total Adjustment to Investor Relations Expense	<u>\$ (83,574)</u>	

Notes and Source

A: Amount from the response to ND-PSC-06.27 and shown below:

Description	North Dakota Jurisdictional 2018 Test Year Amount	Disallowance Percentage	Staff Adjustment
4 Salaries	\$ 36,747	50%	\$ 18,373
5 Employee Insurance	\$ 4,248	50%	\$ 2,124
6 Employee Retirement Costs	\$ 4,377	50%	\$ 2,189
7 Other Contracted Services	\$ 49,810	50%	\$ 24,905
8 Intercompany Contracted Services	\$ 1,039	50%	\$ 519
9 Office Supplies	\$ 3,975	50%	\$ 1,987
10 Postage	\$ 23,007	50%	\$ 11,504
11 Dues & Subscriptions	\$ 36,887	50%	\$ 18,444
12 Meeting Expense	\$ 2,003	50%	\$ 1,001
13 Education & Training	\$ 250	50%	\$ 125
14 Advertising & Promotion	\$ 2,128	50%	\$ 1,064
15 Payroll Taxes	\$ 2,676	50%	\$ 1,338
16 Total	<u>\$ 164,472</u>		<u>\$ 83,574</u>

Otter Tail Power Company
Corporate Aircraft Expense
Test Year Ending December 31, 2018
Exhibit RCS-1
Schedule C-3
Case No. PU-17-398
Page 1 of 1

Line No.	Description	Amount (A)	Reference
1	Adjustment to Reduce Corporate Aircraft Expense	\$ (100,037)	A

Notes and Source

A: Amount derived from the response to ND-PSC-06.07 and calculated below:

Description	Amount
2 North Dakota Jurisdictional 2017 Aircraft Expense	\$ 133,374
3 Total 2017 Aircraft Expense	\$ 329,240
4 North Dakota Jurisdictional Allocation Factor	<u>40.5097%</u>
5 Allocation of 2017 Aircraft Expense from Otter Tail Corporation	\$ 246,945
6 North Dakota Jurisdictional Allocation Factor	<u>40.5097%</u>
7 North Dakota Jurisdictional Allocated Aircraft Expense	<u>\$ 100,037</u>

Line 4

Otter Tail Power Company
Payroll Expense

Exhibit RCS-1
Schedule C-4
Case No. PU-17-398
Page 1 of 1

Test Year Ending December 31, 2018

Line No.	FERC Account Description	OTP Total Company Amounts (A)	Staff Recommended Disallowance Percentage (B)	Staff Adjustment to Total Company Amounts (C)	Staff Adjusted Total Company Amounts (D)	North Dakota Jurisdictional Factor (E)	North Dakota Jurisdictional Amounts Per Staff (F)	North Dakota Jurisdictional Amounts Per OTP (G)	Staff Adjustment (H)
1	5000 Steam Power Generation - Operation supervision and engineering	\$ 2,254,223	-4.74%	\$ (106,771)	\$ 2,147,452	35.658308%	\$ 765,745	\$ 803,818	\$ (38,073)
2	5010 Steam Power Generation - Fuel	\$ 492,470	-4.74%	\$ (23,326)	\$ 469,144	35.658308%	\$ 167,289	\$ 175,607	\$ (8,318)
3	5020 Steam Power Generation - Steam expenses	\$ 1,848,987	-4.74%	\$ (87,577)	\$ 1,761,410	35.658308%	\$ 628,089	\$ 659,318	\$ (31,228)
4	5050 Steam Power Generation - Electric expenses	\$ 2,352,995	-4.74%	\$ (111,449)	\$ 2,241,546	35.658308%	\$ 799,297	\$ 839,038	\$ (39,741)
5	5060 Steam Power Generation - Miscellaneous steam power expenses	\$ 3,251,288	-4.74%	\$ (153,997)	\$ 3,097,291	35.658308%	\$ 1,104,441	\$ 1,159,354	\$ (54,913)
6	5100 Steam Power Generation - Maintenance supervision and engineering	\$ 1,007,245	-4.74%	\$ (47,708)	\$ 959,537	35.658308%	\$ 342,155	\$ 359,166	\$ (17,012)
7	5110 Steam Power Generation - Maintenance of structures	\$ 371,364	-4.74%	\$ (17,590)	\$ 353,774	35.658308%	\$ 126,150	\$ 132,422	\$ (6,272)
8	5120 Steam Power Generation - Maintenance of boiler plant	\$ 2,848,033	-4.74%	\$ (134,897)	\$ 2,713,136	35.658308%	\$ 967,458	\$ 1,015,560	\$ (48,102)
9	5130 Steam Power Generation - Maintenance of electric plant	\$ 501,257	-4.74%	\$ (23,742)	\$ 477,515	35.658308%	\$ 170,274	\$ 178,740	\$ (8,466)
10	5140 Steam Power Generation - Maintenance of miscellaneous steam plant	\$ 933,821	-4.74%	\$ (44,230)	\$ 889,591	35.658308%	\$ 317,213	\$ 332,985	\$ (15,772)
11	5350 Hydraulic Power Generation - Operation supervision and engineering	\$ 20,230	-4.74%	\$ (958)	\$ 19,272	35.658308%	\$ 6,872	\$ 7,214	\$ (342)
12	5370 Hydraulic Power Generation - Hydraulic Expenses	\$ 8,724	-4.74%	\$ (413)	\$ 8,311	35.658308%	\$ 2,963	\$ 3,111	\$ (147)
13	5380 Hydraulic Power Generation - Electric Expenses	\$ 92,821	-4.74%	\$ (4,396)	\$ 88,425	35.658308%	\$ 31,531	\$ 33,098	\$ (1,568)
14	5390 Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses	\$ 734	-4.74%	\$ (35)	\$ 699	35.658308%	\$ 249	\$ 262	\$ (12)
15	5410 Hydraulic Power Generation - Maintenance of electric plant	\$ 1,519	-4.74%	\$ (72)	\$ 1,447	35.658308%	\$ 516	\$ 542	\$ (26)
16	5430 Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	\$ 161,988	-4.74%	\$ (7,673)	\$ 154,315	35.658308%	\$ 55,026	\$ 57,762	\$ (2,736)
17	5440 Hydraulic Power Generation - Maintenance of electric plant	\$ 3,164	-4.74%	\$ (150)	\$ 3,014	35.658308%	\$ 1,075	\$ 1,128	\$ (53)
18	5460 Other Power Generation - Operation supervision and engineering	\$ 122,526	-4.74%	\$ (5,803)	\$ 116,723	35.658308%	\$ 41,622	\$ 43,691	\$ (2,069)
19	5480 Other Power Generation - Generation Expenses	\$ 222,970	-4.74%	\$ (10,651)	\$ 212,319	35.658308%	\$ 75,742	\$ 79,507	\$ (3,766)
20	5490 Other Power Generation - Miscellaneous other power generation expenses	\$ 815,921	-4.74%	\$ (38,646)	\$ 777,275	35.658308%	\$ 277,163	\$ 290,944	\$ (13,781)
21	5510 Other Power Generation - Maintenance supervision and engineering	\$ 29,004	-4.74%	\$ (1,374)	\$ 27,630	35.658308%	\$ 9,853	\$ 10,342	\$ (490)
22	5520 Other Power Generation - Maintenance of structures	\$ 5,655	-4.74%	\$ (268)	\$ 5,387	35.658308%	\$ 1,921	\$ 2,016	\$ (96)
23	5530 Other Power Generation - Maintenance of generating and electric plant	\$ 310,034	-4.74%	\$ (14,685)	\$ 295,349	35.658308%	\$ 105,317	\$ 110,553	\$ (5,236)
24	5540 Other Power Generation - Maintenance of misc other power generation plant	\$ 2,750	-4.74%	\$ (130)	\$ 2,620	35.658308%	\$ 934	\$ 981	\$ (46)
25	5560 Other Power Supply Expenses - System control and load dispatching	\$ 251,839	-4.74%	\$ (11,928)	\$ 239,911	35.658308%	\$ 85,548	\$ 89,802	\$ (4,253)
26	5570 Other Power Supply Expenses - Other Expenses	\$ 188,296	-4.74%	\$ (8,919)	\$ 179,377	35.658308%	\$ 63,963	\$ 67,143	\$ (3,180)
27	5600 Transmission Expenses - Operation supervision and engineering	\$ 495,480	-4.74%	\$ (23,468)	\$ 472,012	39.598907%	\$ 186,911	\$ 196,205	\$ (9,293)
28	5611 Transmission Expenses - Load dispatch - reliability	\$ 83,675	-4.74%	\$ (3,963)	\$ 79,712	39.598907%	\$ 31,565	\$ 33,135	\$ (1,569)
29	5612 Transmission Expenses - Load dispatch - monitor and operate transmission system	\$ 2,937,881	-4.74%	\$ (139,153)	\$ 2,798,728	39.598907%	\$ 1,088,266	\$ 1,163,369	\$ (75,103)
30	5615 Transmission Expenses - Reliability, planning, and standards development	\$ 797,936	-4.74%	\$ (34,526)	\$ 763,410	39.598907%	\$ 274,979	\$ 288,651	\$ (13,672)
31	5616 Transmission Expenses - Transmission service studies	\$ 3,781	-4.74%	\$ (179)	\$ 3,602	39.598907%	\$ 1,426	\$ 1,497	\$ (71)
32	5620 Transmission Expenses - Station expenses	\$ 289,783	-4.74%	\$ (13,726)	\$ 276,057	39.598907%	\$ 109,316	\$ 114,751	\$ (5,435)
33	5630 Transmission Expenses - Overhead line expenses	\$ 148,577	-4.74%	\$ (7,037)	\$ 141,540	39.598907%	\$ 56,048	\$ 58,835	\$ (2,787)
34	5660 Transmission Expenses - Miscellaneous transmission expenses	\$ 462,020	-4.74%	\$ (21,884)	\$ 440,136	39.598907%	\$ 174,289	\$ 182,955	\$ (8,666)
35	5680 Transmission Expenses - Maintenance supervision and engineering	\$ 288,475	-4.74%	\$ (13,664)	\$ 274,811	39.598907%	\$ 108,822	\$ 114,233	\$ (5,411)
36	5691 Transmission Expenses - Maintenance of computer hardware	\$ 89,159	-4.74%	\$ (4,223)	\$ 84,936	39.598907%	\$ 33,634	\$ 35,206	\$ (1,672)
37	5692 Transmission Expenses - Maintenance of computer software	\$ 577,544	-4.74%	\$ (27,355)	\$ 550,189	39.598907%	\$ 217,869	\$ 228,701	\$ (10,832)
38	5693 Transmission Expenses - Maintenance of communication equipment	\$ 94,833	-4.74%	\$ (4,492)	\$ 90,341	39.598907%	\$ 35,774	\$ 37,553	\$ (1,779)
39	5700 Transmission Expenses - Maintenance of station equipment	\$ 776,431	-4.74%	\$ (36,776)	\$ 739,655	39.598907%	\$ 292,895	\$ 307,458	\$ (14,563)
40	5710 Transmission Expenses - Maintenance of overhead lines	\$ 500,402	-4.74%	\$ (23,701)	\$ 476,701	39.598907%	\$ 188,768	\$ 198,154	\$ (9,385)
41	5752 Regional Market Expenses - Day-ahead and real-time market administration	\$ 518,521	-4.74%	\$ (24,560)	\$ 493,961	39.598907%	\$ 195,603	\$ 205,328	\$ (9,725)
42	5753 Regional Market Expenses - Transmission rights market administration	\$ 76,017	-4.74%	\$ (3,601)	\$ 72,416	39.598907%	\$ 28,676	\$ 30,102	\$ (1,426)
43	5755 Regional Market Expenses - Ancillary Services Market Admin	\$ 6,547	-4.74%	\$ (310)	\$ 6,237	39.598907%	\$ 2,470	\$ 2,593	\$ (123)
44	5756 Regional Market Expenses - Market Monitoring and Compliance	\$ 1,940	-4.74%	\$ (92)	\$ 1,848	39.598907%	\$ 732	\$ 768	\$ (36)
45	5763 Regional Market Expenses - Maintenance of computer software	\$ 34,795	-4.74%	\$ (1,648)	\$ 33,147	39.598907%	\$ 13,126	\$ 13,779	\$ (653)
46	5800 Distribution Expenses - Operation supervision and engineering	\$ 361,592	-4.74%	\$ (17,127)	\$ 344,465	45.870509%	\$ 158,008	\$ 165,864	\$ (7,856)
47	5810 Distribution Expenses - Load Dispatching	\$ 275,131	-4.74%	\$ (13,032)	\$ 262,099	45.870509%	\$ 120,226	\$ 126,204	\$ (5,978)
48	5820 Distribution Expenses - Station expenses	\$ 148,526	-4.74%	\$ (7,035)	\$ 141,491	45.870509%	\$ 64,903	\$ 68,130	\$ (3,227)
49	5830 Distribution Expenses - Overhead line expenses	\$ 314,188	-4.74%	\$ (14,881)	\$ 299,307	45.870509%	\$ 137,294	\$ 144,120	\$ (6,826)
50	5840 Distribution Expenses - Underground line expenses	\$ 1,058,169	-4.74%	\$ (50,120)	\$ 1,008,049	45.870509%	\$ 462,397	\$ 485,387	\$ (22,990)
51	5850 Distribution Expenses - Street lighting and signal system expenses	\$ 1,588	-4.74%	\$ (75)	\$ 1,513	45.870509%	\$ 694	\$ 729	\$ (34)
52	5860 Distribution Expenses - Meter expenses	\$ 1,451,314	-4.74%	\$ (68,741)	\$ 1,382,573	45.870509%	\$ 634,193	\$ 665,725	\$ (31,532)
53	5870 Distribution Expenses - Customer installation expenses	\$ 213,790	-4.74%	\$ (10,126)	\$ 203,664	45.870509%	\$ 93,422	\$ 98,067	\$ (4,645)
54	5880 Distribution Expenses - Miscellaneous distribution expenses	\$ 2,035,412	-4.74%	\$ (96,407)	\$ 1,939,005	45.870509%	\$ 889,432	\$ 933,654	\$ (44,222)
55	5900 Distribution Expenses - Maintenance supervision and engineering	\$ 999,396	-4.74%	\$ (47,336)	\$ 952,060	45.870509%	\$ 436,715	\$ 458,428	\$ (21,713)
56	5920 Distribution Expenses - Maintenance of station equipment	\$ 495,794	-4.74%	\$ (23,483)	\$ 472,311	45.870509%	\$ 216,652	\$ 227,423	\$ (10,772)
57	5930 Distribution Expenses - Maintenance of overhead lines	\$ 2,936,659	-4.74%	\$ (139,095)	\$ 2,797,564	45.870509%	\$ 1,283,257	\$ 1,347,060	\$ (63,804)
58	5940 Distribution Expenses - Maintenance of underground lines	\$ 870,567	-4.74%	\$ (41,234)	\$ 829,333	45.870509%	\$ 380,415	\$ 399,329	\$ (18,914)
59	5950 Distribution Expenses - Maintenance of line transformers	\$ 50,762	-4.74%	\$ (2,404)	\$ 48,358	45.870509%	\$ 22,182	\$ 23,285	\$ (1,103)
60	5960 Distribution Expenses - Maintenance of street lighting and signal systems	\$ 889,259	-4.74%	\$ (42,120)	\$ 847,139	45.870509%	\$ 388,587	\$ 407,907	\$ (19,321)
61	5970 Distribution Expenses - Maintenance of meters	\$ 561,839	-4.74%	\$ (26,611)	\$ 535,228	45.870509%	\$ 245,512	\$ 257,718	\$ (12,207)
62	5980 Distribution Expenses - Maintenance of miscellaneous distribution plant	\$ 103,375	-4.74%	\$ (4,896)	\$ 98,479	45.870509%	\$ 45,173	\$ 47,419	\$ (2,246)
63	9010 Customer Accounts Expenses - Supervision	\$ 219,543	-4.74%	\$ (10,399)	\$ 209,144	44.765037%	\$ 93,623	\$ 98,278	\$ (4,655)
64	9020 Customer Accounts Expenses - Meter reading expenses	\$ 3,538,038	-4.74%	\$ (167,579)	\$ 3,370,459	44.765037%	\$ 1,508,787	\$ 1,583,804	\$ (75,017)
65	9030 Customer Accounts Expenses - Customer records and collection expenses	\$ 5,722,121	-4.74%	\$ (271,028)	\$ 5,451,093	44.765037%	\$ 2,440,184	\$ 2,561,509	\$ (121,326)
66	9050 Customer Accounts Expenses - Miscellaneous customer accounts expenses	\$ 151,808	-4.74%	\$ (7,190)	\$ 144,618	44.765037%	\$ 64,739	\$ 67,957	\$ (3,219)
67	9070 Customer Service and Informational Exp - Supervision	\$ 776,214	-4.74%	\$ (36,765)	\$ 739,449	44.633048%	\$ 330,039	\$ 346,448	\$ (16,409)
68	9080 Customer Service and Informational Exp - Customer assistance expenses	\$ 1,042,330	-4.74%	\$ (49,370)	\$ 992,960	44.633048%	\$ 443,188	\$ 465,224	\$ (22,035)
69	9090 Cust Service and Informational Exp - Informational and instructional adv exp	\$ 5,444	-4.74%	\$ (258)	\$ 5,186	44.633048%	\$ 2,314	\$ 2,430	\$ (115)
70	9100 Cust Service and Informational Exp - Misc customer service and informational exp	\$ 5,567	-4.74%	\$ (264)	\$ 5,303	44.633048%	\$ 2,367	\$ 2,485	\$ (118)
71	9110 Sales Expenses - Supervision	\$ 24,812	-4.74%	\$ (1,175)	\$ 23,637	44.633048%	\$ 10,550	\$ 11,075	\$ (524)
72	9120 Sales Expenses - Demonstrating and selling expenses	\$ 265,639	-4.74%	\$ (12,582)	\$ 253,057	44.633048%	\$ 112,947	\$ 118,563	\$ (5,616)
73	9130 Sales Expenses - Advertising expenses	\$ 1,274	-4.74%	\$ (60)	\$ 1,214	44.633048%	\$ 542	\$ 568	\$ (27)
74	9160 Sales Expenses - Miscellaneous sales expenses	\$ 7,737	-4.74%	\$ (366)	\$ 7,371	44.633048%	\$ 3,290	\$ 3,453	\$ (163)
75	9200 Administrative and general salaries	\$ 15,855,815	-4.74%	\$ (751,010)	\$ 15,104,805	36.440914%	\$ 5,504,329	\$ 5,778,004	\$ (273,675)
76	9240 Property insurance	\$ 6,306	-4.74%	\$ (299)	\$ 6,007	36.083434%	\$ 2,167	\$ 2,275	\$ (108)
77	9250 Injuries and damages	\$ 379,727	-4.74%	\$ (17,986)	\$ 361,741	36.083434%	\$ 130,528	\$ 137,018	\$ (6,490)
78	9260 Employee pensions and benefits	\$ 379,742	-4.74%	\$ (17,986)	\$ 361,756	36.440914%	\$ 131,827	\$ 138,381	\$ (6,554)
79	9280 Regulatory commission expenses	\$ 450,667	-4.74%	\$ (21,346)	\$ 429,321	37.962207%	\$ 162,980	\$ 171,083	\$ (8,103)
80	9301 General advertising expenses	\$ 50,148	-4.74%	\$ (2,375)	\$ 47,773	44.633048%	\$ 21,323	\$ 22,383	\$ (1,060)
81	9302 Miscellaneous general expenses	\$ 93,322	-4.74%	\$ (4,420)	\$ 88,902	41.078842%	\$ 36,520	\$ 38,336	\$ (1,816)
82	9350 Maintenance of general plant	\$ 2,544,596	-4.74%	\$ (120,525)	\$ 2,424,071	41.078842%	\$ 995,780	\$ 1,045,290	\$ (49,510)
83	Total 2018 Test Year Payroll Expense Per OTP	\$ 70,502,854		\$ (3,339,362)	\$ 67,163,492		\$ 26,786,658	\$ 28,118,487	\$ (1,331,830)

Notes and Source

Col. A Amounts from the response to ND-PSC-15.03

B Staff recommended disallowance percentage calculated below

Description	Actual Payroll Expense (I)	Budgeted Payroll Expense (J)	Variance (K)	Percentage Difference (L)	
84	OTP Total Company 2016 Payroll Expense	\$ 63,329,041	\$ 65,897,249	\$ (2,568,208)	-3.90%
85	OTP Total Company 2017 Payroll Expense	\$ 65,265,663	\$ 69,119,559	\$ (3,853,896)	-5.88%
86	Average Variance Percentage			-4.74%	

Col. I Actual payroll expense amounts from the response to ND-PSC-15.04

Col. J Budgeted payroll expense amounts from the response to ND-PSC-15.02

CONFIDENTIAL

Line No.	Description	North Dakota Jurisdictional Amount	Reference
1	Staff Adjustment to Incentive Compensation Expense	\$ <u>(437,805)</u>	A

Notes and Source

A: Staff recommended adjustment to incentive compensation expense calculated below:

	Description	Amount	Reference
2	[BEGIN CONFIDENTIAL]		
3			
4			
5			
6			
7			
8			
9			
10			
11			
12	Total Recommended Adjustment to Incentive Compensation Expense	\$ <u>437,805</u>	L6 + L11

[END CONFIDENTIAL]

Test Year Ending December 31, 2018

Line No.	Description	North Dakota Jurisdictional Amount	Reference
1	Adjustment to Remove Stock-Based Compensation	\$ (647,048)	A
		(A)	

Notes and Source

A: Amount from the response to ND-PSC-15.20 and calculated below:

Description	Total Company Amount	North Dakota Blended Jurisdictional Factor	North Dakota Jurisdictional Amount
2 Stock-Based Compensation Direct Charged to OTP in 2018 Test Year	\$ 1,297,392	40.5095%	\$ 525,567
3 Stock-Based Compensation Allocated to OTP by OTC in 2018 Test Year	\$ 299,882	40.5095%	\$ 121,481
4 Total Stock-Based Compensation Included in 2018 Test Year	<u>\$ 1,597,274</u>		<u>\$ 647,048</u>

Line No.	Description	North Dakota Jurisdictional Amount	Reference
1	Total Non-Employee Director Compensation Included in OTP's 2018 Test Year Filing	\$ (118,091)	A

Notes and Source

A: Amounts reflected in 2018 Test Year filing from the response to ND-PSC-18.01

	Per 2018 Test Year Filing	Reference
2	Total Non-Employee Director Compensation Reflected in 2018 Test Year Filing	ND-PSC-18.01
3	Portion of Total Non-Employee Director Compensation Related to Restricted Stock Grants	Per email from OTP dated 5/14/2018
4	Non-Employee Director Restricted Stock Grants Allocated to OTP	Per email from OTP dated 5/14/2018
5	North Dakota Blended Jurisdictional Allocation Factor	ND-PSC-18.01
6	North Dakota Jurisdictional Non-Employee Director Restricted Stock Grants	

Line No.	Description	Reference	Payroll Adjustment			
			North Dakota Jurisdictional Amount (A)	Medicare Tax 1.45% (B)	FICA Tax* 6.20% (C)	Payroll Tax Expense Adjustment (D)
1	Staff Adjustment to North Dakota Jurisdictional Payroll Expense	A	\$ (1,331,830)	\$ (19,312)	\$ (82,573)	\$ (101,885)
2	Staff Adjustment to Incentive Compensation Expense	B	\$ (437,805)	\$ (6,348)	\$ (27,144)	\$ (33,492)
3	Staff Adjustment to Stock-Based Compensation Expense	C	\$ (647,048)	\$ (9,382)	\$ (40,117)	\$ (49,499)
4	Staff Adjustment to Non-Employee Director Restricted Stock Grants	D	\$ (118,091)	\$ (1,712)	\$ (7,322)	\$ (9,034)
5	Total of Staff Adjustments Listed Above		\$ (2,534,774)	\$ (36,754)	\$ (157,156)	\$ (193,910)

Notes and Source

- A: See Schedule C-4
- B: See Schedule C-5
- C: See Schedule C-6
- D: See Schedule C-7

* The maximum amount of wages in 2018 subject to the 6.20% Social Security tax is \$128,400. To the extent that the salaries of certain individuals included in the adjustments listed are above the threshold of \$128,400, it will be necessary to modify this adjustment to Payroll Tax expense.

Otter Tail Power Company
 Executive Survivor and Supplemental Retirement Plan

Exhibit RCS-1
 Schedule C-9
 Case No. PU-17-398
 Page 1 of 1

Test Year Ending December 31, 2018

Line No.	Description	Total Company Amount (A)	North Dakota Blended Jurisdictional Factor (B)	North Dakota Jurisdictional Amount (C)
1	Adjustment to Remove Executive Survivor and Supplemental Retirement Plan Expense	\$ (1,426,000)	40.5095%	\$ (577,665)

Notes and Source

A: Amounts above from the response to ND-PSC-15.21

Test Year Ending December 31, 2018

Line No.	Description	Amount (A)	Reference
1	Adjustment to Rate Case Expense	\$ (174,687)	A

Notes and Source			
A: Staff's recommended adjustment to rate case expense derived from Volume 4a from OTP's filing and calculated below:			
Description	Per OTP	Per Staff	Staff Adjustment
2 External Attorney Fees	\$ 400,000	\$ -	
3 Administrative Costs, Consultants, etc.	\$ 200,000	\$ 75,000	
4 PSC Costs	\$ 175,000	\$ 175,000	
5 Estimated Rate Case Expense	\$ 775,000	\$ 250,000	
6 Regulated Revenue	\$ 452,917,347	\$ 452,917,347	
7 Unregulated Revenue	\$ 811,214	\$ 811,214	
8 Total Regulated and Unregulated Revenue	\$ 453,728,561	\$ 453,728,561	
9 Percent Unregulated	0.18%	0.18%	
10 Less Allocation to Unregulated Activity	\$ 1,386	\$ 447	
11 Total Estimated Rate Case Expense	\$ 773,614	\$ 249,553	
12 Amortization Period (Years)	3	3	
13 Rate Case Expense Included in 2018 Test Year	\$ 257,871	\$ 83,184	\$ (174,687)

Otter Tail Power Company
Interest Synchronization

Exhibit RCS-1
Schedule C-11
Case No. PU-17-398
Page 1 of 1

Test Year Ending December 31, 2018

Line No.	Description	North Dakota Jurisdictional Amount (A)	AG Amount (B)
1	Adjusted Rate Base, per Staff	\$ 359,772,291	Schedule B
2	Weighted Cost of Debt, per Staff	<u>2.52%</u>	Schedule D
3	Interest Deduction for Tax Purposes	\$ 9,055,469	L1 x L2
4	Interest Deduction per Company	<u>\$ 9,067,310</u>	Note A
5	Decrease in Deductible Interest	\$ (11,841)	L3 - L4
6	Combined Federal & State Income Tax Rate Per OTP Supplemental Filing	<u>24.40%</u>	
7	Increase to Income Tax Expense	<u>\$ 2,890</u>	L5 x L6

Notes and Source

Note A: Amount from Exhibit_(TAA-1), Schedule C-5 from OTP filing

Other Tail Power Company
Deferred Income Tax Expense Adjustment for Excess Federal Accumulated Deferred Income Taxes Amortization
As of December 31, 2017
Adjustment to Reduce 2018 Deferred Income Tax Expense for Amortization of Non-Protected Excess ADIT

Test Year Ending December 31, 2018

Line No	Description	FERC Account	Total OTP Amount (A)	North Dakota OTP Allocated Amount (B)	OTP Proposed Amortization 2018 TY		Staff Proposed Amortization 2018 TY	
					Method (C)	Amount (D)	Method (E)	Amount (F)
	Protected Excess ADIT							
1	Excess Tax Over Book Depreciation	282	\$ (106,177,537)	\$ (38,312,502)	ARAM	Note A	ARAM	Note A
2	Excess Tax Over Book Depreciation - AQCS SL 7	281	\$ (1,623,952)	\$ (585,977)	ARAM	Note A	ARAM	Note A
3	Subtotal - Protected Excess ADIT		\$ (107,801,489)	\$ (38,898,479)				
4	Non-Protected Excess ADIT	190	\$ 13,835,519	\$ 4,992,331	ARAM	Note B	3 years, straight-line	\$ 1,664,110
5		282	\$ (6,480,550)	\$ (2,338,405)	ARAM	Note B	3 years, straight-line	\$ (79,468)
6		283	\$ (8,285,172)	\$ (2,989,575)	ARAM	Note B	3 years, straight-line	\$ (996,525)
7	Subtotal - Non-Protected Excess ADIT		\$ (930,203)	\$ (335,649)			3 years, straight-line	\$ (111,883)
8	Total Excess Federal ADIT at December 31, 2017		\$ (108,731,692)	\$ (39,234,128)				
9	Excess ADIT amortization in OTP's supplemental filing (reduction to deferred income tax expense)					Note B		\$ -
10	Staff adjustment to Deferred Federal Income Tax Expense for Non-Protected Excess ADIT Amortization							\$ (111,883)

Notes and Source

Cols A&B OTP's response to DR ND-PSC-03 06, Attachment 1 and ND-PSC-16 02, Attachment 1
[A] Amount of ARAM based excess federal ADIT amortization for the 2018 test year has not been identified
[B] No 2018 excess ADIT amortization amount has been identified in OTP's supplemental filing

Col E: Amortization period is rate case cycle (same period used for amortization of rate case expense)

Otter Tail Power Company
TCJA Related Revenue Requirement Savings in 2018 Before Rate Adjustments Occurred
Estimated Refundable Amount and Annual Revenue Requirement Reduction
If Flowed Back to Customers Over Five Years

Test Year Ending December 31, 2018

Line No.	Description	Total Annual OTP Revenue Requirement Amount (A)	Estimated Two Months of Revenue Requirement Savings (B)	Refundable Amount (C)
1	Interim Base Rate Revenue Requirement Savings	\$ (4,500,000)	\$ (750,000)	
	Estimated Annual Rider Revenue Requirement Savings			
2	Transmission	\$ (521,738)	\$ (86,956)	
3	Renewable	\$ (343,828)	\$ (57,305)	
4	Environmental	\$ (775,925)	\$ (129,321)	
5	Total Estimated Revenue Requirement Savings for Riders	\$ (1,641,491)	\$ (273,582)	
6	Total Estimated Revenue Requirement Savings	\$ (6,141,491)	\$ (1,023,582)	
7	Refundable Amount			\$ (1,023,582)
8	Annual Revenue Requirement Reduction if Refundable Amount is flowed back over five years			\$ (341,000)

Notes and Source

Col.A: OTP's response to DR ND-PSC-19-03

Col.B: Col. A x 2 / 12 months

Line 8: Line 7 / 3 years (rounded to \$1,000)

Otter Tail Power Company
Case No. PU-17-398
Exhibit RCS-2
Copies of OTP's Non-Confidential Responses to Data Requests
Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
ND-PSC-15.37	Specific project included in CWIP; In-service date of CWIP project; Project accrues AFUDC, but may not be taken due to uncertainty of project going forward; OTP's CWIP and AFUDC in years 2015 through 2017; OTP's policy for accruing AFUDC; Short-term CWIP inadvertently included Project 105245-Winger Thief River.	No	4	3 - 6
ND-PSC-06.28	Amounts by account of employee gift expenses and employee recognition included in years 2016, 2017, and 2018 operating expenses.	No	1	7
ND-PSC-06.29	Amounts for gifts, life events, other employee gift expenses, and employee recognition and entertainment expenses were disallowed as not reasonable and necessary in OTP's most recent Minnesota rate case; OTP included similar expenses in its proposed 2018 operating expenses for North Dakota.	No	1	8
ND-PSC-06.27	OTP provided 2016 and 2017 actual Investor Relations expenses and 2018 forecasted Investor Relations for Total Corporation, OTP Share, and ND Share.	No	2	9 - 10
ND-PSC-06.06	OTP provided make, model, and annual cost (total and North Dakota allocation) of corporate aircraft owned by OTP.	No	1	11
ND-PSC-06.07	Explanation of how the cost of corporate aircraft was charged in 2017 and 2018, by account, to OTP North Dakota.	No	2	12 - 13
ND-PSC-16.05	OTP's budgeted amount of corporate aircraft costs is not itemized to the level of actual results; Explanation of how the fixed costs allocated to OTP from Otter Tail Corporation were derived.	No	2	14 - 15
ND-PSC-06.08	OTP provided cost-benefit analysis that OTP has concerning corporate aircraft costs versus alternatives.	No	3	16 - 18
ND-PSC-15.02	Identification of number of actual full-time equivalent employees for each month of years 2016, 2017, and 2018 to date; Number of budgeted full-time equivalent employees for each month of years 2016, 2017, and 2018 to date; Budgeted payroll cost by FERC account; Retirement projections are based on historical data and average retirement age; OTP does not budget for any material impacts resulting from retirements or other attrition. (Confidential Attachment 3 not included)	No	15	19 - 33
ND-PSC-15.03	Amount of payroll cost by FERC account for each month of the 2018 test year.	No	3	34 - 36
ND-PSC-15.04	Amount of actual payroll costs by FERC account for month for years 2016 and 2017.	No	3	37 - 39
ND-PSC-15.07	Identification of 2018 Actuals versus Budget payroll cost differences.	No	4	40 - 43
ND-PSC-15.19	Amount of incentive compensation allocated to, and budgeted for, OTP from Otter Tail Corp; Amount of incentive compensation was not derived from union contracts; OTP's adjustment to cap management performance incentives and corporate bonuses and 25% is a five-year average of actual results. (Attachment not included)	No	1	44
ND-PSC-15.20	Amount of stock-based compensation related expense directly charged to account 5240.3000.0921; Amount of stock-based compensation related expense allocated to OTP by Otter Tail Corp charged to account 5240.3000.0921; Restricted Stock Units and Performance Share Awards were included in charges to OTP for test year; Copy of Otter Tail Corporation 2014 Stock Incentive Plan.	No	17	45 - 61
ND-PSC-06.23	Description of Board of Directors incentive compensation programs.	No	1	62
ND-PSC-18.01	Total amount of Board of Directors retainers and grants of restricted stock that is allocated to OTP, the ND share and account; Otter Tail Corp Board Chairman does not receive other cash compensation; The Board Chairman receives annual restricted stock grants; Purpose of annual grants of restricted stock to the non-employee directors; Identification and explanation of the restrictions that relate to the annual grants of restricted stock to the non-employee directors.	No	5	63 - 67
ND-PSC-03.04	Balances of OTP's ADIT accounts as of December 31, 2017; Breakout of amounts between federal and state ADIT.	No	2	68 - 69
ND-PSC-03.06	Breakdown of ADIT and excess ADIT balances for each timing difference; Two items relate to used of accelerated tax depreciation for federal income tax purpose.	No	2	70 - 71
ND-PSC-18.02	Listing of ADIT balance in each FERC account at December 31, 2017; Calculation of state and federal effective tax rates used for 2017 activity; Listing of the originating and reversing timing differences that had activity in 2017; Breakdown of excess ADIT balance by timing difference in each FERC account at December 31, 2017; Identification of "protected" and "non-protected" excess property-related ADIT amounts.	No	5	72 - 76
ND-PSC-16.02	Explanation of basis for calculation of excess ADIT; North Dakota's allocation factor calculated from OTP's cost of service; Detailed calculation of excess ADIT for OTP's North Dakota jurisdictional operations base upon December 31, 2017 general ledger ADIT balances; Explanation of whether and how the excess ADIT balances are reflected in OTP's supplemental filing.	No	3	77 - 79
ND-PSC-18.11	Summary of OTP's calculation of excess ADIT performed at year-end 2017 and related journal entries made to adjust the ADIT balances.	No	2	80 - 81
ND-PSC-05.02	Explanation of how OTP will be applying the ARAM to the "protected" portions of the excess federal ADIT balances that relate to the use of accelerated tax depreciation for federal income tax purposes; Explanation of how OTP calculates the ARAM.	No	2	82 - 83
ND-PSC-05.05	Explanation and illustration of how the cost of removal/negative net salvage component of OTP's depreciation rates has an impact on the derivation of the ARAM for application of excess federal ADIT related to the use of accelerated tax depreciation.	No	4	84 - 87
ND-PSC-18.03	OTP uses the PowerTax module of the PowerPlant system to track tax basis and tax depreciation; Explanation of the capabilities of the software for tracking tax basis and tax depreciation by plant account by vintage; Explanation of capabilities of the software for calculating amortization of excess ADIT using an ARAM.	No	1	88
ND-PSC-18.04	OTP uses PowerPlan 2016.1 for its fixed asset tracking system for its utility plant in service assets; Explanation of the capabilities of that software for tracking book basis and book depreciation by plant account by vintage; Explanation of capabilities of that software for calculating amortization of excess ADIT using an ARAM.	No	1	89
ND-PSC-18.07	Explanation of how OTP will be applying the ARAM to the protected portions of excess ADIT amounts and how the PowerTax system calculated ADIT using ARAM; OTP is not proposing an alternative method to amortize the protected portion of excess ADIT; Provision of OTP's 2018 depreciation rates by plant account and sub-accounts, including Life and Cost of Removal breakouts.	No	2	90 - 91
ND-MLEC-141	Listing of temporary items by FERC account for year-end 2017; Identification of temporary items considered to be protected; OTP uses the PowerTax system to track and calculate the reversal of ADIT balances related to property; Estimated average life of property to be 25 years; Amount of estimated reversal of protected ADIT; OTP proposes that unprotected excess ADIT be treated the same as protected excess ADIT with the same amortization schedule.	No	3	92 - 94

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
ND-PSC-19.03	OTP experienced savings in income tax expense associated with the TCJA in January and February 2018; Explanation of how the income tax savings to OTP in January and February can be calculated; Calculations of revenue requirement reductions, by rider; Effective rate change for the Transmission, Renewable, and Environmental riders was March 1, 2018.	No	2	95 - 96
ND-MLEC-214	Listing of projects now being recovered via riders which OTP proposes to roll into base rates, shown with original investments, net plant in service, and the 2018 test year revenue requirement at time of roll-in.	No	2	97 - 98
ND-PSC-15.39	Actual monthly over/under recovered ECRR balances from the period January 1, 2016 through March 31, 2018; Projected monthly over/under recovered ECRR balances for the period April through December 2018; Actual amount of ECRR revenue for each month January 2016 through March 2018; Expected amount of ECRR revenue for each month April through December 2018; Actual amount of ECRR costs, by account, for each month January 2016 through March 2018; Expected amount of ECRR costs, by account, for each month April through December 2018.	No	4	99 - 102
ND-PSC-15.40	Actual monthly over/under recovered TCRR balances from the period January 1, 2016 through March 31, 2018; Projected monthly over/under recovered TCRR balances for the period April through December 2018; Actual amount of TCRR revenue for each month January 2016 through March 2018; Expected amount of TCRR revenue for each month April through December 2018; Actual amount of TCRR costs, by account, for each month January 2016 through March 2018; Expected amount of TCRR costs, by account, for each month April through December 2018.	No	4	103 - 106
ND-PSC-15.41	Actual monthly over/under recovered RRAR balances from the period January 1, 2016 through March 31, 2018; Projected monthly over/under recovered RRAR balances for the period April through December 2018; Actual amount of RRAR revenue for each month January 2016 through March 2018; Expected amount of RRAR revenue for each month April through December 2018; Actual amount of RRAR costs, by account, for each month January 2016 through March 2018; Expected amount of RRAR costs, by account, for each month April through December 2018.	No	4	107 - 110
ND-PSC-15.45	OTP maintains and inventory of renewable energy credits; OTP provided a monthly inventory of RECs for January 2015 through December 2017, which includes the quantity in inventory, quantity acquired by generation, and quantity and proceeds from RECs sold; OTP has not purchased any North Dakota allocated RECs; OTP does not allocate any cost to RECs generated from, or sold from, its system resources.	No	2	111 - 112
ND-PSC-15.46	OTP retired RECs in MRETS in April 2016 to demonstrate compliance with the North Dakota Renewable Energy Objective for the year 2015.	No	1	113
ND-PSC-15.42	OTP's Energy Adjustment Rider, Tariff Section 13.01 calculates base cost of energy based on the OTP Total System costs; Costs and revenues by FERC account that were included in the numerator for calculating the base cost of energy; Denominator is based on forecasted Total Company kWh sales for the 2018 test year; Fuel and purchased power costs by account that OTP proposes to transfer into the ECR; Identification of all FERC accounts and sub-accounts that contain costs or revenues that OTP proposes to include and recover in the ECR; OTP proposes that Intersystem Sales be included in the calculation of the EAR; OTP proposes to include the cost of reagents and emissions allowances, which are currently being recovered under the REAA Rider, into the EAR; OTP proposes that Coyote Station pebble lime reagent costs also be moved out of base rate recovery and into the EAR. (Includes updated Attachment)	No	3	114 - 116
ND-PSC-01.16	Cost of Mr. Hevert's services to OTP; Mr. Hevert's fees are included in the rate case expense request at a set amount along with other consultants such as for the Marginal Cost Study and other administrative expenses; Stockholders absorb any excess expenses if the actual amount exceeds the requested amount.	No	1	117
ND-PSC-19.04	Current CISone implementation schedule; Revisions to the CISone implementation schedule that occurred in 2017 and 2018; Amount of AFUDC OTP is accruing on the CISone project from inception to date (actual) and estimated for remaining months until completion; Provision of August 17, 2015 meeting minutes in which OTP board of directors approved CISone project; Original estimate of project; OTP expects project costs to be above original estimate; CISone project does not replace any assets recorded on OTP's books as of January 1, 2018; Explanation of why OTP does not anticipate immediate cost savings related to the project; OTP has not seen impacts of any cost changes with the implementation of Cayenta Utilities; Determination of OTP's proposed 10-year depreciable life of CISone project; OTP's 2018 test year revenue requirement request does not include rental, maintenance, or other costs related to systems being replaced by the CISone.	No	9	118 - 126
ND-PSC-15.34	Amount of expected capital expenditures between years 2017 and 2021 broken out by plant account, amount, and expected in-service date of the capital expenditures included in OTP's 2018 test year filing.	No	4	127 - 130
Total Pages Including Content Pages			130	

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

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/07/2018

Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

CWIP.

- a. What specific projects are included in the \$271,747 of CWIP?
- b. For each CWIP project, identify when the Company projects it will be placed into service.
- c. Does any portion of the \$271,747 of CWIP accrue AFUDC? If not, explain fully why not. If so, identify the related AFUDC amounts and show in detail how they were calculated.
- d. Did the Company have CWIP or AFUDC in 2015, 2016 or 2017? If so, identify the amounts of CWIP and AFUDC in each year.
- e. Identify and provide the Company's policy for accruing AFUDC.

Attachments: 1

Attachment 1 to DR ND-PSC-15.37.pdf

Response:

- a. Project No. 105245-Winger Thief River Falls 230kV Line.
- b. The in-service date for Project No. 105245-Winger Thief River Falls is 12/2023.
- c. There is no AFUDC taken on Project No. 105245-Winger Thief River Falls due to uncertainty of the project going forward
- d. Yes, as a company, OTP does have CWIP and AFUDC every year. See the table below for Total Company CWIP and ADUDC amounts for 2015, 2016 and 2017 (all amounts are Total Company as long-term CWIP and AFUDC are not allocated to ND).:

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Response to Data Request ND-PSC-15.37
Page 2 of 2

	2015	2016	2017
CWIP	\$64,117,181	\$149,997,025	\$132,556,715
AFUDC Debt	723,318	494,942	740,730
AFUDC Equity	1,302,804	856,829	986,150

e. Please see Attachment 1 to DR ND-PSC-15.37 for the OTP's AFUDC Policy.

In completing this Data Request, we inadvertently found that OTP's short-term CWIP should not have included the above Project 105245-Winger Thief River. Short-term CWIP will be corrected in the final compliance filing.

NOTED AND ROUTED

Mgr.		Dept. Head	
Off. Mgr		Div. Acct.	

Accounting Circular No. 134
Revised: August 7, 2015

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

POLICY: Allowance for funds used during construction (AFUDC) will be charged on certain capital projects.

SCOPE: This circular provides procedures for determining when AFUDC will be charged on projects and for calculating the charges.

AFUDC is calculated in accordance with FERC Order No. 561. It's an annual rate that is monitored and recalculated monthly. Therefore, the rate used may vary from month to month so that the overall annual rate is attained by year-end. The rate is calculated by the Financial Reporting Department and delivered to the Fixed Assets Department for use in the PowerPlant Fixed Assets system.

PROCEDURE:

1. Effective May 1, 2006, all capital projects will be considered for AFUDC except the following:
 - a. Projects estimated to cost less than \$10,000.
 - b. Projects estimated to take less than 30 days to construct.
 - c. Customer Service Center blanket projects.
 - d. One time purchase of equipment that does not involve construction.
 - e. Other Projects as determined by the Fixed Assets Department as not meeting AFUDC eligibility requirements. (Examples include but are not limited to billing projects and if customer will own some of the installed materials.)
2. Projects to receive AFUDC will be flagged as such in Oracle Projects and PowerPlant Fixed Assets system at the time of project setup. Project sponsors will indicate whether the project should be considered for AFUDC. The Fixed Assets department will review and approve the eligibility.
3. AFUDC is calculated using the current AFUDC rate. See Financial Reporting or Fixed Asset Department for the rate.
4. AFUDC is calculated on a monthly basis, within PowerPlant, by applying the monthly rate to the sum of the balance of the project at the beginning of the month plus one-half

of the current month's charges. The Construction Work in Progress (CWIP) accounts AFUDC is calculated on are:

100.0X0.0000.1780.0000.0360.XXXXXX
100.0X0.0000.1780.0000.0290.XXXXXX
100.0X0.0000.1780.0000.1510.XXXXXX
100.0X0.0000.1780.0000.1140.XXXXXX
100.0X0.0000.1780.0000.1145.XXXXXX

To effect annual compounding, the accumulated AFUDC in each project will be added to that projects beginning balance each January on which AFUDC will be calculated.

5. The following entry is made on a monthly basis:

Debit 100.0X0.0000.1780.8150.ACTY.XXXXXX
Credit 100.0X0.0000.4310.3000.... (FERC Account 419.1)
Credit 100.0X0.0000.5310.4000.... (FERC Account 432)

6. AFUDC will start on eligible projects in the month of first charge.
7. AFUDC will be taken on projects through the month of its being placed in-service or "ready" for service.
8. If AFUDC has been applied to projects after we are notified of an earlier in-service date, PowerPlant will reverse the subsequent AFUDC.
9. AFUDC will be suspended on projects that incur extended construction delays
10. The Fixed Assets Department will review the application of AFUDC at the time of closing the project. Adjustments will be made as necessary.

Manager, Accounting

Approved: _____
Controller

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

Response to: North Dakota Public Commission
Analyst: Victor Schock
Date Received: 02/20/2018
Date Due: 03/06/2018
Date of Response: 03/06/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Has the Company included any amount in its requested 2018 operating expenses for employee gifts, life events, or other employee gift expenses and/or for employee recognition and entertainment expenses?

- a. If so, please identify the 2018 amounts by account. Identify the amounts by account for total company and for OTP North Dakota. Please also provide comparative actual information for 2016 and 2017.

Attachments: 0

Response:

Please see the following table for employee gifts and employee recognition expenses. Otter Tail Power does not incur entertainment expenses.

	2016		2016		2017		2017		2018 TY (1)		2018 TY	
	(OTP Total)	(OTP ND Total)	(OTP Total)	(OTP ND Total)	(OTP Total)	(OTP ND Total)	(OTP Total)	(OTP ND Total)	(OTP Total)	(OTP ND Total)	(OTP Total)	(OTP ND Total)
Gift Expense	\$ 30,038	\$ 12,177	\$ 30,914	\$ 12,523	\$ 30,476	\$ 12,346						
Employee Recognition	\$ 47,083	\$ 19,087	\$ 48,445	\$ 19,625	\$ 47,764	\$ 19,349						
Entertainment Expenses (2)	-		-		-							

(1) The 2018 Test Year O&M budget does not budget to this level of detail. This amount is an average of the two prior years

(2) Otter Tail Power does not have any entertainment expenses.

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

Response to: North Dakota Public Commission
Analyst: Victor Schock
Date Received: 02/20/2018
Date Due: 03/06/2018
Date of Response: 03/06/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

In OTP's most recent Minnesota rate case (Docket No. E-017/GR-15-1033) were \$18,310 for gifts, life events, and other employee gift expenses, and \$7,380 in employee recognition and entertainment expenses were disallowed as not reasonable and necessary for the provision of utility services?

- a. If not, explain the statements at the Minnesota Commission's May 1, 2017 Order in Docket No. E-017/GR-15-1033 at pages 47-48.
- b. Has OTP included any similar expenses in its proposed 2018 operating expenses for its North Dakota utility operations?
- c. If the response to part b is "yes" identify the amounts by account in total and on a North Dakota jurisdictional basis.

Attachments: 0

Response:

- a. As stated in the Minnesota Order, OTP argued and still strongly argues that items given for employee recognition are extremely modest, reasonable and prudent, and should be eligible for rate recovery as they help to build employee morale and promote retention. OTP believes the expenses are appropriate for recovery so includes them in each rate case revenue requirement. Loss of employee morale and increase attrition would be far more costly than the identified expenses.
- b. Yes.
- c. Please see OTP's response to ND-PSC-06.28 for the OTP Total and OTP North Dakota amounts.

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Response to Data Request ND-PSC-06.27
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Commission
Analyst: Victor Schock
Date Received: 02/20/2018
Date Due: 03/06/2018
Date of Response: 03/06/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Identify the amount of investor relations expense by account that the Company has requested for 2018. Identify the amounts by account for total company and for OTP North Dakota. Please also provide comparative actual information for 2016 and 2017.

Attachments: 1

Attachment 1 to ND-PSC-6.27.xlsx

Response:

Attachment 1 to ND-PSC-6.27 includes 2016 and 2017 actual Investor Relations expenses and 2018 forecasted Investor Relations expenses for Total Corporation, OTP Share, and ND Share.

Case No. PU-17-398 Attachment 1 to DR ND-PSC-6-27 Page 1 of 1

**Investor Relations Expenses
North Dakota Data Request 6.27**

	Total Investor Relations Expenses			OTP Total			ND Share*		
	2016	2017	2018	2016	2017	2018	2016	2017	2018
	Actual	Actual	Forecast	Actual	Actual	Forecast	Actual	Actual	Forecast
Salaries	145,206	148,375	151,187	87,124	89,347	90,712	35,293	36,194	36,747
Payroll Taxes	10,146	10,705	11,012	6,088	6,444	6,607	2,466	2,610	2,676
Employee Insurance	22,470	18,059	17,478	13,484	10,916	10,487	5,462	4,422	4,248
Employee Retirement Costs	21,768	13,082	18,009	13,033	7,911	10,805	5,280	3,205	4,377
Other Contracted Services	161,393	166,923	204,933	87,236	100,754	122,960	35,339	40,815	49,810
Intercompany Contracted Services	7,700	1,821	4,275	4,620	1,093	2,565	1,872	443	1,039
Office Supplies	27,323	17,417	16,353	16,394	10,450	9,812	6,641	4,233	3,975
Postage	98,704	91,401	94,657	59,222	54,841	56,794	23,991	22,216	23,007
Dues & Subscriptions	143,200	151,429	151,765	85,920	90,857	91,059	34,806	36,806	36,887
Travel	3,612	1,400	4,738	-	-	-	-	-	-
Meeting Expense	7,106	5,454	8,240	4,264	3,272	4,944	1,727	1,326	2,003
Meals & Entertainment	73	84	463	-	-	-	-	-	-
Education & Training	1,095	(15)	1,030	657	(9)	618	266	(4)	250
Advertising & Promotion	4,741	3,924	8,755	2,845	2,355	5,253	1,152	954	2,128
Repairs & Maintenance	14,900	-	-	8,940	-	-	3,622	-	-
Miscellaneous	(2,441)	(821)	-	-	-	-	-	-	-
Total	666,997	629,239	692,893	389,826	378,230	412,615	157,916	153,219	167,148

*Based on blended allocation factor of: 40.50948%

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Response to Data Request ND-PSC-06.06
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/20/2018
Date Due: 03/06/2018
Date of Response: 03/06/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Identify the make, model and annual cost of corporate aircraft owned and/or leased by the Company and/or by Otter Tail Corporation for which cost is charged or allocated to OTP

Attachments: 0

Response:

OTP owns a 1987 322 King Air turboprop aircraft. While the plane is owned by OTP, the pilots are employees of Otter Tail Corporation and the plane is scheduled by administrative staff of Otter Tail Corporation. The plane is used for the business purposes of both OTP and Otter Tail Corporation. At the end of each year Otter Tail Corporation and OTP divide up the fixed costs on a pro-rata share.

In 2017, the cost allocated to OTP for its proportionate usage of the plane is \$329,240 (Total), \$133,374(ND).

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/20/2018
Date Due: 03/06/2018
Date of Response: 03/14/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

For each corporate aircraft identified in response to the previous request, show in detail how the cost was charged in 2017 and 2018, by account to OTP North Dakota.

Attachments: 0

Response:

OTP owns a single plane. For each flight, the entity using the plane, OTP or Otter Tail Corporation, is charged a variable cost based on the distance of the trip. At the end of the year, the plane costs that have not been invoiced are allocated to OTP and Otter Tail Corporation pro rata based on the number of flights. In 2017, OTP was allocated \$246,945 (Total) for 71 flights. After removing flights associated with capital projects or below the line lobbying activities, the total of invoiced and allocated costs used for calculating the Cost of Service for OTP is \$329,240 (Total) and \$133,374 (ND). The 2018 allocation is included in the general allocator from Otter Tail Corporation so is not itemized but is expected to be similar to 2017. In OTP's 2008 rate case (Case No. 08-862) we included approximately \$278,000 (total)/\$117,033 (ND). 2017 costs are less than a 1.5% increase in aircraft cost per year since the 2007 test year.

FERC Account

1070	Construction work in progress	57,107.03
4264	Expenditures for civil, political	6,025.65
5000	Steam Power Generation- Operations	3,405.31
5060	Steam Power Generation- Miscellaneous	3,855.20
5570	Other Power Supply Expenses	202.02
5880	Distribution Expenses	1,337.30
9080	Customer Service and Information	4,977.55
9210	Office Supplies and expenses	54,672.31

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Response to Data Request ND-PSC-06.07
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9280	Regulatory Commission expenses	12,269.03
9302	Miscellaneous general expenses	1,577.17
<hr/>		
	Total	145,428.57
	Less 1070	57,107.03
	Less 4264	6,025.65
<hr/>		
		82,295.89
	Allocation from Corporate	246,944.55
<hr/>		
	Total Aircraft Expense for 2017:	329,240.44

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

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/07/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Corporate Aircraft. Refer to the response to ND-PSC-06.07.

- a. Please confirm whether the \$133,374 is the amount of aircraft costs included in the 2018 test year cost of service. If not confirmed, please identify the amount of corporate aircraft expense that is included in 2018 test year cost of service and show how it was derived. Show detailed calculations.
- b. Please explain fully and in detail how the fixed costs of \$246,945 that were allocated to OTP from Otter Tail Corporation were derived. Show detailed calculations.

Attachments: 0

Response:

- a. As ND-PSC-06.07 states the 2018 allocation is included in the general allocator from Otter Tail Corporation and is expected to be similar to actual 2017 results. The budgeted amount is not itemized to the level of actual results.
- b. Total costs are captured at the corporate level and a direct bill is created for each flight for the entity utilizing the plane (Otter Tail Corporation or a subsidiary). Remaining costs that are unbilled at year-end are assigned to each of the entities according to the percentage of the total flights each entity took in that year. Below is the calculation for the plane's costs in 2017:

Pilot salaries	\$301,868
Plane Repairs	\$74,238
Fuel	\$106,889
Rental of Hanger	\$10,800
Pilot Education	\$24,710

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Response to Data Request ND-PSC-16.05
Page 2 of 2

Miscellaneous	\$7,834
Total	\$526,339
Less: Billings for Direct Usage of Plane	(\$174,224)
Total Costs of Plane	\$352,115
Less: Non-Utility Usage	(\$105,170)
Billing to Utility	\$246,945

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/20/2018
Date Due: 03/06/2018
Date of Response: 03/12/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Identify and provide any cost-benefit analyses that OTP has concerning corporate aircraft costs versus alternatives.

Attachments: 1

Attachment 1 to DR ND-PSC-06.08.pdf

Response:

OTP prepared a cost-benefit analysis using flight data from 2017, which is included as Attachment 1 to ND-PSC-6.08. OTP's cost/benefit analysis compares the total flight costs against the total costs of driving. This analysis is performed for the flights taken by OTP, excluding flights for below the line activities which are not included for cost recovery; flights attributable to capital projects or below the line activities are removed for developing the Cost of Service, as discussed in the response to ND-PSC-6.07.

OTP's cost/benefit analysis found that driving costs for the 71 flights in 2017 would have been \$417,470 (Total) if the aircraft had not been used. Alternatively, the total flying cost for 2017 was \$400,872 (Total), which includes the variable costs of each trip and the portion of the total fixed costs allocated to the utility. This analysis shows that owning and operating aircraft provides a benefit of at least \$16,598 (Total). There are additional costs of driving that are not included in this quantification that would increase the benefit of owning the plane. Such costs include additional fleet vehicles that would be needed, additional staff that would be required, and incidental costs such as meals that would be incurred by lengthening travel time. Considering the tangible and intangible costs, owning and operating a plane is beneficial for OTP and reduces costs for OTP customers.

Case No. PU-17-398
Attachment 1 to DR ND-PSC-06.08
Page 1 of 2

2017 OTP Trip #	Date	Destination city	State	Passenger List	Purpose of Flight	Invoice Flight Amount	Hours - driving	Hours - flying	Productive Hours - Driving	Productive Hours - Flying	OTP Driving Costs
1	1/5/2017	Bismarck	ND	CATHY FOGALE, MATT OLSEN, KIRBY KUGLER, CHARLES WICKLUND, BILL ZUMER	NERC compliance	\$ 1,477.69	9.5	1.81	66.50	12.67	\$ 6,015
2	1/12/2017	St. Paul	MN	BRIAN DRAXTEN, BRAD TOLLERSON, BRUCE GERHARDSON, STEPHANIE HOFF	Meet with Minnesota Power on generation issue and attend CEEE Fort	\$ 1,443.31	7.25	1.37	29.00	5.48	\$ 3,714
3	1/16/2017	Denver	CO	LAURA GRIFFITH, RON SPANGLER, BRETT JOHNSON, STEVE WEVLEY, COLLIN K	OTP to meet with IREA to discuss business impacts and structure chan	\$ 4,067.90	26.5	5.06	132.50	25.30	\$ 11,455
4	1/19/2017	Devils Lake	ND	JOANN THOMPSON, TODD LANGSTON, KYLE FRIGAARD	Attend Rugby Safety Meeting and field trip to look over projects in the	\$ 1,099.80	7.75	1.46	23.25	4.38	\$ 2,443
5	1/27/2017	Sioux City	IA	MARIA BERINGER, PAUL HENNE	Receiving/verifying material (poles) for BSSE project.	\$ 1,385.10	11	2.1	22.00	4.20	\$ 2,013
6	1/31/2017	Bismarck	ND	PETE BETHON, BRUCE GERHARDSON, STUART TOMMERDAHL, TOM BRAUSE	Farewell party for Commission Kalk.	\$ 1,373.49	9.5	1.81	38.00	7.24	\$ 4,837
7	2/3/2017	Bismarck	ND	TIM ROGELSTAD, BRAD TOLLERSON, TOM BRAUSE, BRIAN DRAXTEN, STEPHAN	ND Public Service Commission pie meeting.	\$ 1,154.98	9.5	1.81	57.00	10.86	\$ 7,735
8	2/17/2017	Pierre	SD	BRIAN DRAXTEN, TIM ROGELSTAD, BRAD TOLLERSON, TOM BRAUSE, JOANN T	Meet with SD PUC on resource planning issues.	\$ 1,423.49	10.5	1.97	52.50	9.85	\$ 8,170
9	2/22/2017	Brookings/Bemidji	SD/MN	GARY EGGEN, MARK THOMA, NIKOLA KLEVEN	NG2020 project - site visit to Solway Plant.	\$ 2,321.17	16	3.03	48.00	9.09	\$ 3,505
10	2/23/2018	St. Paul	MN	TIM ROGELSTAD, JASON WEIERS, TINO HARRIS, GINA ICE, CHUCK MAGFARLAN	MN Rate Case Oral Arguments	\$ 1,195.40	7.25	1.37	43.50	8.22	\$ 4,574
11	2/27/2018	Sioux City	IA	MARIA BERINGER, ANDREA HARRINGTON	Receiving/verifying material (poles) for BSSE project.	\$ 1,443.05	11	2.1	22.00	4.20	\$ 2,013
12	3/2/2018	St. Paul	MN	TIM ROGELSTAD, JESSICA FYHRIE, CRIS OEHLER, STEPHANIE HOFF, BRYCE HAU	MN Rate Case Deliberations	\$ 1,134.13	7.25	1.37	58.00	10.96	\$ 5,580
13	3/3/2018	St. Paul	MN	TANYA KELM, DEB OPATZ, RYAN RETZLAFF, NATE JENSEN, STACIE HEBERT, JAS	Attend MPUC MISO Quarterly update	\$ 1,266.46	7.25	1.37	43.50	8.22	\$ 3,416
14	3/10/2018	Superior	WI	MARK REMER, STEVE SCHOENECK, JASON WEIERS, JESSE TOMFORD	Meet with Enbridge	\$ 1,178.84	8	1.53	32.00	6.12	\$ 2,332
15	3/13/2018	Spearfish	SD	GARY EGGEN, VICKI SEVENS, DAVE KANTRUD, SCOTT RUUD, KAREN MOSTI	IRWA Conference & Class	\$ 2,618.84	16.75	3.18	100.50	19.08	\$ 12,328
16	3/20/2018	Carrington	ND	TIM ROGELSTAD, CRIS OEHLER, PETE WASBERG, JENNIFER SMESTAD, TOM BR	Executive Forum presentation at Field Conference	\$ 1,019.05	7	1.33	49.00	9.31	\$ 5,834
17	3/21/2018	Pierre	SD	MARK THOMA, BILL SWANSON, MARK BRING, JASON WEIERS, STEPHANIE HO	Meet with SD PUC staff to review and discuss the NG2020 project.	\$ 2,152.36	10.5	1.97	52.50	9.85	\$ 7,190
18	3/22/2018	Worthington	ND	MARK REMER, STEVE SCHOENECK, RITCHE WOLFE, CHRIS WALTZ	Meeting with MN Soybean Processors Company on possible new load	\$ 1,076.83	7.25	1.48	31.00	5.92	\$ 2,261
19	3/23/2018	Carrington	ND	PETE WASBERG, TOM BRAUSE, JOANN THOMPSON, GEORGE BELL, CARY STEP	Executive Forum presentation at Field Conference	\$ 1,889.74	7	1.33	42.00	7.98	\$ 5,834
20	3/27/2018	Marshall	TX	DAVE CHAPUT, KRIS KOCH, MYRON RADER, DAN ALBRECHT, DANNY FREDERICK	BSSE Project - Materials Production Inspection	\$ 5,786.91	42	7.99	252.00	47.94	\$ 22,524
21	3/30/2018	Beulah	ND	TIM ROGELSTAD, PETE WASBERG, JENNIFER SMESTAD, CRIS OEHLER, JOANN	Executive Forum presentation at Coyote Station.	\$ 1,473.15	11.75	2.23	70.50	13.38	\$ 11,663
22	3/31/2018	Sioux City	IA	LORI MOXNESS, ALAYNA BOYUM	Receiving/verifying material (poles) for BSSE project.	\$ 1,381.67	11	2.1	22.00	4.20	\$ 2,013
23	4/3/2018	Vancouver	BC	MATT BUCHER, ANNA ROBERTS, BRETT JOHNSON, DON REDDEN, MARK HELL	Project Sponsors to meet with Cayenta Executives and Anna Roberts t	\$ 8,739.76	55.25	9.93	331.50	59.58	\$ 29,277
24	4/7/2018	St. Paul	MN	JESSICA FYHRIE, CRIS OEHLER, PETE BETHON, BRUCE GERHARDSON, M	Attend MSBA event.	\$ 1,121.63	7.25	1.37	43.50	8.22	\$ 4,364
25	4/18/2018	Bismarck	ND	STEVE RAU, SHANE WEVLEY, TODD STRUBE, TOM OBOWA, BILL ZUMAWALDE	MIC/MUG & UTC conference hosted by Basin Electric	\$ 1,394.36	9.5	1.81	47.50	9.05	\$ 4,178
26	4/20/2018	Bismarck	ND	STUART TOMMERDAHL, DAVE PRAZAK, CARY STEPHENSON	Meet with ND commission staff on proposed Economic Development	\$ 2,255.07	9.5	1.81	28.50	5.43	\$ 2,894
27	5/2/2018	Greenville	SC	DAVE CHAPUT, MYRON RADER, RYAN RETZLAFF, MARK HELLAND	BSSE Project - Materials Production Inspection	\$ 6,584.97	48.75	9.28	341.25	64.96	\$ 29,475
28	5/22/2018	Bismarck	ND	MARIA BERINGER, NATE JENSEN, TANYA KELM	Attend ND PSC meeting on MISO update.	\$ 1,247.46	9.5	1.81	28.50	5.43	\$ 2,514
29	5/22/2018	Sioux City	IA	MARIA BERINGER, KRIS KOCH, PAUL HENNE	Receiving/verifying material (poles) for BSSE project.	\$ 1,388.91	11	2.1	33.00	6.30	\$ 2,966
30	5/25/2018	Bemidji	MN	MARK HELLAND, JOANN THOMPSON, TIM ROGELSTAD, RICK JOHNSON, REBE	Bemidji Chamber of Commerce	\$ 692.92	4.25	0.8	21.25	4.00	\$ 2,924
31	5/31/2018	Bemidji	MN	TIM ROGELSTAD, JAN RUDOLF	Meeting in Bemidji	\$ 615.17	4.25	0.8	8.50	1.60	\$ 1,454
32	6/1/2018	St. Paul	MN	JESSICA FYHRIE, RYAN RETZLAFF, STACIE HEBERT, JASON WEIERS, BRIAN DR	Meeting with Dorsey & Whitney LLP	\$ 1,212.13	7.25	1.37	10.96	58.00	\$ 4,286
33	6/16/2018	Minot	ND	BRAD TORGERSON, MARK RICK, SHANNON BJORGGAARD	Parshall 46kV MWEC Source Project	\$ 1,500.00	11.75	2.24	35.25	6.72	\$ 2,910
34	6/16/2018	Minot	ND	BRAD TORGERSON, MARK RICK, SHANNON BJORGGAARD	Parshall 46kV MWEC Source Project	\$ 1,425.00	11.75	3.24	35.25	9.72	\$ 2,409
35	6/22/2018	Bismarck	ND	MARK BRING, TIM ROGELSTAD	Meeting with MDU	\$ 683.61	9.5	1.81	19.00	3.62	\$ 3,250
36	6/27/2018	Bismarck	ND	STUART TOMMERDAHL, BILL SWANSON, CARY STEPHENSON, BRYCE HAUGEN	Informal meeting with Commissioners regarding ND ECR.	\$ 1,341.94	9.5	1.81	57.00	10.86	\$ 6,557
37	6/29/2018	St. Paul	MN	BRUCE GERHARDSON, DAVE PRAZAK, BRYCE HAUGEN, MARK REMER, STEVE	MN Energy Intensive Trade Exposed	\$ 1,127.12	7.25	1.37	36.25	6.85	\$ 3,237
38	7/27/2018	St. Paul	ND	BRIAN DRAXTEN, STEPHANIE HOFF, BRUCE GERHARDSON	Attend MPUC meeting in Externality Docket.	\$ 1,120.84	7.25	1.37	21.75	4.11	\$ 2,494
39	8/1/2018	Pierre	SD	BRIAN DRAXTEN, KRIS DAHL, MATT OLSEN	Attend SD PUC hearing on Cont'd PURPA complaint	\$ 1,508.48	10.5	1.97	31.50	5.91	\$ 3,170
40	8/8/2018	Millbank	SD	MARK HELLAND, STEVE SCHOENECK, DON REDDEN, PETE WASBERG, TIM ROG	Presenting award to service reps and line men.	\$ 541.34	3.5	0.63	21.00	3.78	\$ 2,950
41	8/10/2018	Bismarck	ND	STUART TOMMERDAHL, MATT OLSEN, BRIAN DRAXTEN, PETE BETHON, DEB	Meeting with ND PSC Staff on Potential Rate Case Filing	\$ 1,373.64	9.5	1.81	47.50	9.05	\$ 4,959
42	8/15/2018	Jamestown	ND	TIM ROGELSTAD, DON REDDEN, REBECCA MICHAEL, JOANN THOMPSON, CHR	Attend safety meetings to recognize EE storm restoration award.	\$ 795.96	5.75	1.06	34.50	6.36	\$ 5,120
43	8/17/2018	Jamestown	ND	MARK BRING, MARK HELLAND, BRAD TOLLERSON, LOREN LAUGTUG, JASON F	Attend Greater North Dakota Chamber policy summit	\$ 1,474.79	9.5	1.81	47.50	9.05	\$ 6,563
44	8/21/2018	Vancouver	BC	MATT BUCHER, ANNA ROBERTS, LAURA GRIFFITH, MARK HELLAND	Visit Cayenta's headquarters	\$ 10,176.43	55.25	9.94	221.00	39.76	\$ 29,277
45	8/27/2018	Omaha	NE	HEIDI KOYANENBELT, BILL ZUMAWALDE, SHANE WEVLEY, CHRIS HEIER	NCEA Conference	\$ 2,964.38	14.75	2.78	59.00	11.12	\$ 7,537
46	8/30/2018	Brookings	SD	TIM ROGELSTAD, SARAH CASEY, CRIS OEHLER, GARY EGGEN	Completion of BSSB line, ribbon cutting	\$ 861.50	6	1.13	24.00	4.52	\$ 2,888
47	9/7/2018	Watertown	SD	CHRIS WALTZ, STEVE SCHOENECK, TODD LANGSTON, JESSE TOMFORD	Industrial customer expansion.	\$ 659.09	4.75	0.87	19.00	3.48	\$ 1,403
48	9/8/2018	Bismarck	ND	STUART TOMMERDAHL, MATT OLSEN, DAVE PRAZAK, BRYCE HAUGEN	Meeting with Commission Staff.	\$ 1,444.56	9.5	1.81	38.00	7.24	\$ 2,761
49	9/18/2018	Minneapolis	MN	CHRIS WALTZ, BOB SITZMANN, KEVIN DISSEE, STEVE SCHOENECK, WADE THO	2017 MN Energy Expo	\$ 1,054.73	7	1.3	42.00	7.80	\$ 3,020
50	9/20/2018	St. Paul	MN	STACIE HEBERT, TJ NEWKIRK, TANYA KELM, RYAN RETZLAFF, JESSE TOMFOR	Quarterly PUC/MISO	\$ 1,266.54	7.25	1.37	45.50	8.22	\$ 3,505
51	9/22/2018	St. Paul	MN	BRUCE GERHARDSON, JASON WEIERS, CRIS OEHLER, RYAN RETZLAFF	Presenting at the Board of Directors meeting.	\$ 1,211.78	7.25	1.37	29.00	5.48	\$ 3,749
52	9/27/2018	Bemidji	MN	JESSE TOMFORD, TOM HRDLICKA, JAKE HECK, ALI PAULY, JAKE ELEFSON, ASK	CSC MEETING IN BEMIDJI	\$ 723.19	4.25	0.8	25.50	4.80	\$ 1,860
53	10/2/2018	Vermillion	SD	AL KOECKERITZ, JENNIFER SMESTAD, KRIS DAHL	BSSE oral argument	\$ 1,442.81	10.5	1.97	31.50	5.91	\$ 3,708
54	10/3/2018	Sioux Falls	SD	MARK HELLAND, DON REDDEN, STEVE SCHOENECK, STEVE RAU, JUSTIN FORD	Economic Development	\$ 1,343.53	8.25	1.54	49.50	9.24	\$ 5,635
55	10/4/2018	Bismarck	ND	TIM ROGELSTAD, MARK BRING	Lighte Energy Council Board of Directors Meeting & Fall Conference.	\$ 1,299.35	9.5	1.81	19.00	3.62	\$ 3,262
56	10/5/2018	Bismarck	ND	CARY STEPHENSON, BRAD TOLLERSON, RANDY SYMSTUEN, BILL SWANSON, E	ND PSC Merricour/Astoria ADP Hearing	\$ 1,774.17	9.5	1.81	57.00	10.86	\$ 7,459
57	10/9/2018	Bismarck	ND	MARK BRING, LOREN LAUGTUG, BRAD TOLLERSON	ND Legislative Interim Energy Development & Transmission Committee	\$ 1,308.76	9.5	1.81	28.50	5.43	\$ 4,279
58	10/10/2018	Beulah	ND	TANYA KELM, BRAD TOLLERSON, MARK BRING, LOREN LAUGTUG, STEPHANIE	2017 Great Plains & EmPower ND Energy Conference	\$ 1,678.80	11.75	2.23	58.75	11.15	\$ 11,663
59	10/11/2018	St. Paul	MN	BRIAN DRAXTEN, STEPHANIE HOFF, BRUCE GERHARDSON	Attend Great Plains Institute Energy Innovation Celebration	\$ 1,201.18	7.25	1.37	21.75	4.11	\$ 4,598
60	10/12/2018	Bismarck	ND	STACIE HEBERT, TJ NEWKIRK, TANYA KELM, JASON WEIERS, RANDY SYMSTUE	Attend ND PSC SPP / MISO meetings	\$ 1,265.32	9.5	1.81	47.50	9.05	\$ 4,653
61	10/19/2018	St. Paul	MN	BRUCE GERHARDSON, MATT OLSEN, PETE BETHON, STUART TOMMERDAHL	MPUC agenda meeting.	\$ 1,146.80	7.25	1.37	45.50	8.22	\$ 4,400
62	10/22/2018	Bismarck	ND	CARY STEPHENSON, CHRIS WALTZ, STEVE SCHOENECK, DALE RUBISH, LINDSA	ND PSC ND Minn-Kota Ag Products Inc. CPCH Hearing	\$ 1,808.51	9.5	1.81	47.50	9.05	\$ 4,566
63	10/24/2018	Pierre	SD	MARK THOMA, PAUL VUKONICH, KYLE FRIGAARD, MYRON RADER	Present at SD Engineering Society Fall Conference	\$ 1,356.21	10.5	1.97	42.00	7.88	\$ 3,509

64	10/26/2018	St. Paul	MIN	CARY STEPHENSON, BRIAN DRAXTEN, RANDY SYNSTELIEN	MN RRA/RES Eligibility - Merricourt	\$ 1,172.65	7.25	1.37	21.75	4.11	\$ 2,533
65	10/30/2018	Sioux City	IA	MARIA BERINGER, AL KOECKERITZ	Receiving/verifying material (poles) for BSSE project	\$ 1,464.95	11	2.1	22.00	4.20	\$ 2,442
66	11/15/2018	Shreveport	LA	GREG RAUSCH, MARK THOMA, MAVERICK THOMPSON, DARRIN SOLBERG, MIK	PAC supplier ADA-CS facility visit.	\$ 5,782.82	40.5	7.7	202.50	38.50	\$ 17,364
67	11/28/2018	Bismarck	ND	TIM ROGELSTAD	LEC management committee meeting.	\$ 1,221.20	9.5	1.81	9.50	1.81	\$ 1,670
68	12/11/2018	Sioux City	IA	PAUL HENNING, MARIA BERINGER, GREG RAUSCH	Receiving/verifying material (poles) for BSSE project.	\$ 1,612.27	11	2.1	33.00	6.30	\$ 2,966
69	12/15/2018	St. Paul	MN	STACIE HEBERT, BRIAN DRAXTEN, DEB OPATZ, NATE JENSEN, RANDY SYNSTELIEN	MISO/MN quarterly update meeting at the PUC.	\$ 1,292.73	7.25	1.37	43.50	8.22	\$ 4,032
70	12/19/2018	Pierre	SD	MARK BRING, PETE BETHON	Attend the SD Electric Utility Companies' annual meeting a with SD PUC	\$ 1,473.25	10.5	1.97	21.00	3.94	\$ 2,983
71	12/20/2018	Bismarck	ND	CARY STEPHENSON, PETE BEITHON, MATT OLSEN, CHRIS WALTZ	PSC meeting regarding approval of Interim Rates	\$ 1,410.59	9.5	1.81	38.00	7.24	\$ 4,348
						\$ 127,926.76			3906.96	794.31	\$ 417,470
						246,945					
						26,000					
						\$ 400,871.76					\$ 417,470

*Flights for below the line activities that are not included for cost recovery have been removed.

Fixed costs allocated to the utility
 1/5 of \$130,000 maintenance performed in 2015
 Total Costs

Total Cost of Driving	\$ 417,470
Total Cost of Flying	\$ 400,872
Savings by Plane Ownership	\$ 16,598

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Response to Data Request ND-PSC-15.02
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/04/2018

Responding Witness: Peter Wasberg, Director, Human Resources and Safety - (218) 739-8940

Data Request:

Refer to page 2 of the direct testimony of Company witness Peter Wasberg.

- a. For each month of 2016, 2017 and 2018 to date, please identify the number of actual full-time equivalent employees in total and broken out between union employees and non-union employees. For the non-union employees, please breakout between (1) the OTP President and 10 (or however many) other executives; (2) exempt employees; and (3) non-exempt employees.
- b. For each month of 2016, 2017 and 2018, please identify the number of budgeted full-time equivalent employees in total and broken out between union employees and non-union employees. For the non-union employees, please breakout between (1) the OTP President and 10 (or however many) other executives; (2) exempt employees; and (3) non-exempt employees.
- c. For each month of 2016, 2017 and 2018 to date, please identify the actual payroll cost by FERC account in total and broken out between union employees and non-union employees. For the non-union employees, please breakout the monthly actual payroll cost between (1) the OTP President and 10 (or however many) other executives; (2) exempt employees; and (3) non-exempt employees.
- d. For each month of 2016, 2017 and 2018 to date, please identify the budgeted payroll cost by FERC account in total and broken out between union employees and non-union employees. For the non-union employees, please breakout the monthly actual payroll cost between (1) the OTP President and 10 (or however many) other executives; (2) exempt employees; and (3) non-exempt employees.
- e. Mr. Wasberg states that the Company expects that over 35% of its employees (over 275 employees) will retire during the next 10 years. Please provide a breakout of the anticipated retirements that are reflected in the 2018 test year, and show the related impacts on 2018 payroll, by account, in total and broken out between union employees and non-union employees. For the non-union employees, please breakout the monthly actual payroll cost between (1) the OTP

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Response to Data Request ND-PSC-15.02

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President and 10 (or however many) other executives; (2) exempt employees; and (3) non-exempt employees.

- f. Please show in detail how the full-time equivalent employees and the Company's requested payroll cost in total and by account that is included in the 2018 test year reflect employee retirements and new hires.

Attachments: 4

Attachment 1 to DR ND-PSC-15.02.pdf

Attachment 2 to DR ND-PSC-15.02.pdf

Attachment 3 to DR-ND-PSC-15.02_NOTPUBLIC.pdf

Attachment 4 to DR ND-PSC-15.02.pdf

Response:

This response references schedules, attachments, and/or exhibits that that Otter Tail deems to be trade secrets, valuable or sensitive commercial or financial information, or information that is otherwise confidential or proprietary and subject to restrictions against unauthorized use and disclosure under North Dakota law and the Parties' Confidentiality Agreement. Such materials are noted as NOT PUBLIC.

- a) See Attachment 1 to DR ND-PSC-15.02.
- b) See Attachment 2 to DR ND-PSC-15.02. OTP does not budget to the level of exempt and non-exempt.
- c) See Attachment 3 to DR ND-PSC-15.02_NOTPUBLIC.
- d) See Attachment 4 to DR ND-PSC-15.02. OTP does not budget to the level of exempt and non-exempt.
- e) The projections listed in the noted testimony are based on employees reaching age 62 but are not tied to specific employees. We use age 62 because that is the approximate average age of retirees. We generally do not know the specific employees or positions until such a time as notice is given for a retirement. We seldom would know, during the budgeting process, all, or even a portion of the expected retirements. As a result, we base our projections on what we know, historical data, and on projections based on our average retirement age.
- f) We did not budget for any material impacts resulting from the retirements or other attrition. We do, however, recognize we are never at full staffing because of attrition and within our total labor budget we manually reduce our budgeted employee count by incorporating a "negative Full-time Equivalent (FTE)". As a result our actual FTEs will be below the amount of FTEs budgeted within individual cost centers.

15.02 (b)

2018 Budget Cost Center+	January	February	March	April	May	June	July	August	September	October	November	December
0670 - FERC/RTO Policy	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
0680 - Legal Affairs	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
0690 - Business Unit Administration	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0720 - Human Resources	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.0	9.0	9.0
0750 - Business Planning	4.9	4.9	4.9	5.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
0760 - Power Services	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
0770 - Environmental Services	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0790 - Generation Services	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
0800 - Supply Engineering	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
0810 - Strategic Sourcing	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
0840 - Market Planning	9.9	9.8	9.7	9.7	9.5	9.6	9.5	9.5	9.5	9.7	9.8	9.8
0850 - Regulatory Administration	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
0860 - State Regulatory Compliance and Filings	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
0870 - Land Rights and Permitting	8.0	8.0	8.0	8.0	10.0	10.0	10.0	10.0	8.0	8.0	8.0	8.0
0880 - Regulatory Recovery & Advocacy	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
0900 - Safety Services	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
0960 - Accounting Transactions	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)	(10.0)
1020 - Hoot Lake Plant	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
1100 - BSP-Administrative	9.0	9.0	9.0	9.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
1110 - BSP-Electrical	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
1120 - BSP-Maintenance	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
1130 - BSP-Operations	32.0	32.0	32.0	32.0	32.0	33.0	33.0	33.0	32.0	32.0	32.0	32.0
1140 - BSP-Yard	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
1200 - Coyote-Administrative	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	10.0	10.0	10.0	10.0
1210 - Coyote-Electrical	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
1220 - Coyote-Maintenance	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
1230 - Coyote-Operations	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
1240 - Coyote-Yard	6.0	6.0	6.0	6.0	6.0	8.0	8.0	8.0	6.0	6.0	6.0	6.0
1440 - Solway Combustion Turbine	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
1690 - Wind Generation - Development	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
1980 - Central Stores	6.8	6.7	6.7	6.8	6.7	6.8	6.7	6.7	6.8	6.7	6.8	6.8
1990 - Transportation	11.7	11.6	11.6	11.8	12.7	13.6	13.7	13.1	12.0	11.6	11.8	11.6
9000 - Lost Time/Non-Active Employees	3.3	(0.0)	(0.0)	(0.0)	(0.0)	1.1	1.1	(0.0)	1.1	(0.0)	1.1	1.1
Grand Total	782.3	777.1	778.0	778.8	779.3	788.1	786.5	783.5	766.7	764.9	766.3	767.1

15.02 (b)

2017 Budget Cost Center+	January	February	March	April	May	June	July	August	September	October	November	December
0670 - FERC/RTO Policy	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
0680 - Legal Affairs	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
0690 - Business Unit Administration	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0720 - Human Resources	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
0750 - Business Planning	5.0	4.9	4.9	5.0	4.9	4.9	4.9	4.9	4.9	5.0	4.9	4.9
0760 - Power Services	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
0770 - Environmental Services	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0790 - Generation Services	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
0800 - Supply Engineering	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
0810 - Strategic Sourcing	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
0840 - Market Planning	9.7	9.7	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
0850 - Regulatory Administration	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
0860 - State Regulatory Compliance and Filings	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0870 - Land Rights and Permitting	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
0880 - Regulatory Recovery & Advocacy	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
0900 - Safety Services	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
0960 - Accounting Transactions	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)	(23.0)
1020 - Hoot Lake Plant	39.0	39.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
1100 - BSP-Administrative	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	10.0	10.0	10.0	10.0
1110 - BSP-Electrical	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
1120 - BSP-Maintenance	21.0	21.0	21.0	21.0	21.0	23.0	23.0	23.0	21.0	21.0	21.0	21.0
1130 - BSP-Operations	32.0	32.0	32.0	32.0	32.0	34.0	34.0	34.0	32.0	32.0	32.0	32.0
1140 - BSP-Yard	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
1200 - Coyote-Administrative	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
1210 - Coyote-Electrical	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
1220 - Coyote-Maintenance	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
1230 - Coyote-Operations	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
1240 - Coyote-Yard	6.0	6.0	6.0	6.0	6.0	8.0	8.0	8.0	6.0	6.0	6.0	6.0
1440 - Solway Combustion Turbine	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
1690 - Wind Generation - Development	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
1980 - Central Stores	6.7	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
1990 - Transportation	11.9	11.9	11.9	11.9	12.3	13.7	13.7	13.7	12.3	11.5	11.5	11.5
9000 - Lost Time/Non-Active Employees	3.3	(0.0)	(0.0)	(0.0)	(0.0)	1.1	1.1	(0.0)	1.1	(0.0)	1.1	1.1
Grand Total	775.8	772.8	771.3	771.7	780.3	795.9	796.7	790.6	770.5	768.7	769.7	769.8

15.02 (b)

2016 Budget Cost Center+	January	February	March	April	May	June	July	August	September	October	November	December
0670 - FERC/RTO Policy	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
0680 - Legal Affairs	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
0690 - Business Unit Administration	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0720 - Human Resources	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
0750 - Business Planning	5.0	4.9	4.9	5.0	4.9	4.9	4.9	4.9	4.9	5.0	4.9	4.9
0760 - Power Services	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0770 - Environmental Services	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
0790 - Generation Development	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
0800 - Supply Engineering	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
0810 - Strategic Sourcing	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
0840 - Market Planning	8.9	8.8	8.8	8.5	8.5	8.5	8.5	8.5	8.6	8.5	8.5	8.5
0850 - Regulatory Administration	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
0860 - State Regulatory Compliance and Filings	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0870 - Land Rights and Permitting	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
0880 - Regulatory Recovery & Advocacy	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
0900 - Safety Services	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
0960 - Accounting Transactions	(18.0)	(17.0)	(16.0)	(15.0)	(14.0)	(10.0)	(10.0)	(10.0)	(10.0)	(8.0)	(8.0)	(8.0)
1020 - Hoot Lake Plant	39.0	40.0	40.0	40.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
1100 - BSP-Administrative	13.0	13.0	13.0	13.0	13.0	14.0	14.0	14.0	13.0	13.0	13.0	13.0
1110 - BSP-Electrical	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0	14.0
1120 - BSP-Maintenance	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
1130 - BSP-Operations	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
1140 - BSP-Yard	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
1200 - Coyote-Administrative	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	11.0	11.0	11.0
1210 - Coyote-Electrical	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
1220 - Coyote-Maintenance	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
1230 - Coyote-Operations	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
1240 - Coyote-Yard	6.0	6.0	6.0	6.0	8.0	8.0	8.0	8.0	6.0	6.0	6.0	6.0
1440 - Solway Combustion Turbine	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
1690 - Wind Generation - Development	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
1980 - Central Stores	6.9	6.9	6.8	7.9	7.8	7.8	7.8	7.9	7.8	6.8	6.8	6.8
1990 - Transportation	12.8	12.6	12.7	12.5	13.2	14.6	14.6	14.3	13.3	11.7	11.8	11.8
9000 - Lost Time/Non-Active Employees	2.8	(0.0)	(0.0)	(0.0)	(0.0)	0.9	0.9	(0.0)	0.9	(0.0)	0.9	0.9
Grand Total	780.9	779.3	780.5	782.8	791.7	806.9	807.1	804.1	787.4	785.3	786.8	786.3

15.02 (d)

2018 Budget

FERC-	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
1070 - Construction work in progress -- Electric				3,611	3,520	3,950	3,806	3,821	171,145	3,720	3,572		26,041
5000 - Steam Power Generation - Operation supervision and engineering	153,335	182,095	186,360	208,127	207,153	194,978	184,229	191,853	171,145	197,569	200,701	176,679	2,254,223
5010 - Steam Power Generation - Fuel	74,803	52,533	34,640	47,108	35,264	37,260	33,639	39,154	36,222	29,398	43,507	28,942	492,470
5020 - Steam Power Generation - Steam expenses	144,306	187,968	190,844	156,414	136,535	153,407	140,384	159,893	156,005	142,585	139,181	141,464	1,848,987
5050 - Steam Power Generation - Electric expenses	181,753	189,751	190,056	218,651	174,473	203,806	199,494	210,535	207,059	190,057	182,721	204,638	2,352,995
5060 - Steam Power Generation - Miscellaneous steam power expenses	237,017	259,614	253,580	285,017	238,627	271,184	248,157	280,675	263,505	313,317	308,398	292,198	3,251,288
5100 - Steam Power Generation - Maintenance supervision and engineering	67,018	77,792	85,885	86,712	80,561	84,379	86,265	86,119	89,156	95,933	89,895	77,529	1,007,245
5110 - Steam Power Generation - Maintenance of structures	33,857	41,977	27,390	30,011	17,990	40,652	37,335	28,563	24,155	29,874	27,357	32,203	371,364
5120 - Steam Power Generation - Maintenance of boiler plant	229,049	230,483	263,004	238,204	336,071	195,731	205,278	206,370	220,491	302,134	201,916	219,301	2,848,093
5130 - Steam Power Generation - Maintenance of electric plant	9,337	26,008	32,013	49,429	90,368	31,284	26,396	31,736	28,649	81,759	45,472	48,806	501,257
5140 - Steam Power Generation - Maintenance of miscellaneous steam plant	62,781	82,409	71,514	78,730	148,169	85,568	70,797	67,669	73,616	62,544	56,815	74,208	933,821
5350 - Hydraulic Power Generation - Operation supervision and engineering	854	2,220	1,386	967	879	217	1,959	1,636	3,125	2,679	2,402	1,905	20,230
5370 - Hydraulic Power Generation - Hydraulic Expenses	668	152	1,248	3,281	1,949	102	58		194			1,071	8,724
5380 - Hydraulic Power Generation - Electric Expenses	3,039	2,990	230	5,871	4,167	5,971	8,473	16,564	15,514	14,383	8,987	6,631	92,821
5390 - Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses	647	228		1,291		4,907	12,009	23,824	24,931	22,232	27,891	17,332	161,988
5410 - Hydraulic Power Generation - Maintenance supervision and engineering	4,986	5,240	9,437	2,707	6,491	4,907	12,009	23,824	24,931	22,232	27,891	17,332	161,988
5430 - Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways				588	1,113				1,462				3,164
5440 - Hydraulic Power Generation - Maintenance of electric plant	8,667	13,603	11,772	21,153	25,832	2,167	7,353	6,316	7,768	9,147	3,626	5,124	122,526
5460 - Other Power Generation - Operation supervision and engineering	33,787	27,663	24,038	11,100	19,234	13,020	19,836	18,977	32,909	8,111	7,346	6,949	222,970
5480 - Other Power Generation - Generation Expenses	70,250	79,026	62,347	70,576	69,020	69,827	66,634	62,799	57,772	67,818	68,075	71,777	815,921
5490 - Other Power Generation - Miscellaneous other power generation expenses	4,813	4,604	4,066	3,400	619		1,709	2,005	4,330	2,253	1,824		29,004
5510 - Other Power Generation - Maintenance supervision and engineering			4,535	501									5,655
5520 - Other Power Generation - Maintenance of structures			4,535	501									5,655
5530 - Other Power Generation - Maintenance of generating and electric plant	19,564	29,869	40,186	15,607	28,836	24,481	23,012	15,458	24,781	38,329	19,105	30,805	310,094
5540 - Other Power Generation - Maintenance of miscellaneous other power generation plant	235	259	837	430	522		468						2,750
5560 - Other Power Supply Expenses - System control and load dispatching	12,662	12,828	10,453	14,423	14,120	22,833	23,140	22,847	26,408	38,157	27,561	26,621	252,053
5570 - Other Power Supply Expenses - Other Expenses			730	17,667	16,182	23,443	20,699	22,137	22,157	23,181	22,854	19,245	188,296
5600 - Transmission Expenses - Operation supervision and engineering	35,266	37,406	36,004	39,162	31,405	42,749	38,552	40,362	48,043	50,457	44,784	50,688	495,480
5611 - Transmission Expenses - Load dispatch - reliability	7,055	6,737	6,065	6,940	7,920	7,154	6,632	7,074	6,993	6,507	7,197	7,400	83,675
5612 - Transmission Expenses - Load dispatch - monitor and operate transmission system	225,908	253,869	251,588	244,819	245,848	249,644	246,992	259,806	233,266	244,642	221,019	260,482	2,937,881
5615 - Transmission Expenses - Reliability, planning, and standards development	49,093	50,723	51,321	47,886	66,264	63,316	58,847	66,366	68,759	75,598	71,050	59,713	728,936
5616 - Transmission Expenses - Transmission service studies	3,382			399									3,781
5620 - Transmission Expenses - Station expenses	23,588	31,056	23,900	28,388	15,344	18,636	17,114	23,033	19,853	25,687	24,040	39,144	289,783
5630 - Transmission Expenses - Overhead line expenses	5,910	6,397	10,629	13,781	15,758	12,159	16,382	11,427	13,873	17,026	11,887	13,348	148,577
5660 - Transmission Expenses - Miscellaneous transmission expenses	56,347	67,430	63,225	37,144	58,757	15,445	17,997	14,548	19,053	34,621	39,118	38,121	461,806
5680 - Transmission Expenses - Maintenance supervision and engineering	22,254	21,326	27,729	29,424	21,221	33,287	28,958	19,649	22,605	22,973	16,875	22,173	288,475
5691 - Transmission Expenses - Maintenance of computer hardware	604	1,064	4,142	8,442	9,165	3,997	7,397	7,297	11,826	18,411	7,210	9,603	89,159
5692 - Transmission Expenses - Maintenance of computer software	43,351	44,933	53,826	41,486	48,805	53,350	47,575	51,141	48,194	47,869	48,421	48,593	577,544
5693 - Transmission Expenses - Maintenance of communication equipment	5,493	3,109	8,693	5,687	8,552	10,370	6,818	9,296	9,851	12,083	7,638	7,243	94,833
5700 - Transmission Expenses - Maintenance of station equipment	48,341	53,428	85,668	(53,677)	66,704	96,112	82,423	75,848	99,097	132,898	53,474	36,117	776,471

15.02 (d)

2018 Budget													
FERC#	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
5750 - Transmission Expenses - Maintenance of overhead lines	39,738	47,355	37,945	66,217	64,150	38,214	43,214	22,471	32,613	30,137	23,663	54,684	500,402
5752 - Regional Market Expenses - Day-ahead and real-time market administration	56,161	60,567	67,046	12,780	12,530	8,059	6,827	35,366	38,021	36,967	39,492	33,768	518,521
5753 - Regional Market Expenses - Transmission rights market administration								6,690	7,793	7,577	7,192	6,569	76,017
5755 - Regional Market Expenses - Ancillary services market administration	1,815	2,299	2,433										6,547
5756 - Regional Market Expenses - Market monitoring and compliance	372	230	1,338										1,940
5763 - Regional Market Expenses - Maintenance of computer software	21,218	29,166	1,484	293	1,233	4,576	4,520	4,759	4,501	4,454	4,341	4,499	34,795
5800 - Distribution Expenses - Operation supervision and engineering	14,593	16,396	15,183	27,295	26,011	27,515	30,340	27,390	26,201	30,793	19,131	14,282	361,592
5810 - Distribution Expenses - Load Dispatching	11,001	8,962	11,735	10,384	14,014	10,600	15,447	14,065	17,252	12,226	12,138	10,701	275,131
5820 - Distribution Expenses - Station expenses	20,159	35,629	35,310	24,684	23,560	23,525	27,107	23,543	22,802	23,851	28,433	25,585	148,526
5830 - Distribution Expenses - Overhead line expenses	28,657	30,665	44,080	44,259	119,277	117,493	108,004	133,870	126,809	118,450	124,204	62,400	314,188
5840 - Distribution Expenses - Underground line expenses				1,588									1,588
5850 - Distribution Expenses - Street lighting and signal system expenses	105,925	126,075	136,575	194,006	160,507	82,613	89,118	92,968	126,549	119,080	110,491	107,407	1,451,314
5860 - Distribution Expenses - Meter expenses	11,127	16,326	13,672	16,846	19,896	16,823	20,371	19,270	24,298	20,485	17,888	16,790	213,790
5870 - Distribution Expenses - Customer installation expenses	234,708	268,573	234,296	209,263	142,048	148,217	106,338	127,924	121,164	147,531	135,677	159,674	2,035,412
5880 - Distribution Expenses - Miscellaneous distribution expenses	95,811	108,615	108,143	80,712	64,928	66,443	66,053	76,715	67,465	90,028	85,841	88,641	999,396
5900 - Distribution Expenses - Maintenance supervision and engineering	43,177	43,430	43,151	42,737	30,466	42,281	45,118	49,870	35,563	39,077	50,540	30,385	495,794
5920 - Distribution Expenses - Maintenance of station equipment	256,400	244,455	250,001	264,264	241,057	226,120	247,333	243,637	247,161	245,296	237,071	233,864	2,936,659
5930 - Distribution Expenses - Maintenance of overhead lines	33,286	34,857	34,511	49,993	85,550	94,812	69,390	95,008	111,505	102,143	86,798	72,702	870,557
5940 - Distribution Expenses - Maintenance of underground lines	3,306	2,011	7,222	4,061	3,960	4,318	3,802	4,589	4,473	4,482	4,428	4,109	50,762
5950 - Distribution Expenses - Maintenance of line transformers	70,013	106,898	76,388	73,333	60,033	51,331	52,028	63,153	75,172	78,959	73,626	108,325	889,259
5960 - Distribution Expenses - Maintenance of street lighting and signal systems	39,485	56,013	62,563	41,481	47,326	40,536	43,385	49,512	35,742	36,840	54,974	53,982	561,839
5970 - Distribution Expenses - Maintenance of meters	9,030	12,570	10,667	9,26	7,778	7,678	9,371	8,817	10,445	5,436	8,057	7,599	103,375
5980 - Distribution Expenses - Maintenance of miscellaneous distribution plant	3,233	3,893	4,492	23,006	24,499	19,475	23,559	22,642	20,152	23,886	24,492	26,214	219,543
9010 - Customer Accounts Expenses - Supervision	385,965	405,485	389,867	319,533	256,643	238,235	207,408	248,238	242,872	246,986	283,808	312,998	3,538,038
9020 - Customer Accounts Expenses - Meter reading expenses	355,786	481,029	453,978	551,254	506,770	430,583	416,319	498,692	493,174	507,858	503,151	523,526	5,772,121
9030 - Customer Accounts Expenses - Customer records and collection expenses	13,539	18,598	14,884	9,695	13,228	8,817	11,954	9,740	11,621	12,741	10,923	16,068	151,808
9050 - Customer Accounts Expenses - Miscellaneous customer accounts expenses	46,376	52,403	52,788	90,570	56,893	59,150	55,230	74,015	74,143	68,581	78,385	67,680	776,214
9070 - Customer Service and Informational Expenses - Supervision	60,274	67,145	60,189	87,113	91,785	95,817	82,945	100,085	81,862	106,279	97,995	110,840	1,042,330
9080 - Customer Service and Informational Expenses - Customer assistance expenses	339	342	899	367	351	602	533	281	641	560	260	270	5,444
9090 - Customer Service and Informational Expenses - Informational/Instructional advertising exp.			138		261	520	629	2,591	567	417	391	55	5,567
9100 - Customer Service and Informational Expenses - Misc. customer service/Informational exp.	6,724	10,014	8,074										24,812
9110 - Sales Expenses - Supervision	12,877	19,489	21,133	26,076	32,207	19,238	26,154	26,274	20,360	27,545	16,572	17,712	265,639
9120 - Sales Expenses - Demonstrating and selling expenses				953	21	18					158	124	1,274
9130 - Sales Expenses - Advertising expenses													
9160 - Sales Expenses - Miscellaneous sales expenses	1,187,187	1,457,886	1,332,514	1,437,826	1,533,783	1,300,545	1,191,404	1,306,202	1,227,040	1,341,748	1,244,424	1,295,256	15,855,815
9200 - Administrative and general salaries				405	742				2,954				6,906
9240 - Property insurance				1,113	1,091				2,954				
9250 - Injuries and damages	28,712	36,411	34,934	38,993	38,049	28,978	22,354	23,309	32,026	32,533	32,037	31,392	379,727
9260 - Employee pensions and benefits	24,189	27,432	24,536	34,231	38,245	37,290	41,872	38,437	3,133	45,421	34,195	30,764	379,742
9280 - Regulatory commission expenses	54,081	59,259	91,966	15,196	16,140	30,553	29,756	29,122	34,617	30,497	29,696	29,785	450,667
9301 - General advertising expenses	3,110	7,001	3,604	3,405	3,600	3,583	3,551	5,768	7,838	2,775	3,823	2,090	50,148
9302 - Miscellaneous general expenses	8,614	11,570	20,679	9,166	11,018	2,901	2,982	4,180	5,397	4,540	6,905	5,768	93,322
9350 - Maintenance of general plant	224,393	228,903	209,072	212,868	209,925	215,186	197,321	204,286	189,390	220,382	202,461	230,407	2,544,596
Grand Total	5,391,402	6,227,437	6,077,170	6,134,070	6,287,506	5,640,159	5,352,311	5,807,878	5,708,896	6,219,550	5,772,115	5,910,401	70,528,895

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2017 Budget

	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
FERC-													
1070 - Construction work in progress -- Electric	3,592	3,592	3,592	3,592	3,592	3,592	3,592	3,592	3,592	3,592	3,592	3,592	35,920
5000 - Steam Power Generation - Operation supervision and engineering	170,428	219,844	193,500	211,205	210,774	190,844	183,817	190,338	176,945	195,446	202,165	184,718	2,330,027
5010 - Steam Power Generation - Fuel	89,622	73,097	63,863	49,310	34,209	38,292	33,106	38,772	36,293	28,748	41,970	28,616	555,899
5020 - Steam Power Generation - Steam expenses	132,564	157,572	148,450	159,506	135,128	153,929	137,992	160,526	155,946	138,883	138,167	143,044	1,761,708
5050 - Steam Power Generation - Electric expenses	201,642	213,644	218,822	222,832	171,723	209,821	191,994	207,608	209,084	179,017	179,212	203,574	2,408,973
5060 - Steam Power Generation - Miscellaneous steam power expenses	226,133	298,211	288,139	290,939	230,280	278,869	240,950	279,933	262,667	297,559	300,655	291,987	3,286,321
5100 - Steam Power Generation - Maintenance supervision and engineering	65,249	93,422	83,673	88,444	82,494	91,349	90,509	91,481	94,499	95,642	90,947	79,915	1,047,623
5110 - Steam Power Generation - Maintenance of structures	21,389	30,608	26,450	30,762	18,005	42,356	38,413	29,078	24,883	27,957	26,949	31,498	348,349
5120 - Steam Power Generation - Maintenance of boiler plant	194,513	177,070	254,937	242,630	282,045	206,303	210,420	206,786	239,411	226,210	190,948	222,064	2,653,337
5130 - Steam Power Generation - Maintenance of electric plant	38,903	44,011	41,637	49,433	89,508	31,605	22,281	32,070	31,932	64,535	42,734	50,936	539,584
5140 - Steam Power Generation - Maintenance of miscellaneous steam plant	48,773	68,325	70,508	79,590	137,063	89,204	68,020	68,038	76,507	53,366	55,208	76,110	890,713
5350 - Hydraulic Power Generation - Operation supervision and engineering	1,013	948	957	941	851	207	1,913	1,585	3,038	2,588	2,323	1,870	18,234
5370 - Hydraulic Power Generation - Hydraulic Expenses	1,180	794	1,993	2,928	1,896	103	54	190	190	190	190	1,211	10,347
5380 - Hydraulic Power Generation - Electric Expenses	4,813	6,323	5,593	6,103	4,016	6,158	8,530	16,019	15,516	13,854	8,477	6,411	101,812
5390 - Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses				1,346						84			84
5410 - Hydraulic Power Generation - Maintenance supervision and engineering	2,101	2,718	5,180	2,525	6,322	5,060	12,126	23,010	25,064	21,226	26,167	16,859	148,357
5430 - Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	281		583	544	1,081				1,438				3,928
5440 - Hydraulic Power Generation - Maintenance of electric plant	13,972	28,149	13,732	19,621	25,413	2,071	3,023	5,356	7,161	3,998	3,421	4,820	130,737
5460 - Other Power Generation - Operation supervision and engineering	27,035	25,693	16,645	9,928	18,892	12,450	13,918	16,311	33,086	3,237	9,100	6,267	192,561
5480 - Other Power Generation - Generation Expenses	33,045	49,094	75,721	59,522	60,086	60,397	54,614	51,508	45,887	59,841	57,702	62,032	669,448
5490 - Other Power Generation - Miscellaneous other power generation expenses	14,876	7,650	6,877	3,273			1,652	1,544	3,846	2,041	1,679		43,438
5510 - Other Power Generation - Maintenance supervision and engineering	298	267	147	430	601								1,743
5520 - Other Power Generation - Maintenance of structures	12,318	22,840	13,218	13,746	28,281	23,083	17,312	12,681	25,930	32,485	22,619	27,109	251,625
5530 - Other Power Generation - Maintenance of generating and electric plant													
5540 - Other Power Generation - Maintenance of miscellaneous other power generation plant	12,108	13,754	15,910	14,429	13,223	23,495	24,166	22,224	24,168	35,506	27,026	25,502	251,511
5560 - Other Power Supply Expenses - System control and load dispatching	14,647	19,270	15,071	17,222	15,704	22,405	22,302	21,844	22,619	23,413	23,194	21,966	239,656
5570 - Other Power Supply Expenses - Other Expenses	40,840	42,616	38,222	39,972	31,252	47,681	41,682	44,643	49,393	53,721	49,433	53,383	532,839
5600 - Transmission Expenses - Operation supervision and engineering	8,788	6,203	9,007	7,552	8,464	6,848	6,430	6,081	6,653	6,197	7,118	6,546	85,887
5611 - Transmission Expenses - Load dispatch - reliability													
5612 - Transmission Expenses - Load dispatch - monitor and operate transmission system	227,480	249,038	259,608	265,632	261,291	239,179	239,882	224,142	221,929	233,205	218,556	230,549	2,870,490
5615 - Transmission Expenses - Reliability, planning, and standards development	37,541	55,206	50,976	47,364	62,232	61,060	57,222	60,136	64,050	70,200	67,917	58,999	692,904
5616 - Transmission Expenses - Transmission service studies			103	400									503
5620 - Transmission Expenses - Station expenses	13,628	18,780	18,368	27,206	14,992	17,734	16,120	22,527	19,541	23,897	23,188	38,504	254,483
5630 - Transmission Expenses - Overhead line expenses	4,705	10,795	11,893	13,977	16,357	11,713	12,230	10,549	13,735	12,335	12,547	12,569	143,406
5660 - Transmission Expenses - Miscellaneous transmission expenses	42,791	68,484	51,638	37,648	58,724	16,016	14,318	15,870	18,258	29,834	38,651	37,258	429,489
5680 - Transmission Expenses - Maintenance supervision and engineering	18,145	20,423	20,783	29,348	21,894	34,423	30,180	19,566	23,032	23,390	17,000	23,166	281,351
5691 - Transmission Expenses - Maintenance of computer hardware	3,649	3,203	10,304	8,696	8,712	4,185	8,281	7,652	11,134	18,113	7,274	9,853	101,057
5692 - Transmission Expenses - Maintenance of computer software	35,777	49,950	46,212	45,148	52,160	51,033	46,119	43,964	45,783	45,587	47,916	42,609	552,259
5693 - Transmission Expenses - Maintenance of communication equipment	6,030	5,145	5,170	5,805	8,170	10,445	7,662	9,865	9,989	12,648	8,369	7,187	96,484

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2016 Budget													
	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
FERC-													
5000 - Steam Power Generation - Operation supervision and engineering	147,300	192,449	179,564	184,518	187,137	168,780	169,821	165,522	165,296	172,736	185,753	167,508	2,086,385
5010 - Steam Power Generation - Fuel	80,672	64,907	60,803	45,720	34,087	36,219	31,574	36,372	34,285	27,457	40,059	27,941	520,095
5020 - Steam Power Generation - Steam expenses	113,396	123,903	133,483	134,304	106,995	125,980	124,265	140,681	141,597	122,591	122,725	129,263	1,519,183
5050 - Steam Power Generation - Electric expenses	175,653	188,326	202,745	191,501	145,392	182,063	176,918	185,859	194,411	170,847	167,835	187,994	2,169,543
5060 - Steam Power Generation - Miscellaneous steam power expenses	197,989	267,417	267,397	260,118	216,656	254,982	224,286	254,110	246,855	290,892	277,878	273,663	3,032,243
5100 - Steam Power Generation - Maintenance supervision and engineering	60,472	85,160	81,774	83,160	79,956	89,704	90,826	106,023	97,070	93,316	92,429	79,503	1,039,393
5110 - Steam Power Generation - Maintenance of structures	19,587	27,071	23,755	31,772	16,058	38,522	36,225	26,554	23,548	27,274	25,790	30,459	326,615
5120 - Steam Power Generation - Maintenance of boiler plant	176,879	152,459	236,699	275,789	300,972	173,047	193,694	187,008	224,562	258,282	184,738	204,238	2,568,366
5130 - Steam Power Generation - Maintenance of electric plant	34,238	38,827	39,409	52,691	85,855	24,413	21,090	29,117	28,848	66,235	41,835	47,698	510,255
5140 - Steam Power Generation - Maintenance of miscellaneous steam plant	45,519	59,553	66,574	83,895	131,992	79,920	65,261	66,344	73,649	54,924	54,286	71,614	853,531
5350 - Hydraulic Power Generation - Operation supervision and engineering	897	1,760	2,367	2,959	760	191	1,684	1,409	2,811	2,266	2,150	1,697	20,953
5370 - Hydraulic Power Generation - Hydraulic Expenses	1,016	753	1,679	3,182	1,726	120	62		221			882	9,641
5380 - Hydraulic Power Generation - Electric Expenses	4,276	5,511	5,264	5,421	4,142	5,895	8,114	14,919	14,616	13,187	8,492	6,197	96,036
5390 - Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses				1,194								81	81
5410 - Hydraulic Power Generation - Maintenance supervision and engineering	1,891	2,333	4,864	2,513	6,373	4,845	11,532	21,441	23,536	20,560	26,496	16,160	142,544
5430 - Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	242		606	546	957				1,207				3,557
5440 - Hydraulic Power Generation - Maintenance of electric plant	11,979	21,394	12,825	18,107	17,948	1,907	2,710	5,140	6,795	3,574	3,164	4,494	110,037
5480 - Other Power Generation - Generation Expenses	24,291	23,904	14,003	10,501	12,857	12,246	12,794	17,494	30,124	2,647	8,204	6,511	175,577
5490 - Other Power Generation - Miscellaneous other power generation expenses	27,645	40,137	70,187	55,683	55,596	55,400	52,786	50,602	43,731	54,172	50,659	58,390	614,988
5510 - Other Power Generation - Maintenance supervision and engineering	11,750	6,927	6,357	3,067	530		1,523	1,571	3,716	1,861	1,551		38,322
5520 - Other Power Generation - Maintenance of structures	256	251	135	481									1,654
5530 - Other Power Generation - Maintenance of generating and electric plant	10,899	21,356	10,676	14,846	21,486	23,641	15,856	14,304	23,290	26,896	20,481	28,209	231,940
5540 - Other Power Generation - Maintenance of miscellaneous other power generation plant		853	535	475	500		435		143				2,940
5560 - Other Power Supply Expenses - System control and load dispatching	11,437	13,184	13,958	13,318	11,736	19,714	21,042	19,370	22,706	31,628	22,581	22,308	222,982
5570 - Other Power Supply Expenses - Other Expenses	16,397	18,759	16,166	18,943	17,006	23,623	23,325	21,814	24,966	27,626	24,009	24,063	256,698
5600 - Transmission Expenses - Operation supervision and engineering	38,648	42,453	38,696	38,018	30,637	47,942	42,430	44,791	48,758	52,050	45,715	51,440	521,579
5611 - Transmission Expenses - Load dispatch - reliability	8,319	5,649	8,334	7,036	7,931	6,512	5,751	5,989	6,479	6,187	7,113	6,835	82,134
5612 - Transmission Expenses - Load dispatch - monitor and operate transmission system	216,135	226,863	240,319	247,404	244,509	226,928	214,904	220,208	215,939	231,966	218,215	240,500	2,743,891
5615 - Transmission Expenses - Reliability, planning, and standards development	35,311	47,516	44,509	43,402	53,193	52,508	48,415	52,356	56,590	59,954	58,326	50,159	602,239
5616 - Transmission Expenses - Transmission service studies			90	335									424
5620 - Transmission Expenses - Station expenses	12,301	18,414	18,236	27,224	14,555	18,881	16,306	19,024	19,218	22,423	21,107	37,384	245,072
5630 - Transmission Expenses - Overhead line expenses	4,620	8,464	10,620	12,080	9,095	9,222	9,272	8,392	11,867	10,255	9,846	11,000	114,733
5660 - Transmission Expenses - Miscellaneous transmission expenses	41,381	66,702	48,521	35,682	51,633	14,360	13,074	14,785	17,544	26,982	33,809	34,402	398,874
5680 - Transmission Expenses - Maintenance supervision and engineering	18,745	19,743	21,654	30,383	21,832	35,558	30,184	18,908	22,830	24,211	15,812	23,716	283,575
5691 - Transmission Expenses - Maintenance of computer hardware	3,734	3,148	9,632	7,602	8,564	4,599	8,792	8,216	12,819	20,278	7,911	10,388	105,684
5692 - Transmission Expenses - Maintenance of computer software	34,224	45,487	42,775	42,060	48,872	48,570	41,239	43,301	44,702	45,515	48,112	44,974	529,831
5693 - Transmission Expenses - Maintenance of communication equipment	5,528	4,557	4,461	5,121	7,812	8,903	6,693	8,922	9,198	10,843	6,933	6,476	85,447
5700 - Transmission Expenses - Maintenance of station equipment	89,352	90,453	80,872	56,405	66,405	88,372	70,746	64,735	88,610	109,886	41,967	31,242	755,871
5710 - Transmission Expenses - Maintenance of overhead lines	38,030	49,037	54,974	66,533	66,576	40,888	44,893	19,793	26,422	24,508	21,718	42,420	495,792
5752 - Regional Market Expenses - Day-ahead and real-time market administration	34,801	39,586	43,894	41,556	41,421	39,825	37,683	34,850	42,842	44,055	41,487	42,222	484,223
5753 - Regional Market Expenses - Transmission rights market administration	12,207	12,592	13,647	13,704	13,168	8,121	7,693	6,592	8,781	9,030	7,555	8,213	121,303

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	January	February	March	April	May	June	July	August	September	October	November	December	Grand Total
5763 - Regional Market Expenses - Maintenance of computer software	1,749	3,049	3,319	297	1,235	4,166	3,918	4,029	4,175	4,235	4,313	4,164	38,649
5800 - Distribution Expenses - Operation supervision and engineering	29,790	37,779	52,654	42,437	31,691	23,391	20,758	29,436	23,832	26,965	35,796	37,301	399,080
5810 - Distribution Expenses - Load Dispatching	20,543	23,360	23,466	27,255	21,080	25,177	22,858	23,328	23,832	24,818	18,853	13,124	267,695
5820 - Distribution Expenses - Station expenses	6,864	8,622	9,459	10,315	9,748	11,180	11,005	12,757	16,860	6,920	11,402	10,800	125,930
5830 - Distribution Expenses - Overhead line expenses	17,885	30,491	20,205	22,172	15,163	18,690	18,094	18,260	19,767	16,709	24,321	21,956	243,714
5840 - Distribution Expenses - Underground line expenses	18,684	22,164	29,203	42,021	120,183	113,744	114,208	123,835	118,031	124,985	116,183	60,188	1,003,428
5850 - Distribution Expenses - Street lighting and signal system expenses	2,539	7,916	990	1,560									13,006
5860 - Distribution Expenses - Meter expenses	94,735	116,722	120,065	193,695	165,278	85,611	89,392	90,827	116,265	119,514	107,528	108,981	1,408,614
5870 - Distribution Expenses - Customer installation expenses	7,829	14,801	11,867	15,600	14,618	15,278	12,866	16,403	22,907	14,394	15,925	16,571	179,049
5880 - Distribution Expenses - Miscellaneous distribution expenses	159,000	272,668	243,067	197,133	127,733	136,593	104,887	110,017	103,628	132,546	116,365	144,960	1,848,598
5900 - Distribution Expenses - Maintenance supervision and engineering	67,650	78,044	81,041	86,257	70,073	72,101	72,490	78,365	70,549	89,756	85,770	92,652	944,748
5920 - Distribution Expenses - Maintenance of station equipment	44,055	54,341	52,962	62,732	47,865	68,320	58,707	60,003	50,342	49,384	66,693	50,545	665,950
5930 - Distribution Expenses - Maintenance of overhead lines	238,086	255,704	222,338	260,123	248,717	215,910	242,750	220,264	228,124	231,521	221,483	221,543	2,806,562
5940 - Distribution Expenses - Maintenance of underground lines	35,901	24,733	28,100	47,989	82,566	89,744	63,159	85,877	99,161	96,284	78,648	69,577	801,739
5950 - Distribution Expenses - Maintenance of line transformers	6,316	2,803	1,206	3,811	1,694	752	7,577	5,199	6,399	10,939	2,644	3,148	52,487
5960 - Distribution Expenses - Maintenance of street lighting and signal systems	57,486	68,858	70,023	68,067	55,264	47,130	50,293	56,493	66,435	71,741	64,954	101,987	778,730
5970 - Distribution Expenses - Maintenance of meters	44,323	58,548	56,912	42,210	52,879	45,292	45,385	51,750	32,516	38,373	55,021	59,110	582,318
5980 - Distribution Expenses - Maintenance of miscellaneous distribution plant	5,320	13,033	10,237	6,008	7,789	6,990	8,123	7,465	9,688	5,169	8,006	7,033	94,862
9010 - Customer Accounts Expenses - Supervision	16,428	20,654	18,710	21,377	23,086	19,068	20,422	18,837	17,097	20,022	20,316	22,753	238,769
9020 - Customer Accounts Expenses - Meter reading expenses	319,053	319,669	346,584	311,599	274,048	231,735	225,865	232,416	232,756	256,051	270,120	302,377	3,322,272
9030 - Customer Accounts Expenses - Customer records and collection expenses	447,510	488,562	506,591	525,846	510,850	421,858	409,462	440,576	439,909	477,220	448,680	476,685	5,593,749
9050 - Customer Accounts Expenses - Miscellaneous customer accounts expenses	7,689	14,432	10,247	9,007	9,659	8,503	9,076	7,951	9,772	10,348	8,956	13,310	118,950
9070 - Customer Service and Informational Expenses - Supervision	62,461	78,456	78,104	86,903	58,729	57,038	60,450	65,571	67,751	68,459	70,492	61,644	816,056
9080 - Customer Service and Informational Expenses - Customer assistance expenses	56,068	77,002	74,783	79,648	76,051	87,348	72,968	82,700	73,928	91,709	85,179	100,032	957,416
9090 - Customer Service and Informational Expenses - Informational/Instructional advertising exp.	188	584	903	328	306	436	610	225	584	527	241	243	5,176
9100 - Customer Service and Informational Expenses - Misc. customer service/Informational exp.	12,073	29,028	26,143	24,882	26,113	17,800	22,082	25,044	20,717	20,670	15,432	16,993	256,978
9120 - Sales Expenses - Demonstrating and selling expenses				973		15	20						1,267
9130 - Sales Expenses - Advertising expenses	685	2,290	1,700	2,290	1,700								4,676
9160 - Sales Expenses - Miscellaneous sales expenses	995,090	1,286,605	1,267,950	1,315,751	1,403,703	1,206,478	1,155,911	1,210,728	1,168,080	1,248,145	1,160,180	1,222,373	14,640,995
9200 - Administrative and general salaries	6,449	564	1,565	392	719								9,689
9240 - Property insurance	32,007	35,769	33,949	37,743	33,166	25,515	23,930	19,379	26,480	28,319	31,742	29,947	357,945
9250 - Injuries and damages	6,449	28,210	31,676	33,190	32,269	34,095	35,502	32,514	37,164	35,732	31,044	27,778	365,621
9260 - Employee pensions and benefits	12,327	22,376	12,287	11,682	11,413	24,090	23,585	22,239	23,758	22,758	24,294	21,877	233,574
9280 - Regulatory commission expenses	312	653	803	3,048	3,140	2,787	4,002	4,710	4,464	2,570	3,586	1,958	32,034
9301 - General advertising expenses	7,228	5,955	5,184	8,265	9,672	1,871	3,322	3,402	4,957	4,272	6,376	5,209	65,713
9302 - Miscellaneous general expenses	181,056	230,856	201,707	205,760	205,915	222,238	197,899	202,958	190,598	212,657	203,348	235,309	2,490,301
9350 - Maintenance of general plant	4,789,847	5,771,034	5,787,356	5,864,439	5,887,211	5,313,849	5,096,147	5,302,724	5,399,841	5,731,256	5,361,172	5,592,373	65,897,249

Public
Response to Data Request ND-PSC-15.03
Page 1 of 1

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/02/2018
Responding Witness: Peter Wasberg, Director, Human Resources and Safety - (218) 739-8940

Data Request:

What amount of payroll cost is the Company requesting for the 2018 test year? Please identify the amount in total for the test year and by month by FERC account.

Attachments: 1

Attachment 1 to DR ND-PSC-15.03.pdf

Response:

Please see Attachment 1 to DR ND-PSC-15.03 for payroll costs by FERC account for each month of the 2018 test year.

2018 Test Year Payroll Costs

FERC Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
5000: Steam Power Generation - Operation supervision and engineering	153,335	182,095	186,360	208,127	207,153	194,978	184,229	191,853
5010: Steam Power Generation - Fuel	74,803	52,533	34,640	47,108	35,264	37,260	33,639	39,154
5020: Steam Power Generation - Steam expenses	144,306	187,968	190,844	156,414	136,535	153,407	140,384	159,893
5050: Steam Power Generation - Electric expenses	181,753	189,751	190,056	218,651	174,473	203,806	199,494	210,535
5060: Steam Power Generation - Miscellaneous steam power expenses	237,017	259,614	253,580	285,017	238,627	271,184	248,157	280,675
5100: Steam Power Generation - Maintenance supervision and engineering	67,018	77,792	85,885	86,712	80,561	84,379	86,265	86,119
5110: Steam Power Generation - Maintenance of structures	33,857	41,977	27,390	30,011	17,990	40,652	37,335	28,563
5120: Steam Power Generation - Maintenance of boiler plant	229,049	230,483	263,004	238,204	336,071	195,731	205,278	206,370
5130: Steam Power Generation - Maintenance of electric plant	9,337	26,008	32,013	49,429	90,368	31,284	26,396	31,736
5140: Steam Power Generation - Maintenance of miscellaneous steam plant	62,781	82,409	71,514	78,730	148,169	85,568	70,797	67,669
5350: Hydraulic Power Generation - Operation supervision and engineering	854	2,220	1,386	967	879	217	1,959	1,636
5370: Hydraulic Power Generation - Hydraulic Expenses	668	152	1,248	3,281	1,949	102	58	
5380: Hydraulic Power Generation - Electric Expenses	3,039	2,990	230	5,871	4,167	5,971	8,473	16,564
5390: Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses	647							
5410: Hydraulic Power Generation - Maintenance supervision and engineering		228		1,291				
5430: Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	4,986	5,240	9,437	2,707	6,491	4,907	12,009	23,824
5440: Hydraulic Power Generation - Maintenance of electric plant				588	1,113			
5460: Other Power Generation - Operation supervision and engineering	8,667	13,603	11,772	21,153	25,832	2,167	7,353	6,316
5480: Other Power Generation - Generation Expenses	33,787	27,663	24,038	11,100	19,234	13,020	19,836	18,977
5490: Other Power Generation - Miscellaneous other power generation expenses	70,250	79,026	62,347	70,576	69,020	69,827	66,634	62,799
5510: Other Power Generation - Maintenance supervision and engineering	4,813	4,604	4,066	3,400			1,709	2,005
5520: Other Power Generation - Maintenance of structures			4,535	501	619			
5530: Other Power Generation - Maintenance of generating and electric plant	19,564	29,869	40,186	15,607	28,836	24,481	23,012	15,458
5540: Other Power Generation - Maintenance of misc other power generation plant	235	259	837	430	522		468	
5560: Other Power Supply Expenses - System control and load dispatching	12,448	12,828	10,453	14,423	14,120	22,833	23,140	22,847
5570: Other Power Supply Expenses - Other Expenses			730	17,667	16,182	23,443	20,699	22,137
5600: Transmission Expenses - Operation supervision and engineering	35,266	37,406	36,004	39,162	31,405	42,749	38,552	40,962
5611: Transmission Expenses - Load dispatch - reliability	7,055	6,737	6,065	6,940	7,920	7,154	6,632	7,074
5612: Transmission Expenses - Load dispatch - monitor and operate transmission system	225,908	253,869	251,588	244,819	245,848	249,644	246,992	259,806
5615: Transmission Expenses - Reliability, planning, and standards development	49,093	50,723	51,321	47,886	66,264	63,316	58,847	66,366
5616: Transmission Expenses - Transmission service studies	3,382			399				
5620: Transmission Expenses - Station expenses	23,588	31,056	23,900	28,388	15,344	18,636	17,114	23,033
5630: Transmission Expenses - Overhead line expenses	5,910	6,397	10,629	13,781	15,758	12,159	16,382	11,427
5660: Transmission Expenses - Miscellaneous transmission expenses	56,561	67,430	63,225	37,144	58,757	15,445	17,997	14,548
5680: Transmission Expenses - Maintenance supervision and engineering	22,254	21,326	27,729	29,424	21,221	33,287	28,958	19,649
5691: Transmission Expenses - Maintenance of computer hardware	604	1,064	4,142	8,442	9,165	3,997	7,397	7,297
5692: Transmission Expenses - Maintenance of computer software	43,351	44,933	53,826	41,486	48,805	53,350	47,575	51,141
5693: Transmission Expenses - Maintenance of communication equipment	5,493	3,109	8,693	5,687	8,552	10,370	6,818	9,296
5700: Transmission Expenses - Maintenance of station equipment	48,341	53,428	85,668	(53,677)	66,704	96,112	82,423	75,848
5710: Transmission Expenses - Maintenance of overhead lines	39,738	47,355	37,945	66,217	64,150	38,214	43,214	22,471
5752: Regional Market Expenses - Day-ahead and real-time market administration	56,161	60,567	67,046	38,755	39,415	39,521	33,441	35,366
5753: Regional Market Expenses - Transmission rights market administration				12,780	12,530	8,059	6,827	6,690
5755: Regional Market Expenses - Ancillary Services Market Admin	1,815	2,299	2,433					
5756: Regional Market Expenses - Market Monitoring and Compliance	372	230	1,338					
5763: Regional Market Expenses - Maintenance of computer software		1,484	135	293	1,233	4,576	4,520	4,759
5800: Distribution Expenses - Operation supervision and engineering	21,218	29,166	30,595	40,480	34,102	22,882	20,382	28,999
5810: Distribution Expenses - Load Dispatching	14,593	16,396	15,183	27,295	26,011	27,515	30,340	27,390
5820: Distribution Expenses - Station expenses	11,001	8,962	11,735	10,384	14,014	10,600	15,447	14,065
5830: Distribution Expenses - Overhead line expenses	20,159	35,629	35,310	24,684	23,560	23,525	27,107	23,543
5840: Distribution Expenses - Underground line expenses	28,557	30,665	44,080	44,259	119,277	117,493	108,004	133,870
5850: Distribution Expenses - Street lighting and signal system expenses				1,588				
5860: Distribution Expenses - Meter expenses	105,925	126,075	136,575	194,006	160,507	82,613	89,118	92,968
5870: Distribution Expenses - Customer installation expenses	11,127	16,326	13,672	16,846	19,896	16,823	20,371	19,270
5880: Distribution Expenses - Miscellaneous distribution expenses	234,708	268,573	234,296	209,263	142,048	148,217	106,338	127,924
5900: Distribution Expenses - Maintenance supervision and engineering	95,811	108,615	108,143	80,712	64,928	66,443	66,053	76,715
5920: Distribution Expenses - Maintenance of station equipment	43,177	43,430	43,151	42,737	30,466	42,281	45,118	49,870
5930: Distribution Expenses - Maintenance of overhead lines	256,400	244,455	250,001	264,264	241,057	226,120	247,333	243,637
5940: Distribution Expenses - Maintenance of underground lines	33,286	34,857	34,511	49,993	85,550	94,812	69,390	95,008
5950: Distribution Expenses - Maintenance of line transformers	3,306	2,011	7,222	4,061	3,960	4,318	3,802	4,589
5960: Distribution Expenses - Maintenance of street lighting and signal systems	70,013	106,898	76,388	73,333	60,033	51,331	52,028	63,153
5970: Distribution Expenses - Maintenance of meters	39,485	56,013	62,563	41,481	47,326	40,536	43,385	49,512
5980: Distribution Expenses - Maintenance of miscellaneous distribution plant	9,030	12,570	10,667	5,926	7,778	7,678	9,371	8,817
9010: Customer Accounts Expenses - Supervision	3,233	3,893	4,492	23,006	24,499	19,475	23,559	22,642
9020: Customer Accounts Expenses - Meter reading expenses	385,965	405,485	389,867	319,533	256,643	238,235	207,408	248,238
9030: Customer Accounts Expenses - Customer records and collection expenses	355,786	481,029	453,978	551,254	506,770	430,583	416,319	498,692
9050: Customer Accounts Expenses - Miscellaneous customer accounts expenses	13,539	18,598	14,884	9,695	13,228	8,817	11,954	9,740
9070: Customer Service and Informational Exp - Supervision	46,376	52,403	52,788	90,570	56,893	59,150	55,230	74,015
9080: Customer Service and Informational Exp - Customer assistance expenses	60,274	67,145	60,189	87,113	91,785	95,817	82,945	100,085
9090: Cust Service and Informational Exp - Informational and instructional adv exp	339	342	899	367	351	602	533	281
9100: Cust Service and Informational Exp - Misc customer service and informational exp			138		261	520	629	2,591
9110: Sales Expenses - Supervision	6,724	10,014	8,074					
9120: Sales Expenses - Demonstrating and selling expenses	12,877	19,489	21,133	26,076	32,207	19,238	26,154	26,274
9130: Sales Expenses - Advertising expenses				953		21	18	
9160: Sales Expenses - Miscellaneous sales expenses		99		2,598	2,085			
9200: Administrative and general salaries	1,187,187	1,457,886	1,332,514	1,437,826	1,533,783	1,300,545	1,191,404	1,306,202
9240: Property insurance		1,113	1,091	405	742			
9250: Injuries and damages	28,712	36,411	34,934	38,993	38,049	28,978	22,354	23,309
9260: Employee pensions and benefits	24,189	27,432	24,536	34,231	38,245	37,290	41,872	38,437
9280: Regulatory commission expenses	54,081	59,259	91,966	15,196	16,140	30,553	29,756	29,122
9301: General advertising expenses	3,110	7,001	3,604	3,405	3,600	3,583	3,551	5,768
9302: Miscellaneous general expenses	8,614	11,570	20,679	9,166	11,018	2,582	2,901	4,180
9350: Maintenance of general plant	224,393	228,903	209,072	212,868	209,925	215,186	197,321	204,286
Grand Total	5,391,402	6,227,437	6,077,170	6,130,459	6,283,986	5,636,168	5,348,505	5,804,057

2018 Test Year Payroll Costs

FERC Description	Sep	Oct	Nov	Dec	2018 Total	Estimated ND	
						ND Allocator	Jurisdiction Amount
5000: Steam Power Generation - Operation supervision and engineering	171,145	197,569	200,701	176,679	2,254,223	35.658308%	\$ 803,818
5010: Steam Power Generation - Fuel	36,222	29,398	43,507	28,942	492,470	35.658308%	\$ 175,607
5020: Steam Power Generation - Steam expenses	156,005	142,585	139,181	141,464	1,848,987	35.658308%	\$ 659,318
5050: Steam Power Generation - Electric expenses	207,059	190,057	182,721	204,638	2,352,995	35.658308%	\$ 839,038
5060: Steam Power Generation - Miscellaneous steam power expenses	263,505	313,317	308,398	292,198	3,251,288	35.658308%	\$ 1,159,354
5100: Steam Power Generation - Maintenance supervision and engineering	89,156	95,933	89,895	77,529	1,007,245	35.658308%	\$ 359,166
5110: Steam Power Generation - Maintenance of structures	24,155	29,874	27,357	32,203	371,364	35.658308%	\$ 132,422
5120: Steam Power Generation - Maintenance of boiler plant	220,491	302,134	201,916	219,301	2,848,033	35.658308%	\$ 1,015,560
5130: Steam Power Generation - Maintenance of electric plant	28,649	81,759	45,472	48,806	501,257	35.658308%	\$ 178,740
5140: Steam Power Generation - Maintenance of miscellaneous steam plant	72,616	62,544	56,815	74,208	933,821	35.658308%	\$ 332,985
5350: Hydraulic Power Generation - Operation supervision and engineering	3,125	2,679	2,402	1,905	20,230	35.658308%	\$ 7,214
5370: Hydraulic Power Generation - Hydraulic Expenses	194			1,071	8,724	35.658308%	\$ 3,111
5380: Hydraulic Power Generation - Electric Expenses	15,514	14,383	8,987	6,631	92,821	35.658308%	\$ 33,098
5390: Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses		88			734	35.658308%	\$ 262
5410: Hydraulic Power Generation - Maintenance supervision and engineering					1,519	35.658308%	\$ 542
5430: Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	24,931	22,232	27,891	17,332	161,988	35.658308%	\$ 57,762
5440: Hydraulic Power Generation - Maintenance of electric plant	1,462				3,164	35.658308%	\$ 1,128
5460: Other Power Generation - Operation supervision and engineering	7,768	9,147	3,626	5,124	122,526	35.658308%	\$ 43,691
5480: Other Power Generation - Generation Expenses	32,909	8,111	7,346	6,949	222,970	35.658308%	\$ 79,507
5490: Other Power Generation - Miscellaneous other power generation expenses	57,772	67,818	68,075	71,777	815,921	35.658308%	\$ 290,944
5510: Other Power Generation - Maintenance supervision and engineering	4,330	2,253			29,004	35.658308%	\$ 10,342
5520: Other Power Generation - Maintenance of structures					5,655	35.658308%	\$ 2,016
5530: Other Power Generation - Maintenance of generating and electric plant	24,781	38,329	19,105	30,805	310,034	35.658308%	\$ 110,553
5540: Other Power Generation - Maintenance of misc other power generation plant					2,750	35.658308%	\$ 981
5560: Other Power Supply Expenses - System control and load dispatching	26,408	38,157	27,561	26,621	251,839	35.658308%	\$ 89,802
5570: Other Power Supply Expenses - Other Expenses	22,157	23,181	22,854	19,245	188,296	35.658308%	\$ 67,143
5600: Transmission Expenses - Operation supervision and engineering	48,043	50,457	44,784	50,688	495,480	39.598907%	\$ 196,205
5611: Transmission Expenses - Load dispatch - reliability	6,993	6,507	7,197	7,400	83,675	39.598907%	\$ 33,135
5612: Transmission Expenses - Load dispatch - monitor and operate transmission system	233,266	244,642	221,019	260,482	2,937,881	39.598907%	\$ 1,163,369
5615: Transmission Expenses - Reliability, planning, and standards development	68,759	75,598	71,050	59,713	728,936	39.598907%	\$ 288,651
5616: Transmission Expenses - Transmission service studies					3,781	39.598907%	\$ 1,497
5620: Transmission Expenses - Station expenses	19,853	25,687	24,040	39,144	289,783	39.598907%	\$ 114,751
5630: Transmission Expenses - Overhead line expenses	13,873	17,026	11,887	13,348	148,577	39.598907%	\$ 58,835
5660: Transmission Expenses - Miscellaneous transmission expenses	19,053	34,621	39,118	38,121	462,020	39.598907%	\$ 182,955
5680: Transmission Expenses - Maintenance supervision and engineering	22,605	22,973	16,875	22,173	288,475	39.598907%	\$ 114,233
5691: Transmission Expenses - Maintenance of computer hardware	11,826	18,411	7,210	9,603	89,159	39.598907%	\$ 35,306
5692: Transmission Expenses - Maintenance of computer software	48,194	47,869	48,421	48,593	577,544	39.598907%	\$ 228,701
5693: Transmission Expenses - Maintenance of communication equipment	9,851	12,083	7,638	7,243	94,833	39.598907%	\$ 37,553
5700: Transmission Expenses - Maintenance of station equipment	99,097	132,898	53,474	36,117	776,431	39.598907%	\$ 307,458
5710: Transmission Expenses - Maintenance of overhead lines	32,613	30,137	23,663	54,684	500,402	39.598907%	\$ 198,154
5752: Regional Market Expenses - Day-ahead and real-time market administration	38,021	36,967	39,492	33,768	518,521	39.598907%	\$ 205,328
5753: Regional Market Expenses - Transmission rights market administration	7,793	7,577	7,192	6,569	76,017	39.598907%	\$ 30,102
5755: Regional Market Expenses - Ancillary Services Market Admin					6,547	39.598907%	\$ 2,593
5756: Regional Market Expenses - Market Monitoring and Compliance					1,940	39.598907%	\$ 768
5763: Regional Market Expenses - Maintenance of computer software	4,501	4,454	4,341	4,499	34,795	39.598907%	\$ 13,779
5800: Distribution Expenses - Operation supervision and engineering	30,858	28,947	36,535	37,431	361,592	45.870509%	\$ 165,864
5810: Distribution Expenses - Load Dispatching	26,201	30,793	19,131	14,282	275,131	45.870509%	\$ 126,204
5820: Distribution Expenses - Station expenses	17,252	12,226	12,138	10,701	148,526	45.870509%	\$ 68,130
5830: Distribution Expenses - Overhead line expenses	22,802	23,851	28,433	25,585	314,188	45.870509%	\$ 144,120
5840: Distribution Expenses - Underground line expenses	126,809	118,450	124,204	62,400	1,058,169	45.870509%	\$ 485,387
5850: Distribution Expenses - Street lighting and signal system expenses					1,588	45.870509%	\$ 729
5860: Distribution Expenses - Meter expenses	126,549	119,080	110,491	107,407	1,451,314	45.870509%	\$ 665,725
5870: Distribution Expenses - Customer installation expenses	24,298	20,485	17,888	16,790	213,790	45.870509%	\$ 98,067
5880: Distribution Expenses - Miscellaneous distribution expenses	121,164	147,531	135,677	159,674	2,035,412	45.870509%	\$ 933,654
5900: Distribution Expenses - Maintenance supervision and engineering	67,465	90,028	85,841	88,641	999,396	45.870509%	\$ 458,428
5920: Distribution Expenses - Maintenance of station equipment	35,563	39,077	50,540	30,385	495,794	45.870509%	\$ 227,423
5930: Distribution Expenses - Maintenance of overhead lines	247,161	245,296	237,071	233,864	2,936,659	45.870509%	\$ 1,347,060
5940: Distribution Expenses - Maintenance of underground lines	111,505	102,143	86,798	72,702	870,557	45.870509%	\$ 399,329
5950: Distribution Expenses - Maintenance of line transformers	4,473	4,482	4,428	4,109	50,762	45.870509%	\$ 23,285
5960: Distribution Expenses - Maintenance of street lighting and signal systems	75,172	78,959	73,626	108,325	889,259	45.870509%	\$ 407,907
5970: Distribution Expenses - Maintenance of meters	35,742	36,840	54,974	53,982	561,839	45.870509%	\$ 257,718
5980: Distribution Expenses - Maintenance of miscellaneous distribution plant	10,445	5,436	8,057	7,599	103,375	45.870509%	\$ 47,419
9010: Customer Accounts Expenses - Supervision	20,152	23,886	24,492	26,214	219,543	44.765037%	\$ 98,278
9020: Customer Accounts Expenses - Meter reading expenses	242,872	246,986	283,808	312,998	3,538,038	44.765037%	\$ 1,583,804
9030: Customer Accounts Expenses - Customer records and collection expenses	493,174	507,858	503,151	523,526	5,722,121	44.765037%	\$ 2,561,509
9050: Customer Accounts Expenses - Miscellaneous customer accounts expenses	11,621	12,741	10,923	16,068	151,808	44.765037%	\$ 67,957
9070: Customer Service and Informational Exp - Supervision	74,143	68,581	78,385	67,680	776,214	44.633048%	\$ 346,448
9080: Customer Service and Informational Exp - Customer assistance expenses	81,862	106,279	97,995	110,840	1,042,330	44.633048%	\$ 465,224
9090: Cust Service and Informational Exp - Informational and instructional adv exp	641	560	260	270	5,444	44.633048%	\$ 2,430
9100: Cust Service and Informational Exp - Misc customer service and informational exp	567	417	391	55	5,567	44.633048%	\$ 2,485
9110: Sales Expenses - Supervision					24,812	44.633048%	\$ 11,075
9120: Sales Expenses - Demonstrating and selling expenses	20,360	27,545	16,572	17,172	265,639	44.633048%	\$ 118,563
9130: Sales Expenses - Advertising expenses			158	124	1,274	44.633048%	\$ 568
9160: Sales Expenses - Miscellaneous sales expenses	2,954				7,737	44.633048%	\$ 3,453
9200: Administrative and general salaries	1,227,040	1,341,748	1,244,424	1,295,256	15,855,815	36.440914%	\$ 5,778,004
9240: Property insurance	2,954				6,306	36.083434%	\$ 2,275
9250: Injuries and damages	32,026	32,533	32,037	31,392	379,727	36.083434%	\$ 137,018
9260: Employee pensions and benefits	3,133	45,421	34,195	30,764	379,742	36.440914%	\$ 138,381
9280: Regulatory commission expenses	34,617	30,497	29,696	29,785	450,667	37.962207%	\$ 171,083
9301: General advertising expenses	7,838	2,775	3,823	2,090	50,148	44.633048%	\$ 22,383
9302: Miscellaneous general expenses	5,397	4,540	6,905	5,768	93,322	41.078842%	\$ 38,336
9350: Maintenance of general plant	189,390	220,382	202,461	230,407	2,544,596	41.078842%	\$ 1,045,290
Grand Total	5,708,896	6,215,830	5,768,542	5,910,401	70,502,854		\$ 28,118,487

Public
Response to Data Request ND-PSC-15.04
Page 1 of 1

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/03/2018
Responding Witness: Peter Wasberg, Director, Human Resources and Safety - (218) 739-8940

Data Request:

Please provide comparative information on actual payroll costs by month for 2016 and 2017 by FERC account.

Attachments: 1

Attachment 1 to DR ND-PSC-15.04.pdf

Response:

See Attachment 1 to DR ND-PSC-15.04 for 2016 and 2017 actual payroll costs by month.

15.04

2017 Actual	January	February	March	April	May	June	July	August	September	October	November	December	Total
FERC-													
5000 - Steam Power Generation - Operation supervision and engineering	113,679	148,454	127,991	148,921	128,930	130,809	116,387	136,910	130,202	114,845	123,219	145,795	1,566,141
5010 - Steam Power Generation - Fuel	70,963	51,085	29,734	22,103	20,562	26,072	23,065	26,691	17,466	18,970	28,011	28,533	363,254
5020 - Steam Power Generation - Steam expenses	151,006	179,175	158,662	161,141	143,707	169,098	147,750	153,712	158,124	148,319	154,008	158,917	1,883,619
5050 - Steam Power Generation - Electric expenses	177,895	187,981	159,691	168,927	155,252	183,521	167,757	178,763	166,574	159,158	169,002	173,401	2,047,923
5060 - Steam Power Generation - Miscellaneous steam power expenses	244,177	198,030	289,976	225,173	274,762	155,054	240,121	202,815	155,509	290,824	161,084	206,630	2,644,156
5100 - Steam Power Generation - Maintenance supervision and engineering	58,545	75,215	68,664	76,175	71,568	71,524	64,071	68,780	67,038	67,918	72,363	68,942	836,802
5110 - Steam Power Generation - Maintenance of structures	31,206	41,395	22,610	37,771	32,826	40,030	49,439	58,227	69,660	44,973	41,592	33,202	502,931
5120 - Steam Power Generation - Maintenance of boiler plant	231,707	229,402	207,798	231,823	246,785	250,444	182,166	189,240	195,199	214,946	207,796	207,023	2,594,328
5130 - Steam Power Generation - Maintenance of electric plant	8,439	25,289	26,845	17,325	55,666	34,717	15,223	29,697	25,730	32,258	21,389	15,859	308,439
5140 - Steam Power Generation - Maintenance of miscellaneous steam plant	56,985	79,738	59,964	55,328	61,513	59,635	44,783	53,585	51,186	50,257	63,494	61,554	698,021
5350 - Hydraulic Power Generation - Operation supervision and engineering	775	2,103	1,289	1,369	680	1,403	1,149	798	706	125	686	1,991	13,073
5370 - Hydraulic Power Generation - Hydraulic Expenses	596	149	911	1,348	1,091	683	1,470	1,225	443	519	592	458	9,484
5380 - Hydraulic Power Generation - Electric Expenses	3,050	2,970	198	203	2,253	5,147	101	1,225	443	2,215	3,584	514	20,237
5390 - Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses	545	2,970	198	1,487	1,493	3,314	1,796	1,303	1,604	2,902	3,922	2,417	20,783
5410 - Hydraulic Power Generation - Maintenance supervision and engineering	234												234
5430 - Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	4,467	5,289	7,928	8,943	10,079	22,412	19,283	18,425	22,354	15,313	28,527	18,216	181,238
5440 - Hydraulic Power Generation - Maintenance of electric plant													26,668
5460 - Other Power Generation - Operation supervision and engineering	8,637	12,715	11,129	9,208	10,637	543	155	9,929	8,138	4,418	4,688	2,404	66,653
5480 - Other Power Generation - Generation Expenses	32,060	27,066	19,941	11,474	22,565	12,205	9,778	8,770	11,171	12,139	12,678	11,890	130,958
5490 - Other Power Generation - Miscellaneous other power generation expenses	61,775	75,882	53,608	73,941	63,055	67,295	50,594	64,809	71,126	55,530	-279,149	21,894	380,359
5510 - Other Power Generation - Maintenance supervision and engineering	4,850	4,346	3,845	5,047	7,590	7,609	4,726	7,268	5,674	1,804	4,450	3,344	60,552
5520 - Other Power Generation - Maintenance of structures			3,928	822	479	148		616			1,426		7,419
5530 - Other Power Generation - Maintenance of generating and electric plant	17,653	29,506	33,341	55,382	22,696	16,145	24,596	14,252	27,405	29,586	-2,872	16,686	284,376
5540 - Other Power Generation - Maintenance of miscellaneous other power generation plant	218	261	687			195	291		195	585		144	2,576
5560 - Other Power Supply Expenses - System control and load dispatching	12,134	12,390	9,630	13,014	9,161	14,520	13,505	18,554	14,573	9,234	11,501	12,591	150,808
5570 - Other Power Supply Expenses - Other Expenses			617			1,797		141	2,537	1,331	315		6,739
5600 - Transmission Expenses - Operation supervision and engineering	32,461	36,396	30,429	33,230	38,035	42,918	39,038	40,070	34,933	42,564	47,807	40,900	458,782
5611 - Transmission Expenses - Load dispatch - reliability	6,554	6,904	5,307	6,157	5,569	7,427	6,020	6,109	6,363	7,726	7,392	6,629	78,155
5612 - Transmission Expenses - Load dispatch - monitor and operate transmission system	211,853	262,242	219,614	214,126	239,403	234,106	209,019	225,916	232,624	200,424	222,449	218,551	2,690,329
5615 - Transmission Expenses - Reliability, planning, and standards development	46,412	48,727	45,538	50,590	44,200	45,805	47,622	60,798	58,728	49,113	50,673	38,854	587,059
5616 - Transmission Expenses - Transmission service studies	2,964							75	1,837			251	5,126
5617 - Transmission Expenses - Generation interconnection studies											152		152
5620 - Transmission Expenses - Station expenses	20,594	30,995	18,034	31,750	18,239	13,388	8,309	11,271	12,935	10,902	15,736	17,860	210,013
5630 - Transmission Expenses - Overhead line expenses	4,882	5,899	10,201	8,928	6,132	7,075	4,580	7,182	7,584	6,622	7,375	8,627	85,087
5660 - Transmission Expenses - Miscellaneous transmission expenses	51,977	67,333	51,887	58,820	43,080	37,580	39,349	47,726	31,254	31,417	55,242	44,456	560,162
5680 - Transmission Expenses - Maintenance supervision and engineering	19,978	21,631	19,872	14,162	20,505	24,275	23,158	21,303	16,932	22,424	16,996	15,776	237,013
5691 - Transmission Expenses - Maintenance of computer hardware	468	1,009	3,500	2,544	4,249	7,328	13,408	5,660	3,592	7,446	10,109	7,573	66,886
5692 - Transmission Expenses - Maintenance of computer software	41,144	46,531	46,817	44,555	42,427	36,770	40,350	29,566	33,878	34,573	38,372	36,515	471,498
5693 - Transmission Expenses - Maintenance of communication equipment	5,293	3,178	7,721	10,309	6,681	8,302	6,768	5,658	9,006	5,501	6,648	4,150	79,215

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FERC-	2017 Actual	January	February	March	April	May	June	July	August	September	October	November	December	Total
5700 - Transmission Expenses - Maintenance of station equipment	42,204	54,569	66,054	48,595	63,009	58,292	49,111	66,047	39,122	48,975	46,839	48,357	631,174	
5710 - Transmission Expenses - Maintenance of overhead lines	32,042	44,422	33,386	48,319	47,497	35,657	23,160	40,240	32,151	33,796	27,868	42,607	441,145	
5752 - Regional Market Expenses - Day-ahead and real-time market administration	48,500	65,293	56,555	62,370	62,044	61,003	55,730	55,566	62,894	52,709	66,042	58,455	707,161	
5753 - Regional Market Expenses - Transmission rights market administration			1,326	125	333					83		211	2,079	
5755 - Regional Market Expenses - Ancillary services market administration	1,559	2,480	2,053	2,044	2,088	2,331	1,926	2,062	2,120	1,791	2,314	2,062	24,829	
5756 - Regional Market Expenses - Market monitoring and compliance	339	243	1,129	707	749	2,261	208	666	416	2,187	1,519	1,184	11,608	
5763 - Regional Market Expenses - Maintenance of computer software		1,574	118	424	3,410	2,728	5,200	3,259	3,077	3,029	3,696	739	27,256	
5800 - Distribution Expenses - Operation supervision and engineering	20,667	27,959	28,373	34,548	26,078	26,305	27,450	28,292	31,391	26,682	30,709	30,897	339,351	
5810 - Distribution Expenses - Load Dispatching	13,522	16,907	13,236	15,938	15,449	20,177	15,287	17,891	16,927	16,952	17,927	16,505	196,719	
5820 - Distribution Expenses - Station expenses	9,954	9,011	8,830	9,171	7,714	11,851	6,241	14,489	7,463	10,743	8,913	10,247	114,627	
5830 - Distribution Expenses - Overhead line expenses	17,402	33,550	32,229	29,684	28,673	29,501	25,737	20,845	18,989	21,471	22,821	22,997	303,899	
5840 - Distribution Expenses - Underground line expenses	25,033	29,533	36,696	109,385	176,112	196,498	157,178	171,679	174,787	169,211	146,139	72,524	1,464,775	
5860 - Distribution Expenses - Meter expenses	99,446	129,448	112,517	156,419	107,979	85,753	72,957	85,160	85,457	89,585	102,279	99,783	1,226,784	
5880 - Distribution Expenses - Miscellaneous distribution expenses	202,705	262,694	191,275	370,986	175,791	192,064	147,920	146,291	197,050	177,388	176,559	237,725	2,478,447	
5900 - Distribution Expenses - Maintenance supervision and engineering	82,363	104,639	88,805	89,055	99,841	103,464	92,273	96,301	102,142	106,299	105,792	96,161	1,167,134	
5920 - Distribution Expenses - Maintenance of station equipment	36,897	40,653	33,891	42,056	49,417	42,493	30,834	49,602	32,955	33,039	30,210	41,872	463,920	
5930 - Distribution Expenses - Maintenance of overhead lines	220,397	235,417	213,100	240,867	248,074	254,408	234,847	229,797	202,943	194,942	186,834	212,285	2,673,912	
5940 - Distribution Expenses - Maintenance of underground lines	28,859	33,744	29,811	58,649	63,725	76,200	78,081	96,612	84,817	70,073	53,103	49,028	722,702	
5950 - Distribution Expenses - Maintenance of line transformers	2,688	1,793	5,828	6,193	5,682	11,251	9,893	9,190	7,736	6,919	11,217	9,752	88,142	
5960 - Distribution Expenses - Maintenance of street lighting and signal systems	58,967	103,655	63,170	57,848	48,915	41,551	43,445	56,803	53,858	67,521	75,207	100,038	770,978	
5970 - Distribution Expenses - Maintenance of meters	40,662	62,630	49,592	51,948	46,120	51,357	52,582	54,594	54,628	50,666	63,334	60,163	638,275	
5980 - Distribution Expenses - Maintenance of miscellaneous distribution plant	8,451	13,053	9,275	8,952	8,017	8,946	9,342	8,175	10,820	8,306	9,916	11,681	114,994	
9010 - Customer Accounts Expenses - Supervision	2,286	3,521	3,639	2,068	7,181	4,113	4,391	6,974	7,530	5,974	6,102	3,712	56,990	
9020 - Customer Accounts Expenses - Meter reading expenses	326,175	390,462	320,585	328,283	304,705	303,273	269,489	308,976	298,083	305,918	305,868	348,022	3,809,840	
9030 - Customer Accounts Expenses - Customer records and collection expenses	301,967	467,498	379,639	364,280	354,708	342,622	297,114	333,578	319,980	316,257	354,681	331,450	4,163,776	
9050 - Customer Accounts Expenses - Miscellaneous customer accounts expenses	11,191	18,364	12,335	11,629	14,278	11,529	11,253	9,877	14,001	16,154	13,765	14,540	158,913	
9070 - Customer Service and Informational Expenses - Supervision	38,114	51,098	43,313	53,386	42,154	38,219	40,081	53,617	41,308	38,003	54,469	38,181	531,942	
9080 - Customer Service and Informational Expenses - Customer assistance expenses	52,225	71,841	51,701	66,023	69,944	60,612	50,151	64,088	67,529	66,077	70,648	63,580	754,420	
9090 - Customer Service and Informational Expenses - Informational and instructional advertising expenses	259	307	608	389	446	70	283	558	222	450	249	704	4,547	
9100 - Customer Service and Informational Expenses - Miscellaneous customer service and informational expenses			113										113	
9110 - Sales Expenses - Supervision	6,901	11,133	7,851	7,037	5,428	7,411	6,442	7,568	9,029	7,939	9,013	5,832	91,584	
9120 - Sales Expenses - Demonstrating and selling expenses	11,002	21,065	17,931	15,226	18,425	19,773	18,295	20,620	10,687	14,557	18,473	17,184	203,238	
9130 - Sales Expenses - Advertising expenses					139		98	49		147			434	
9160 - Sales Expenses - Miscellaneous sales expenses		94	186										279	
9200 - Administrative and general salaries	1,390,906	1,214,935	1,777,562	1,374,469	1,664,942	1,112,069	1,410,568	1,293,959	1,098,909	1,898,797	1,061,183	1,379,346	16,677,644	
9210 - Office supplies and expenses													0	
9240 - Property insurance		1,142	963	647		372		454	640	124	42		4,383	
9250 - Injuries and damages	24,114	32,080	22,919	33,451	34,270	36,229	29,120	29,685	34,007	29,907	36,885	32,676	375,342	
9260 - Employee pensions and benefits	19,831	27,513	21,707	23,278	21,945	21,787	23,477	20,501	21,823	20,401	25,493	20,820	268,577	
9280 - Regulatory commission expenses	45,137	56,516	80,925	205,116	22,383	18,231	14,227	39,596	26,396	13,846	38,515	50,390	611,279	
9301 - General advertising expenses	2,335	6,282	2,437	3,192	2,630	2,230	1,576	1,686	583	242	199	901	24,293	
9302 - Miscellaneous general expenses	7,202	11,754	16,592	31,631	32,789	26,459	24,687	43,848	43,086	33,086	67,180	62,780	401,087	
9350 - Maintenance of general plant	204,061	230,874	170,894	152,735	128,741	139,809	118,149	140,085	140,872	113,108	113,981	130,601	1,783,909	
Grand Total	5,182,291	5,825,424	5,933,222	5,838,269	5,104,200	5,373,612	5,043,293	4,731,357	5,400,840	4,731,357	5,400,840	4,731,357	5,400,840	65,265,663

Public
Response to Data Request ND-PSC-15.07
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/04/2018
Responding Witness: Peter Wasberg, Director, Human Resources and Safety - (218) 739-8940

Data Request:

Has the Company requested in its proposed North Dakota jurisdictional revenue requirements any budgeted payroll amounts for the January through March 2018 portion of the 2018 test year that are different than the actually-incurred payroll amounts for January through March 2018? If so, identify, quantify and explain each difference between (1) the Company's proposed January through March 2018 payroll and (2) actual January through March 2018 payroll, and show the impact by FERC account.

Attachments: 1

Attachment 1 to DR ND-PSC-15.07.pdf

Response:

See Attachment 1 to DR ND-PSC-15.07 for the differences by FERC for the year 2018 Actuals versus Budget.

When comparing January through March 2018 Budget versus Actuals for O&M Expense accounts only, we are under budget mainly due to the updated pension costs. The pension costs were updated in our supplemental filing.

Payroll dollars by FERC
Actual to Budget for 2018

FERC Account	Budget	January	
		Actual	Variance
5000 - Steam Power Generation - Operation supervision and engineering	153,335	116,614	36,721
5010 - Steam Power Generation - Fuel	74,803	63,135	11,668
5020 - Steam Power Generation - Steam expenses	144,306	158,905	(14,599)
5050 - Steam Power Generation - Electric expenses	181,753	200,126	(18,373)
5060 - Steam Power Generation - Miscellaneous steam power expenses	237,017	235,533	1,484
5100 - Steam Power Generation - Maintenance supervision and engineering	67,018	62,451	4,568
5110 - Steam Power Generation - Maintenance of structures	33,857	34,301	(443)
5120 - Steam Power Generation - Maintenance of boiler plant	229,049	205,610	23,439
5130 - Steam Power Generation - Maintenance of electric plant	9,337	12,162	(2,826)
5140 - Steam Power Generation - Maintenance of miscellaneous steam plant	62,781	54,600	8,182
5350 - Hydraulic Power Generation - Operation supervision and engineering	854	2,006	(1,152)
5370 - Hydraulic Power Generation - Hydraulic Expenses	668	321	347
5380 - Hydraulic Power Generation - Electric Expenses	3,039	3,149	(110)
5390 - Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses	647	508	139
5410 - Hydraulic Power Generation - Maintenance supervision and engineering	-	-	-
5430 - Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	4,986	2,625	2,361
5460 - Other Power Generation - Operation supervision and engineering	8,667	10,911	(2,245)
5480 - Other Power Generation - Generation Expenses	33,787	37,522	(3,735)
5490 - Other Power Generation - Miscellaneous other power generation expenses	70,250	32,609	37,641
5510 - Other Power Generation - Maintenance supervision and engineering	4,813	3,339	1,474
5520 - Other Power Generation - Maintenance of structures	-	-	-
5530 - Other Power Generation - Maintenance of generating and electric plant	19,564	12,824	6,740
5540 - Other Power Generation - Maintenance of miscellaneous other power generation plant	235	-	235
5560 - Other Power Supply Expenses - System control and load dispatching	12,662	9,120	3,542
5570 - Other Power Supply Expenses - Other Expenses	-	46	(46)
5600 - Transmission Expenses - Operation supervision and engineering	35,266	37,517	(2,251)
5611 - Transmission Expenses - Load dispatch - reliability	7,055	6,287	768
5612 - Transmission Expenses - Load dispatch - monitor and operate transmission system	225,908	224,725	1,184
5615 - Transmission Expenses - Reliability, planning, and standards development	49,093	38,619	10,474
5616 - Transmission Expenses - Transmission service studies	3,382	-	3,382
5617 - Transmission Expenses - Generation interconnection studies	-	-	-
5620 - Transmission Expenses - Station expenses	23,588	20,518	3,070
5630 - Transmission Expenses - Overhead line expenses	5,910	7,871	(1,961)
5660 - Transmission Expenses - Miscellaneous transmission expenses	56,347	61,967	(5,620)
5680 - Transmission Expenses - Maintenance supervision and engineering	22,254	17,201	5,053
5691 - Transmission Expenses - Maintenance of computer hardware	604	4,054	(3,449)
5692 - Transmission Expenses - Maintenance of computer software	43,351	22,801	20,550
5693 - Transmission Expenses - Maintenance of communication equipment	5,493	7,519	(2,025)
5700 - Transmission Expenses - Maintenance of station equipment	48,341	61,551	(13,210)
5710 - Transmission Expenses - Maintenance of overhead lines	39,738	44,483	(4,745)
5752 - Regional Market Expenses - Day-ahead and real-time market administration	56,161	51,804	4,357
5753 - Regional Market Expenses - Transmission rights market administration	-	-	-
5755 - Regional Market Expenses - Ancillary services market administration	1,815	1,929	(114)
5756 - Regional Market Expenses - Market monitoring and compliance	372	-	372
5763 - Regional Market Expenses - Maintenance of computer software	-	4,023	(4,023)
5800 - Distribution Expenses - Operation supervision and engineering	21,218	26,781	(5,564)
5810 - Distribution Expenses - Load Dispatching	14,593	15,268	(674)
5820 - Distribution Expenses - Station expenses	11,001	7,569	3,432
5830 - Distribution Expenses - Overhead line expenses	20,159	17,053	3,106
5840 - Distribution Expenses - Underground line expenses	28,657	30,564	(1,907)
5860 - Distribution Expenses - Meter expenses	105,925	89,455	16,470
5870 - Distribution Expenses - Customer installation expenses	11,127	6,396	4,731
5880 - Distribution Expenses - Miscellaneous distribution expenses	234,708	231,438	3,270
5900 - Distribution Expenses - Maintenance supervision and engineering	95,811	84,459	11,352
5920 - Distribution Expenses - Maintenance of station equipment	43,177	29,163	14,014
5930 - Distribution Expenses - Maintenance of overhead lines	256,400	229,355	27,045
5940 - Distribution Expenses - Maintenance of underground lines	33,286	35,884	(2,599)
5950 - Distribution Expenses - Maintenance of line transformers	3,306	8,701	(5,395)
5960 - Distribution Expenses - Maintenance of street lighting and signal systems	70,013	91,104	(21,092)
5970 - Distribution Expenses - Maintenance of meters	39,485	54,315	(14,831)
5980 - Distribution Expenses - Maintenance of miscellaneous distribution plant	9,030	9,109	(79)
9010 - Customer Accounts Expenses - Supervision	3,233	2,133	1,101
9020 - Customer Accounts Expenses - Meter reading expenses	385,965	327,514	58,451
9030 - Customer Accounts Expenses - Customer records and collection expenses	355,786	303,737	52,049
9050 - Customer Accounts Expenses - Miscellaneous customer accounts expenses	13,539	12,435	1,104
9070 - Customer Service and Informational Expenses - Supervision	46,376	29,076	17,300
9080 - Customer Service and Informational Expenses - Customer assistance expenses	60,274	57,282	2,992
9090 - Customer Service and Informational Expenses - Informational and instructional advertising expenses	339	494	(155)
9100 - Customer Service and Informational Expenses - Miscellaneous customer service and informational expenses	-	-	-
9110 - Sales Expenses - Supervision	6,724	4,780	1,945
9120 - Sales Expenses - Demonstrating and selling expenses	12,877	13,851	(974)
9200 - Administrative and general salaries	1,187,187	1,345,580	(158,392)
9240 - Property insurance	-	-	-
9250 - Injuries and damages	28,712	28,283	429
9260 - Employee pensions and benefits	24,189	17,144	7,044
9280 - Regulatory commission expenses	54,081	36,361	17,720
9301 - General advertising expenses	3,110	498	2,612
9302 - Miscellaneous general expenses	8,614	43,872	(35,257)
9350 - Maintenance of general plant	224,393	150,720	73,673
OTP Total	5,391,402	5,211,656	179,745

Payroll dollars by FERC
Actual to Budget for 2018

FERC Account	February		
	Budget	Actual	Variance
5000 - Steam Power Generation - Operation supervision and engineering	182,095	141,965	40,130
5010 - Steam Power Generation - Fuel	52,533	37,768	14,766
5020 - Steam Power Generation - Steam expenses	187,968	179,963	8,005
5050 - Steam Power Generation - Electric expenses	189,751	205,940	(16,189)
5060 - Steam Power Generation - Miscellaneous steam power expenses	259,614	221,671	37,943
5100 - Steam Power Generation - Maintenance supervision and engineering	77,792	78,990	(1,198)
5110 - Steam Power Generation - Maintenance of structures	41,977	37,334	4,643
5120 - Steam Power Generation - Maintenance of boiler plant	230,483	223,168	7,316
5130 - Steam Power Generation - Maintenance of electric plant	26,008	37,340	(11,332)
5140 - Steam Power Generation - Maintenance of miscellaneous steam plant	82,409	58,286	24,123
5350 - Hydraulic Power Generation - Operation supervision and engineering	2,220	4,021	(1,801)
5370 - Hydraulic Power Generation - Hydraulic Expenses	152	317	(165)
5380 - Hydraulic Power Generation - Electric Expenses	2,990	945	2,045
5390 - Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses		1,642	(1,642)
5410 - Hydraulic Power Generation - Maintenance supervision and engineering	228		228
5430 - Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	5,240	7,926	(2,686)
5460 - Other Power Generation - Operation supervision and engineering	13,603	15,108	(1,505)
5480 - Other Power Generation - Generation Expenses	27,663	33,286	(5,623)
5490 - Other Power Generation - Miscellaneous other power generation expenses	79,026	31,720	47,305
5510 - Other Power Generation - Maintenance supervision and engineering	4,604	6,717	(2,113)
5520 - Other Power Generation - Maintenance of structures			-
5530 - Other Power Generation - Maintenance of generating and electric plant	29,869	42,247	(12,378)
5540 - Other Power Generation - Maintenance of miscellaneous other power generation plant	259		259
5560 - Other Power Supply Expenses - System control and load dispatching	12,828	8,869	3,959
5570 - Other Power Supply Expenses - Other Expenses			-
5600 - Transmission Expenses - Operation supervision and engineering	37,406	48,171	(10,765)
5611 - Transmission Expenses - Load dispatch - reliability	6,737	6,251	486
5612 - Transmission Expenses - Load dispatch - monitor and operate transmission system	253,869	222,925	30,943
5615 - Transmission Expenses - Reliability, planning, and standards development	50,723	44,476	6,248
5616 - Transmission Expenses - Transmission service studies		78	(78)
5617 - Transmission Expenses - Generation interconnection studies		233	(233)
5620 - Transmission Expenses - Station expenses	31,056	25,634	5,422
5630 - Transmission Expenses - Overhead line expenses	6,397	10,966	(4,570)
5660 - Transmission Expenses - Miscellaneous transmission expenses	67,430	101,629	(34,199)
5680 - Transmission Expenses - Maintenance supervision and engineering	21,326	24,785	(3,459)
5691 - Transmission Expenses - Maintenance of computer hardware	1,064	4,274	(3,209)
5692 - Transmission Expenses - Maintenance of computer software	44,933	30,428	14,504
5693 - Transmission Expenses - Maintenance of communication equipment	3,109	10,612	(7,503)
5700 - Transmission Expenses - Maintenance of station equipment	53,428	57,096	(3,667)
5710 - Transmission Expenses - Maintenance of overhead lines	47,355	67,082	(19,727)
5752 - Regional Market Expenses - Day-ahead and real-time market administration	60,567	71,935	(11,368)
5753 - Regional Market Expenses - Transmission rights market administration		348	(348)
5755 - Regional Market Expenses - Ancillary services market administration	2,299	2,570	(272)
5756 - Regional Market Expenses - Market monitoring and compliance	230	315	(84)
5763 - Regional Market Expenses - Maintenance of computer software	1,484	6,955	(5,472)
5800 - Distribution Expenses - Operation supervision and engineering	29,166	49,378	(20,212)
5810 - Distribution Expenses - Load Dispatching	16,396	16,921	(525)
5820 - Distribution Expenses - Station expenses	8,962	7,060	1,902
5830 - Distribution Expenses - Overhead line expenses	35,629	31,274	4,356
5840 - Distribution Expenses - Underground line expenses	30,665	23,734	6,931
5860 - Distribution Expenses - Meter expenses	126,075	108,275	17,800
5870 - Distribution Expenses - Customer installation expenses	16,326	12,136	4,190
5880 - Distribution Expenses - Miscellaneous distribution expenses	268,573	296,796	(28,223)
5900 - Distribution Expenses - Maintenance supervision and engineering	108,615	110,498	(1,883)
5920 - Distribution Expenses - Maintenance of station equipment	43,430	35,446	7,984
5930 - Distribution Expenses - Maintenance of overhead lines	244,455	195,385	49,069
5940 - Distribution Expenses - Maintenance of underground lines	34,857	33,731	1,126
5950 - Distribution Expenses - Maintenance of line transformers	2,011	11,011	(9,000)
5960 - Distribution Expenses - Maintenance of street lighting and signal systems	106,898	109,924	(3,026)
5970 - Distribution Expenses - Maintenance of meters	56,013	78,062	(22,049)
5980 - Distribution Expenses - Maintenance of miscellaneous distribution plant	12,570	12,659	(89)
9010 - Customer Accounts Expenses - Supervision	3,893	1,226	2,667
9020 - Customer Accounts Expenses - Meter reading expenses	405,485	382,725	22,759
9030 - Customer Accounts Expenses - Customer records and collection expenses	481,029	355,470	125,560
9050 - Customer Accounts Expenses - Miscellaneous customer accounts expenses	18,598	17,031	1,567
9070 - Customer Service and Informational Expenses - Supervision	52,403	44,243	8,160
9080 - Customer Service and Informational Expenses - Customer assistance expenses	67,145	73,890	(6,744)
9090 - Customer Service and Informational Expenses - Informational and instructional advertising expenses	342	1,491	(1,149)
9100 - Customer Service and Informational Expenses - Miscellaneous customer service and informational expenses			-
9110 - Sales Expenses - Supervision	10,014	6,695	3,318
9120 - Sales Expenses - Demonstrating and selling expenses	19,489	19,830	(341)
9200 - Administrative and general salaries	1,457,886	1,213,254	244,632
9240 - Property insurance	1,113	2,717	(1,604)
9250 - Injuries and damages	36,411	37,049	(638)
9260 - Employee pensions and benefits	27,432	24,756	2,675
9280 - Regulatory commission expenses	59,259	45,778	13,481
9301 - General advertising expenses	7,001	1,121	5,880
9302 - Miscellaneous general expenses	11,570	55,228	(43,657)
9350 - Maintenance of general plant	228,903	162,966	65,938
OTP Total	6,227,437	5,689,745	537,692

Payroll dollars by FERC
Actual to Budget for 2018

FERC Account	Budget	March	
		Actual	Variance
5000 - Steam Power Generation - Operation supervision and engineering	186,360	120,441	65,919
5010 - Steam Power Generation - Fuel	34,640	29,252	5,388
5020 - Steam Power Generation - Steam expenses	190,844	150,796	40,048
5050 - Steam Power Generation - Electric expenses	190,056	185,673	4,383
5060 - Steam Power Generation - Miscellaneous steam power expenses	253,580	304,431	(50,851)
5100 - Steam Power Generation - Maintenance supervision and engineering	85,885	69,544	16,341
5110 - Steam Power Generation - Maintenance of structures	27,390	33,335	(5,945)
5120 - Steam Power Generation - Maintenance of boiler plant	263,004	220,792	42,212
5130 - Steam Power Generation - Maintenance of electric plant	32,013	41,800	(9,788)
5140 - Steam Power Generation - Maintenance of miscellaneous steam plant	71,514	56,371	15,143
5350 - Hydraulic Power Generation - Operation supervision and engineering	1,386	128	1,258
5370 - Hydraulic Power Generation - Hydraulic Expenses	1,248	716	532
5380 - Hydraulic Power Generation - Electric Expenses	230	874	(644)
5390 - Hydraulic Power Generation - Miscellaneous hydraulic power generation expenses		1,478	(1,478)
5410 - Hydraulic Power Generation - Maintenance supervision and engineering			-
5430 - Hydraulic Power Generation - Maintenance of reservoirs, dams and waterways	9,437	7,659	1,779
5460 - Other Power Generation - Operation supervision and engineering	11,772	12,426	(654)
5480 - Other Power Generation - Generation Expenses	24,038	26,742	(2,704)
5490 - Other Power Generation - Miscellaneous other power generation expenses	62,347	29,783	32,564
5510 - Other Power Generation - Maintenance supervision and engineering	4,066	4,513	(447)
5520 - Other Power Generation - Maintenance of structures	4,535	1,432	3,103
5530 - Other Power Generation - Maintenance of generating and electric plant	40,186	17,124	23,062
5540 - Other Power Generation - Maintenance of miscellaneous other power generation plant	837	299	538
5560 - Other Power Supply Expenses - System control and load dispatching	10,453	8,380	2,073
5570 - Other Power Supply Expenses - Other Expenses	730		730
5600 - Transmission Expenses - Operation supervision and engineering	36,004	33,317	2,687
5611 - Transmission Expenses - Load dispatch - reliability	6,065	5,744	321
5612 - Transmission Expenses - Load dispatch - monitor and operate transmission system	251,588	216,575	35,012
5615 - Transmission Expenses - Reliability, planning, and standards development	51,321	35,238	16,083
5616 - Transmission Expenses - Transmission service studies		78	(78)
5617 - Transmission Expenses - Generation interconnection studies			-
5620 - Transmission Expenses - Station expenses	23,900	27,183	(3,283)
5630 - Transmission Expenses - Overhead line expenses	10,629	7,948	2,681
5660 - Transmission Expenses - Miscellaneous transmission expenses	63,225	63,356	(132)
5680 - Transmission Expenses - Maintenance supervision and engineering	27,729	23,791	3,938
5691 - Transmission Expenses - Maintenance of computer hardware	4,142	4,842	(699)
5692 - Transmission Expenses - Maintenance of computer software	53,826	23,440	30,386
5693 - Transmission Expenses - Maintenance of communication equipment	8,693	13,019	(4,327)
5700 - Transmission Expenses - Maintenance of station equipment	85,668	48,830	36,838
5710 - Transmission Expenses - Maintenance of overhead lines	37,945	22,289	15,656
5752 - Regional Market Expenses - Day-ahead and real-time market administration	67,046	55,474	11,572
5753 - Regional Market Expenses - Transmission rights market administration		261	(261)
5755 - Regional Market Expenses - Ancillary services market administration	2,433	2,250	184
5756 - Regional Market Expenses - Market monitoring and compliance	1,338	696	642
5763 - Regional Market Expenses - Maintenance of computer software	135	5,581	(5,446)
5800 - Distribution Expenses - Operation supervision and engineering	30,595	33,317	(2,723)
5810 - Distribution Expenses - Load Dispatching	15,183	18,070	(2,887)
5820 - Distribution Expenses - Station expenses	11,735	3,823	7,912
5830 - Distribution Expenses - Overhead line expenses	35,310	33,187	2,123
5840 - Distribution Expenses - Underground line expenses	44,080	26,493	17,587
5860 - Distribution Expenses - Meter expenses	136,575	96,895	39,680
5870 - Distribution Expenses - Customer installation expenses	13,672	10,934	2,739
5880 - Distribution Expenses - Miscellaneous distribution expenses	234,296	206,197	28,099
5900 - Distribution Expenses - Maintenance supervision and engineering	108,143	92,917	15,226
5920 - Distribution Expenses - Maintenance of station equipment	43,151	34,483	8,667
5930 - Distribution Expenses - Maintenance of overhead lines	250,001	215,947	34,054
5940 - Distribution Expenses - Maintenance of underground lines	34,511	37,000	(2,489)
5950 - Distribution Expenses - Maintenance of line transformers	7,222	10,616	(3,394)
5960 - Distribution Expenses - Maintenance of street lighting and signal systems	76,388	92,394	(16,006)
5970 - Distribution Expenses - Maintenance of meters	62,563	65,974	(3,411)
5980 - Distribution Expenses - Maintenance of miscellaneous distribution plant	10,667	10,172	495
9010 - Customer Accounts Expenses - Supervision	4,492	2,896	1,596
9020 - Customer Accounts Expenses - Meter reading expenses	389,867	366,052	23,816
9030 - Customer Accounts Expenses - Customer records and collection expenses	453,978	344,817	109,161
9050 - Customer Accounts Expenses - Miscellaneous customer accounts expenses	14,884	15,580	(696)
9070 - Customer Service and Informational Expenses - Supervision	52,788	29,062	23,726
9080 - Customer Service and Informational Expenses - Customer assistance expenses	60,189	53,154	7,035
9090 - Customer Service and Informational Expenses - Informational and instructional advertising expenses	899	1,131	(232)
9100 - Customer Service and Informational Expenses - Miscellaneous customer service and informational expenses	138		138
9110 - Sales Expenses - Supervision	8,074	7,368	706
9120 - Sales Expenses - Demonstrating and selling expenses	21,133	15,387	5,746
9200 - Administrative and general salaries	1,332,514	1,849,800	(517,285)
9240 - Property insurance	1,091		1,091
9250 - Injuries and damages	34,934	30,076	4,858
9260 - Employee pensions and benefits	24,536	18,592	5,943
9280 - Regulatory commission expenses	91,966	84,511	7,455
9301 - General advertising expenses	3,604	521	3,082
9302 - Miscellaneous general expenses	20,679	69,652	(48,972)
9350 - Maintenance of general plant	209,072	148,553	60,519
OTP Total	6,077,170	5,939,477	137,692

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/02/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Incentive Compensation. Refer to pages 37-38 of the direct testimony of Company witness Stuart Tommerdahl and Volume 4A, workpaper B-16.

- a. Please identify the dollar amount of bonuses and incentive compensation that is allocated to OTP from Otter Tail Corporation and included in the test year ending December 31, 2018, by account and show how this amount was derived. Show detailed calculations.
- b. Are any of the amounts of incentive compensation that were identified in response to part a, above, related to union contracts? If so, identify, quantify and explain such amounts.
- c. Referring to Volume 4 from OPT's filing, please provide workpaper B-16 electronically in Excel with all calculations and formulas intact.
- d. Please provide a schedule electronically in Excel (with calculations and formulas intact), that contains the source data from which the amounts shown in the Company's adjustment to cap management performance incentives and corporate bonuses at 25% workpaper B-16 were derived.

Attachments: 1

Attachment 1 to DR ND-PSC 15.19.xlsx

Response:

- a. The dollar amount of incentive compensation that was allocated to OTP from Otter Tail Corp was \$834,429. Total incentive compensation budgeted at Otter Tail Corp was \$1,720,000.
- b. The amount of incentive compensation was not derived from union contracts.
- c. Please refer to Attachment 1 to DR ND-PSD-15.19 for the electronic version of B-16 with calculations and formulas intact.
- d. As B-16 states, the calculation is a five-year average of actual results.

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

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/04/2018

Responding Witness: Peter Wasberg, Director, Human Resources and Safety - (218) 739-8940

Data Request:

Stock-Based Compensation. Refer to pages 6-7 of the direct testimony of Company witness Peter Wasberg.

- a. List, by amount and account, all stock-based compensation expense in OTP's requested cost of service for the test year ending December 31, 2018, including but not limited to restricted stock units, executive stock options, performance share awards, accruals made pursuant to ASC 718 (formerly SFAS 123R) and any other stock-based compensation awards that result in costs being directly charged to OTP.
- b. List, by amount and account, all stock-based compensation expense in OTP's requested cost of service for the test year ending December 31, 2018 including but not limited to restricted stock units, executive stock options, performance share awards, accruals made pursuant to ASC 718 (formerly SFAS 123R) and any other stock-based compensation awards that is allocated to OTP by Otter Tail Corporation for the test year ending December 31, 2018.
- c. Provide a description of each distinct stock-based compensation program that is included in the charges to OTP for the test year ending December 31, 2018, and provide a copy of the plan documents.

Attachments: 1

Attachment 1 to ND-PSC-15.20.pdf

Response:

- A. \$1,297,392.14 was directly charged to account 5240.3000.0921 related to stock-based compensation.

Public
Response to Data Request ND-PSC-15.20
Page 2 of 2

- B. \$299,882 was allocated to OTP by OTC and charged to account 5240.3000.0921 related to stock-based compensation.
- C. Both Restricted Stock Units and Performance Share Awards were included in the charges to OTP for test year ending December 31, 2018. See Attachment 1 to DR ND-PSC-15.20 for a copy of the Otter Tail Corporation 2014 Stock Incentive Plan.

OTTER TAIL CORPORATION 2014 STOCK INCENTIVE PLAN

Section 1. Purpose.

The purpose of the Plan is to promote the interests of the Company and its shareholders by aiding the Company in attracting and retaining employees, officers, consultants, independent contractors, advisors and non-employee Directors capable of assuring the future success of the Company, to offer such persons incentives to put forth maximum efforts for the success of the Company's business and to compensate such persons through various stock-based arrangements and provide them with opportunities for stock ownership in the Company, thereby aligning the interests of such persons with the Company's shareholders.

Section 2. Definitions.

As used in the Plan, the following terms shall have the meanings set forth below:

(a) "Affiliate" shall mean (i) any entity that, directly or indirectly through one or more intermediaries, is controlled by the Company and (ii) any entity in which the Company has a significant equity interest, in each case as determined by the Committee.

(b) "Award" shall mean any Option, Stock Appreciation Right, Restricted Stock, Restricted Stock Unit, Dividend Equivalent, Performance Award, Stock Award or Other Stock-Based Award granted under the Plan.

(c) "Award Agreement" shall mean any written agreement, contract or other instrument or document evidencing an Award granted under the Plan. An Award Agreement may be in an electronic medium and need not be signed by a representative of the Company or the Participant. Each Award Agreement shall be subject to the applicable terms and conditions of the Plan and any other terms and conditions (not inconsistent with the Plan) determined by the Committee.

(d) "Board" shall mean the Board of Directors of the Company.

(e) "Change in Control" shall mean any one of the following events for Awards granted under the Plan:

(i) The acquisition by any person, entity or "group," within the meaning of Sections 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), other than the Company or any of its Affiliates, or any employee benefit plan of the Company and/or one or more of its Affiliates, of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 25% or more of either the then outstanding Common Shares or the combined voting power of the Company's then outstanding voting securities in a transaction or series of transactions not approved in advance by a vote of at least three-quarters of the Continuing Directors (as hereinafter defined); or

(ii) Individuals who, as of the grant date of the Award, constitute the Board of Directors of the Company (generally the “Directors” and as of the grant date of the Award the “Continuing Directors”) cease for any reason to constitute at least a majority thereof, provided that any person becoming a Director subsequent to the Grant Date whose nomination for election was approved in advance by a vote of at least three-quarters of the Continuing Directors (other than a nomination of an individual whose initial assumption of office is in connection with an actual or threatened solicitation with respect to the election or removal of the Directors of the Company, as such terms are used in Rule 14a-11 of Regulation 14A under the Exchange Act) shall be deemed to be a Continuing Director; or

(iii) The consummation of a reorganization, merger, consolidation, liquidation or dissolution of the Company or of the sale (in one transaction or a series of related transactions) of all or substantially all of the assets of the Company other than a reorganization, merger, consolidation, liquidation, dissolution or sale approved in advance by a vote of at least three-quarters of the Continuing Directors.

(f) “Code” shall mean the Internal Revenue Code of 1986, as amended from time to time, and any regulations promulgated thereunder.

(g) “Committee” shall mean the Compensation Committee of the Board or any successor committee of the Board designated by the Board to administer the Plan. The Committee shall be comprised of not less than such number of Directors as shall be required to permit Awards granted under the Plan to qualify under Rule 16b-3, and each member of the Committee shall be a “Non-Employee Director” within the meaning of Rule 16b-3 and an “outside director” within the meaning of Section 162(m). The Company expects to have the Plan administered in accordance with the requirements for the award of “qualified performance-based compensation” within the meaning of Section 162(m).

(h) “Company” shall mean Otter Tail Corporation, a Minnesota corporation, or any successor corporation.

(i) “Director” shall mean a member of the Board.

(j) “Dividend Equivalent” shall mean any right granted under Section 6(d) of the Plan.

(k) “Eligible Person” shall mean any employee, officer, consultant, independent contractor, advisor or non-employee Director providing services to the Company or any Affiliate whom the Committee determines to be an Eligible Person. An Eligible Person must be a natural person.

(l) “Exchange Act” shall mean the Securities Exchange Act of 1934, as amended.

(m) “Fair Market Value” shall mean, with respect to any property (including, without limitation, any Shares or other securities), the fair market value of such property

determined by such methods or procedures as shall be established from time to time by the Committee. Notwithstanding the foregoing, unless otherwise determined by the Committee, the Fair Market Value of Shares on a given date for purposes of the Plan shall be the closing sale price of the Shares as reported on the NASDAQ National Market System on such date, or if the NASDAQ National Market System is not open for trading on such date, on the most recent preceding date when the NASDAQ National Market System is open for trading.

(n) “Incentive Stock Option” shall mean an option granted under Section 6(a) of the Plan that is intended to meet the requirements of Section 422 of the Code or any successor provision.

(o) “Non-Qualified Stock Option” shall mean an option granted under Section 6(a) of the Plan that is not intended to be an Incentive Stock Option.

(p) “Option” shall mean an Incentive Stock Option or a Non-Qualified Stock Option.

(q) “Other Stock-Based Award” shall mean any right granted under Section 6(g) of the Plan.

(r) “Participant” shall mean an Eligible Person designated to be granted an Award under the Plan.

(s) “Performance Award” shall mean any right granted under Section 6(e) of the Plan.

(t) “Performance Goal” shall mean one or more of the following performance goals, either individually, alternatively or in any combination, applied on a corporate, subsidiary, division, business unit, line of business or product basis: sales, revenue, costs, expenses, earnings (including one or more of net profit after tax, gross profit, operating profit, earnings before interest and taxes, earnings before interest, taxes, depreciation and amortization and net earnings), earnings per share, earnings per share from continuing operations, operating income, pre-tax income, operating income margin, net income, margins (including one or more of gross, operating and net income margins), ratios (including one or more of price to earnings, debt to assets, debt to net assets and ratios regarding liquidity, solvency, productivity or risk) returns (including one or more of return on actual or proforma assets, net assets, equity, investment, capital and net capital employed), stockholder return (including total stockholder return relative to an index or peer group), stock price, market capitalization, economic value added, cash generation, cash flow (including operating cash flow, free cash flow and cash flow return on equity), unit volume, working capital, market share, cost reductions and strategic plan development and implementation. Such goals may reflect whole corporate entity or business unit performance or a relative comparison to the performance of a peer group of entities or other external measure of the selected performance criteria. To the extent consistent with Section 162(m), the Committee may, when it establishes performance criteria, also provide for the adjustment for charges related to an event or occurrence which the Committee determines is appropriate for adjustment, including, but not limited to, any of the following events: asset write-downs; litigation or claim judgments or settlements; changes in tax law, accounting

principles or other such laws or provisions affecting reported results; severance, contract termination and other costs related to exiting certain business activities; acquisitions; and gains or losses from the disposition of businesses or assets or from the early extinguishment of debt.

(u) “Person” shall mean any individual or entity, including a corporation, partnership, limited liability company, association, joint venture or trust.

(v) “Plan” shall mean this Otter Tail Corporation 2014 Stock Incentive Plan, as amended from time to time.

(w) “Restricted Stock” shall mean any Share granted under Section 6(c) of the Plan.

(x) “Restricted Stock Unit” shall mean any unit granted under Section 6(c) of the Plan evidencing the right to receive a Share (or a cash payment equal to the Fair Market Value of a Share) at some future date.

(y) “Rule 16b-3” shall mean Rule 16b-3 promulgated by the Securities and Exchange Commission under the Exchange Act or any successor rule or regulation.

(z) “Section 162(m)” shall mean Section 162(m) of the Code, or any successor provision, and the applicable Treasury Regulations promulgated thereunder.

(aa) “Section 409A” shall mean Section 409A of the Code, or any successor provision, and applicable Treasury Regulations and other applicable guidance thereunder.

(bb) “Shares” shall mean shares of Common Stock, \$5 par value per share, of the Company or such other securities or property as may become subject to Awards pursuant to an adjustment made under Section 4(c) of the Plan.

(cc) “Specified Employee” shall mean a specified employee as defined in Code Section 409A(a)(2)(B) or applicable proposed or final regulations under Code Section 409A.

(dd) “Stock Appreciation Right” shall mean any right granted under Section 6(b) of the Plan.

(ee) “Stock Award” shall mean any Share granted under Section 6(f) of the Plan.

Section 3. Administration.

(a) Power and Authority of the Committee. The Plan shall be administered by the Committee. Subject to the express provisions of the Plan and to applicable law, the Committee shall have full power and authority to: (i) designate Participants; (ii) determine the type or types of Awards to be granted to each Participant under the Plan; (iii) determine the number of Shares to be covered by (or the method by which payments or other rights are to be calculated in connection with) each Award; (iv) determine the terms and conditions of any Award or Award Agreement, including any terms relating to the forfeiture of any Award and the

forfeiture, recapture or disgorgement of any cash, Shares, other securities, other Awards, other property and other amounts payable with respect to any Award; (v) amend the terms and conditions of any Award or Award Agreement, provided, however, that, except as otherwise permitted in connection with an event as provided in Section 4(c) hereof, the Committee shall not reprice, adjust or amend the exercise price of Options or the grant price of Stock Appreciation Rights previously awarded to any Participant, whether through amendment, cancellation and exchange for cash or another Award, a replacement grant, or any other means; (vi) accelerate the exercisability of any Award or the lapse of any restrictions relating to any Award; (vii) determine whether, to what extent and under what circumstances Awards may be exercised in cash, Shares, other securities, other Awards or other property, or canceled, forfeited or suspended; (viii) determine whether, to what extent and under what circumstances cash, Shares, other securities, other Awards, other property and other amounts payable with respect to an Award under the Plan shall be deferred either automatically or at the election of the holder of the Award or the Committee; (ix) interpret and administer the Plan and any instrument or agreement, including any Award Agreement, relating to the Plan; (x) establish, amend, suspend or waive such rules and regulations and appoint such agents as it shall deem appropriate for the proper administration of the Plan; (xi) make any other determination and take any other action that the Committee deems necessary or desirable for the administration of the Plan; and (xii) adopt such modifications, rules, procedures and subplans as may be necessary or desirable to comply with provisions of the laws of non-U.S. jurisdictions in which the Company or an Affiliate may operate, including, without limitation, establishing any special rules for Affiliates, Eligible Persons or Participants located in any particular country, in order to meet the objectives of the Plan and to ensure the viability of the intended benefits of Awards granted to Participants located in such non-United States jurisdictions. Unless otherwise expressly provided in the Plan, all designations, determinations, interpretations and other decisions under or with respect to the Plan or any Award or Award Agreement shall be within the sole discretion of the Committee, may be made at any time and shall be final, conclusive and binding upon any Participant, any holder or beneficiary of any Award or Award Agreement, and any employee of the Company or any Affiliate.

(b) Delegation. The Committee may delegate its powers and duties under the Plan to one or more Directors or officers of the Company, subject to such terms, conditions and limitations as the Committee may establish in its sole discretion; provided, however, that the Committee shall not delegate its powers and duties under the Plan (i) with regard to officers or directors of the Company or any Affiliate who are subject to Section 16 of the Exchange Act or (ii) in such a manner as would cause the Plan not to comply with the requirements of Section 162(m).

(c) Power and Authority of the Board of Directors. Notwithstanding anything to the contrary contained herein, the Board may, at any time and from time to time, without any further action of the Committee, exercise the powers and duties of the Committee under the Plan, unless the exercise of such powers and duties by the Board would cause the Plan not to comply with the requirements of Rule 16b-3 or Section 162(m).

Section 4. Shares Available for Awards.

(a) Shares Available. Subject to adjustment as provided in Section 4(c) of the Plan, the aggregate number of Shares that may be issued under all Awards under the Plan shall be 1,900,000. Shares to be issued under the Plan may be authorized but unissued Shares, treasury shares or Shares acquired in the open market or otherwise. If an Award terminates or is forfeited or cancelled without the issuance of any Shares, or if any Shares covered by an Award or to which an Award relates are not issued for any other reason, then the number of Shares counted against the aggregate number of Shares available under the Plan with respect to such Award, to the extent of any such termination, forfeiture, cancellation or other event, shall again be available for granting Awards under the Plan. If Shares of Restricted Stock are forfeited or otherwise reacquired by the Company prior to vesting, whether or not dividends have been paid on such Shares, then the number of Shares counted against the aggregate number of Shares available under the Plan with respect to such Award of Restricted Stock, to the extent of any such forfeiture or reacquisition by the Company, shall again be available for granting Awards under the Plan. Shares that are withheld in full or partial payment to the Company of the purchase or exercise price relating to any Award or in connection with the satisfaction of tax obligations relating to any Award, or Shares that are acquired by the Company on the open market with cash delivered to the Company for any such purposes, shall not be available for granting Awards under the Plan.

(b) Accounting for Awards. For purposes of this Section 4, if an Award entitles the holder thereof to receive or purchase Shares, the number of Shares covered by such Award or to which such Award relates shall be counted on the date of grant of such Award against the aggregate number of Shares available for granting Awards under the Plan. For Stock Appreciation Rights settled in Shares upon exercise, the aggregate number of Shares with respect to which the Stock Appreciation Right is exercised, rather than the number of Shares actually issued upon exercise, shall be counted against the number of Shares available for Awards under the Plan. If an Option is net exercised, as permitted by Section 6(a)(iii), the number of Shares counted against the aggregate number of Shares available under the Plan with respect to such Award shall be the gross amount of Shares subject to the Award. Awards that do not entitle the holder thereof to receive or purchase Shares and Awards that are settled in cash shall not be counted against the aggregate number of Shares available for Awards under the Plan.

(c) Adjustments. In the event that any dividend or other distribution (whether in the form of cash, Shares, other securities or other property), recapitalization, stock split, reverse stock split, reorganization, merger, consolidation, split-up, spin-off, combination, repurchase or exchange of Shares or other securities of the Company, issuance of warrants or other rights to purchase Shares or other securities of the Company or other similar corporate transaction or event affects the Shares such that an adjustment is necessary in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the Plan, then the Committee shall, in such manner as it may deem equitable, adjust any or all of (i) the number and type of Shares (or other securities or other property) that thereafter may be made the subject of Awards, (ii) the number and type of Shares (or other securities or other property) subject to outstanding Awards, (iii) the purchase or exercise price with respect to any Award and (iv) the limitations contained in Section 4(d) of the Plan.

(d) Award Limitations Under the Plan.

(i) Section 162(m) Limitation for Certain Types of Awards. No Eligible Person may be granted Options, Stock Appreciation Rights or any other Award or Awards under the Plan, the value of which Award or Awards is based solely on an increase in the value of the Shares after the date of grant of such Award or Awards, for more than 500,000 Shares (subject to adjustment as provided in Section 4(c) of the Plan) in the aggregate in any calendar year.

(ii) Section 162(m) Limitation for Performance Awards. The maximum amount payable to any Participant that may be a “covered person” within the meaning of Section 162(m) pursuant to all Performance Awards which are intended to represent “qualified performance-based compensation” within the meaning of Section 162(m) in the aggregate in any calendar year shall be \$5,000,000 in value, whether payable in cash, Shares or other property. This limitation does not apply to any Award subject to the limitation contained in Section 4(d)(i) of the Plan.

Section 5. Eligibility.

Any Eligible Person shall be eligible to be designated a Participant. In determining which Eligible Persons shall receive an Award and the terms of any Award, the Committee may take into account the nature of the services rendered by the respective Eligible Persons, their present and potential contributions to the success of the Company or such other factors as the Committee, in its discretion, shall deem relevant. Notwithstanding the foregoing, an Incentive Stock Option may only be granted to full-time or part-time employees (which term as used herein includes, without limitation, officers and Directors who are also employees), and an Incentive Stock Option shall not be granted to an employee of an Affiliate unless such Affiliate is also a “subsidiary corporation” of the Company within the meaning of Section 424(f) of the Code or any successor provision. Further, notwithstanding the foregoing, Options and Stock Appreciation Rights shall not be granted to an Eligible Person providing direct services to an Affiliate unless the Company has a “controlling interest” in such Affiliate within the meaning of Treas. Reg. Sec. 1.409A-1(b)(5)(iii)(E)(1).

Section 6. Awards.

(a) Options. The Committee is hereby authorized to grant Options to Eligible Persons with the following terms and conditions and with such additional terms and conditions not inconsistent with the provisions of the Plan as the Committee shall determine:

(i) Exercise Price. The purchase price per Share purchasable under an Option shall be determined by the Committee and shall not be less than 100% of the Fair Market Value of a Share on the date of grant of such Option; provided, however, that the Committee may designate a per share exercise price below Fair Market Value on the date of grant (A) to the extent necessary or appropriate, as determined by the Committee, to satisfy applicable legal or

regulatory requirements of a foreign jurisdiction or (B) if the Option is granted in substitution for a stock option previously granted by an entity that is acquired by or merged with the Company or an Affiliate.

(ii) Option Term. The term of each Option shall be fixed by the Committee but shall not be longer than 10 years from the date of grant.

(iii) Time and Method of Exercise. The Committee shall determine the time or times at which an Option may be exercised in whole or in part and the method or methods by which, and the form or forms (including, without limitation, cash, Shares, other securities, other Awards or other property, or any combination thereof, having a Fair Market Value on the exercise date equal to the applicable exercise price) in which, payment of the exercise price with respect thereto may be made or deemed to have been made. Alternatively, the Committee may, in its discretion, permit a Non-Qualified Stock Option (but not an Incentive Stock Option) to be exercised by delivering to the Participant a number of Shares having an aggregate Fair Market Value (determined as of the date of exercise) equal to the excess, if positive, of the Fair Market Value of the Shares underlying the Non-Qualified Stock Option being exercised, on the date of exercise, over the exercise price of the Non-Qualified Stock Option for such Shares.

(b) Stock Appreciation Rights. The Committee is hereby authorized to grant Stock Appreciation Rights to Eligible Persons subject to the terms of the Plan and any applicable Award Agreement. A Stock Appreciation Right granted under the Plan shall confer on the holder thereof a right to receive upon exercise thereof the excess of (i) the Fair Market Value of one Share on the date of exercise (or, if the Committee shall so determine, at any time during a specified period before or after the date of exercise) over (ii) the grant price of the Stock Appreciation Right as specified by the Committee, which price shall not be less than 100% of the Fair Market Value of one Share on the date of grant of the Stock Appreciation Right. Subject to the terms of the Plan and any applicable Award Agreement, the grant price, term, methods of exercise, dates of exercise, methods of settlement and any other terms and conditions of any Stock Appreciation Right shall be as determined by the Committee; provided, however, that the term of each Stock Appreciation Right shall not be longer than 10 years from the date of grant. The Committee may impose such conditions or restrictions on the exercise of any Stock Appreciation Right as it may deem appropriate.

(c) Restricted Stock and Restricted Stock Units. The Committee is hereby authorized to grant Awards of Restricted Stock and Restricted Stock Units to Eligible Persons with the following terms and conditions and with such additional terms and conditions not inconsistent with the provisions of the Plan as the Committee shall determine:

(i) Restrictions. Shares of Restricted Stock and Restricted Stock Units shall be subject to such restrictions as the Committee may impose (including, without limitation, any limitation on the right to vote a Share of Restricted Stock or the right to receive any dividend or other right or property with respect thereto), which restrictions may lapse separately or in combination at such time or times, in such installments or otherwise, as the Committee may deem appropriate. Notwithstanding the foregoing, the Committee may permit

acceleration of vesting of such Awards in certain events including, but not limited to, the Participant's death, disability, termination or retirement or a Change in Control.

(ii) Issuance and Delivery of Shares. Any Restricted Stock granted under the Plan shall be issued at the time such Awards are granted and may be evidenced in such manner as the Committee may deem appropriate, including book-entry registration or issuance of a stock certificate or certificates, which certificate or certificates shall be held by the Company. Such certificate or certificates shall be registered in the name of the Participant and shall bear an appropriate legend referring to the restrictions applicable to such Restricted Stock. Shares representing Restricted Stock that are no longer subject to restrictions shall be delivered to the Participant promptly after the applicable restrictions lapse or are waived. In the case of Restricted Stock Units, no Shares shall be issued at the time such Awards are granted. Upon the lapse or waiver of restrictions and the restricted period relating to Restricted Stock Units evidencing the right to receive Shares, such Shares shall be issued and delivered to the holder of the Restricted Stock Units.

(iii) Forfeiture. Except as otherwise determined by the Committee, upon a Participant's termination of employment or resignation or removal as a Director (in either case, as determined under criteria established by the Committee) during the applicable restriction period, all Shares of Restricted Stock and all Restricted Stock Units held by the Participant at such time shall be forfeited and reacquired by the Company; provided, however, that the Committee may, when it finds that a waiver would be in the best interest of the Company, waive in whole or in part any or all remaining restrictions with respect to Shares of Restricted Stock or Restricted Stock Units.

(d) Dividend Equivalents. The Committee is hereby authorized to grant Dividend Equivalents to Eligible Persons under which the Participant shall be entitled to receive payments (in cash, Shares, other securities, other Awards or other property as determined in the discretion of the Committee) equivalent to the amount of cash dividends paid by the Company to holders of Shares with respect to a number of Shares determined by the Committee. Subject to the terms of the Plan and any applicable Award Agreement, such Dividend Equivalents may have such terms and conditions as the Committee shall determine. Notwithstanding the foregoing, the Committee may not grant Dividend Equivalents to Eligible Persons in connection with grants of Options, Stock Appreciation Rights or unvested Performance Awards to such Eligible Persons.

(e) Performance Awards. The Committee is hereby authorized to grant Performance Awards to Eligible Persons subject to the terms of the Plan and any applicable Award Agreement. A Performance Award granted under the Plan (i) may be denominated or payable in cash, Shares (including, without limitation, Restricted Stock and Restricted Stock Units), other securities, other Awards or other property and (ii) shall confer on the holder thereof the right to receive payments, in whole or in part, upon the achievement of one or more performance goals during such performance periods as the Committee shall establish. Subject to the terms of the Plan, the performance goals to be achieved during any performance period, the length of any performance period, the amount of any Performance Award granted, the amount of any payment or transfer to be made pursuant to any Performance Award and any other terms and conditions of any Performance Award shall be determined by the Committee. Performance

Awards that are granted to Eligible Persons who may be “covered employees” under Section 162(m) and that are intended to be “qualified performance-based compensation” within the meaning of Section 162(m), to the extent required by Section 162(m), shall be conditioned solely on the achievement of one or more objective Performance Goals established by the Committee within the time prescribed by Section 162(m), and shall otherwise comply with the requirements of Section 162(m).

(f) Stock Awards. The Committee is hereby authorized to grant to Eligible Persons Shares without restrictions thereon, as deemed by the Committee to be consistent with the purpose of the Plan. Subject to the terms of the Plan and any applicable Award Agreement, such Stock Awards may have such terms and conditions as the Committee shall determine.

(g) Other Stock-Based Awards. The Committee is hereby authorized to grant to Eligible Persons such other Awards that are denominated or payable in, valued in whole or in part by reference to, or otherwise based on or related to, Shares (including, without limitation, securities convertible into Shares), as are deemed by the Committee to be consistent with the purpose of the Plan. The Committee shall determine the terms and conditions of such Awards, subject to the terms of the Plan and the Award Agreement. Shares, or other securities delivered pursuant to a purchase right granted under this Section 6(g), shall be purchased for consideration having a value equal to at least 100% of the Fair Market Value of such Shares or other securities on the date the purchase right is granted. The consideration paid by the Participant may be paid by such method or methods and in such form or forms (including, without limitation, cash, Shares, other securities, other Awards or other property, or any combination thereof), as the Committee shall determine.

(h) General.

(i) Consideration for Awards. Awards may be granted for no cash consideration or for any cash or other consideration as may be determined by the Committee or required by applicable law.

(ii) Awards May Be Granted Separately or Together. Awards may, in the discretion of the Committee, be granted either alone or in addition to, in tandem with or in substitution for any other Award or any award granted under any other plan of the Company or any Affiliate. Awards granted in addition to or in tandem with other Awards or in addition to or in tandem with awards granted under any other plan of the Company or any Affiliate may be granted either at the same time as or at a different time from the grant of such other Awards or awards.

(iii) Forms of Payment under Awards. Subject to the terms of the Plan and of any applicable Award Agreement, payments or transfers to be made by the Company or an Affiliate upon the grant, exercise or payment of an Award may be made in such form or forms as the Committee shall determine (including, without limitation, cash, Shares, other securities, other Awards or other property, or any combination thereof), and may be made in a single payment or transfer, in installments or on a deferred basis, in each case in accordance with rules and procedures established by the Committee. Such rules and procedures may include, without limitation, provisions for the payment or crediting of reasonable interest on installment or

deferred payments or the grant or crediting of Dividend Equivalents with respect to installment or deferred payments.

(iv) Term of Awards. The term of each Award shall be for a period not longer than 10 years from the date of grant.

(v) Limits on Transfer of Awards. Except as otherwise provided by the Committee or the terms of this Plan, no Award (other than a Stock Award) and no right under any such Award shall be transferable by a Participant for value other than by will or by the laws of descent and distribution. The Committee may establish procedures as it deems appropriate for a Participant to designate a Person or Persons, as beneficiary or beneficiaries, to exercise the rights of the Participant and receive any property distributable with respect to any Award in the event of the Participant's death. The Committee, in its discretion and subject to such additional terms and conditions as it determines, may permit a Participant to transfer a Non-Qualified Stock Option to any "family member" (as such term is defined in the General Instructions to Form S-8 (or any successor to such Instructions or such Form) under the Securities Act of 1933, as amended) at any time that such Participant holds such Option, provided that such transfers may not be for value (i.e., the transferor may not receive any consideration therefor) and the family member may not make any subsequent transfers other than by will or by the laws of descent and distribution. Each Award under the Plan or right under any such Award shall be exercisable during the Participant's lifetime only by the Participant (except as provided herein or in an Award Agreement or amendment thereto relating to a Non-Qualified Stock Option) or, if permissible under applicable law, by the Participant's guardian or legal representative. No Award (other than a Stock Award) or right under any such Award may be pledged, alienated, attached or otherwise encumbered, and any purported pledge, alienation, attachment or encumbrance thereof shall be void and unenforceable against the Company or any Affiliate.

(vi) Restrictions; Securities Exchange Listing. All Shares or other securities delivered under the Plan pursuant to any Award or the exercise thereof shall be subject to such restrictions as the Committee may deem advisable under the Plan, applicable federal or state securities laws and regulatory requirements, and the Committee may cause appropriate entries to be made or legends to be placed on the certificates for such Shares or other securities to reflect such restrictions. If the Shares or other securities are traded on a securities exchange, the Company shall not be required to deliver any Shares or other securities covered by an Award unless and until such Shares or other securities have been admitted for trading on such securities exchange.

(vii) Section 409A Provisions. Notwithstanding anything in the Plan or any Award Agreement to the contrary, to the extent that any amount or benefit that constitutes "deferred compensation" to a Participant under Section 409A of the Code and applicable guidance thereunder is otherwise payable or distributable to a Participant under the Plan or any Award Agreement solely by reason of the occurrence of a Change of Control or due to the Participant's disability or "separation from service" (as such term is defined under Section 409A), such amount or benefit will not be payable or distributable to the Participant by reason of such circumstance unless the Committee determines in good faith that (i) the circumstances giving rise to such Change of Control, disability or separation from service meet the definition of

a change in ownership or control, disability or separation from service, as the case may be, in Section 409A(a)(2)(A) of the Code and applicable proposed or final regulations, or (ii) the payment or distribution of such amount or benefit would be exempt from the application of Section 409A by reason of the short-term deferral exemption or otherwise. Any payment or distribution that otherwise would be made to a Participant who is a Specified Employee (as determined by the Committee in good faith) on account of separation from service may not be made before the date which is 6 months after the date of the Specified Employee's separation from service (or if earlier, upon the Specified Employee's death) unless the payment or distribution is exempt from the application of Section 409A by reason of the short-term deferral exemption or otherwise.

Section 7. Amendment and Termination; Corrections.

(a) Amendments to the Plan. The Board may amend, alter, suspend, discontinue or terminate the Plan at any time; provided, however, that, notwithstanding any other provision of the Plan or any Award Agreement, prior approval of the shareholders of the Company shall be required for any amendment to the Plan that:

(i) requires shareholder approval under the rules or regulations of the Securities and Exchange Commission or The NASDAQ Stock Market LLC or any other securities exchange that are applicable to the Company;

(ii) increases the number of shares authorized under the Plan as specified in Section 4(a) of the Plan;

(iii) increases the number of shares subject to the limitations contained in Section 4(d)(i) of the Plan or the dollar amount subject to the limitation contained in Section 4(d)(ii) of the Plan;

(iv) permits repricing of Options or Stock Appreciation Rights, which is prohibited by Section 3(a)(v) of the Plan;

(v) permits the award of Options or Stock Appreciation Rights at a price less than 100% of the Fair Market Value of a Share on the date of grant of such Option or Stock Appreciation Right, contrary to the provisions of Section 6(a)(i) of the Plan; and

(vi) would cause Section 162(m) to become unavailable with respect to the Plan.

(b) Amendments to Awards. Subject to the provisions of the Plan, the Committee may waive any conditions of or rights of the Company under any outstanding Award, prospectively or retroactively. Except as otherwise provided in the Plan, the Committee may amend, alter, suspend, discontinue or terminate any outstanding Award, prospectively or retroactively, but no such action may adversely affect the rights of the holder of such Award without the consent of the Participant or holder or beneficiary thereof. The Company intends that Awards under the Plan shall satisfy the requirements of Section 409A to avoid any adverse tax results thereunder, and the Committee shall administer and interpret the Plan and all Award

Agreements in a manner consistent with that intent. If any provision of the Plan or an Award Agreement would result in adverse tax consequences under Section 409A, the Committee may amend that provision (or take any other action reasonably necessary) to avoid any adverse tax results and no action taken to comply with Section 409A shall be deemed to impair or otherwise adversely affect the rights of any holder of an Award or beneficiary thereof.

(c) Correction of Defects, Omissions and Inconsistencies. The Committee may correct any defect, supply any omission or reconcile any inconsistency in the Plan or in any Award or Award Agreement in the manner and to the extent it shall deem desirable to implement or maintain the effectiveness of the Plan.

Section 8. Income Tax Withholding.

In order to comply with all applicable federal, state, local or foreign income tax laws or regulations, the Company may take such action as it deems appropriate to ensure that all applicable federal, state, local or foreign payroll, withholding, income or other taxes, which are the sole and absolute responsibility of a Participant, are withheld or collected from such Participant. In order to assist a Participant in paying all or a portion of the applicable taxes to be withheld or collected upon exercise or receipt of (or the lapse of restrictions relating to) an Award, the Committee, in its discretion and subject to such additional terms and conditions as it may adopt, may permit the Participant to satisfy such tax obligation by (a) electing to have the Company withhold a portion of the Shares otherwise to be delivered upon exercise or receipt of (or the lapse of restrictions relating to) such Award with a Fair Market Value equal to the amount of such taxes or (b) delivering to the Company Shares other than Shares issuable upon exercise or receipt of (or the lapse of restrictions relating to) such Award with a Fair Market Value equal to the amount of such taxes. The election, if any, must be made on or before the date that the amount of tax to be withheld is determined.

Section 9. General Provisions.

(a) No Rights to Awards. No Eligible Person, Participant or other Person shall have any claim to be granted any Award under the Plan, and there is no obligation for uniformity of treatment of Eligible Persons, Participants or holders or beneficiaries of Awards under the Plan. The terms and conditions of Awards need not be the same with respect to any Participant or with respect to different Participants.

(b) Award Agreements. No Participant shall have rights under an Award granted to such Participant unless and until an Award Agreement shall have been duly executed on behalf of the Company and, if requested by the Company, signed by the Participant, or until such Award Agreement is delivered and accepted through an electronic medium in accordance with procedures established by the Company.

(c) No Rights of Stockholders. Except with respect to Restricted Stock and Stock Awards, neither a Participant nor the Participant's legal representative shall be, or have any of the rights and privileges of, a stockholder of the Company with respect to any Shares issuable upon the exercise or payment of any Award, in whole or in part, unless and until the Shares have been issued.

(d) No Limit on Other Compensation Plans or Arrangements. Nothing contained in the Plan shall prevent the Company or any Affiliate from adopting or continuing in effect other or additional compensation plans or arrangements, and such plans or arrangements may be either generally applicable or applicable only in specific cases.

(e) No Right to Employment or Directorship. The grant of an Award shall not be construed as giving a Participant the right to be retained as an employee of the Company or any Affiliate, or a Director to be retained as a Director, nor will it affect in any way the right of the Company or an Affiliate to terminate a Participant's employment at any time, with or without cause. In addition, the Company or an Affiliate may at any time dismiss a Participant from employment free from any liability or any claim under the Plan or any Award, unless otherwise expressly provided in the Plan or in any Award Agreement.

(f) Governing Law. The validity, construction and effect of the Plan or any Award, and any rules and regulations relating to the Plan or any Award, shall be determined in accordance with the laws of the State of Minnesota.

(g) Severability. If any provision of the Plan or any Award is or becomes or is deemed to be invalid, illegal or unenforceable in any jurisdiction or would disqualify the Plan or any Award under any law deemed applicable by the Committee, such provision shall be construed or deemed amended to conform to applicable laws, or if it cannot be so construed or deemed amended without, in the determination of the Committee, materially altering the purpose or intent of the Plan or the Award, such provision shall be stricken as to such jurisdiction or Award, and the remainder of the Plan or any such Award shall remain in full force and effect.

(h) No Trust or Fund Created. Neither the Plan nor any Award shall create or be construed to create a trust or separate fund of any kind or a fiduciary relationship between the Company or any Affiliate and a Participant or any other Person. To the extent that any Person acquires a right to receive payments from the Company or any Affiliate pursuant to an Award, such right shall be no greater than the right of any unsecured general creditor of the Company or any Affiliate.

(i) No Fractional Shares. No fractional Shares shall be issued or delivered pursuant to the Plan or any Award, and the Committee shall determine whether cash shall be paid in lieu of any fractional Share or whether such fractional Share or any rights thereto shall be canceled, terminated or otherwise eliminated.

(j) Headings. Headings are given to the Sections and subsections of the Plan solely as a convenience to facilitate reference. Such headings shall not be deemed in any way material or relevant to the construction or interpretation of the Plan or any provision thereof.

Section 10. Clawback or Recoupment.

All Awards under this Plan shall be subject to forfeiture or other penalties under any clawback or recoupment policy of the Company in effect from time to time and such forfeiture or penalty provisions as determined by the Committee and set forth in the applicable Award Agreement.

Section 11. Effective Date of the Plan; Effect on Prior Plan.

The Plan shall be subject to approval by the stockholders of the Company at the annual meeting of shareholders of the Company to be held on April 14, 2014 and the Plan shall be effective as of the date of such shareholder approval. On and after the date of shareholder approval of the Plan, no awards shall be granted under the Company's 1999 Stock Incentive Plan, but all outstanding awards previously granted under the 1999 Stock Incentive Plan shall remain outstanding in accordance with the terms thereof.

Section 12. Term of the Plan.

The Plan shall terminate at midnight on **December 31, 2023**, unless terminated before then by the Board. Awards may be granted under the Plan until the earlier to occur of termination of the Plan or the date on which all Shares available for Awards under the Plan have been purchased or acquired; provided, however, that Incentive Stock Options may not be granted following the 10-year anniversary of the Board's adoption of the Plan. As long as any Awards are outstanding under the Plan, the terms of the Plan shall govern such Awards.

Adopted by the Board of Directors on February 6, 2014, subject to and effective upon shareholder approval.

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Response to Data Request ND-PSC-06.23
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/20/2018
Date Due: 03/06/2018
Date of Response: 03/06/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Identify and provide documents describing the board of directors incentive compensation programs.

Attachments: 0

Response:

OTP Board of Directors:

To be clear, please note that the OTP Board of Directors is made up of Officers of Otter Tail Corporation. There is not a compensation program for the OTP Board of Directors.

Otter Tail Corporation Board of Directors:

Non-employee Directors of Otter Tail Corporation receive an annual retainer for their services as a Director. Non-employee Directors, except the Chairman, receive an annual retainer of \$60,000. The Chairman receives an annual retainer of \$125,000. Each Committee chair currently receives an additional retainer of \$14,000 per year and, starting in April 2018, the Audit Committee chair's retainer will be increased to \$20,000. Directors do not receive a meeting fee for attending Board or committee meetings.

Each non-employee Director receives an annual grant of restricted stock with an approximate value of \$80,000 granted under the terms of the 2014 Stock Incentive Plan on the date of the Annual Meeting. The amount is fixed and is not defined as incentive compensation as it is not tied to individual performance or Otter Tail Corporation's financial performance. The shares of restricted stock vest over a period of four years at the rate of 25% per year and are eligible for full dividend and voting rights. Starting in April 2018, on the date of the Annual Meeting, each non-employee Director will receive an additional grant of restricted stock with an approximate value of \$10,000 for each committee on which they serve, and the Board Chair will receive an additional grant of restricted stock with an approximate value of \$25,000. All shares of restricted stock awarded to non-employee Directors will vest over a period of three years at the rate of 33.3% per year and will be eligible for full dividend and voting rights.

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/25/2018
Date Due: 05/09/2018
Date of Response: 05/09/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Refer to the response to ND-PSC-06.23. This response states that Otter Tail Corporation's non-employee directors receive an annual retainer of \$60,000 and that the Chairman receives an annual retainer of \$125,000. In addition, beginning in April 2018, each Committee chair will receive an additional retainer of \$20,000 (up from \$14,000).

This response also states that each non-employee Director receives an annual grant of restricted stock with an approximate value of \$80,000, but that starting in April 2018, each non-employee Director will receive an additional grant of restricted stock with an approximate value of \$10,000 for each committee on which they serve. Moreover, the Board Chair will receive an additional grant of restricted stock with an approximate value of \$25,000.

- a. Please state whether and how much the 2018 test year in the Company's supplemental filing dated March 23, 2018 reflects for the annual retainer (\$60,000) that each non-employee Director of Otter Tail Corporation. Quantify, by amount and account, the total amount of each non-employee Director retainer and identify where and in what amounts these non-employee Director retainers are reflected in the Company's supplemental filing for its North Dakota jurisdictional operations.
- b. Please state whether and how much 2018 test year in the Company's supplemental filing dated March 23, 2018 reflects for the annual retainer (\$125,000) that the Chairman of Otter Tail Corporation receives. Quantify, by amount and account, the total amount identify where and in what amounts this Chairman Director retainer are reflected in the Company's supplemental filing for its North Dakota jurisdictional operations.
- c. Does the Chairman of Otter Tail Corporation receive any other pay other than his board compensation? If so, please identify, quantify and explain the other compensation, and identify how much of each amount is included in the Company's supplemental filing for its North Dakota jurisdictional operations.

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Response to Data Request ND-PSC-18.01
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- d. Does the 2018 test year in the Company's supplemental filing dated March 23, 2018 reflect any amounts for the annual retainer (\$20,000 starting in April 2018) that each Committee chair of Otter Tail Corporation receives? If so, quantify, by amount and account, and identify where these retainers are reflected in the Company's supplemental filing. Please identify the amounts in total, and as allocated to OTP's North Dakota jurisdictional operations.
- e. Does the 2018 test year in the Company's supplemental filing dated March 23, 2018 reflect any cost for annual grants of restricted stock (\$80,000) that each non-employee Director of Otter Tail Corporation receives? If so, quantify, by amount and account, and identify where these restricted stock grant amounts are reflected in the Company's supplemental filing. Please identify the amounts in total, and as allocated to OTP's North Dakota jurisdictional operations.
- f. What is the purpose of the annual grants of restricted stock to the non-employee directors?
- g. Identify and explain the restrictions that relate to the annual grants of restricted stock to the non-employee directors?
- h. Does the 2018 test year in the Company's supplemental filing dated March 23, 2018 reflect any cost for annual grants of restricted stock (\$10,000) that each non-employee Director of Otter Tail Corporation receives for each committee on which they serve? If so, quantify, by amount and account, and identify where these restricted stock costs are reflected in the Company's supplemental filing. Please identify the amounts in total, and as allocated to OTP's North Dakota jurisdictional operations.
- i. Does the 2018 test year in the Company's supplemental filing dated March 23, 2018 reflect any cost for the annual grants of restricted stock (valued at \$25,000) that the Board Chair of Otter Tail Corporation receives? If so, quantify, by amount and account, and identify where this restricted stock cost is reflected in the Company's supplemental filing. Please identify the amounts in total, and as allocated to OTP's North Dakota jurisdictional operations.

Attachments: 1

Attachment 1 to DR ND-PSC-18.01.xlsx

Response:

Before addressing the specific questions in this data request, one clarification is needed in connection with the intro paragraph above, which incorrectly states that all Committee Chair's will receive an increase in their retainer from \$14,000 per year to \$20,000 per year beginning April of 2018. To be clear, OTP's response to Data Request ND-PSC-06.23 states the following:

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Response to Data Request ND-PSC-18.01
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Each Committee chair currently receives an additional retainer of \$14,000 per year and, starting in April 2018, the Audit Committee chair's retainer will be increased to \$20,000.

The other two Committee chairs' retainers remained at \$14,000 per year.

Attachment 1 to ND-PSC-18.01 reflects the Non-Employee Director Compensation as computed under the plan information as described in data request ND-PSC-06.23. Total estimated compensation shown on line 19 in column B of Attachment 1 to be allocated is \$825,900 (OTP Total) and \$334,568 (OTP ND).

At the time OTP's Test Year was developed, the estimated allocation of Director Compensation was \$710,704 (OTP Total) / \$287,903 (OTP ND), as shown on line 21. These estimates were based on previous assumptions associated with Director Compensation. No adjustments were made to the Test Year amounts in the Supplemental Filing. These amounts are inclusive of those individual compensation components identified in question subparts (a.) through (i.).

- a. See Attachment 1 to DR ND-PSC-18.01 for the total allocated to OTP, the ND share and account.
- b. See Attachment 1 to DR ND-PSC-18.01 for the total allocated to OTP, the ND share and account.
- c. The Otter Tail Corporation Board Chairman does not receive any other cash compensation. The Board Chairman, along with the other non-employee Board Members, receive annual restricted stock grants.
- d. See Attachment 1 to DR ND-PSC-18.01 for the total allocated to OTP, the ND share and account.
- e. See Attachment 1 to DR ND-PSC-18.01 for the total allocated to OTP, the ND share and account.
- f. Directors of Otter Tail Corporation who are not Corporation employees receive competitive compensation for their service as Board members. Compensation is delivered through a combination of cash retainers and stock grants. The use of stock grant is based on a combination of competitive practice and a desire to align the interests of the Directors with the long-term performance and success of the organization.
- g. Starting with the 2018 award, the restricted shares will vest one-third per year, commencing on April 8, 2019. [Prior to 2018, the restricted shares vested 25% each year over a four-year period] As the shares vest the restrictions with respect to the shares lapse. Until the shares vest, none of the shares may be sold, assigned, transferred, pledged, hypothecated or otherwise disposed or encumbered. If a given Director's service

Public
Response to Data Request ND-PSC-18.01
Page 4 of 4

on the Board ceases for reasons other than disability, death, retirement or resignation at the end of a term prior to the vesting of the shares, that Director's rights to all of the unvested shares is immediately and irrevocable forfeited including the right to vote such shares and to receive cash dividends.

- h. See Attachment 1 to DR ND-PSC-18.01 for the total allocated to OTP, the ND share and account.
- i. See Attachment 1 to DR ND-PSC-18.01 for the total allocated to OTP, the ND share and account.

**Otter Tail Corporation
 Non-Employee Director Compensation
 2018 Allocation to OTP**

	A	B	C
	Total Per Plan	60% OTP Total	Blended Allocator 0.40509 ND Share
1	\$ 60,000		
2			
3	⁷		
4	\$ 420,000	\$ 252,000	\$ 102,084
5	\$ 125,000	\$ 75,000	\$ 30,382
6			
7			
8	\$ 18,500	\$ 11,100	\$ 4,497
9	\$ 28,000	\$ 16,800	\$ 6,806
10	\$ 46,500	\$ 27,900	\$ 11,302
11			
12	\$ 80,000		
13			
14	⁸		
15	\$ 640,000	\$ 384,000	\$ 155,556
16	\$ 25,000	\$ 15,000	\$ 6,076
17	\$ 120,000	\$ 72,000	\$ 29,167
18	\$ 785,000	\$ 471,000	\$ 190,800
19	\$ 1,376,500	\$ 825,900	\$ 334,568
20			
21	\$ 1,184,507	\$ 710,704	\$ 287,903
22			
23			
24			
25			

Retainer per Director
 Number of Directors
 Total

Board Chair Retainer

Committee Chairs
 Audit Committee Chair (1)
 Other Committee Chairs
 2 Directors @ \$14k
 Total

Restricted Stock per Director
 Number of Directors
 Director Total
 Board Chairman
 Committee Membership (2)
 Total

Totals for 2018

Budgeted Test Year Amounts for Director Compensation (3)

(1) Audit Committee Chair Retainer was increased from \$14k to \$20k in April. New Amount effective April - December (\$14,000/12*3) + (\$20,000/12/*9)

(2) Six members are each on 2 committees. \$10,000 per committee per member (6 x 2 x \$10,000)

(3) Budgeted Director Compensation included in Test Year - Estimates at time budget set were based on different assumptions regarding non-employee director compensation.

Public
Response to Data Request ND-PSC-03.04
Page 1 of 1

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/09/2018
Date Due: 02/23/2018
Date of Response: 02/22/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Identify the amounts recorded in each of the following accumulated deferred income tax (ADIT) accounts as of December 31, 2017 and provide a break out of such amounts between federal and state ADIT:

- a. Account 190
- b. Account 282
- c. Account 283
- d. any other accounts (identify and explain) in which the Company recorded ADIT

Attachments: 1

Attachment 1 for DR ND-PSC-03.04.pdf

Response:

Please see attached file "Attachment 1 for DR ND-PSC-03.04" for the balances of Otter Tail Power's December 2017 balances for Accumulated Deferred Income Taxes(ADIT).

Otter Tail Power Company
Dece 2017 Year end balances of ADIT

North Dakota Case No PU-17-398
Attachment 1 to DR ND-PSC-03.04
Page 1 of 1

	<u>Dec 2017</u>
Total 190 Accounts	103,691,997
Subtotal Other Accounts	(170,431,259)
Subtotal 281 Accounts	(4,887,290)
Subtotal 282 Accounts	(186,474,995)
Subtotal 283 Accounts	(14,753,611)
<i>Total ADIT from above</i>	(272,855,158)
Non-Operating DIT Balances to remove	
Total Non-Operating DIT Balances to Remove	(4,669,205)
Total ADIT	<u>(268,185,953)</u>
Federal	(198,218,217)
Minnesota	(33,306,864)
North Dakota	<u>(36,660,872)</u>
	(268,185,953)

Public
Response to Data Request ND-PSC-03.06
Page 1 of 1

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/09/2018
Date Due: 02/23/2018
Date of Response: 02/27/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Referring to the information provided in the responses to DR 3-4 and 3-5, for the federal ADIT that was accumulated using a 35% federal corporate income tax rate please identify the amount that represents excess ADIT, applying the 21% federal corporate income tax rate that became effective January 1, 2018 as part of the Tax Cuts and Jobs Act (TCJA) that was signed into law by President Trump on December 22, 2017. For each item of such excess ADIT, explain whether and how it relates to the use of accelerated tax depreciation for federal income tax purposes.

Attachments: 1

Attachment 1 to DR ND-PSC-03.06.xlsx

Response:

The excess federal ADIT balances were calculated based upon the change in the federal tax rate from 35% to 21%, due to the passing of the Tax Cuts and Job Acts. A detail breakdown of the ADIT and excess balances for each timing difference is presented in Attachment 1 to DR ND-PSC-03.06.

Of the listed items in Attachment 1 to DR ND-PSC-03.06, two-line items, Excess Tax over Book Depreciation in FERC account 282 and Excess Tax over Book Depreciation – AQCS SL 7, relate to the use of accelerated tax depreciation for federal income tax purpose.

FERC	Description	Federal	Minnesota	North Dakota	Grand Total	Excess ADIT
190	Accrued Vacation Pay	1,436,400	177,379	102,758	1,716,537	574,560
	Bad Debts	374,216	47,836	25,739	447,791	149,686
	Capitalized A & G	1,940,615	197,184	143,439	2,281,238	776,246
	Capitalized A & G - 481(a) - Reversing	(17,398)	(34,086)	334	(51,150)	(6,959)
	Capitalized Customer Rebates	116,093	2,468	6,476	125,038	46,437
	CIAC Capitalized	67,667	6,796	4,742	79,205	27,067
	Executive Supplemental Pension	3,801,303	495,150	250,120	4,546,574	1,520,521
	Interest Capitalized on Construction	4,922,890	626,057	332,767	5,881,714	1,969,156
	Loan Pool	3,952	315	418	4,684	1,581
	Medicare Part D Capitalized	412,428	-	34,439	446,868	164,971
	Post Employment Benefit	308,515	40,862	21,861	371,238	123,406
	Post Retirement Benefit	18,536,386	2,348,106	1,266,623	22,151,116	7,414,555
	Property Repairs	(253,055)	(38,616)	(12,673)	(304,344)	(101,222)
	Restricted Stock	(39,441)	(8,810)	589	(47,662)	(15,776)
	South Dakota Flow Thru-Overheads	(140,756)	-	-	(140,756)	(56,302)
	South Dakota Flow Thru-Repairs	219,828	-	-	219,828	87,931
	Unicap Adjustment	30,460	4,344	1,675	36,479	12,184
	Workmans Comp	258,247	33,096	17,743	309,086	103,299
	Big Stone II Discount	139,878	16,111	10,832	166,821	55,951
	Deferred State NOL's - ND	-	-	2,301,359	2,301,359	-
	Bonus Incentive	737,395	111,663	37,267	886,324	294,958
	Deferred Federal NOL	1,408,821	-	-	1,408,821	563,528
	Non Qual Retirement Savings (FERC 190.1)	324,355	42,773	21,044	388,172	129,742
	190 Total	34,588,799	4,068,628	4,567,552	43,224,979	13,835,519
282	ADR Repair Allowance	(1,747,780)	(207,822)	(131,750)	(2,087,353)	(699,112)
	AFUDC on Debt	(2,773,431)	(351,408)	(197,902)	(3,322,741)	(1,109,372)
	Capitalized Overheads	44,747	14,378	(10,487)	48,639	17,899
	Excess Tax over book Depreciation*	(265,443,843)	(32,779,482)	(17,544,151)	(315,767,476)	(106,177,537)
	Highway Reimbursements	(18,226)	(11,554)	8,927	(20,854)	(7,291)
	Prepaid Expenses	(363,658)	(52,527)	(20,126)	(436,310)	(145,463)
	Sec 162 & 174 R&D Deduction	(3,064,387)	(413,424)	(184,586)	(3,662,397)	(1,225,755)
	South Dakota Flow Thru-Overheads	(10,567)	-	-	(10,567)	(4,227)
	Sec 481(a) Cap to Repair Basis Adjustments (PY)	4,068,743	555,547	215,361	4,839,651	1,627,497
	Repairs Deduction - Basis Adjustments	(11,169,277)	(1,078,928)	(798,107)	(13,046,312)	(4,467,711)
	Big Stone II Deferred Costs	(930,687)	(91,620)	(83,232)	(1,105,540)	(372,275)
	Retirements Method Change	163,640	23,251	9,092	195,983	65,456
	Amort of Loss on Reacquired Debt (FERC 282.1)	(400,491)	(32,421)	(41,599)	(474,511)	(160,196)
	282 Total	(281,645,218)	(34,426,008)	(18,778,562)	(334,849,788)	(112,658,087)
283	Deferred State NOL's - Fed Haircut	(811,297)	-	-	(811,297)	(324,519)
	MN Rate Case Expense (2010)	(19,384)	(3,052)	(966)	(23,402)	(7,754)
	Pensions	(17,596,422)	(2,471,652)	(1,047,635)	(21,115,709)	(7,038,569)
	Transmission Rider Revenue	423,920	74,841	17,240	516,000	169,568
	Wind Rider Revenue	(204,750)	(14,264)	(27,159)	(246,173)	(81,900)
	ESSRP Regulatory Adjustments	850,016	-	-	850,016	340,007
	Environmental Rider Revenue	554,788	90,348	26,742	671,878	221,915
	SPP Cost Tracker	199,181	30,577	9,800	239,558	79,672
	EITE Revenue Tracker	(24,606)	(3,777)	(1,211)	(29,594)	(9,842)
	ND Rate Case Expense (2017)	(101,081)	(15,518)	(4,974)	(121,572)	(40,432)
	Conservation Improvement Program (FERC 283.1)	(3,983,297)	(571,402)	(221,704)	(4,776,403)	(1,593,319)
	283 Total	(20,712,931)	(2,883,899)	(1,249,868)	(24,846,698)	(8,285,172)
281	Excess Tax over book Depreciation - AQCS SL 7*	(4,059,879)	(624,157)	(203,254)	(4,887,290)	(1,623,952)
	Grand Total	(271,829,230)	(33,865,436)	(15,664,131)	(321,358,797)	(108,731,692)

*These line items relates to ADIT balances which are created due to the Company using accelerated tax depreciation.

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

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/09/2018

Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Details of ADIT balances at December 31, 2017.

- a. Identify the December 31, 2017 recorded per-book balance of Accumulated Deferred Income Taxes (ADIT) in each account (account 190, 282, 283 etc.).
- b. Show by each book-tax difference, the components which comprise the ADIT in each ADIT account.
- c. For each component of the ADIT listed in response to the above requests, please also provide the following information:
 - (1) The state income tax rate used to compute the ADIT.
 - (2) The federal income tax rate used to compute the ADIT.
 - (3) The combined state and federal income tax rate used to compute the ADIT.
 - (4) The balance (book-tax difference at 12/31/2017) to which the state and federal income tax rates were applied to compute the ADIT.
- d. For each component in the ADIT accounts, identify the amount representing "excess" ADIT (i.e., calculated using the new 21% flat federal corporate income tax rate versus the previous FIT rate [e.g., of 34% or 35%] that the Company used).
- e. For each amount of excess property-related ADIT in account 282, please indicate whether it is "protected" (i.e., related to the use of accelerated tax depreciation including MACRS and bonus tax depreciation) or "non-protected" (i.e., related to other book-tax differences such as repairs deductions, etc.)

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Response to Data Request ND-PSC-18.02
Page 2 of 2

Attachments: 3

Attachment 1 to DR ND-PSC-18.02.pdf

Attachment 2 to DR ND-PSC-18.02.pdf

Attachment 3 to DR ND-PSC-18.02.pdf

Response:

- a. See Attachment 1 to DR ND-PSC-18.02 for a detailed listing of ADIT balance in each FERC account at December 31, 2017.
- b. See Attachment 1 to DR ND-PSC-18.02 for a detailed listing of ADIT balance in each FERC account at December 31, 2017.
- c. The accumulated ADIT balance is an accumulation of each year's originating and reversing activity. Originating ADIT is calculated based upon that year's effective tax rate. See Attachment 2 to DR ND-PSC-18.02 for the calculation of both state and federal effective tax rates used for 2017 activity. Additionally, see Attachment 3 to DR ND-PSC-18.02 for a listing of the originating and reversing timing differences which had activity in 2017.
- d. See Attachment 1 to DR ND-PSC-18.02 for a breakdown of the excess ADIT balance by timing difference in each FERC account at December 31, 2017.
- e. In FERC account 282, the only protected timing difference is "Excess Tax over Book Depreciation", all others are unprotected. OTP also has ADIT in FERC account 281 which is based on the timing differences between book and tax depreciation which we've labeled as being protected, similar to FERC 282.

Allocation of Excess Deferred Income Tax
Balance as of December 31, 2017

North Dakota Case No PU-17-398
Attachment 1 to DR ND-PSC-18.02
Page 1 of 1

FERC	Description	Protected					Excess
			Federal	Minnesota	North Dakota	Grand Total	ADIT
190	Accrued Vacation Pay	No	1,436,400	177,379	102,758	1,716,537	574,560
	Bad Debts	No	374,216	47,836	25,739	447,791	149,686
	Capitalized A & G	No	1,940,615	197,184	143,439	2,281,238	776,246
	Capitalized A & G - 481(a) - Reversing	No	(17,398)	(34,086)	334	(51,150)	(6,959)
	Capitalized Customer Rebates	No	116,093	2,468	6,476	125,038	46,437
	CIAC Capitalized	No	67,667	6,796	4,742	79,205	27,067
	Executive Supplemental Pension	No	3,801,303	495,150	250,120	4,546,574	1,520,521
	Interest Capitalized on Construction	No	4,922,890	626,057	332,767	5,881,714	1,969,156
	Loan Pool	No	3,952	315	418	4,684	1,581
	Medicare Part D Capitalized	No	412,428	-	34,439	446,868	164,971
	Post Employment Benefit	No	308,515	40,862	21,861	371,238	123,406
	Post Retirement Benefit	No	18,536,386	2,348,106	1,266,623	22,151,116	7,414,555
	Property Repairs	No	(253,055)	(38,616)	(12,673)	(304,344)	(101,222)
	Restricted Stock	No	(39,441)	(8,810)	589	(47,662)	(15,776)
	South Dakota Flow Thru-Overheads	No	(140,756)	-	-	(140,756)	(56,302)
	South Dakota Flow Thru-Repairs	No	219,828	-	-	219,828	87,931
	Unicap Adjustment	No	30,460	4,344	1,675	36,479	12,184
	Workmans Comp	No	258,247	33,096	17,743	309,086	103,299
	Big Stone II Discount	No	139,878	16,111	10,832	166,821	55,951
	Deferred State NOL's - ND	No	-	-	2,301,359	2,301,359	-
	Bonus Incentive	No	737,395	111,663	37,267	886,324	294,958
	Deferred Federal NOL	No	1,408,821	-	-	1,408,821	563,528
	Non Qual Retirement Savings (FERC 190.1)	No	324,355	42,773	21,044	388,172	129,742
	190 Total		34,588,799	4,068,628	4,567,552	43,224,979	13,835,519
282	ADR Repair Allowance	No	(1,747,780)	(207,822)	(131,750)	(2,087,353)	(699,112)
	AFUDC on Debt	No	(2,773,431)	(351,408)	(197,902)	(3,322,741)	(1,109,372)
	Capitalized Overheads	No	44,747	14,378	(10,487)	48,639	17,899
	Excess Tax over book Depreciation*	Yes	(265,443,843)	(32,779,482)	(17,544,151)	(315,767,476)	(106,177,537)
	Highway Reimbursements	No	(18,226)	(11,554)	8,927	(20,854)	(7,291)
	Prepaid Expenses	No	(363,658)	(52,527)	(20,126)	(436,310)	(145,463)
	Sec 162 & 174 R&D Deduction	No	(3,064,387)	(413,424)	(184,586)	(3,662,397)	(1,225,755)
	South Dakota Flow Thru-Overheads	No	(10,567)	-	-	(10,567)	(4,227)
	Sec 481(a) Cap to Repair Basis Adjustments (PY)	No	4,068,743	555,547	215,361	4,839,651	1,627,497
	Repairs Deduction - Basis Adjustments	No	(11,169,277)	(1,078,928)	(798,107)	(13,046,312)	(4,467,711)
	Big Stone II Deferred Costs	No	(930,687)	(91,620)	(83,232)	(1,105,540)	(372,275)
	Retirements Method Change	No	163,640	23,251	9,092	195,983	65,456
	Amort of Loss on Reacquired Debt (FERC 282.1)	No	(400,491)	(32,421)	(41,599)	(474,511)	(160,196)
	282 Total		(281,645,218)	(34,426,008)	(18,778,562)	(334,849,788)	(112,658,087)
283	Deferred State NOL's - Fed Haircut	No	(811,297)	-	-	(811,297)	(324,519)
	MN Rate Case Expense (2010)	No	(19,384)	(3,052)	(966)	(23,402)	(7,754)
	Pensions	No	(17,596,422)	(2,471,652)	(1,047,635)	(21,115,709)	(7,038,569)
	Transmission Rider Revenue	No	423,920	74,841	17,240	516,000	169,568
	Wind Rider Revenue	No	(204,750)	(14,264)	(27,159)	(246,173)	(81,900)
	ESSRP Regulatory Adjustments	No	850,016	-	-	850,016	340,007
	Environmental Rider Revenue	No	554,788	90,348	26,742	671,878	221,915
	SPP Cost Tracker	No	199,181	30,577	9,800	239,558	79,672
	EITE Revenue Tracker	No	(24,606)	(3,777)	(1,211)	(29,594)	(9,842)
	ND Rate Case Expense (2017)	No	(101,081)	(15,518)	(4,974)	(121,572)	(40,432)
	Conservation Improvement Program (FERC 283.1)	No	(3,983,297)	(571,402)	(221,704)	(4,776,403)	(1,593,319)
	283 Total		(20,712,931)	(2,883,899)	(1,249,868)	(24,846,698)	(8,285,172)
281	Excess Tax over book Depreciation - AQCS SL 7*	Yes	(4,059,879)	(624,157)	(203,254)	(4,887,290)	(1,623,952)
	Grand Total		(271,829,230)	(33,865,436)	(15,664,131)	(321,358,797)	(108,731,692)

*These line items relates to ADIT balances which are created due to the Company using accelerated tax depreciation.

Effective Tax Rate calculation

For the year ended December 31, 2017

North Dakota Case No PU-17-398

Attachment 2 to DR ND-PSC-18.02

Page 1 of 1

	FEDERAL	MN	ND	TOTAL
INCOME	1,000	1,000	1,000	
TAX EXPENSE DEDUCTIONS				
FEDERAL				
MINNESOTA	50			
NORTH DAKOTA	16			
SUBTOTAL	934	1,000	1,000	
APPORTIONMENT FACTOR (OTP separate)	100%	51.1944%	37.3100%	
TAXABLE INCOME	934	512	373	
TAX RATE	35.00%	9.80%	4.31%	
TAX	327	50	16	
EFFECTIVE TAX RATE	32.6812%	5.0171%	1.6081%	39.3063%
RATE TO USE: (INSERT FOR ROUNDING)	32.7%	5.0%	1.6%	39.3%

Timing Difference Activity		North Dakota Case No PU-17-398
For the year ended December 31, 2017		Attachment 3 to DR ND-PSC-18.02
		Page 1 of 1
	Item	FED
	<u>Property Related Temporary:</u>	
M-00130	Highway Reimbursements	(242,094)
M-00140	Removal Costs	(3,006,569)
M-00160	Interest Capitalized on Construction (Taxable)	1,251,731
M-00190	Customer Rebates Capitalized - Originating	37,386
M-00150	AFUDC on Debt Originating	(740,730)
P-00240	Income from ARCS & MACRS Property	1,354,836
M-00800	Tax Depreciation	(87,368,793)
M-00800	Book Depreciation	52,930,225
	<u>Other:</u>	
M-00220	Accrued Vacation Pay	4,213,614
M-00220	Accrued Vacation Pay - Reversing	(4,239,624)
M-00230	Amort of Loss on Reaquired Debt (Pre-Holdco)-Reversing	325,098
M-00240	Restricted Stock - Book Expense	175,147
M-00240	Restricted Stock Incentive (Tax Ded - Employee Gain)	(324,916)
M-00250	Pension Contributions (FAS 87 & 88)	(20,000,000)
M-00250	Pension Provision (FAS 87 & 88)	5,736,168
M-00271	Conservation Improvement Program - MN & SD - Net (BTL)	(2,752,813)
M-00290	Supplemental Pension Reserve Provision	1,438,129
M-00290	Supplemental Pension Reserve Charges	(1,175,712)
M-00300	Post Retirement Benefits Provision (FAS 106)	5,273,460
M-00300	Post Retirement Benefits Charges (FAS 106)	(3,588,211)
M-00310	Post Employment Benefits Provision (FAS 112)	142,974
M-00310	Post Employment Benefits Charges (FAS 112)	(362,696)
M-00340	Wind Rider Revenue (Billed in CIS)	9,191,994
M-00340	Wind Rider Revenue (Total Revenue Booked)	(7,389,492)
M-00350	Transmission Rider Revenue (Billed in CIS)	12,144,029
M-00350	Transmission Rider Revenue (Total Revenue Booked)	(13,689,302)
M-00351	Environmental Resource Rider (Billed in CIS)	21,665,926
M-00351	Environmental Resource Rider (Total Revenue Booked)	(20,275,130)
M-00352	SPP Cost Tracker (Total Booked)	609,468
M-00353	EITE Revenue Tracker (Total Booked)	(75,291)
M-00361	Big Stone II Deferred Costs - Reversing	998,552
M-00362	Big Stone II Discount - Reversing	(118,092)
M-00390	ND Rate Case Deferred Expenses (2017) - Originating	(309,293)
M-00410	MN Rate Case Deferred Expenses (2016) - Reversing	203,815
M-00410	MN Rate Case Deferred Expenses (2016) - Originating	(100,910)
M-00440	Bad Debts Provision	1,575,570
M-00440	Bad Debts Charges	(1,301,140)
M-00450	Loan Pool Charges	2
M-00480	Workmen's Comp Provision	296,263
M-00480	Workmen's Comp Charges	(281,048)
M-00530	Unicap Adjustment - Reversing	(91,787)
M-00530	Unicap Adjustment - Originating	93,043
M-00550	Non-Qual Retire Savings - Emp Contib (Book Expense)	244,120
M-00550	Non-Qual Retire Savings - Distrib (Tax Deduction)	(48,384)
M-10016	Prepaid Expenses - Originating	(1,276,704)
M-10016	Prepaid Expenses - Reversing	916,587
M-00580	Bonus Incentive Provision	2,482,857
M-00580	Bonus Incentive Charges	(1,909,893)

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/25/2018
Date Due: 05/09/2018
Date of Response: 05/07/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Accumulated Deferred Income Taxes (ADIT). Refer to the response to ND-PSC-03.06, which requested that the Company identify the amount that represents excess ADIT after applying the 21% federal income tax rate that became effective on January 1, 2018 pursuant to the passage of the TCJA on December 22, 2017.

- a. Referring to Attachment 1 from ND-PSC-03.06, the amounts shown under the column "Excess ADIT" were calculated by multiplying the amounts under the "Federal" column by 40%. Please explain the basis for this calculation.
- b. Pursuant to part "a", the excess ADIT amounts provided were calculated from the amounts under the "Federal" column on Attachment 1. Please quantify the portion of the excess ADIT's that relates to OTP's North Dakota jurisdictional operations and show how they were derived. Show detailed calculations electronically in Excel with all formulas and calculations intact.
- c. Please quantify and explain fully and in detail whether and how the excess ADIT balances identified in ND-PSC-03.06 are reflected in OTP's supplemental filing dated March 23, 2018.

Attachments: 1

Attachment 1 to DR ND-PSC-16.02.xlsx

Response:

- a. The federal statutory tax rate has remained 35% for over 30 years. With the passage of TCJA the rate was reduced to 21%, which is a reduction of 40% ($35-21 = 14$; $14/35=40$). OTP calculated the excess DIT ledger balances by multiplying the 2017 ending ADIT (before tax reform) by this reduction percentage of 40%.

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Response to Data Request ND-PSC-16.02
Page 2 of 2

- b. North Dakota's allocation factor calculated from OTP's cost of service is 36.083434%. See Attachment 1 to ND-PSC-16.02 for the detailed calculation of excess DIT for OTP's North Dakota jurisdictional operations based upon 12/31/17 general ledger ADIT balances.
- c. Any adjustment for excess ADIT would have been a balance sheet adjustment to reallocate the excess balance from ADIT FERC accounts to a regulated liability account, therefore total liabilities and rate base would remain unchanged, but the aforementioned amounts would be included in OTP's supplemental filing.

Allocation of Excess Deferred Income Tax
Balance as of December 31, 2017

Case No PU-17-398
Attachment 1 to DR ND-PSC-16.02

North Dakota Allocation Factor (NEPIS)

36.083434%

FERC	Description	Per 12/31/17 General Ledger				TCJA	North
		Federal	Minnesota	North Dakota	Grand Total	Excess ADIT	Dakota's Portion
190	Accrued Vacation Pay	1,436,400	177,379	102,758	1,716,537	574,560	207,321
	Bad Debts	374,216	47,836	25,739	447,791	149,686	54,012
	Capitalized A & G	1,940,615	197,184	143,439	2,281,238	776,246	280,096
	Capitalized A & G - 481(a) - Reversing	(17,398)	(34,086)	334	(51,150)	(6,959)	(2,511)
	Capitalized Customer Rebates	116,093	2,468	6,476	125,038	46,437	16,756
	CIAC Capitalized	67,667	6,796	4,742	79,205	27,067	9,767
	Executive Supplemental Pension	3,801,303	495,150	250,120	4,546,574	1,520,521	548,656
	Interest Capitalized on Construction	4,922,890	626,057	332,767	5,881,714	1,969,156	710,539
	Loan Pool	3,952	315	418	4,684	1,581	570
	Medicare Part D Capitalized	412,428	-	34,439	446,868	164,971	59,527
	Post Employment Benefit	308,515	40,862	21,861	371,238	123,406	44,529
	Post Retirement Benefit	18,536,386	2,348,106	1,266,623	22,151,116	7,414,555	2,675,426
	Property Repairs	(253,055)	(38,616)	(12,673)	(304,344)	(101,222)	(36,524)
	Restricted Stock	(39,441)	(8,810)	589	(47,662)	(15,776)	(5,693)
	South Dakota Flow Thru-Overheads	(140,756)	-	-	(140,756)	(56,302)	(20,316)
	South Dakota Flow Thru-Repairs	219,828	-	-	219,828	87,931	31,729
	Unicap Adjustment	30,460	4,344	1,675	36,479	12,184	4,396
	Workmans Comp	258,247	33,096	17,743	309,086	103,299	37,274
	Big Stone II Discount	139,878	16,111	10,832	166,821	55,951	20,189
	Deferred State NOL's - ND	-	-	2,301,359	2,301,359	-	-
	Bonus Incentive	737,395	111,663	37,267	886,324	294,958	106,431
	Deferred Federal NOL	1,408,821	-	-	1,408,821	563,528	203,340
	Non Qual Retirement Savings (FERC 190.1)	324,355	42,773	21,044	388,172	129,742	46,815
	190 Total	34,588,799	4,068,628	4,567,552	43,224,979	13,835,519	4,992,331
282	ADR Repair Allowance	(1,747,780)	(207,822)	(131,750)	(2,087,353)	(699,112)	(252,264)
	AFUDC on Debt	(2,773,431)	(351,408)	(197,902)	(3,322,741)	(1,109,372)	(400,300)
	Capitalized Overheads	44,747	14,378	(10,487)	48,639	17,899	6,458
	Excess Tax over book Depreciation*	(265,443,843)	(32,779,482)	(17,544,151)	(315,767,476)	(106,177,537)	(38,312,502)
	Highway Reimbursements	(18,226)	(11,554)	8,927	(20,854)	(7,291)	(2,631)
	Prepaid Expenses	(363,658)	(52,527)	(20,126)	(436,310)	(145,463)	(52,488)
	Sec 162 & 174 R&D Deduction	(3,064,387)	(413,424)	(184,586)	(3,662,397)	(1,225,755)	(442,294)
	South Dakota Flow Thru-Overheads	(10,567)	-	-	(10,567)	(4,227)	(1,525)
	Sec 481(a) Cap to Repair Basis Adjustments (PY)	4,068,743	555,547	215,361	4,839,651	1,627,497	587,257
	Repairs Deduction - Basis Adjustments	(11,169,277)	(1,078,928)	(798,107)	(13,046,312)	(4,467,711)	(1,612,104)
	Big Stone II Deferred Costs	(930,687)	(91,620)	(83,232)	(1,105,540)	(372,275)	(134,330)
	Retirements Method Change	163,640	23,251	9,092	195,983	65,456	23,619
	Amort of Loss on Reacquired Debt (FERC 282.1)	(400,491)	(32,421)	(41,599)	(474,511)	(160,196)	(57,804)
	282 Total	(281,645,218)	(34,426,008)	(18,778,562)	(334,849,788)	(112,658,087)	(40,650,907)
283	Deferred State NOL's - Fed Haircut	(811,297)	-	-	(811,297)	(324,519)	(117,098)
	MN Rate Case Expense (2010)	(19,384)	(3,052)	(966)	(23,402)	(7,754)	(2,798)
	Pensions	(17,596,422)	(2,471,652)	(1,047,635)	(21,115,709)	(7,038,569)	(2,539,757)
	Transmission Rider Revenue	423,920	74,841	17,240	516,000	169,568	61,186
	Wind Rider Revenue	(204,750)	(14,264)	(27,159)	(246,173)	(81,900)	(29,552)
	ESSRP Regulatory Adjustments	850,016	-	-	850,016	340,007	122,686
	Environmental Rider Revenue	554,788	90,348	26,742	671,878	221,915	80,075
	SPP Cost Tracker	199,181	30,577	9,800	239,558	79,672	28,749
	EITE Revenue Tracker	(24,606)	(3,777)	(1,211)	(29,594)	(9,842)	(3,551)
	ND Rate Case Expense (2017)	(101,081)	(15,518)	(4,974)	(121,572)	(40,432)	(14,589)
	Conservation Improvement Program (FERC 283.1)	(3,983,297)	(571,402)	(221,704)	(4,776,403)	(1,593,319)	(574,924)
	283 Total	(20,712,931)	(2,883,899)	(1,249,868)	(24,846,698)	(8,285,172)	(2,989,575)
281	Excess Tax over book Depreciation - AQCS SL 7*	(4,059,879)	(624,157)	(203,254)	(4,887,290)	(1,623,952)	(585,977)
	Grand Total	(271,829,230)	(33,865,436)	(15,664,131)	(321,358,797)	(108,731,692)	(39,234,128)

*These line items relates to ADIT balances which are created due to the Company using accelerated tax depreciation.

Public
Response to Data Request ND-PSC-18.11
Page 1 of 1

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/25/2018
Date Due: 05/09/2018
Date of Response: 05/08/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Does the Company have any journal entries and journal entry workpapers showing how it identified and recorded amounts of excess accumulated deferred income taxes ("EADIT") as of December 31, 2017 as a net regulatory liability? If not, explain fully why not. If so, identify and provide the journal entries and journal entry workpapers and supporting calculations. For each component of the EADIT balances, please identify the total amounts and the amounts that are related to the Company's North Dakota jurisdictional operations.

Attachments: 1

Attachment 1 to DR-PSC-18.11.pdf

Response:

Please see Attachment 1 to the Company's response to DR ND-PSC-18.11 for a detailed summary workpaper of the Company's calculation of excess ADIT performed at year-end 2017 and related journal entries made to adjust the ADIT balances.

Summary Workpaper and Journal Entry for Excess ADIT

North Dakota Case No PU-17-398
Attachment 1 to DR ND-PSC-18.11
Page 1 of 1

North Dakota Allocation Factor (NEPIS) **36.083434%**

Balance Sheet	Category	Reference	Description	Jurisdiction	12/31/2017	Excess Taxes	12/31/2017	Gross Up	Total	North Dakota's
					Defrd End Bal. at Old Rate	Adjustment Needed	Defrd End Bal. at New Rate	Factor at 1.3556	Grossed Up Excess	Portion of Excess ADIT
1895.1000	Other	M-00220	Accrued Vacation Pay	Federal	1,436,400	(574,560)	861,840	(204,313.53)	(778,873.49)	(207,321)
		M-00240	Restricted Stock	Federal	(39,441)	15,776	(23,665)	5,610.09	21,386.48	5,693
		M-00290	Executive Supplemental Pension	Federal	3,801,303	(1,520,521)	2,280,782	(540,697.38)	(2,061,218.70)	(548,656)
		M-00300	Post Retirement Benefit	Federal	18,536,386	(7,414,555)	11,121,832	(2,636,615.58)	(10,051,170.10)	(2,675,426)
		M-00310	Post Employment Benefit	Federal	308,515	(123,406)	185,109	(43,883.14)	(167,289.03)	(44,529)
		M-00362	Big Stone II Discount	Federal	139,878	(55,951)	83,927	(19,896.20)	(75,847.27)	(20,189)
		M-00420	Charitable Contributions	Federal	-	-	-	-	-	-
		M-00430	Property Taxes	Federal	-	-	-	-	-	-
		M-00440	Bad Debts	Federal	374,216	(149,687)	224,530	(53,228.54)	(202,915.09)	(54,012)
		M-00450	Loan Pool	Federal	3,952	(1,581)	2,371	(562.12)	(2,142.89)	(570)
		M-00460	Injuries & Damages	Federal	-	-	-	-	-	-
		M-00470	Property Repairs	Federal	(253,055)	101,222	(151,833)	35,994.52	137,216.46	36,524
		M-00480	Workmans Comp	Federal	258,247	(103,299)	154,948	(36,733.04)	(140,031.80)	(37,274)
		M-00490	Deferred Severance Settlement	Federal	-	-	-	-	-	-
		M-00520	Mapleton Industrial Park	Federal	-	-	-	-	-	-
		M-00530	Unicap Adjustment	Federal	30,460	(12,184)	18,276	(4,332.58)	(16,516.42)	(4,396)
		M-00550	Non Qual Retirement Savings	Federal	324,355	(129,742)	194,613	(46,136.26)	(175,878.26)	(46,815)
		M-00560	FIN 48 Interest - Tax Repairs UTP	Federal	-	-	-	-	-	-
		M-00580	Bonus Incentive	Federal	737,395	(294,958)	442,437	(104,887.05)	(399,844.99)	(106,431)
		M-00917	Deferred Federal NOL	Federal	1,408,821	(563,528)	845,293	(200,390.70)	(763,919.10)	(203,340)
		M-00930	Prior Year Deferred Tax Adjustment in Current Year	Federal	-	-	-	-	-	-
		M-10009	South Dakota Flow Thru-Repairs	Federal	219,828	(87,931)	131,897	(31,268.34)	(119,199.55)	(31,729)
	Property	M-10006	South Dakota Flow Thru-Overheads	Federal	(140,756)	56,302	(84,454)	20,021.13	76,323.54	20,316
	Prior Peri	M-10013	PY Return to Accrual Recon JE (see entry for detail)	Federal	-	-	-	-	-	-
	Credits	M-00890	Research & Development Tax Credit	Federal	374,580	-	374,580	-	-	-
	Power Tax	M-00100	Capitalized A & G	Federal	1,940,615	(776,246)	1,164,369	(276,033.09)	(1,052,279.12)	(280,096)
		M-00101	Capitalized A & G - 481(a) - Reversing	Federal	(17,398)	6,959	(10,439)	2,474.69	9,433.88	2,511
		M-00160	Interest Capitalized on Construction	Federal	4,922,890	(1,969,156)	2,953,734	(700,231.84)	(2,669,387.76)	(710,539)
		M-00170	CIAC Capitalized	Federal	67,667	(27,067)	40,600	(9,624.94)	(36,691.71)	(9,767)
		M-00190	Capitalized Customer Rebates	Federal	116,093	(46,437)	69,656	(16,513.12)	(62,950.46)	(16,756)
		M-00320	Amortization of Asbestos Removal	Federal	-	-	-	-	-	-
		M-00720	Medicare Part D Capitalized	Federal	412,428	(164,971)	247,457	(58,663.78)	(223,635.03)	(59,527)
			1895.1000 Total		34,963,379	(13,835,520)	21,127,859	(4,919,910.78)	(18,755,430.41)	(4,992,331)
1895.2100	Credits	M-10002	North Dakota Investment Tax Credit - Federal Haircut	Federal	7,431,385	(4,617,173)	2,814,212	-	-	(1,666,035)
			1895.2100 Total		7,431,385	(4,617,173)	2,814,212	-	-	(1,666,035)
1895.2110	Prior Peri	M-10013	PY Return to Accrual Recon JE (see entry for detail)	Federal	-	-	-	-	-	-
	Credits	M-00880	Deferred Production Tax Credit	Federal	40,639,557	-	40,639,557	-	-	-
			1895.2110 Total		40,639,557	-	40,639,557	-	-	-
2525.0000	Credits	M-10004	Federal Investment Tax Credit	Federal	(146,225)	-	(146,225)	-	-	-
			2525.0000 Total		(146,225)	-	(146,225)	-	-	-
2575.2000	Property	M-00121	Sec 162 & 174 R&D Deduction-BSII	Federal	-	-	-	-	-	-
		M-00230	Amort of Loss on Recquired Debt (pre holdco)	Federal	(400,491)	160,196	(240,295)	56,965.83	217,162.20	57,804
		M-00361	Big Stone II Deferred Costs	Federal	(930,687)	372,275	(558,412)	132,390.96	504,655.88	134,330
		M-00570	Retirements Method Change	Federal	163,640	(65,456)	98,184	(23,276.18)	(88,732.26)	(23,619)
		M-10006	South Dakota Flow Thru-Overheads	Federal	(10,567)	4,227	(6,340)	1,503.05	5,729.84	1,525
		M-10016	Prepaid Expenses	Federal	(363,658)	145,463	(218,195)	51,726.66	197,189.71	52,488
	Prior Peri	M-10013	PY Return to Accrual Recon JE (see entry for detail)	Federal	-	-	-	-	-	-
	Power Tax	M-00110	ADR Repair Allowance	Federal	(1,747,780)	699,112	(1,048,668)	248,604.27	947,716.38	252,264
		M-00120	Sec 162 & 174 R&D Deduction	Federal	(3,064,387)	1,225,755	(1,838,632)	435,878.48	1,661,633.47	442,294
		M-00130	Highway Reimbursements	Federal	(18,226)	7,291	(10,936)	2,592.51	9,883.04	2,631
		M-00150	AFUDC on Debt	Federal	(2,773,431)	1,109,372	(1,664,059)	394,492.85	1,503,865.31	400,300
		M-00180	Capitalized Overheads	Federal	44,747	(17,899)	26,848	(6,364.81)	(24,263.59)	(6,458)
		M-00590	Repairs Deduction - Basis Adjustments	Federal	(11,169,277)	4,467,711	(6,701,566)	1,588,717.99	6,056,428.89	1,612,104
		M-00600	Sec 481(a) Cap to Repair Basis Adjustments (PY)	Federal	4,068,743	(1,627,497)	2,441,246	(578,738.04)	(2,206,235.32)	(587,257)
		M-00800	Excess Tax over book Depreciation	Federal	(265,443,843)	106,177,537	(159,266,306)	37,756,732.27	143,934,209.61	38,312,502
			2575.2000 Total		(281,645,218)	112,658,087	(168,987,131)	40,061,215.84	152,719,303.15	40,650,907
2575.3000	Other	M-00210	Mark to Market Derivative	Federal	-	-	-	-	-	-
		M-00250	Pensions	Federal	(17,596,422)	7,038,569	(10,557,853)	2,502,915.00	9,541,483.60	2,539,757
		M-00271	Conservation Improvement Program - MN & SD - Net (BTL)	Federal	(3,983,297)	1,593,319	(2,389,978)	566,584.16	2,159,902.96	574,924
		M-00340	Wind Rider Revenue	Federal	(204,750)	81,900	(122,850)	29,123.64	111,023.63	29,552
		M-00350	Transmission Rider Revenue	Federal	423,920	(169,568)	254,352	(60,298.33)	(229,866.19)	(61,186)
		M-00351	Environmental Rider Revenue	Federal	554,788	(221,915)	332,873	(78,913.07)	(300,828.32)	(80,075)
		M-00352	SPP Cost Tracker	Federal	199,181	(79,672)	119,509	(28,331.52)	(108,003.95)	(28,749)
		M-00353	EITE Revenue Tracker	Federal	(24,606)	9,842	(14,764)	3,499.97	13,342.39	3,551
		M-00360	Big Stone II Recovery Costs	Federal	-	-	-	-	-	-
		M-00380	MN Rate Case Expense (2008)	Federal	-	-	-	-	-	-
		M-00390	ND Rate Case Expense (2017)	Federal	(101,081)	40,432	(60,648)	14,377.73	54,810.05	14,589
		M-00401	SD Rate Case Expense (2010)	Federal	9	(4)	5	(1.29)	(4.91)	(1)
		M-00410	MN Rate Case Expense (2010)	Federal	(19,384)	7,754	(11,630)	2,757.17	10,510.76	2,798
		M-00540	ND Schedule 16 & 17	Federal	-	-	-	-	-	-
		M-00915	Federal Deduction for State Taxes Paid (Cash) - MN	Federal	-	-	-	-	-	-
		M-00916	Federal Deduction for State Taxes Paid (Cash) - ND	Federal	-	-	-	-	-	-
		M-10000	Deferred State NOL's - Fed Haircut	Federal	(811,297)	324,519	(486,778)	115,398.86	439,917.60	117,098
		M-10017	Prepaid Insurance	Federal	-	-	-	-	-	-
		M-10018	Regulatory Adjustments - JE 820 ESSRP	Federal	1,307,719	(457,702)	850,017	-	-	-
	Property	M-00361	Big Stone II Deferred Costs	Federal	-	-	-	-	-	-
	Prior Peri	M-10013	PY Return to Accrual Recon JE (see entry for detail)	Federal	-	-	-	-	-	-
			2575.3000 Total		(20,255,219)	8,167,473	(12,087,746)	3,067,112.34	11,692,287.64	3,112,259
2575.2010	Credits	M-10021	North Dakota Investment Tax Credit - Federal	Federal	(11,542,931)	4,617,173	(6,925,758)	-	-	1,666,035
			2575.2010 Total		(11,542,931)	4,617,173	(6,925,758)	-	-	1,666,035
2575.1000	Power Tax	M-00801	Excess Tax over book Depreciation - AQCS SL 7	Federal	(4,059,879)	1,623,952	(2,435,927)	577,477.18	2,201,428.77	585,977
			2575.1000 Total		(4,059,879)	1,623,952	(2,435,927)	577,477.18	2,201,428.77	585,977
			Grand Total		(234,615,151)	108,613,993	(126,001,159)	38,785,894.58	147,857,589.14	39,356,813

JE #1	Entry to Reduce FERC Accounts for Excess ADIT and set up regulated liability	Debit	Credit
100.010.0000.1895.9300.0000.000000.1900.0000		0.12684794	18,755,430.41
100.010.0000.2575.2100.0000.000000.2820.0000		1.03288106	152,719,303.15
100.010.0000.2575.3400.0000.000000.2830.0000			11,692,287.64
100.010.0000.2575.2100.0000.000000.2820.0000			2,201,428.77
100.010.0000.2510.1000.0000.000000.2540.0000			147,857,589.14
		166,613,019.55	166,613,019.55

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

ARAM. Referring to the 21% federal corporate income tax rate that became effective January 1, 2018 as part of the Tax Cuts and Jobs Act (TCJA) that was signed into law by President Trump on December 22, 2017 and the identification of excess federal ADIT as of December 31, 2017, explain whether and how the Company will be applying the Average Rate Assumption Method (ARAM) to the "protected" portions of the excess federal ADIT balances that relate to the use of accelerated tax depreciation for federal income tax purposes, and show in detail how the Company is calculating the ARAM.

Attachments: 1

Attachment 1 to DR ND-PSC-05.02.pdf

Response:

To be in compliance with the normalization requirements of the Internal Revenue Service, the Company will be applying the Average Rate Assumption Method (ARAM) to the protected portions of the excess federal ADIT balances that relate to the use of accelerated tax depreciation for federal income tax purposes. This is consistent with past practice as related to the reversing deferred taxes on the books today. The average rate method uses the ending deferred tax balances divided by ending timing difference balance to derive the rate needed to reverse deferred taxes so they all are reversed at the time that the timing difference expires.

The Company uses the software PowerTax to track and calculate the origination and reversal of ADIT balances. Please see Attachment 1 to DR ND-PSC-05.02 for an example from the PowerTax system. This report illustrates how the system tracks each jurisdiction, vintage, and tax class and computes an ARAM for each.

Case No. PU-17-398
 Attachment 1 to DR ND-PSC-05.02
 Page 1 of 1

Deferred Tax Grid

Required Filters: Tax Year, Company, In Service Month, Normalization Scheme, Tax Class, Tax Record ID, Tax Rollups, Vintage

Optional Filters: [None]

Company: Other Tail Power | Tax Year: 2017 | Federal | Jurisdiction: FED M/L | Vintage: 2014 50% | Normalization: 2014 50% | Tax Class: COMPUTERS | Month: 1

Company	Tax Year	Federal	Jurisdiction	Vintage	Normalization	Tax Class	Month	Diff Balance Be	Diff Balance Be	Diff Balance E	Diff Balance E	Reconcile Item	Tax Record ID
Other Tail Power	2017	Federal	FED M/L	2014 50%	2014 50%	COMPUTERS	1	137,594.24	420,285.23	0.00	-59,025.44	00.3274	270623
											78,568.80		
											239,990.46		

2015 50% Q1: 2015 1 3 2
 2014 50%: 2014 1 12 1
 2013 50%: 2013 1 12
 2013 100%: 2013 1 12
 2012 50%: 2012 1 12 1

Public
Response to Data Request ND-PSC-05.05
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Does the cost of removal/negative net salvage component of the Company's depreciation rates have any impact on the derivation of the Average Rate Assumption Method that is specified in the Tax Cuts and Jobs Act for application to excess federal ADIT related to the use of accelerated tax depreciation? If "yes" explain fully, and provide an illustrative example showing how the cost of emoval/negative net salvage component of the Company's depreciation rates impacts the ARAM.

Attachments: 1

Attachment 1 to DR ND-PSC-05.05.pdf

Response:

The average rate assumption method (ARAM) uses the ending deferred tax balances compared to the ending timing difference balance to derive the rate needed to reverse deferred taxes. The Company uses the PowerTax module of our PowerPlan software to calculate tax depreciation and deferred income taxes on property related items. The book depreciation detail is imported into this module, from the Depreciation module of PowerPlan.

The temporary timing difference between book and tax depreciation is what deferred taxes are calculated on. The book depreciation rate includes a component for removal costs. This would impact both the timing difference and deferred taxes each year. Over the life of the assets the amount would originate and fully reverse out when actual removal costs are charged/paid. While books include the cost of removal (COR) in depreciation expense each month, tax is only allowed to deduct these amounts when removal costs are incurred.

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Response to Data Request ND-PSC-05.05
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An illustrative example is included in Attachment 1 to DR ND-PSC-05.05.

This example shows the calculation of accumulated deferred income taxes both with and without the cost of removal component, and the effect that would have on the ARAM. As shown in the example, the COR would impact the timing difference and ADIT, but may not impact the average rate used to reverse deferred taxes (ARAM). The factors which would determine this would be the rates used to originate deferred taxes, and the timing of when those rates would have changed for specific vintages and classes of assets.

CASE NO. PU-17-398
Attachment 1 to DR ND-PSC-05.05
Page 1 of 2

Scenario 1:

\$ 10,000 Total Capitalized Cost

	<u>Tax</u> <u>Depreciation</u>	<u>Tax Deduction</u> <u>for COR</u>	<u>Total Tax</u> <u>Deduction</u>	<u>Book</u> <u>Depreciation</u>	<u>Cost of</u> <u>Removal</u>	<u>Total Book</u> <u>Depreciation</u>	<u>Timing</u> <u>Difference</u>	<u>Total Timing</u> <u>Difference</u>	<u>Tax Rate</u> <u>(ARAM)</u>	<u>ADIT</u> <u>Activity</u>	<u>Total</u> <u>ADIT</u>
1	2,000	-	2,000	400	4	404	1,598	1,598	35.0%	559	559
2	3,200	-	3,200	400	4	404	2,796	4,392	35.0%	979	1,537
3	1,920	-	1,920	400	4	404	1,516	5,908	35.0%	531	2,068
4	1,152	-	1,152	400	4	404	748	6,656	35.0%	282	2,330
5	1,152	-	1,152	400	4	404	748	7,404	35.0%	262	2,591
6	576	-	576	400	4	404	172	7,576	35.0%	60	2,652
7	-	-	-	400	4	404	(404)	7,172	35.0%	(141)	2,510
8	-	-	-	400	4	404	(404)	6,768	35.0%	(141)	2,369
9	-	-	-	400	4	404	(404)	6,364	35.0%	(141)	2,227
10	-	-	-	400	4	404	(404)	5,960	35.0%	(141)	2,086
11	-	-	-	400	4	404	(404)	5,556	35.0%	(141)	1,945
12	-	-	-	400	4	404	(404)	5,152	35.0%	(141)	1,803
13	-	-	-	400	4	404	(404)	4,748	35.0%	(141)	1,662
14	-	-	-	400	4	404	(404)	4,344	35.0%	(141)	1,520
15	-	-	-	400	4	404	(404)	3,940	35.0%	(141)	1,379
16	-	-	-	400	4	404	(404)	3,536	35.0%	(141)	1,238
17	-	-	-	400	4	404	(404)	3,132	35.0%	(141)	1,096
18	-	-	-	400	4	404	(404)	2,728	35.0%	(141)	955
19	-	-	-	400	4	404	(404)	2,324	35.0%	(141)	813
20	-	-	-	400	4	404	(404)	1,920	35.0%	(141)	672
21	-	-	-	400	4	404	(404)	1,516	35.0%	(141)	531
22	-	-	-	400	4	404	(404)	1,112	35.0%	(141)	389
23	-	-	-	400	4	404	(404)	708	35.0%	(141)	248
24	-	-	-	400	4	404	(404)	304	35.0%	(141)	106
25	-	100	100	400	4	404	(304)	-	35.0%	(106)	-
	10,000	100	10,100	10,000	100	10,100	-	-	-	-	-

\$ 10,000 Total Capitalized Cost

	<u>Tax</u> <u>Depreciation</u>	<u>Tax Deduction</u> <u>for COR</u>	<u>Total Tax</u> <u>Deduction</u>	<u>Book</u> <u>Depreciation</u>	<u>Cost of</u> <u>Removal</u>	<u>Total Book</u> <u>Depreciation</u>	<u>Timing</u> <u>Difference</u>	<u>Total Timing</u> <u>Difference</u>	<u>Tax Rate</u> <u>(ARAM)</u>	<u>ADIT</u> <u>Activity</u>	<u>Total</u> <u>ADIT</u>	<u>Difference in</u> <u>ARAM</u> <u>from above</u>
1	2,000	-	2,000	400	-	400	1,600	1,600	35.0%	560	560	0.0000%
2	3,200	-	3,200	400	-	400	2,800	4,400	35.0%	980	1,540	0.0000%
3	1,920	-	1,920	400	-	400	1,520	5,920	35.0%	532	2,072	0.0000%
4	1,152	-	1,152	400	-	400	752	6,672	35.0%	263	2,335	0.0000%
5	1,152	-	1,152	400	-	400	752	7,424	35.0%	263	2,598	0.0000%
6	576	-	576	400	-	400	176	7,600	35.0%	62	2,660	0.0000%
7	-	-	-	400	-	400	(400)	7,200	35.0%	(140)	2,520	0.0000%
8	-	-	-	400	-	400	(400)	6,800	35.0%	(140)	2,380	0.0000%
9	-	-	-	400	-	400	(400)	6,400	35.0%	(140)	2,240	0.0000%
10	-	-	-	400	-	400	(400)	6,000	35.0%	(140)	2,100	0.0000%
11	-	-	-	400	-	400	(400)	5,600	35.0%	(140)	1,960	0.0000%
12	-	-	-	400	-	400	(400)	5,200	35.0%	(140)	1,820	0.0000%
13	-	-	-	400	-	400	(400)	4,800	35.0%	(140)	1,680	0.0000%
14	-	-	-	400	-	400	(400)	4,400	35.0%	(140)	1,540	0.0000%
15	-	-	-	400	-	400	(400)	4,000	35.0%	(140)	1,400	0.0000%
16	-	-	-	400	-	400	(400)	3,600	35.0%	(140)	1,260	0.0000%
17	-	-	-	400	-	400	(400)	3,200	35.0%	(140)	1,120	0.0000%
18	-	-	-	400	-	400	(400)	2,800	35.0%	(140)	980	0.0000%
19	-	-	-	400	-	400	(400)	2,400	35.0%	(140)	840	0.0000%
20	-	-	-	400	-	400	(400)	2,000	35.0%	(140)	700	0.0000%
21	-	-	-	400	-	400	(400)	1,600	35.0%	(140)	560	0.0000%
22	-	-	-	400	-	400	(400)	1,200	35.0%	(140)	420	0.0000%
23	-	-	-	400	-	400	(400)	800	35.0%	(140)	280	0.0000%
24	-	-	-	400	-	400	(400)	400	35.0%	(140)	140	0.0000%
25	-	-	-	400	-	400	(400)	-	35.0%	(140)	-	0.0000%
	10,000	-	10,000	10,000	-	10,000	-	-	-	-	-	-

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Attachment 1 to DR ND-PSC-05.05
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Scenario 2:

5 10,000 Total Capitalized Cost

	<u>Tax</u>	<u>Tax Deduction</u>	<u>Total Tax</u>	<u>Book</u>	<u>Cost of</u>	<u>Total Book</u>	<u>Timing</u>	<u>Total Timing</u>	<u>Tax Rate</u>	<u>ADIT</u>	<u>Total</u>
	<u>Depreciation</u>	<u>for COR</u>	<u>Deduction</u>	<u>Depreciation</u>	<u>Removal</u>	<u>Depreciation</u>	<u>Difference</u>	<u>Difference</u>	<u>(ARAM)</u>	<u>Activity</u>	<u>ADIT</u>
1	2,000	-	2,000	400	4	404	1,596	1,596	40.0%	638	638
2	3,200	-	3,200	400	4	404	2,796	4,392	35.0%	979	1,617
3	1,920	-	1,920	400	4	404	1,516	5,908	35.0%	531	2,148
4	1,152	-	1,152	400	4	404	748	6,656	35.0%	262	2,409
5	1,152	-	1,152	400	4	404	748	7,404	35.0%	262	2,671
6	576	-	576	400	4	404	172	7,576	35.0%	60	2,731
7	-	-	-	400	4	404	(404)	7,172	35.1%	(146)	2,586
8	-	-	-	400	4	404	(404)	6,768	35.1%	(146)	2,440
9	-	-	-	400	4	404	(404)	6,364	35.1%	(146)	2,294
10	-	-	-	400	4	404	(404)	5,960	35.1%	(146)	2,149
11	-	-	-	400	4	404	(404)	5,556	35.1%	(146)	2,003
12	-	-	-	400	4	404	(404)	5,152	35.1%	(146)	1,857
13	-	-	-	400	4	404	(404)	4,748	35.1%	(146)	1,712
14	-	-	-	400	4	404	(404)	4,344	35.1%	(146)	1,566
15	-	-	-	400	4	404	(404)	3,940	35.1%	(146)	1,421
16	-	-	-	400	4	404	(404)	3,536	35.1%	(146)	1,275
17	-	-	-	400	4	404	(404)	3,132	35.1%	(146)	1,129
18	-	-	-	400	4	404	(404)	2,728	35.1%	(146)	984
19	-	-	-	400	4	404	(404)	2,324	35.1%	(146)	838
20	-	-	-	400	4	404	(404)	1,920	35.1%	(146)	692
21	-	-	-	400	4	404	(404)	1,516	35.1%	(146)	547
22	-	-	-	400	4	404	(404)	1,112	35.1%	(146)	401
23	-	-	-	400	4	404	(404)	708	35.1%	(146)	255
24	-	-	-	400	4	404	(404)	304	35.1%	(146)	110
25	-	100	100	400	4	404	(304)	-	35.1%	(110)	-
	10,000	100	10,100	10,000	100	10,100	-	-	-	-	-

5 10,000 Total Capitalized Cost

	<u>Tax</u>	<u>Tax Deduction</u>	<u>Total Tax</u>	<u>Book</u>	<u>Cost of</u>	<u>Total Book</u>	<u>Timing</u>	<u>Total Timing</u>	<u>Tax Rate</u>	<u>ADIT</u>	<u>Total</u>	<u>Difference in</u>
	<u>Depreciation</u>	<u>for COR</u>	<u>Deduction</u>	<u>Depreciation</u>	<u>Removal</u>	<u>Depreciation</u>	<u>Difference</u>	<u>Difference</u>	<u>(ARAM)</u>	<u>Activity</u>	<u>ADIT</u>	<u>from above</u>
1	2,000	-	2,000	400	-	400	1,600	1,600	40.0%	640	640	0.0000%
2	3,200	-	3,200	400	-	400	2,800	4,400	35.0%	980	1,620	0.0000%
3	1,920	-	1,920	400	-	400	1,520	5,920	35.0%	532	2,152	0.0000%
4	1,152	-	1,152	400	-	400	752	6,672	35.0%	263	2,415	0.0000%
5	1,152	-	1,152	400	-	400	752	7,424	35.0%	263	2,678	0.0000%
6	576	-	576	400	-	400	176	7,600	35.0%	62	2,740	0.0000%
7	-	-	-	400	-	400	(400)	7,200	35.1%	(144)	2,596	-0.0007%
8	-	-	-	400	-	400	(400)	6,800	35.1%	(144)	2,452	-0.0007%
9	-	-	-	400	-	400	(400)	6,400	35.1%	(144)	2,307	-0.0007%
10	-	-	-	400	-	400	(400)	6,000	35.1%	(144)	2,163	-0.0007%
11	-	-	-	400	-	400	(400)	5,600	35.1%	(144)	2,019	-0.0007%
12	-	-	-	400	-	400	(400)	5,200	35.1%	(144)	1,875	-0.0007%
13	-	-	-	400	-	400	(400)	4,800	35.1%	(144)	1,731	-0.0007%
14	-	-	-	400	-	400	(400)	4,400	35.1%	(144)	1,586	-0.0007%
15	-	-	-	400	-	400	(400)	4,000	35.1%	(144)	1,442	-0.0007%
16	-	-	-	400	-	400	(400)	3,600	35.1%	(144)	1,298	-0.0007%
17	-	-	-	400	-	400	(400)	3,200	35.1%	(144)	1,154	-0.0007%
18	-	-	-	400	-	400	(400)	2,800	35.1%	(144)	1,009	-0.0007%
19	-	-	-	400	-	400	(400)	2,400	35.1%	(144)	865	-0.0007%
20	-	-	-	400	-	400	(400)	2,000	35.1%	(144)	721	-0.0007%
21	-	-	-	400	-	400	(400)	1,600	35.1%	(144)	577	-0.0007%
22	-	-	-	400	-	400	(400)	1,200	35.1%	(144)	433	-0.0007%
23	-	-	-	400	-	400	(400)	800	35.1%	(144)	288	-0.0007%
24	-	-	-	400	-	400	(400)	400	35.1%	(144)	144	-0.0007%
25	-	-	-	400	-	400	(400)	-	35.1%	(144)	-	-0.0007%
	10,000	-	10,000	10,000	-	10,000	-	-	-	-	-	-

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Response to Data Request ND-PSC-18.03
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/07/2018

Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

What software does the Company use to track the tax basis and tax depreciation of its utility plant assets?

- a. Explain the capabilities of that software for tracking tax basis and tax depreciation by plant account by vintage (year in which the plant was placed into service).
- b. Explain the capabilities of that software for calculating amortization of excess accumulated deferred income taxes (EADIT) using an average rate assumption method (ARAM).

Attachments: 0

Response:

- a. The Company uses the PowerTax module of the PowerPlant system to track tax basis and tax depreciation. This software loads each year's actual current additions and retirements from the PowerPlant module (which tracks the company's book plant activity) and allocates it by tax depreciation group. This information is maintained by tax account per each vintage year.
- b. The PowerTax system calculates each year's reversing ADIT based upon the average rate assumption method (ARAM). The software calculates an ARAM rate for tax depreciation account, for each vintage using the accumulated ending ADIT balance divided by the total accumulated timing difference.

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Response to Data Request ND-PSC-18.04
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/25/2018
Date Due: 05/09/2018
Date of Response: 05/09/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

What software does the Company use to track the book basis and book depreciation of its utility plant assets?

- a. Explain the capabilities of that software for tracking book basis and book depreciation by plant account by vintage (year in which the plant was placed into service).
- b. Explain the capabilities of that software for calculating amortization of excess accumulated deferred income taxes (EADIT) using an average rate assumption method (ARAM).

Attachments: 0

Response:

Otter Tail Power Company uses PowerPlan 2016.1 for its fixed asset tracking system for its utility plant in service assets.

- a) The PowerPlan fixed asset software tracks the utility plant in service assets by plant account and at their book cost and in-service vintage. The associated accumulated depreciation for these assets are allocated to the individual plant assets within that plant account by vintage.
- b) See response to DR ND-PSC-18.03.

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

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/25/2018

Date Due: 05/09/2018

Date of Response: 05/07/2018

Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Referring to the 21% federal corporate income tax rate that became effective January 1, 2018 as part of the Tax Cuts and Jobs Act (TCJA) that was signed into law by President Trump on December 22, 2017 and the identification of excess federal ADIT as of December 31, 2017:

- a. Explain whether and how the Company will be applying the Average Rate Assumption Method (ARAM) to the "protected" portions of the excess federal ADIT balances that relate to the use of accelerated tax depreciation for federal income tax purposes, and show in detail how the Company is calculating the ARAM.
- b. Is the Company proposing to use an alternative method for amortizing the "protected" portion of its excess ADIT? If so, identify and describe the method and show in detail how the Company is applying it.
- c. Please provide the Company's currently authorized depreciation rates, by plant account (and sub-account if applicable). For each depreciation rate, please provide a breakout of the rate between (1) the portion related to the recovery of original cost over the plant's estimated useful life and (2) the portion related to cost of removal/negative net salvage.
- d. How does the Company account for the cost of removal when actual removal costs are incurred, and how does the Company account for the component of depreciation rates (and depreciation expense) that relates to negative net salvage in recording Depreciation Expense and Accumulated Depreciation? Please explain fully, identify and provide accounting policies related to this, and provide illustrative journal entries made in 2017 and 2018 showing the accounting.
- e. Does the cost of removal/negative net salvage component of the Company's depreciation rates have any impact on the derivation of the Average Rate Assumption Method that is specified in the Tax Cuts and Jobs Act for application to excess federal ADIT related to the use of accelerated tax depreciation? If "yes" explain fully, and provide an illustrative example showing how the cost of

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Response to Data Request ND-PSC-18.07
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removal/negative net salvage component of the Company's depreciation rates impacts the ARAM.

Attachments: 0

Response:

- a. The Company will be using the PowerTax module of the PowerPlant software system to calculate the reversal of the protected portion of the excess federal ADIT balance that related to the use of accelerated tax depreciation for federal income tax purposes. Please see our response to DR ND-PSC-05.02 for an example of how the PowerTax system calculates ADIT using the ARAM method.
- b. No, the Company is not proposing an alternate method to amortize the protected portion of its excess ADIT.
- c. Please refer to Attachment 1 to DR ND-PSC-05.03 for Otter Tail's 2018 Depreciation Rates by plant account and sub-accounts, including Life, and Cost of Removal (COR) breakouts.
- d. Please refer to OTP's response to DR ND-PSC-05.04.
- e. Please refer to OTP's response to DR ND-PSC-05.05.

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Response to Data Request ND-MLEC-141
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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: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Provide the excess accumulated deferred income taxes (ADIT) by FERC account/subaccount and temporary difference. If not evident by the account/subaccount description, provide a description of the temporary difference.

- a. For each temporary difference identified in response to this question, indicate whether the Company believes the related ADIT is protected or unprotected. Other than for ADIT due to accelerated tax depreciation, if the Company believes that the ADIT is protected, provide all citations to the IRC, Regulations, Private Letter Rulings, and all other authoritative sources that support the Company's position.
- b. For each temporary difference identified in response to this question as protected, provide the projected amortization and the underlying calculations for the Test Year consistent with the reversal of the underlying temporary difference and consistent with the ARAM. Provide these amounts on a total company and jurisdictional basis.
- c. For each temporary difference identified in response to this question as unprotected, provide the projected amortization of the excess ADIT, the revenue equivalent, and the underlying calculations for 2018 and 2019 consistent with the reversal of the underlying temporary difference. Provide these amounts on a total company and jurisdictional basis.

Attachments: 1

Attachment 1 to DR ND-MLEC-141.pdf

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Response to Data Request ND-MLEC-141
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Response:

- a. See Attachment 1 to DR ND-MLEC-141 for a listing of temporary items by FERC account for year-end 2017. The only temporary items listed that we consider to be protected are related to excess tax over book depreciation, which includes (\$106,177,537) in account 282 and (\$1,623,952) in account 281.
- b. Otter Tail uses the PowerTax system to track and calculate the reversal of ADIT balances related to property. Due to the amount of information used and the fact that the reversal of ADIT is dependent on each year's book versus tax activity, it is difficult to forecast the exact amount these balances will reverse each year.

Based upon our 2017 Technical update to the annual depreciation filing, we have estimated the average life of property to be 25 years. Using this average life, we estimate the reversal of protected ADIT to be approximately \$4,312,000 (\$106,177,537 plus \$1,623,952 equals \$107,802,489 divided by 25 years).

- c. Each unprotected temporary item listed in Attachment 1 to DR ND-MLEC-141 is unique. The reversing of the deferred is dependent on each year's activity related to that temporary item and the time could range from one year to over 30 years. Due to the number of unprotected items and the complexity of the items, it is difficult to estimate how the excess ADIT balances will reverse.

Due to the fact that the unprotected items total only (\$930,203) of the total excess ADIT balance of \$108,731,692, we suggest the unprotected items are treated the same as the protected items with the same amortization schedule, to be reversed using ARAM. This would follow the actual activity related to each item for tax accounting. Assuming a 25-year life, the amortization would equal only \$37,208 annually (\$930,203 divided by 25 years).

The revenue requirement for these unprotected temporary items would include a gross up amount, the gross up factor subsequent to tax reform equals 1.32284 resulting in a total revenue requirement of \$1,230,510 or \$49,220/annually (\$1,230,510 divided by 25 years).

Based upon our most current cost of service for North Dakota, North Dakota's allocation factor is .36086122. This results in \$335,674 of the \$903,203 unprotected balance would be allocated to North Dakota customers.

Case No. PU-17-398
Attachment 1 to DR ND-MLEC-141
Page 1 of 1

FERC Account	Description	Company Classifying as a Protected Item	Federal ADIT Balance YE 2017	Excess ADIT YE 2017
190	Accrued Vacation Pay	No	1,436,400	574,560
	Bad Debts	No	374,216	149,686
	Capitalized A & G	No	1,940,615	776,246
	Capitalized A & G - 481(a) - Reversing	No	(17,398)	(6,959)
	Capitalized Customer Rebates	No	116,093	46,437
	CIAC Capitalized	No	67,667	27,067
	Executive Supplemental Pension	No	3,801,303	1,520,521
	Interest Capitalized on Construction	No	4,922,890	1,969,156
	Loan Pool	No	3,952	1,581
	Medicare Part D Capitalized	No	412,428	164,971
	Post Employment Benefit	No	308,515	123,406
	Post Retirement Benefit	No	18,536,386	7,414,555
	Property Repairs	No	(253,055)	(101,222)
	Restricted Stock	No	(39,441)	(15,776)
	South Dakota Flow Thru-Overheads	No	(140,756)	(56,302)
	South Dakota Flow Thru-Repairs	No	219,828	87,931
	Unicap Adjustment	No	30,460	12,184
	Workmans Comp	No	258,247	103,299
	Big Stone II Discount	No	139,878	55,951
	Deferred State NOL's - ND	No	-	-
	Bonus Incentive	No	737,395	294,958
	Deferred Federal NOL	No	1,408,821	563,528
	Non Qual Retirement Savings (FERC 190.1)	No	324,355	129,742
	190 Total		34,588,799	13,835,519
282	ADR Repair Allowance	No	(1,747,780)	(699,112)
	AFUDC on Debt	No	(2,773,431)	(1,109,372)
	Capitalized Overheads	No	44,747	17,899
	Excess Tax over book Depreciation*	Yes	(265,443,843)	(106,177,537)
	Highway Reimbursements	No	(18,226)	(7,291)
	Prepaid Expenses	No	(363,658)	(145,463)
	Sec 162 & 174 R&D Deduction	No	(3,064,387)	(1,225,755)
	South Dakota Flow Thru-Overheads	No	(10,567)	(4,227)
	Sec 481(a) Cap to Repair Basis Adjustments (PY)	No	4,068,743	1,627,497
	Repairs Deduction - Basis Adjustments	No	(11,169,277)	(4,467,711)
	Big Stone II Deferred Costs	No	(930,687)	(372,275)
	Retirements Method Change	No	163,640	65,456
	Amort of Loss on Reacquired Debt (FERC 282.1)	No	(400,491)	(160,196)
	282 Total		(281,645,218)	(112,658,087)
283	Deferred State NOL's - Fed Haircut	No	(811,297)	(324,519)
	MN Rate Case Expense (2010)	No	(19,384)	(7,754)
	Pensions	No	(17,596,422)	(7,038,569)
	Transmission Rider Revenue	No	423,920	169,568
	Wind Rider Revenue	No	(204,750)	(81,900)
	ESSRP Regulatory Adjustments	No	850,016	340,007
	Environmental Rider Revenue	No	554,788	221,915
	SPP Cost Tracker	No	199,181	79,672
	EITE Revenue Tracker	No	(24,606)	(9,842)
	ND Rate Case Expense (2017)	No	(101,081)	(40,432)
	Conservation Improvement Program (FERC 283.1)	No	(3,983,297)	(1,593,319)
	283 Total		(20,712,931)	(8,285,172)
281	Excess Tax over book Depreciation - AQCS SL 7*	Yes	(4,059,879)	(1,623,952)
	Grand Total		(271,829,230)	(108,731,692)

*These line items relates to ADIT balances which are created due to the Company using accelerated tax depreciation.

Public
Response to Data Request ND-PSC-19.03
Page 1 of 2

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/27/2018
Date Due: 05/11/2018
Date of Response: 05/11/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Refer to the Supplemental Direct Testimony of Tyler Akerman at page 2.

- a. Did the Company experience any savings in income tax expense associated with the TCJA in January and February of 2018? If not, explain fully why not.
- b. Is the savings in income tax expense associated with the TCJA in January and February of 2018 equate to a revenue requirement of approximately 2/12ths (i.e., 2 out of 12 months) of the \$4.5 million reduction mentioned on page 2? If not, explain fully and show in detail how the income tax savings to the Company in January and February 2018 can be estimated.
- c. At page 2, lines 9-10, Mr. Akerman states that: "OTP's revenue requirements for its Transmission, Renewable and Environmental riders will be reduced by approximately \$1.7 million." Identify and provide the calculations relating to this, showing the amount of reduction by rider and how it was derived.
- d. What are the effective rate change dates for each of these OTP riders: Transmission, Renewable and Environmental?

Attachments: 0

Response:

- a. Yes. The Company experienced the impacts of the TCJA effective January 1, 2018. The Company has been provisioning an estimated amount of interim rate refund for January and February. During those months the Company had interim rates in effect which did not yet include the impacts of the TCJA.

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Response to Data Request ND-PSC-19.03
Page 2 of 2

- b. The estimated impact of the TCJA on January and February could be calculated using method noted of allocating the \$4.5 million annual income tax reduction equally by month for the year. Given the Cost of Service Study (COSS) used to calculate the impact on the TCJA is based on a 2018 annual Test Year, it seems to be appropriate to use this approach. The Company does not calculate COSS results on a monthly basis but rather on a calendar year.
- c. The table below identifies the amount of revenue requirement from the Transmission, Renewable, and Environmental riders. The amounts in the supplemental filing were modeled in Utilities International. The modeling in the supplemental filing reflects the lower federal income tax rate and lower tax gross-up factor for each of the three riders. The total difference amount below is also shown in Exhibit __ (TAA-2), Schedule 7.

Rider Revenue Requirements	Supplemental Filing	Initial Filing	Difference
Transmission	7,391,542	7,913,280	(521,738)
Renewable	8,868,053	9,211,881	(343,828)
Environmental	7,581,594	8,357,519	(775,925)
Total	23,841,189	25,482,680	(1,641,491)

- d. The effective rate change date for the Transmission, Renewable, and Environmental riders was March 1, 2018.

Public
Response to Data Request ND-MLEC-214
Page 1 of 2

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

Data Request:

Please list the projects now being recovered via riders which OTP proposes to roll into base rates.

- a. With respect to each of the foregoing, please show the original investments and the unamortized balances, and revenue requirements at the time of roll-in along with any differences between revenue requirements before and after roll-in.

Attachments: 0

Response:

OTP provides Table 1 to this response detailing the projects that will roll from riders in to base rates at the time of final rates (Column A), the current rider recovery mechanism (Column B), the original investment (Column C), the net plant in service (Column D), and the 2018 test year revenue requirement (Column E). These projects remain in their respective riders until the time of final rates at which time the projects transfer out of the riders and into rate base. As an example, if final rates are implemented August 2018, the July 2018 rate base amounts for these projects will be rolled in to rate base.

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Response to Data Request ND-MLEC-214
Page 2 of 2

Table 1

	A	B	C	D	E
Line No.	Project	Rider	12/31/2017 Projected Plant Balance (Original Investments)	12/31/2017 Net Plant in Service (Unamortized Balance)	Revenue Requirement at time of Roll-in ¹
1	Rider Projects Rolling into Base Rates				
2	Big Stone Plant AQCS	ECRR	\$192,985,866	\$181,728,947	\$7,090,956
3	HLP MATS	ECRR	\$6,460,514	\$3,078,448	\$490,884
4	Langdon Wind Project	RRAR	\$79,309,589	\$48,158,907	\$2,917,548
5	Ashtabula Wind Project	RRAR	\$116,261,976	\$73,896,299	\$3,403,758
6	Luverne Wind Project	RRAR	\$72,996,881	\$48,984,948	\$2,556,750
7	CAPX 2020: Fargo	TCRR	\$81,428,592	\$77,100,337	\$2,469,369
8	CAPX 2020: Bemidji	TCRR	\$16,331,201	\$15,147,656	\$606,672
9	Cass Lake-Nary-Helga-Bemidji	TCRR	\$7,039,948	\$6,604,415	\$98,404
10	Rugby Wind Interconnection	TCRR	\$394,399	\$370,449	\$12,486
11	Casselton – Buffalo 115 kV Project	TCRR	\$13,509,407	\$12,998,650	\$253,204
12	CAPX 2020: Brookings - Hampton	TCRR	\$26,322,129	\$24,827,040	\$220,764
13	MVP: Big Stone Area Transmission	TCRR	\$72,700,759	\$72,332,731	\$63,053
14	Ramsey 230/115 kW Transformer Upgrade	TCRR	\$416,398	\$343,661	\$14,090
15	Karlstad, MN Capacitor Bank Project	TCRR	\$1,103,974	\$1,036,467	\$36,455
16	Oakes Area Transmission Improvements	TCRR	\$7,010,019	\$6,708,331	\$211,544
17	Hankinson Transformer Addition	TCRR	\$828,844	\$778,512	\$23,998
18	NERC Compliance	TCRR	\$14,078,440	\$12,809,861	\$507,654
19	Summit Transformer	TCRR	\$853,991	\$851,872	\$25,652
20	Spiritwood Station Interconnection	TCRR	\$720,137	\$698,553	\$24,169
21	Rugby Breaker Station	TCRR	\$1,824,862	\$1,813,072	\$47,292
22	Granville Jct Breaker Station	TCRR	\$1,015,655	\$1,008,915	\$25,932

¹OTP's February 15, 2018 filing updating interim rates for TCJA for Volume 2a Bryce C. Haugen Exhibit_(BCH-1), Schedules 3, 4 & 5

OTP has proposed that any over or under collection remaining in the riders at the time these projects roll-in to base rates be recovered through the respective rider over the subsequent twelve months.

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Response to Data Request ND-PSC-15.39
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/04/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Environmental Cost Recovery Rider (ECRR). Refer to pages 23-24 of the direct testimony of Company witness Akerman. Mr. Akerman states that the 2018 test year rate base includes ECRR projects totaling \$72.6 million on a North Dakota jurisdictional basis, which are currently recovered through the ECRR.

- a. Please provide the actual monthly over/under recovered ECRR balances from the period January 1, 2016 through March 31, 2018.
- b. Please provide the projected monthly over/under recovered ECRR balances for the period April through December 2018.
- c. Provide the actual amount of ECRR revenue for each month, January 2016 through March 2018.
- d. Provide the expected amount of ECRR revenue for each month, April 2018 through December 2018.
- e. Provide the actual amount of ECRR costs, by account for each month, January 2016 through March 2018.
- f. Provide the expected amount of ECRR costs, by account, for each month, April 2018 through December 2018.

Attachments: 2

Attachment 1 to DR ND-PSC-15.39.pdf
Attachment 2 to DR ND-PSC-15.39.pdf

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Response to Data Request ND-PSC-15.39
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Response:

OTP provides Attachment 1 to DR ND-PSC-15.39 in response to a.-d. of this request and also provides Attachment 2 to DR ND-PSC-15.39 in response to e.-f. of this request. OTP proposes to move both ECRR Projects out of the ECRR and into base rates concurrent with the implementation of final rates in this case. For the purposes of this response OTP anticipates final rates to be effective October 1, 2018.

Otter Tail Power Company		North Dakota Case No PU-17-398		
Summary of North Dakota Environmental Cost Recovery Rider		Attachment 1 to DR ND-PSC-15.39		
		Page 1 of 1		
	Net Revenue Requirement*	Actual Billed Revenue	(Over)/Under	
Actual				
January 2016	\$ 905,592	\$ 1,166,949	\$ (261,357)	
February 2016	914,655	1,096,483	(181,828)	
March 2016	915,115	1,013,479	(98,364)	
April 2016	906,725	928,957	(22,232)	
May 2016	907,344	799,999	107,344	
June 2016	910,009	864,022	45,987	
July 2016	909,344	775,660	133,683	
August 2016	914,579	815,428	99,151	
September 2016	915,568	818,015	97,552	
October 2016	908,135	697,332	210,803	
November 2016	907,716	791,732	115,984	
December 2016	914,977	887,681	27,296	
January 2017	839,194	1,046,843	(207,649)	
February 2017	837,353	977,658	(140,305)	
March 2017	838,631	875,488	(36,858)	
April 2017	844,605	818,150	26,456	
May 2017	838,090	692,819	145,271	
June 2017	838,558	745,184	93,374	
July 2017	837,617	754,671	82,946	
August 2017	842,045	762,314	79,731	
September 2017	840,624	755,308	85,316	
October 2017	834,381	635,599	198,781	
November 2017	833,904	818,528	15,376	
December 2017	846,084	860,255	(14,171)	
January 2018	623,417	852,756	(229,339)	
February 2018	626,329	806,825	(180,496)	
March 2018	622,317	664,037	(41,721)	
Forecast				
April 2018	\$ 624,999	\$ 647,823	\$ (22,824)	
May 2018	624,999	553,488	71,511	
June 2018	624,999	571,204	53,795	
July 2018	624,999	592,253	32,746	
August 2018	624,999	614,465	10,534	
September 2018	624,999	608,968	16,031	
October 2018**	-	-	-	
November 2018**	-	-	-	
December 2018**	-	-	-	
* Revenue requirement does not include carrying charge/credit.				
** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.				

Otter Tail Power Company							North Dakota Case No PU-17-398	
Summary of North Dakota Environmental Cost Recovery Rider							Attachment 2 to DR ND-PSC-15.39	
Page 1 of 1								
ECRR Costs								
	Return on Rate Base	O&M Costs	Property Taxes	Depreciation	Interest	Income Taxes	Net Revenue Requirement*	
Actual								
January 2016	\$ 323,708	\$ 9,249	\$ 3,430	\$ 229,178	\$ 148,990	\$ 191,038	\$ 905,592	
February 2016	323,708	18,188	3,430	229,302	148,990	191,038	914,655	
March 2016	323,708	18,455	3,430	229,494	148,990	191,038	915,115	
April 2016	323,708	10,234	3,430	229,326	148,990	191,038	906,725	
May 2016	323,708	10,794	3,430	229,384	148,990	191,038	907,344	
June 2016	323,708	13,466	3,430	229,376	148,990	191,038	910,009	
July 2016	323,708	12,487	3,430	229,690	148,990	191,038	909,344	
August 2016	323,708	14,852	3,430	232,560	148,990	191,038	914,579	
September 2016	323,708	15,607	3,430	232,795	148,990	191,038	915,568	
October 2016	323,708	11,087	3,430	229,882	148,990	191,038	908,135	
November 2016	323,708	10,236	3,430	230,314	148,990	191,038	907,716	
December 2016	323,708	17,483	3,430	230,327	148,990	191,038	914,977	
January 2017	293,210	16,949	4,022	217,020	134,953	173,040	839,194	
February 2017	293,210	15,105	4,022	217,023	134,953	173,040	837,353	
March 2017	293,210	16,350	4,022	217,056	134,953	173,040	838,631	
April 2017	293,210	23,867	4,022	215,513	134,953	173,040	844,605	
May 2017	293,210	17,352	4,022	215,513	134,953	173,040	838,090	
June 2017	293,210	17,700	4,022	215,634	134,953	173,040	838,558	
July 2017	293,210	16,758	4,022	215,634	134,953	173,040	837,617	
August 2017	293,210	21,186	4,022	215,634	134,953	173,040	842,045	
September 2017	293,210	19,766	4,022	215,634	134,953	173,040	840,624	
October 2017	293,210	13,522	4,022	215,634	134,953	173,040	834,381	
November 2017	293,210	12,960	4,022	215,718	134,953	173,040	833,904	
December 2017	293,210	25,140	4,022	215,718	134,953	173,040	846,084	
January 2018	226,836	17,311	3,667	194,973	107,399	73,231	623,417	
February 2018	226,836	20,224	3,667	194,973	107,399	73,231	626,329	
March 2018	226,836	16,211	3,667	194,973	107,399	73,231	622,317	
Forecast								
April 2018	\$ 226,836	\$ 18,893	\$ 3,667	\$ 194,973	\$ 107,399	\$ 73,231	\$ 624,999	
May 2018	226,836	18,893	3,667	194,973	107,399	73,231	624,999	
June 2018	226,836	18,893	3,667	194,973	107,399	73,231	624,999	
July 2018	226,836	18,893	3,667	194,973	107,399	73,231	624,999	
August 2018	226,836	18,893	3,667	194,973	107,399	73,231	624,999	
September 2018	226,836	18,893	3,667	194,973	107,399	73,231	624,999	
October 2018**	-	-	-	-	-	-	-	
November 2018**	-	-	-	-	-	-	-	
December 2018**	-	-	-	-	-	-	-	

* Revenue requirement does not include carrying charge/credit.

** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.

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Response to Data Request ND-PSC-15.40
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/04/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Transmission Cost Recovery Rider (TCRR). Refer to pages 23-24 of the direct testimony of Company witness Ackerman. Mr. Ackerman states that the 2018 test year rate base includes TCRR projects totaling \$47.2 million on a North Dakota jurisdictional basis, which are currently recovered through the TCRR.

- a. Please provide the actual monthly over/under recovered TCRR balances from the period January 1, 2016 through March 31, 2018.
- b. Please provide the projected monthly over/under recovered TCRR balances for the period April through December 2018.
- c. Provide the actual amount of TCRR revenue for each month, January 2016 through March 2018.
- d. Provide the expected amount of TCRR revenue for each month, April 2018 through December 2018.
- e. Provide the actual amount of TCRR costs, by account for each month, January 2016 through March 2018.
- f. Provide the expected amount of TCRR costs, by account, for each month, April 2018 through December 2018.

Attachments: 2

Attachment 1 to DR ND-PSC-15.40.pdf
Attachment 2 to DR ND-PSC-15.40.pdf

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Response to Data Request ND-PSC-15.40
Page 2 of 2

Response:

OTP provides Attachment 1 to DR ND-PSC-15.40 in response to questions a-d and Attachment 2 to DR ND-PSC-15.40 in response to questions e-f. OTP proposes to move the 16 TCRR Projects that are expected to be in service at the time final rates go into effect out of the TCRR and into base rates concurrent with the implementation of final rates in this case. For the purposes of this response OTP anticipates final rates to be effective October 1, 2018.

Otter Tail Power Company		North Dakota Case No PU-17-398		
Summary of North Dakota Transmission Cost Recovery Rider		Attachment 1 to DR ND-PSC-15.40		
		Page 1 of 1		
	Net Revenue Requirement *	Actual Billed Revenue	(Over)/Under	
Actual				
January 2016	\$ 699,540	\$ 973,403	\$ (273,863)	
February 2016	646,344	912,173	(265,829)	
March 2016	612,028	845,906	(233,878)	
April 2016	580,092	769,063	(188,971)	
May 2016	866,078	674,565	191,513	
June 2016	473,260	678,025	(204,766)	
July 2016	513,692	706,896	(193,204)	
August 2016	579,524	744,122	(164,598)	
September 2016	490,732	746,452	(255,720)	
October 2016	630,123	695,897	(65,775)	
November 2016	662,720	776,811	(114,090)	
December 2016	799,076	878,623	(79,547)	
January 2017	947,052	713,189	233,863	
February 2017	971,246	663,351	307,895	
March 2017	476,327	598,526	(122,199)	
April 2017	700,027	551,200	148,827	
May 2017	604,594	476,867	127,727	
June 2017	571,546	474,824	96,722	
July 2017	630,097	481,209	148,888	
August 2017	646,559	502,412	144,147	
September 2017	630,060	498,794	131,266	
October 2017	666,308	459,887	206,420	
November 2017	897,306	580,165	317,141	
December 2017	799,840	609,614	190,226	
January 2018	655,061	865,720	(210,659)	
February 2018	1,579,695	806,154	773,540	
March 2018	670,787	693,188	(22,401)	
Forecast				
April 2018	\$ 620,670	\$ 784,698	\$ (164,028)	
May 2018	478,787	636,902	(158,115)	
June 2018	450,091	602,064	(151,972)	
July 2018	478,301	625,933	(147,632)	
August 2018	480,730	647,468	(166,738)	
September 2018	484,761	645,353	(160,592)	
October 2018 **	219,994	625,380	(405,386)	
November 2018 **	248,604	742,485	(493,881)	
December 2018 **	324,662	836,546	(511,884)	
* Revenue requirement includes projects and RTO revenue and expenses. Does not include carrying charge/credit.				
** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.				

Otter Tail Power Company							North Dakota Case No PU-17-398			
Summary of North Dakota Transmission Cost Recovery Rider Revenue Requirement							Attachment 2 to DR ND-PSC-15.40			
							Page 1 of 1			
TCRR Costs										
	Return on Rate Base	O&M Costs	Property Taxes	Depreciation	Interest Expense	Income Taxes	Net MISO & SPP Rev/Exp	Wholesale Revenue Credit	Net Revenue Requirement *	
Actual										
January 2016	\$ 180,031	\$ 14,933	\$ 58,873	\$ 59,328	\$ 82,862	\$ 106,247	\$ 208,057	\$ (10,791)	\$ 699,540	
February 2016	180,031	26,884	58,888	60,791	82,862	106,247	141,573	(10,932)	646,344	
March 2016	180,031	148	58,888	61,143	82,862	106,247	133,674	(10,965)	612,028	
April 2016	180,031	291	58,887	61,371	82,862	106,247	101,391	(10,988)	580,092	
May 2016	186,973	22,430	58,879	61,355	82,862	99,305	365,277	(11,003)	866,078	
June 2016	186,817	90	58,878	62,061	82,862	99,460	(5,840)	(11,068)	473,260	
July 2016	180,031	7,829	58,878	62,184	82,862	106,247	26,745	(11,084)	513,692	
August 2016	180,031	603	58,878	62,282	82,862	106,247	99,716	(11,095)	579,524	
September 2016	180,031	14,131	58,878	62,401	82,862	106,247	(2,714)	(11,104)	490,732	
October 2016	180,031	75	58,878	63,785	82,862	106,247	149,499	(11,254)	630,123	
November 2016	180,031	4,665	58,931	63,915	82,862	106,247	177,344	(11,275)	662,720	
December 2016	180,031	75	58,931	63,889	82,862	106,247	318,320	(11,279)	799,076	
January 2017	184,545	76	60,316	64,144	84,939	108,910	452,943	(8,821)	947,052	
February 2017	184,545	10,577	60,316	64,133	84,939	108,910	464,268	(6,442)	971,246	
March 2017	184,545	76	60,316	64,227	84,939	108,910	(17,856)	(8,830)	476,327	
April 2017	184,545	75	60,316	64,229	84,939	108,910	205,849	(8,836)	700,027	
May 2017	184,535	2,155	60,316	64,263	84,939	108,920	110,645	(11,179)	604,594	
June 2017	184,539	75	60,316	64,259	84,939	108,916	77,341	(8,839)	571,546	
July 2017	184,545	863	60,316	64,274	84,939	108,910	135,090	(8,840)	630,097	
August 2017	184,545	1,612	60,316	65,793	84,939	108,910	149,397	(8,953)	646,559	
September 2017	184,545	75	60,316	65,816	84,939	108,910	134,411	(8,952)	630,060	
October 2017	184,545	75	60,317	66,480	84,939	108,910	169,995	(8,953)	666,308	
November 2017	184,545	633	60,317	66,492	84,939	108,910	400,425	(8,955)	897,306	
December 2017	184,545	215	60,317	68,420	84,939	108,910	301,469	(8,975)	799,840	
January 2018	162,196	1,328	59,551	65,646	76,794	52,363	256,049	(18,866)	655,061	
February 2018	162,196	1,675	59,551	65,643	76,794	52,363	1,180,338	(18,865)	1,579,695	
March 2018	162,196	202	59,551	65,649	76,794	52,363	272,897	(18,865)	670,787	
Forecast										
April 2018	\$ 162,196	\$ 88	\$ 59,551	\$ 65,640	\$ 76,794	\$ 52,363	\$ 222,904	\$ (18,866)	\$ 620,670	
May 2018	162,176	88	59,551	65,682	76,794	52,383	80,986	(18,873)	478,787	
June 2018	162,163	5,688	59,551	65,723	76,794	52,396	46,658	(18,882)	450,091	
July 2018	162,196	88	59,551	65,763	76,794	52,363	80,434	(18,888)	478,301	
August 2018	162,196	88	59,551	65,804	76,794	52,363	82,829	(18,895)	480,730	
September 2018	162,196	5,688	59,551	65,845	76,794	52,363	81,228	(18,904)	484,761	
October 2018 **	9,705	-	570	1,037	4,595	3,133	203,324	(2,370)	219,994	
November 2018 **	9,705	-	570	2,505	4,595	3,133	230,740	(2,644)	248,604	
December 2018 **	9,705	-	570	2,546	4,595	3,133	306,765	(2,652)	324,662	

* Revenue requirement includes projects and RTO revenue and expenses. Does not include carrying charge/credit.

** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.

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Response to Data Request ND-PSC-15.41
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/04/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting -
(218) 739-8298

Data Request:

Renewable Resource Adjustment Rider (RRAR). Refer to pages 23-24 of the direct testimony of Company witness Ackerman. Mr. Ackerman states that the 2018 test year rate base includes RRAR projects totaling \$101 million on a North Dakota jurisdictional basis, which are currently recovered through the RRAR.

- a. Please provide the actual monthly over/under RRAR balances from the period January 1, 2016 through March 31, 2018.
- b. Please provide the projected monthly over/under RRAR balances for the period April through December 2018.
- c. Provide the actual amount of RRAR revenue for each month, January 2016 through March 2018.
- d. Provide the expected amount of RRAR revenue for each month, April 2018 through December 2018.
- e. Provide the actual amount of RRAR costs, by account for each month, January 2016 through March 2018.
- f. Provide the expected amount of RRAR costs, by account, for each month, April 2018 through December 2018.

Attachments: 2

Attachment 1 to DR ND-PSC-15.41.pdf
Attachment 2 to DR ND-PSC-15.41.pdf

Public
Response to Data Request ND-PSC-15.41
Page 2 of 2

Response:

OTP provides Attachment 1 to DR ND-PSC-15.41 and Attachment 2 to DR ND-PSC-15.41. OTP proposes to move the three RRAR Projects out of the RRAR and into base rates concurrent with the implementation of final rates in this case. For the purposes of this response OTP anticipates final rates to be effective October 1, 2018.

Otter Tail Power Company
Summary of North Dakota Renewable Resource
Adjustment Rider

North Dakota Case No PU-17-398
Attachment 1 to DR ND-PSC-15.41
Page 1 of 1

	Net Revenue Requirement *	Actual Billed Revenue	REC Sales	(Over)/Under
Actual				
January 2016	\$ 744,774	\$ 516,648		\$ 228,125
February 2016	745,499	485,484		260,015
March 2016	674,947	449,057		225,890
April 2016	563,269	411,857		151,411
May 2016	620,627	354,330	\$ 60,333	205,964
June 2016	665,848	383,086		282,762
July 2016	758,056	745,371		12,686
August 2016	766,873	782,917		(16,044)
September 2016	650,634	785,386		(134,752)
October 2016	554,432	669,901		(115,469)
November 2016	605,070	760,163	105,957	(261,049)
December 2016	532,204	851,869		(319,665)
January 2017	574,125	1,004,180		(430,055)
February 2017	626,273	938,383		(312,110)
March 2017	586,659	839,470		(252,811)
April 2017	593,223	726,454		(133,231)
May 2017	578,772	615,527	34,800	(71,555)
June 2017	647,587	661,159		(13,572)
July 2017	792,202	669,828		122,374
August 2017	820,720	700,559		120,162
September 2017	609,242	694,255		(85,013)
October 2017	455,878	585,016		(129,137)
November 2017	525,111	752,888		(227,777)
December 2017	780,587	791,465		(10,878)
January 2018	672,030	999,685		(327,655)
February 2018	667,566	948,576		(281,010)
March 2018	691,490	832,161		(140,671)
Forecast				
April 2018	\$ 757,792	\$ 753,624		\$ 4,168
May 2018	681,705	685,258		(3,553)
June 2018	739,787	732,116		7,671
July 2018	766,676	800,440		(33,764)
August 2018	782,345	798,582		(16,237)
September 2018	739,257	775,339		(36,082)
October 2018	-	-		- **
November 2018	-	-		- **
December 2018	-	-		- **

* Revenue requirement does not include carrying charge/credit or REC sales.

** Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.

Otter Tail Power Company
Summary of North Dakota Renewable Resource Adjustment Rider Revenue Requirement

North Dakota Case No PU-17-398
Attachment 2 to DR ND-PSC-15.41
Page 1 of 1

	Net Income	O&Ms	Depreciation	Property Tax	Interest Expense	Income Tax	PTCs	ITCs	Net Revenue Requirement *
Actual									
January 2016	\$ 303,945	\$ 117,686	\$378,447	\$14,243	\$139,864	\$32,406	\$ (212,781)	\$ (29,035)	\$ 744,774
February 2016	303,945	109,097	378,447	14,243	139,864	35,927	(206,988)	(29,035)	745,499
March 2016	303,945	96,534	378,447	14,243	139,864	14,006	(243,056)	(29,035)	674,947
April 2016	303,945	116,402	378,447	14,243	139,864	(35,721)	(324,876)	(29,035)	563,269
May 2016	283,981	90,871	361,760	13,615	133,697	4,636	(240,178)	(27,755)	620,627
June 2016	283,981	97,104	361,744	13,615	133,697	19,380	(215,919)	(27,755)	665,848
July 2016	283,981	105,970	361,715	13,615	133,697	50,896	(164,062)	(27,755)	758,056
August 2016	283,981	111,285	361,715	13,615	133,697	52,220	(161,884)	(27,755)	766,873
September 2016	283,981	107,773	361,715	13,615	133,697	9,607	(231,999)	(27,755)	650,634
October 2016	283,981	80,866	361,324	13,615	133,697	(16,439)	(274,856)	(27,755)	554,432
November 2016	283,981	136,026	361,326	13,615	133,697	(18,149)	(277,670)	(27,755)	605,070
December 2016	283,981	102,628	361,844	13,615	133,697	(33,265)	(302,541)	(27,755)	532,204
January 2017	286,907	94,123	362,525	13,615	135,074	(15,014)	(275,350)	(27,755)	574,125
February 2017	286,907	132,720	362,525	13,615	135,074	(9,891)	(266,921)	(27,755)	626,273
March 2017	286,907	85,922	362,525	13,615	135,074	(7,176)	(262,454)	(27,755)	586,659
April 2017	286,907	123,984	362,525	13,615	135,074	(19,083)	(282,044)	(27,755)	593,223
May 2017	286,907	97,173	362,525	13,615	135,074	(14,410)	(274,357)	(27,755)	578,772
June 2017	286,907	97,313	362,269	13,615	135,074	11,647	(231,483)	(27,755)	647,587
July 2017	286,907	116,846	362,269	13,615	135,074	58,930	(153,683)	(27,755)	792,202
August 2017	286,907	86,885	362,268	13,615	135,074	81,036	(117,310)	(27,755)	820,720
September 2017	286,907	101,665	362,273	13,615	135,074	(4,495)	(258,042)	(27,755)	609,242
October 2017	286,907	102,554	362,273	13,615	135,074	(62,805)	(353,985)	(27,755)	455,878
November 2017	286,907	108,744	362,165	13,615	135,074	(38,933)	(314,706)	(27,755)	525,111
December 2017	286,907	116,718	362,345	13,615	135,074	54,558	(160,876)	(27,755)	780,587
January 2018	248,401	98,438	347,499	13,048	117,609	23,291	(149,657)	(26,600)	672,030
February 2018	248,401	90,109	347,499	13,048	117,609	24,234	(146,735)	(26,600)	667,566
March 2018	248,401	84,544	347,499	13,048	117,609	31,431	(124,442)	(26,600)	691,490
Forecast									
April 2018	\$ 248,401	\$ 162,928	\$347,499	\$13,048	\$117,609	\$28,482	\$ (130,769)	\$ (29,406)	\$ 757,792
May 2018	248,401	104,663	347,573	13,048	117,609	24,115	(144,297)	(29,406)	681,705
June 2018	248,401	101,901	347,573	13,048	117,609	38,964	(98,302)	(29,406)	739,787
July 2018	248,401	102,396	347,721	13,048	117,609	45,369	(78,461)	(29,406)	766,676
August 2018	248,401	112,100	347,721	13,048	117,609	46,825	(73,952)	(29,406)	782,345
September 2018	248,401	120,311	347,721	13,048	117,609	34,306	(112,732)	(29,406)	739,257
October 2018**	-	-	-	-	-	-	-	-	-
November 2018**	-	-	-	-	-	-	-	-	-
December 2018**	-	-	-	-	-	-	-	-	-

* Revenue requirement does not include carrying charge/credit or REC sales.

** Implementation of final rates. Any amounts (over)/under remaining at completion of rate case are expected to flow through the rider.

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

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/04/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Does the Company maintain an inventory of renewable energy credits (RECs)? If not, explain fully why not. If so, please show the following information by month from January 1, 2015 through March 31, 2018 for each type of REC: (1) quantity in inventory; (2) quantity acquired by purchase; (3) quantity acquired by generation; (4) cost of RECs purchased; (5) cost (if any is accounted for) of RECs generated; (6) cost of RECs sold; (7) quantity and proceeds from RECs sold.

Attachments: 0

Response:

Otter Tail generates RECs from renewable system resources (primarily wind) which are tracked in the Midwest Renewable Energy Tracking System (M-RETS). Otter Tail allocates RECs to each jurisdiction (MN, SD, ND) based on a monthly load-ratio calculation. Otter Tail maintains an inventory of ND allocated RECs which is currently done through the Renewable Resource Adjustment. Otter Tail sells ND allocated RECs and returns the proceeds to ND customers in accordance with the expectations of the ND Public Service Commission. To minimize administrative burden, Otter Tail sells RECs once or twice per year. The responses below are based on the North Dakota (not MN or SD) allocated RECs. The table includes RECs through December 2017. Not all of the RECs have been loaded into MRETS and the monthly allocations have not taken place yet for 2018.

- 1) For the inventory of RECs, see table below.
- 2) Otter Tail has not purchased any ND allocated RECs.
- 3) For RECs acquired by generation, see table below.
- 4) Otter Tail has not purchased any ND allocated RECs.
- 5) Otter Tail does not allocate any cost to RECs generated from its system resources.
- 6) Otter Tail does not allocate any cost to RECs sold from its system resources.
- 7) For the quantity and proceeds from RECs sold, see table below.

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Response to Data Request ND-PSC-15.46
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/03/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

During the period January 1, 2015 through March 31, 2018 did the Company retire any RECs? If so, identify the quantity of RECs by type retired in each month and indicate the reason for the retirements.

Attachments: 0

Response:

In April 2016, Otter Tail retired 176,948 RECs in the Midwest Renewable Energy Tracking System to demonstrate compliance with the ND Renewable Energy Objective for the year 2015 (10% of ND retail load). The retired RECs were wind RECs generated in the year 2014 and prior. Upon the direction of the ND PSC, Otter Tail has not retired any ND allocated RECs since April 2016. Rather, Otter Tail has sold ND allocated RECs and returned the proceeds to ND customers.

Public
Response to Data Request ND-PSC-15.42
Page 1 of 2

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

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/08/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Energy Adjustment Rider ("ECR"). Refer to the direct testimony of Company witness Tommerdahl at page 25.

- a. Show in detail how the \$0.024327 per kWh base cost of energy was calculated. Include complete supporting workpapers and Excel files, with formulas intact.
- b. Show exactly what costs from each FERC account and which revenues (if any) by FERC account were included in the numerator for calculating the \$0.024327 per kWh base cost of energy.
- c. Show in detail how the Company derived the denominator that was used to compute the \$0.024327 per kWh base cost of energy. Was that based on a sales forecast for some period? If so, identify the period and provide the forecast.
- d. Identify all fuel and purchased power costs by account that OTP proposes to transfer into the ECR.
- e. Identify all FERC accounts and sub-accounts that contain costs or revenues that the Company proposes to included and recover in the ECR.
- f. Would the Company's proposed ECR reflect any revenue from sales for resale? If not, explain fully why not. If so, explain fully and show how sales for resale revenue would be reflected.
- g. Would the Company's proposed ECR reflect any cost for environmental reagents? If so, explain fully and show how which specific reagent costs would be reflected.
- h. Would the Company's proposed ECR reflect any cost for emission allowances? If so, explain fully and show how which specific reagent costs would be reflected.

Attachments: 1

Attachment 1 to DR ND-PSC-15.42.xlsx

Public
Response to Data Request ND-PSC-15.42
Page 2 of 2

Response:

- a. OTP's Energy Adjustment Rider (EAR), Tariff Section 13.01, calculates costs based on the OTP Total System costs. OTP provided the calculation in its Initial Filing in Volume 1, Part E, Schedule 1. The Excel file for Volume 1, Part E, Schedule 1 was provided in response to DR ND-PSC-01.1.
- b. OTP provides Attachment 1 to DR ND-PSC-15.42.
- c. OTP provided the denominator in its Initial Filing in Volume 1, Part E, Schedule 1. The denominator is based on forecasted Total Company kWh sales for the 2018 Test Year.
- d. Please refer to OTP's response to part b of this request.
- e. Please refer to OTP's response to part b of this request. In addition to those components already included in the Energy Adjustment Rider, OTP proposes to include the costs for reagents and emission allowances. OTP provides the account information for reagents and emission allowances in response to DR ND-PSC-06.12 and ND-PSC-20.05.
- f. Yes. OTP proposes that Intersystem Sales be included in the calculation of the Energy Adjustment Rider and includes Intersystem Sales data in the details provided in Attachment 1 to DR ND-PSC-15.42.
- g. Yes. For administrative efficiency, OTP proposes to include the cost of reagents and emissions allowances, which are currently being recovered under the separate Reagents and Emissions Allowance Adjustment (REAA) Rider as detailed in Electric Rate Schedule 13.08, into the Energy Adjustment Rider. The REAA is computed using the exact same mechanism as the Energy Adjustment Rider and so the consolidation of these costs from two identical recovery mechanisms to one will have no bill impact. As noted in Mr. Tommerdahl's Supplemental Direct Testimony on pages 5 and 6, OTP also proposes that Coyote Station pebble lime reagent costs also be moved out of base rate recovery and into the EAR.
These costs would be included in the Energy and Renewable Adjustment amount displayed on the customer billing. The details of the adjustment calculation would be provided in the notice of change in the adjustment as required by ND Statute 69-09-02-39.
- h. Please refer to OTP's response to part g of this request.

Otter Tail Power Company
Base Cost of Energy

Line No.	Description	2018 Interim Test Year	Primary FERC	Secondary FERC	Description	Purchased Power	Generation Costs	MISO Schedules 16 & 17	Reagent & Emissions Allowances	Total
1	Purchased Power (Inclusive of MISO Market Purchases)	\$ 63,420,074				\$ 63,420,074				
2	Generation Costs	\$ 54,071,661								
3	Fuel Costs for Intersystem Sales	\$ (103,690)								
4	MISO Schedules 16 & 17	\$ 649,613								
5	Reagents & Emissions Allowances	\$ -								
6	Total Energy Costs	\$ 118,037,658								
400			400	447	Net Ancillary Services Market Revenue/Expenses	\$ 98,147	\$ 53,967,971	\$ 649,613	\$ -	\$ 118,037,658
401			401	501	Steam Power Generation - Fuel - Coyote-Lignite		\$ 21,745,748			
401			401	501	Steam Power Generation - Fuel - Coyote-Oil		\$ 294,766			
401			401	501	Steam Power Generation - Fuel - Big Stone-Subbituminous		\$ 24,654,643			
401			401	501	Steam Power Generation - Fuel - Big Stone-oil		\$ 257,985			
401			401	501	Steam Power Generation - Fuel - Hoot Lake-Subbituminous		\$ 6,786,500			
401			401	501	Steam Power Generation - Hoot Lake-Oil		\$ 30,590			
401			401	502	Steam Power Generation - Steam Expenses					
401			401	509	Steam Power Generation - Allowances					
401			401	547	Other Power Generation - Fuel - Jamestown CT					
401			401	547	Other Power Generation - Fuel - Lake Preston CT					
401			401	547	Other Power Generation - Fuel - Solway CT -LM6000					
401			401	501 or 547	Fuel Costs for Intersystem Sales	\$ 301,429	\$ (103,690)			
401			401	555	Purchased Power for System Use	\$ 46,732,600				
401			401	555	Other Energy Purchaes	\$ 16,589,327				
401			401	555	Schedule 16			\$ 21,830		
401			401	555	Schedule 17			\$ 627,783		

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Response to Data Request ND-PSC-01.16
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OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Sara Cardwell
Date Received: 11/29/2017
Date Due: 12/13/2017
Date of Response: 12/11/2017
Responding Witness: Robert B. Hevert, Partner, ScottMadden, Inc. (508) 202-7923

Data Request:

How much does the Company pay for the services of Mr. Hevert? Are stockholders and, or the corporate office paying some of the costs of Mr. Hevert's services? If the stockholders and, or the corporate office are not paying some of these costs, explain why the stockholders and corporate office shouldn't be paying for some of the costs of Mr. Hevert's involvement.

Attachments: 0

Response:

In OTP's recent Minnesota rate case, OTP incurred \$160,000 for the services of Mr. Hevert to testify (including direct, rebuttal, surrebuttal and respond to many information requests) to an appropriate return on equity. Mr. Hevert's fees are included in the rate case expense request at a set amount along with other consultants such as for the Marginal Cost Study and other administrative expenses. The amount of these expenses included in this rate case is the same amount as was included in OTP's last North Dakota rate case (PU-08-862). If the actual amount of these expenses exceeds the requested amount, stockholders will absorb any excess expenses. As a subsidiary of a holding company OTP has its own capital structure. The return on equity request is only for the OTP portion of equity. Determining an appropriate return on equity necessary to allow the Company reasonable access to capital is a function of funding the investments necessary to provide utility service. Without a sufficient level of return, the Company would not be able to access capital at reasonable rates. Stockholders provide capital if sufficient return is offered; it is incumbent on the parties seeking to utilize capital to determine what rate is sufficient to incentivize investment.

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

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/27/2018

Date Due: 05/11/2018

Date of Response: 05/11/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Refer to the Supplemental Direct Testimony of Tyler Akerman at page 7 and to the Tommerdahl Direct Testimony at pages 17-21.

- a. Identify and provide the most current CISone implementation schedule.
- b. Identify and explain any revisions to the CISone implementation schedule that occurred in 2017 and 2018.
- c. Is the Company accruing AFUDC on the CISone project? If not, explain fully why not. If so, identify the AFUDC amounts (broken out between equity and debt AFUDC) by month from the inception to date (actual) and estimated for the remaining months until the CISone goes into operation.
- d. Was the CISone project approved by the OTP board or executive management? If not, explain fully why not. If so, identify and provide the documentation related to the approval of the CISone project.
- e. What was the original approved budget for the CISone project?
- f. Did the Company experience any cost overruns on the CISone project? If so, identify, quantify and explain the cost overruns.
- g. Does the CISone project replace any assets that were recorded on OTP's books as of January 1, 2018? If so, which assets are being replaced, what is the January 1, 2018 amount of each by account.
- h. Have the assets that are being replaced by the CISone been removed from rate base?
- i. Is the Company anticipating any cost savings related to the CISone project? If not, explain fully why not. If so, identify, quantify and explain the cost savings.
- j. Has the Company reflected any savings associated with the CISone project? If so, identify the amounts of savings and explain how they were reflected. If not, explain fully why not.
- k. What is the anticipated useful life of the CISone project?
- l. Show in detail how the anticipated useful life of the CISone project determined.
- m. Has the Company's 2018 test year based revenue requirement request included any rental, maintenance or other costs related to the systems that are being replaced by the CISone? If so, identify the amounts by account, and for OTP total and OTP North Dakota.

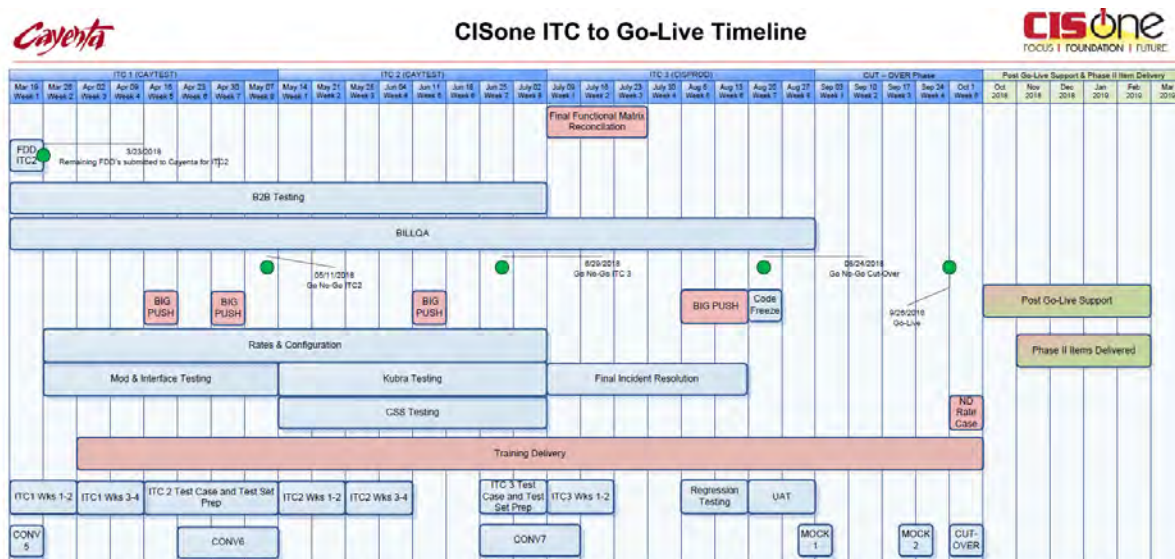
Attachments: 2

Attachment 1 to DR ND-PSC-19.04.xlsx

Attachment 2 to DR ND-PSC-19.04.pdf

Response:

- a. The project team’s current schedule (see below) reflects implementation taking place at the end of September 2018, with operation to commence on October 1, 2018. As indicated in the Direct Testimony of Stuart D. Tommerdahl, at page 19, “[i]mplementation will only occur after CISone has been fully tested to confirm that OTP’s customer billings will be accurately and correctly computed and accounted for.”



- b. The original schedule created in mid-2015 estimated the CISone project to go-live in Q1 2018. Later the projected go-live date was moved to Q3 2018 to address the complexity associated with integrating the Cayenta product into OTP’s decades-old legacy customer information system.
- c. Yes. See Attachment 1 to DR ND-PSC-19.04.
- d. Yes. Attachment 2 to DR ND-PSC-19.04 are the August 17, 2015 meeting minutes and resolution in which the Otter Tail Power Company board of directors originally authorized entering into vendor agreements, staffing and completing the work of the project.
- e. The project was originally estimated to cost approximately \$16 million in 2015 dollars, as identified in the Attachment 2 to DR ND-PSC-19.04.

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- f. Through March 2018, \$11.851 million has been spent on the project. The total amount spent on the project will depend on the duration required to complete the integration of the Cayenta system with OTP's legacy systems, testing, etc. The project team expects to incur costs over the 2015 original estimate associated with the time needed to complete integration and testing. This is largely due to the archaic architecture of the 30-year old legacy customer information system that is being replaced. The current estimated cost to complete integration, testing and post-go-live activities is an amount up to \$17,850,000. The amount could be less depending on integration testing outcomes. As indicated in Mr. Tommerdahl's Direct Testimony, Otter Tail will keep the Commission informed of the project's progress and will update the record during this case.
- g. No.
- h. N/A
- i. OTP does not anticipate immediate cost savings from the system. In the future we anticipate that the automation of many of the functions by the new system will result in time savings over manual processes that exist today. However, the system will add tasks for functions that the current 30-year old legacy system cannot perform today. Rather than drive cost savings, the CISone project is intended to provide a modern platform for services and conveniences that customers have grown to expect from their service providers. For example, in the future, customers will realize more options with rates, as the system is capable of interfacing with future automated meter infrastructure (AMI). The system will also provide a platform for an outage management system (OMS) to assist with outage information and restoration times. The benefits of the system are described by Mr. Stuart at p.18 of his Direct Testimony.
- j. OTP has not yet seen the impacts of any cost changes with the implementation of Cayenta Utilities. As described above, it is expected that future technology projects, that are made possible by adding the CISone platform, will give OTP the ability to drive organizational change and subsequently provide efficiencies that don't exist today.
- k. Otter Tail is proposing a 10-year depreciable life as described in OTP's March 23, 2018 Supplemental filing.
- l. Significant software projects such as CISone are intended to have a longer useful life. Therefore, a 10-year life was determined to be the most reasonable. Future upgrades/capital investment in the system may allow a longer life, at which time, depreciation rates would be adjusted as needed.
- m. No.

Item Date	Receiver	GL Date	Project	Task	Quantity	Comment	Expend Org	Trans Id
30-Sep-15		30-Sep-15	105660	4	16354.16	Project AFUDC Calculation	0260 IT Operations	9845257
30-Sep-15		30-Sep-15	105660	4	16354.16	Project AFUDC Calculation	0260 IT Operations	9845495
31-Oct-15		31-Oct-15	105660	4	40259.74	Project AFUDC Calculation	0260 IT Operations	9983682
31-Oct-15		31-Oct-15	105660	4	\$ 205	ALLOCAFEU-Allow for Funds-Equi	0260 IT Operations	9983933
30-Nov-15		30-Nov-15	105660	4	\$ 202	ALLOCAFEU-Allow for Funds-Equi	0260 IT Operations	10241351
30-Nov-15		30-Nov-15	105660	4	\$ 369	ALLOCAFEU-Allow for Funds-Equi	0260 IT Operations	10241577
31-Dec-15		31-Dec-15	105660	4	\$ 342	ALLOCAFEU-Allow for Funds-Equi	0260 IT Operations	10431382
31-Dec-15		31-Dec-15	105660	4	\$ 631	ALLOCAFEU-Allow for Funds-Equi	0260 IT Operations	10431582
31-Jan-16		31-Jan-16	105660	4	\$ 445	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	10487774
31-Jan-16		31-Jan-16	105660	4	\$ 706	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	10487903
29-Feb-16		29-Feb-16	105660	4	\$ 1,252	ALLOCAFEU-Allow for Funds-Equi	0260 IT Operations	10548300
29-Feb-16		29-Feb-16	105660	4	\$ 1,937	ALLOCAFEU-Allow for Funds-Equi	0260 IT Operations	10548464
31-Mar-16		31-Mar-16	105660	4	\$ 2,424	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	10604438
31-Mar-16		31-Mar-16	105660	4	\$ 3,679	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	10604493
30-Apr-16		30-Apr-16	105660	4	\$ 3,139	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	10668518
30-Apr-16		30-Apr-16	105660	4	\$ 5,122	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	10668636
31-May-16		31-May-16	105660	4	\$ 3,153	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	10729467
31-May-16		31-May-16	105660	4	\$ 5,165	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	10729601
30-Jun-16		30-Jun-16	105660	4	\$ 3,688	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	10797405
30-Jun-16		30-Jun-16	105660	4	\$ 6,105	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	10797466
31-Jul-16		31-Jul-16	105660	4	\$ 8,060	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	10862405
31-Jul-16		31-Jul-16	105660	4	\$ 4,615	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	10862494
31-Aug-16		31-Aug-16	105660	4	\$ 4,707	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	10926491
31-Aug-16		31-Aug-16	105660	4	\$ 9,143	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	10926611
30-Sep-16		30-Sep-16	105660	4	\$ 5,190	ALLOCAFEU-Allow for Funds-Equi	0100 Bemidji Customer Service Center	10997171
30-Sep-16		30-Sep-16	105660	4	\$ 10,667	ALLOCAFEU-Allow for Funds-Equi	0100 Bemidji Customer Service Center	10997394
31-Oct-16		31-Oct-16	105660	4	\$ 6,239	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	11060089
31-Oct-16		31-Oct-16	105660	4	\$ 12,502	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	11060169
30-Nov-16		30-Nov-16	105660	4	\$ 7,064	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11126804
30-Nov-16		30-Nov-16	105660	4	\$ 14,289	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11126979
31-Dec-16		31-Dec-16	105660	4	\$ 9,272	ALLOCAFEU-Allow for Funds-Equi	0040 Morris Customer Service Center	11221450
31-Dec-16		31-Dec-16	105660	4	\$ 18,638	ALLOCAFEU-Allow for Funds-Equi	0040 Morris Customer Service Center	11221675
31-Dec-16		31-Dec-16	105660	4	\$ (9,272)	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	11222995
31-Dec-16		31-Dec-16	105660	4	\$ (18,638)	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	11223259
31-Dec-16		31-Dec-16	105660	4	\$ 18,638	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11224320
31-Jan-17		31-Jan-17	105660	4	\$ 9,678	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11224387
31-Jan-17		31-Jan-17	105660	4	\$ 13,230	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11284614
28-Feb-17		28-Feb-17	105660	4	\$ 11,268	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11284769
28-Feb-17		28-Feb-17	105660	4	\$ 14,871	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	11355781
31-Mar-17		31-Mar-17	105660	4	\$ 12,658	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	11355913
31-Mar-17		31-Mar-17	105660	4	\$ 17,796	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11429905
30-Apr-17		30-Apr-17	105660	4	\$ 13,322	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11429972
30-Apr-17		30-Apr-17	105660	4	\$ 18,702	ALLOCAFEU-Allow for Funds-Equi	0160 CISone	11497852
31-May-17		31-May-17	105660	4	\$ 15,723	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	11497980
31-May-17		31-May-17	105660	4	\$ 15,723	ALLOCAFEU-Allow for Funds-Equi	0300 Asset Management Support	11580249

Item Date	Receiver GL Date	Project Task	Quantity	Comment	Expend Org	Trans Id
31-May-17	31-May-17	105660	4	\$ 19,052 ALLOCATEU-Allow for Funds-Equi	0300 Asset Management Support	11580359
30-Jun-17	30-Jun-17	105660	4	\$ 17,477 ALLOCATEU-Allow for Funds-Debt	0300 Asset Management Support	11659666
30-Jun-17	30-Jun-17	105660	4	\$ 21,387 ALLOCATEU-Allow for Funds-Equi	0300 Asset Management Support	11659894
31-Jul-17	31-Jul-17	105660	4	\$ 18,551 ALLOCATEU-Allow for Funds-Debt	0160 CIsone	11734190
31-Jul-17	31-Jul-17	105660	4	\$ 23,140 ALLOCATEU-Allow for Funds-Equi	0160 CIsone	11734306
31-Aug-17	31-Aug-17	105660	4	\$ 24,243 ALLOCATEU-Allow for Funds-Debt	1690 Wind Generation - Development	11821539
31-Aug-17	31-Aug-17	105660	4	\$ 28,546 ALLOCATEU-Allow for Funds-Equi	1690 Wind Generation - Development	11821800
30-Sep-17	30-Sep-17	105660	4	\$ 25,084 ALLOCATEU-Allow for Funds-Debt	0160 CIsone	11895220
30-Sep-17	30-Sep-17	105660	4	\$ 31,871 ALLOCATEU-Allow for Funds-Equi	0160 CIsone	11895474
31-Oct-17	31-Oct-17	105660	4	\$ 26,118 ALLOCATEU-Allow for Funds-Debt	0300 Asset Management Support	11977459
31-Oct-17	31-Oct-17	105660	4	\$ 34,374 ALLOCATEU-Allow for Funds-Equi	0300 Asset Management Support	11977673
30-Nov-17	30-Nov-17	105660	4	\$ 25,500 ALLOCATEU-Allow for Funds-Debt	0300 Asset Management Support	12062138
30-Nov-17	30-Nov-17	105660	4	\$ 41,364 ALLOCATEU-Allow for Funds-Equi	0300 Asset Management Support	12062160
31-Dec-17	31-Dec-17	105660	4	\$ 28,277 ALLOCATEU-Allow for Funds-Debt	0300 Asset Management Support	12139907
31-Dec-17	31-Dec-17	105660	4	\$ 43,012 ALLOCATEU-Allow for Funds-Equi	0300 Asset Management Support	12139930
31-Jan-18	31-Jan-18	105660	4	\$ 24,699 ALLOCATEU-Allow for Funds-Debt	0160 CIsone	12211622
31-Jan-18	31-Jan-18	105660	4	\$ 46,784 ALLOCATEU-Allow for Funds-Equi	0160 CIsone	12211656
28-Feb-18	28-Feb-18	105660	4	\$ 26,223 ALLOCATEU-Allow for Funds-Debt	0160 CIsone	12284159
28-Feb-18	28-Feb-18	105660	4	\$ 49,501 ALLOCATEU-Allow for Funds-Equi	0160 CIsone	12284164
31-Mar-18	31-Mar-18	105660	4	\$ 27,257 ALLOCATEU-Allow for Funds-Debt	1690 Wind Generation - Development	12357227
31-Mar-18	31-Mar-18	105660	4	\$ 50,134 ALLOCATEU-Allow for Funds-Equi	1690 Wind Generation - Development	12357257
				<u>\$908,792</u>		

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Year	Month	Debt	Equity	Month Total	Accumulated	
2015	September	\$44.12	\$80.93	\$125.05	\$125.05	Actual
2015	October	\$112.34	\$205.04	\$317.38	\$442.43	Actual
2015	November	\$201.95	\$369.04	\$570.99	\$1,013.42	Actual
2015	December	\$341.60	\$631.46	\$973.06	\$1,986.48	Actual
2016	January	\$444.70	\$706.39	\$1,151.09	\$3,137.57	Actual
2016	February	\$1,251.75	\$1,936.58	\$3,188.33	\$6,325.90	Actual
2016	March	\$2,423.83	\$3,678.66	\$6,102.49	\$12,428.39	Actual
2016	April	\$3,139.47	\$5,121.92	\$8,261.39	\$20,689.78	Actual
2016	May	\$3,153.29	\$5,165.03	\$8,318.32	\$29,008.10	Actual
2016	June	\$3,687.56	\$6,105.23	\$9,792.79	\$38,800.89	Actual
2016	July	\$8,060.07	\$4,615.46	\$12,675.53	\$51,476.42	Actual
2016	August	\$4,707.29	\$9,142.96	\$13,850.25	\$65,326.67	Actual
2016	September	\$5,189.62	\$10,667.41	\$15,857.03	\$81,183.70	Actual
2016	October	\$6,238.50	\$12,501.99	\$18,740.49	\$99,924.19	Actual
2016	November	\$7,064.11	\$14,289.31	\$21,353.42	\$121,277.61	Actual
2016	December	\$9,272.48	\$18,638.31	\$27,910.79	\$149,188.40	Actual
2017	January	\$9,677.65	\$13,229.80	\$22,907.45	\$172,095.85	Actual
2017	February	\$11,268.14	\$14,870.59	\$26,138.73	\$198,234.58	Actual
2017	March	\$12,657.56	\$17,795.84	\$30,453.40	\$228,687.98	Actual
2017	April	\$13,321.96	\$18,702.44	\$32,024.40	\$260,712.38	Actual
2017	May	\$15,723.10	\$19,051.91	\$34,775.01	\$295,487.39	Actual
2017	June	\$17,476.70	\$21,387.21	\$38,863.91	\$334,351.30	Actual
2017	July	\$18,550.66	\$24,140.06	\$42,690.72	\$377,042.02	Actual
2017	August	\$23,242.83	\$28,546.03	\$51,788.86	\$428,830.88	Actual
2017	September	\$25,084.21	\$31,871.21	\$56,955.42	\$485,786.30	Actual
2017	October	\$26,117.89	\$34,374.05	\$60,491.94	\$546,278.24	Actual
2017	November	\$25,499.74	\$41,364.30	\$66,864.04	\$613,142.28	Actual
2017	December	\$28,276.81	\$43,012.29	\$71,289.10	\$684,431.38	Actual
2018	January	\$24,699.36	\$46,783.50	\$71,482.86	\$755,914.24	Actual
2018	February	\$26,223.03	\$49,500.59	\$75,723.62	\$831,637.86	Actual
2018	March	\$27,257.02	\$50,134.38	\$77,391.40	\$909,029.26	Actual
2018	April	\$25,559.00	\$36,857.00	\$62,416.00		Budget
2018	May	\$26,494.00	\$38,206.00	\$64,700.00		Budget
2018	June	\$27,077.00	\$39,046.00	\$66,123.00		Budget
2018	July	\$13,684.00	\$19,733.00	\$33,417.00		Budget

**REGULAR MEETING
BOARD OF DIRECTORS
OTTER TAIL POWER COMPANY
AUGUST 17, 2015**

A regular meeting of the Board of Directors of Otter Tail Power Company was held on Monday, August 17, 2015 at 8:30 a.m. in the Fargo office of Otter Tail Corporation, 4334 18th Avenue SW, Suite 200, Fargo, North Dakota.

The following Directors were present:

Chuck MacFarlane	Timothy Rogelstad
Kevin Moug	John Abbott
George Koeck	

Also present for all or a part of the meeting were:

Paul Knutson Vice President, Human Resources, Otter Tail Corporation
Cris Oehler, Vice President, Corporate Communications, Otter Tail Corporation and
Vice President, Public Relations, Otter Tail Power Company
Jennifer O. Smestad, General Counsel and Secretary, Otter Tail Power Company
Rodney C.H. Scheel, Vice President, IT and Special Projects
Heidi Konynenbelt, Manager, Computer Systems
Matt Bucher, Senior Project Manager

Chuck MacFarlane served as Chairman and Jennifer Smestad served as Secretary. Mr. MacFarlane announced a quorum was present for the transaction of the business of the Board of Directors of Otter Tail Power Company.

Timothy Rogelstad, President, Otter Tail Power Company, introduced CISone Project Team members. Rodney C.H. Scheel, Vice President, IT and Special Projects, Otter Tail Power Company introduced the CISone Project and goals for the presentation. Heidi Konynenbelt, Manager, Computer Systems, Otter Tail Power Company provided the members of the Board with an overview of the Project budget and schedule. She reviewed the capabilities that will be built into the system, including mobile work management, batch scheduling and electronic customer interface. She reviewed the bidding and vendor selection process utilized by Otter Tail Power Company and provided a cost-benefit analysis of the CISone Project. Completion of the Project is expected in 2018. Ms. Konynenbelt, Messrs. Scheel and Rogelstad responded to numerous questions from the Board. Following a robust discussion, and upon a motion and second, the Board of Directors passed the following resolution:

**RESOLUTION OF
OTTER TAIL POWER COMPANY
BOARD OF DIRECTORS
AUTHORIZING THE CONVERSION AND INSTALLATION OF A NEW CUSTOMER
INFORMATION SYSTEM
August 17, 2015**

WHEREAS, Otter Tail Power Company is in the beginning stages of a three-year Customer Information System Project (the "CISone Project") to replace its Customer Information System ("CIS"). The current CIS is twenty-nine (29) years old and has limited capabilities.

WHEREAS, over the past year, Otter Tail Power Company has undertaken an extensive bidding and evaluation effort and has now selected a vendor for the CISone Project for the planning, data conversion, configuration, testing, training, installation and implementation of the CISone Project.

NOW, THEREFORE, BE IT RESOLVED that, subject to the approval of the Otter Tail Corporation Board of Directors, the Otter Tail Power Company Board of Directors does hereby authorize any one or more of the following individuals: Chuck MacFarlane and Timothy Rogelstad or their designees (the "Authorized Officers") to take the necessary steps to enter into the CISone Project vendor agreements to install and implement the CISone Project, provided, in the opinion of such Authorized Officers, it remains in the best interest of Otter Tail Power Company to do so.

BE IT FURTHER RESOLVED that the CISone Project development costs incurred to date of approximately Six Hundred Twenty Thousand Dollars (\$620,000), with a forecasted additional spend of approximately Three Hundred Fifty Thousand Dollars (\$350,000) through the date the CISone Project vendor agreements are anticipated to be signed in fourth quarter 2015, are hereby approved and those spent to date are ratified as prudent and reasonably incurred.

BE IT FURTHER RESOLVED that, subject to the approval of the Otter Tail Corporation Board of Directors, the Authorized Officers be, and they hereby are, authorized to spend up to an additional amount of Fourteen Million Nine Hundred Thousand Dollars (\$14,900,000) (in 2015 dollars) to be incurred through 2018 for the conversion, installation and implementation of the CISone Project.

BE IT FURTHER RESOLVED that, subject to the approval of the Otter Tail Corporation Board of Directors, the Authorized Officers be, and they hereby are, authorized to prepare and execute any and all such further agreements, in addition to those hereinabove mentioned, in the name and on behalf of the Otter Tail Power Company, to make any and all payments, to obtain

and employ persons whose services may be necessary or desirable and to do and perform, or cause to be done and performed, any and all such other acts and things as such Authorized Officers, or any of them, may deem necessary or advisable in connection with the planning, data conversion, configuration, testing, training, installation and implementation of the CISone Project in order to carry out the purposes and intent of the foregoing resolutions.

There being no further business to come before the Board of Directors, the meeting was adjourned.

Dated: November 12, 2015.



Chuck MacFarlane, Board Chair



Jennifer O. Smestad, Secretary

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Page 1 of 1

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/20/2018
Date Due: 05/04/2018
Date of Response: 05/04/2018
Responding Witness: Bruce Gerhardson, Vice President, Regulatory Affairs

Data Request:

Capital Additions. Refer to the direct testimony of Company witness Bruce Gerhardson. On page 6 of his testimony, Mr. Gerhardson states that OTP expects to have capital expenditures of \$821 million on a total Company basis between 2017 and 2021.

- a. Of the \$821 million of expected capital expenditures between 2017-2021, please quantify and explain the amount of capital expenditures included in the Company's 2018 test year filing.
- b. Provide a breakout by plant account, amount, and expected in-service date of the capital expenditures included in the Company's 2018 test year filing.

Attachments: 1

Attachment 1 to DR ND-PSC-15.34.xlsx

Response:

Please see Attachment 1 to DR ND-PSC-15.34. OTP does not forecast projects by plant account so the functional classifications have been provided.

Business Segment W	Fund Proj Number	Work Order Long Desc	Est In Service Date	Total
Distribution	4449	Bemidji - General Distribution - Relocate	12/20/2018	\$21,535.00
Distribution	4451	Bemidji - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$58,143.00
Distribution	4499	Fergus Falls - General Distribution - Reliability	12/20/2018	\$72,702.00
Distribution	4502	Fergus Falls - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$35,181.00
Distribution	4507	Jamestown - General Distribution - Reliability	12/20/2018	\$39,978.00
Distribution	4508	Jamestown - General Distribution - Relocate	12/20/2018	\$24,659.00
Distribution	4520	Wahpeton (Jamestown) - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$14,820.00
Distribution	4532	Wahpeton - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$22,574.00
Distribution	4560	Morris - General Distribution - Voltage Capacity	12/20/2018	\$44,526.00
Distribution	D05014.028	Sisseton-Replace Dangerous Solid Copper, Rotten Crossarms and Poles	6/30/2018	\$22,500.00
Distribution	D05033.028	Voltage Regulator Purchases (2018)	12/20/2018	\$800,000.00
Distribution	D05048.048	Storm Work Order - Distribution - 41.6 kV & Below	12/20/2018	\$610,000.00
Distribution	D06033.028	Distribution Substation Transformer Purchases (2018)	12/21/2018	\$900,000.00
Distribution	4467	Rugby - General Distribution - New Load	12/20/2018	\$689,661.00
Distribution	4501	Fergus Falls - General Distribution - Replace	12/20/2018	\$239,739.00
Distribution	4516	Wahpeton (Jamestown) - General Distribution - Reliability	12/20/2018	\$26,650.00
Distribution	4526	Wahpeton - General Distribution - Reliability	12/20/2018	\$44,837.00
Distribution	4547	Milbank - General Distribution - Replace	12/20/2018	\$118,026.00
Distribution	4553	Morris - General Distribution - New Load	12/20/2018	\$1,460,951.00
Distribution	4557	Morris - General Distribution - Relocate	12/20/2018	\$23,821.00
Distribution	D05014.037	Milbank CSC-Replace Remaining Unsafe Underground Facilities	8/31/2018	\$14,050.00
Distribution	D05014.098	Lake Norden-Replace Unsafe Copper-Out of Sag-Unrepairable	8/31/2018	\$15,000.00
Distribution	4448	Bemidji - General Distribution - Reliability	12/20/2018	\$25,123.00
Distribution	4455	Crookston - General Distribution - Relocate	12/20/2018	\$23,201.00
Distribution	4457	Crookston - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$15,513.00
Distribution	4469	Rugby - General Distribution - Relocate	12/20/2018	\$22,419.00
Distribution	4541	Milbank - General Distribution - Reliability	12/20/2018	\$26,160.00
Distribution	D02010.183	Bemidji:3 Sub Design w/ Express Feeders & Source Transfer (2013-23)	12/1/2023	\$650,000.00
Distribution	D05002.027	Starkweather - Replace Substation (2017-2018)	10/30/2018	\$110,000.00
Distribution	D05004.038	Herman-Replace Dangerous Solid Copper, Rotten Crossarms and Poles	6/30/2018	\$22,500.00
Distribution	D05048.058	Motor Operators / SCADA - Proactive Replacement	12/20/2018	\$115,000.00
Distribution	4445	Bemidji - General Distribution - New Load	12/20/2018	\$1,107,772.00
Distribution	4454	Crookston - General Distribution - Reliability	12/20/2018	\$28,503.00
Distribution	4461	Devils Lake - General Distribution Reliability	12/20/2018	\$38,925.00
Distribution	4465	Devils Lake - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$22,732.00
Distribution	4528	Wahpeton - General Distribution - Relocate	12/20/2018	\$22,574.00
Distribution	4538	Milbank - General Distribution - New Load	12/20/2018	\$780,873.00
Distribution	4555	Morris - General Distribution - Reliability	12/20/2018	\$33,472.00
Distribution	4864	Install distribution cap banks across the system	6/3/2018	\$75,000.00
Distribution	D05048.038	Foundation/Frost - Proactive Replacement 2018	12/1/2018	\$150,000.00
Distribution	D05048.068	Remove Abandoned Facilities (2018)	10/30/2018	\$30,000.00
Distribution	D06031.018	Voltage Support - 1500 KVAR at Barrett	12/15/2018	\$40,000.00
Distribution	D06031.028	Capacitor Banks at Turtle Lake - 600 KVAR	7/1/2018	\$20,000.00
Distribution	4453	Crookston - General Distribution - New Load	12/20/2018	\$826,383.00
Distribution	4464	Devils Lake - General Distribution Replace	12/20/2018	\$146,045.00
Distribution	4471	Rugby - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$20,549.00
Distribution	4549	Milbank - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$16,349.00
Distribution	D03033.028	OCR Changeout Program (2018)	12/20/2018	\$120,000.00
Distribution	D05004.037	Morris CSC-Replace Remaining Unsafe Underground Facilities	9/30/2018	\$26,000.00
Distribution	4470	Rugby - General Distribution - Replace	12/20/2018	\$126,411.00
Distribution	4505	Jamestown - General Distribution - New Load	12/20/2018	\$864,336.00
Distribution	4518	Wahpeton (Jamestown) - General Distribution - Relocate	12/20/2018	\$16,439.00
Distribution	4519	Wahpeton (Jamestown) - General Distribution - Replace	12/20/2018	\$93,030.00
Distribution	5352	Fergus Falls Area-Replace Steel Distribution Wire (2021)	6/30/2021	\$24,900.00
Distribution	D05014.078	Browns Valley-Replace Rotten Poles and Crossarm	4/30/2018	\$20,000.00
Distribution	D05014.088	Peever-Replace Dangerous Solid Copper, Rotten Crossarms and Poles	7/31/2018	\$22,500.00
Distribution	D05048.028	Underground Primary - Proactive Replacement (2018)	12/20/2018	\$575,000.00
Distribution	4456	Crookston - General Distribution - Replace	12/20/2018	\$122,636.00
Distribution	4460	Devils Lake - General Distribution New Load	12/20/2018	\$860,709.00
Distribution	4468	Rugby - General Distribution - Reliability	12/20/2018	\$33,158.00
Distribution	4476	Rush Otter/Ottertail City-Rebuild/Reconductor	7/31/2022	\$124,400.00
Distribution	4500	Fergus Falls - General Distribution - Relocate	12/20/2018	\$38,916.00
Distribution	4512	Jamestown - General Distribution - Voltage Capacity (Increase)	12/20/2018	\$22,231.00
Distribution	4529	Wahpeton - General Distribution - Replace	12/20/2018	\$129,682.00
Distribution	4559	Morris - General Distribution - Replace	12/20/2018	\$137,937.00
Distribution	D04009.028	Great Bend Rural - Distribution Improvements	10/30/2018	\$50,000.00
Distribution	D05004.048	Boyd - Replace Rotten Poles Throughout the Town	7/30/2018	\$22,710.00
Distribution	4450	Bemidji - General Distribution - Replace	12/20/2018	\$123,107.00
Distribution	4462	Devils Lake - General Distribution Relocate	12/20/2018	\$26,156.00
Distribution	4496	Fergus Falls - General Distribution - New Load	12/20/2018	\$2,120,905.00
Distribution	4509	Jamestown - General Distribution - Replace	12/20/2018	\$139,549.00
Distribution	4515	Wahpeton (Jamestown) - General Distribution - New Load	12/20/2018	\$576,217.00
Distribution	4523	Wahpeton - General Distribution - New Load	12/20/2018	\$726,895.00
Distribution	4546	Milbank - General Distribution - Relocate	12/20/2018	\$20,242.00
Distribution	D03031.048	T&D Unallocated Funds (2018)	12/20/2018	\$2,000,000.00
Distribution	D05004.028	Hancock-Replace Dangerous Solid Copper, Rotten Crossarms and Poles	6/30/2018	\$22,500.00
Distribution	D05014.048	Elkton Sub#7903-Raise the Distribution Bus to Regulation Heights	5/31/2018	\$20,000.00
Total Distribution				\$18,875,012.00
General Plant	4363	Replace Unit #614 with 48 FT ABMH	10/31/2019	\$61,486.00
General Plant	4365	Replace Unit # 2015 with a Car	10/31/2018	\$27,323.00
General Plant	4377	Replace Unit # 44 with a All Wheel Drive Crossover Vehicle	10/31/2019	\$35,323.00
General Plant	4444	Communications Tower - new or replacement	12/15/2022	\$220,000.00
General Plant	D03031.058	General Unallocated Funds (2018)	12/20/2018	\$478,952.00
General Plant	G07199.028	Replace Unit #545 w/4x4 ABMH 37'	10/31/2018	\$153,086.00

General Plant	G07199.108	Replace Unit #540 with 4x4 Flatbed One Ton Dually	10/31/2018	\$56,186.00
General Plant	G07199.168	Replace Unit # 903 with a 4X4 Cargo Van Equipped for Communication Tech	10/31/2018	\$58,336.00
General Plant	I03026.015	Customer Information System Project (CISone) (2016-18)	10/1/2018	\$4,474,717.40
General Plant	5427	Telephone System Replacement (2019) - Crookston and Bemidji phone system to the Mitel system	11/8/2019	\$110,000.00
General Plant	G03026.028	Server Purchases and Replacements (2018)	12/17/2018	\$46,000.00
General Plant	G04034.028	Network Equipment Purchases and Replacements (2018)	12/17/2018	\$200,000.00
General Plant	G05033.028	Asset Management Tool Budget (2018)	12/20/2018	\$150,000.00
General Plant	G07199.148	Replace Unit #622 with 4x4 UB Pickup	10/31/2018	\$61,486.00
General Plant	G07199.258	Replace Unit #577 with 4x4 UB Pickup	10/31/2018	\$57,000.00
General Plant	G07199.268	Replace Unit # 241 with 4x4 Flatbed One Ton Dually	10/31/2018	\$56,186.00
General Plant	4380	Replace Unit # 358 with 4x4 Pickup	10/31/2020	\$45,323.00
General Plant	4416	CSC Roof Replacement (2018)	12/20/2020	\$100,000.00
General Plant	G03026.038	PC Life Cycle Replacements (2018)	12/17/2018	\$150,000.00
General Plant	G05199.028	Transportation Department Tool Budget (2018)	12/15/2018	\$20,000.00
General Plant	G07199.018	Replace Unit #522 with 4x4 ABMH 37'	10/31/2018	\$145,000.00
General Plant	G07199.048	Replace Unit #547 w/4x4 ABMH 37'	10/31/2018	\$153,086.00
General Plant	G07199.058	Replace Unit #532 with 4x4 ABMH	10/31/2018	\$146,000.00
General Plant	G07199.068	Replace Unit #804 w/4x4 ABMH 37' Truck	10/31/2018	\$153,086.00
General Plant	G07199.118	Replace Unit # 558 with 4x4 UB Pickup	10/31/2018	\$61,486.00
General Plant	G07199.308	Replace Unit #535 with a 4X4 Cargo Van Equipped for Electrical Tech	10/31/2018	\$61,486.00
General Plant	G07199.318	Replace Unit # 623 with 4x4 Extended Cab Pickup	10/31/2018	\$38,823.00
General Plant	G07199.338	Replace CSC Trailers for Service Reps	10/31/2018	\$26,343.00
General Plant	G08053.308	Facility Equipment- System wide	12/20/2018	\$10,000.00
General Plant	G08053.318	Capital Projects OTP Facilities (ASB Roof)	12/20/2018	\$225,000.00
General Plant	5382	IDMS 1 Easement Project	12/17/2018	\$160,000.00
General Plant	G07199.098	Replace Unit #612 with 4x4 UB Pickup	10/31/2018	\$61,486.00
General Plant	G07199.188	Cargo Cable Trailer for Lake Preston, SD	11/1/2018	\$16,500.00
General Plant	G07199.218	Replace Unit #611 with 4x4 UB Pickup	10/31/2018	\$61,486.00
General Plant	G07199.238	Replace Unit #901 with 4x4 Cargo Van	10/31/2018	\$61,500.00
General Plant	G07199.278	Replace Unit #573 with 4x4 UB Pickup	10/31/2018	\$61,486.00
General Plant	G07199.378	Replace Unit #616 with Pickup	10/31/2018	\$40,000.00
General Plant	4551	Multi Function & Laser Printer 2018	12/17/2018	\$50,000.00
General Plant	D02063.028	Purchase Meters and Metering Equipment	12/12/2018	\$1,450,000.00
General Plant	G04034.038	Communication Shelter replacement (2018)	11/20/2018	\$78,000.00
General Plant	G07199.348	Replace U#538 with Crew Cab Pickup	10/31/2018	\$45,255.00
General Plant	G07199.358	Replace Unit # 601 with 4x4 Extended Cab Pickup	10/31/2018	\$39,166.00
General Plant	G08053.277	General Office_Restroom Upgrades	11/30/2017	\$200,000.00
General Plant	G08053.328	Community Rooms AV Equipment	12/20/2018	\$60,000.00
General Plant	4177	Replace Plate Setter	11/30/2022	\$90,000.00
General Plant	4321	Replace Unit #581 with 4x4 Flatbed	10/31/2021	\$56,186.00
General Plant	4366	Replace Unit #563 with 4x4 Crew Cab Pickup	10/31/2018	\$47,723.00
General Plant	G03026.048	Storage Area Network (2018)	12/17/2018	\$106,000.00
General Plant	G04034.048	Cybersecurity Upgrades and Additions	12/17/2018	\$330,000.00
General Plant	G05150.028	Operations Support Tool Budget (2018)	12/20/2018	\$60,000.00
General Plant	G07199.138	Replace Unit #621 with 4x4 UB Pickup	10/31/2018	\$61,486.00
General Plant	G07199.248	Replace Unit #527 with 4x4 UB Pickup	10/31/2018	\$57,000.00
General Plant	P03102.056	Demolition of Unit #1	12/20/2017	\$0.00
General Plant	4374	Replace Unit # 905 with a 4X4 Cargo Van Equipped for Meter Tech	10/31/2018	\$58,336.00
General Plant	4382	Replace Unit # 2008 with a Car	10/31/2018	\$23,323.00
General Plant	G07199.078	Transportation Department Vehicle & Equipment Salvage Account (2018)	12/15/2018	(\$150,000.00)
General Plant	G07199.088	Replace Unit #390 with 4x4 UB Pickup	10/31/2018	\$61,486.00
General Plant	G07199.128	Replace Pole Trailers	10/31/2018	\$96,343.00
General Plant	G07199.158	Replace Unit # 902 with a 4X4 Cargo Van Equipped for Electrical Tech	10/31/2018	\$61,486.00
General Plant	G07199.198	Flatbed Trailer for Stringing Racks	10/30/2018	\$8,500.00
General Plant	G07199.288	Replace Unit # 906 with a 4X4 Cargo Van Equipped for Relay Tech	10/31/2018	\$58,336.00
General Plant	G07199.328	Replace Unit # 625 with 4x4 Crew Cab Pickup	10/31/2018	\$47,723.00
General Plant	G07199.368	Replace U#537 with Crew Cab Pickup	10/31/2018	\$45,255.00
General Plant	4319	Replace Unit #571 with 4x4 UB Pickup	10/31/2020	\$61,486.00
General Plant	4330	Replace Video Services DVD Duplicator	2/2/2020	\$2,750.00
General Plant	4375	Replace Unit # 12 with a 7 passenger small Van	10/31/2020	\$25,323.00
General Plant	4381	Replace Unit # 89 with a Car	10/31/2018	\$23,323.00
General Plant	G07199.178	Cargo Cable Trailer for Langdon, ND	11/1/2018	\$16,500.00
General Plant	G07199.208	Replace Unit #600 with 4x4 Utility Body Pickup	10/31/2018	\$61,500.00
General Plant	G07199.228	4x4 UB Pickup for Garrison ND	10/31/2018	\$61,486.00
General Plant	G08053.358	Pole Yard Expansion CST Facility Capital Projects (2018)	11/8/2018	\$60,000.00
Total General Plant				\$11,398,144.40
Intangible	5445	WOE and WMS software purchase (2020)	12/15/2020	\$711,000.00
Intangible	I03036.026	Primary and Backup Control Center Energy Management System Upgrade	7/31/2018	\$733,928.00
Intangible	I03300.015	Gathering Geospatial information of UG Cable	12/15/2018	\$400,000.00
Total Intangible				\$1,844,928.00
Production	3322	Ashtabula Wind Farm - Vintage Class Subscription (Software Upgrade)	12/20/2018	\$320,000.00
Production	P03102.018	HLP - Miscellaneous Tools & Equipment (2018)	12/15/2018	\$49,999.92
Production	4543	Replace Bags and Cages in Baghouse (2019-2020)	11/1/2020	\$904,981.00
Production	P02141.018	Lake Preston Peaking Plant - General Budget (2018)	12/10/2018	\$42,000.00
Production	P04101.098	Replace Plant Vehicle (2018)	7/1/2018	\$17,787.00
Production	P04101.108	Replace APH Hot and Cold End Baskets	12/1/2018	\$1,617,000.00
Production	P04101.727	Ash Reclaim Pond Water Recycle (2017)	12/1/2017	\$70,609.00
Production	P05103.028	Replace PC's and Office Equipment - 2018	12/20/2018	\$5,250.00
Production	P05103.048	CEMS Analyzer Replacement - SO2, NOx, CO2 Monitors	8/31/2018	\$17,500.00
Production	P05103.108	Mercury Vapor Light Fixture Replacements	9/30/2018	\$17,500.00
Production	P05103.188	Baghouse Bag Replacement - 2018	7/31/2018	\$175,000.00
Production	P05103.228	Coal system fire detector replacement	12/20/2018	\$21,000.00
Production	5304	Coal Unloading System Replacement	11/1/2021	\$107,800.00
Production	P04101.637	BSP Bottom Ash and Economizer Ash Retrofit (2017-2019)	7/31/2019	\$3,368,750.00

Production	P05103.637	Dust Collection System Replacements and Additions - 2017-2019	7/31/2019	\$280,000.00
Production	5453	New Plant Vehicle/Hydro Truck	5/1/2018	\$40,000.00
Production	P02144.027	Solway Plant - Control System Upgrade (2017-2018)	11/15/2018	\$840,000.00
Production	P04101.777	Replace Feedwater Heaters 16 & 17	12/1/2018	\$646,800.00
Production	P05103.018	Contingency Budget (2018)	12/20/2018	\$52,500.00
Production	P05103.128	PLCS Control Replacements (2018)	7/31/2018	\$71,750.00
Production	P05103.248	Skidsteer #8214 Replacement	5/31/2018	\$19,250.00
Production	P06169.026	Merricourt Wind Project	1/1/2020	\$78,060,413.00
Production	P07080.014	Astoria Station	4/1/2021	\$862,975.45
Production	4992	Cyclone Secondary Air Instrument Upgrade	12/1/2021	\$269,500.00
Production	5667	Expansion Joint Replacement (2018)	12/1/2021	\$544,390.00
Production	P02144.018	Solway Plant - General Budget (2018)	12/15/2018	\$32,000.00
Production	P04101.118	Replace One Plant Air Compressor	12/1/2018	\$86,240.00
Production	5701	Cyclone Secondary Air Flow Instrument Upgrade	12/1/2018	\$269,500.00
Production	P01138.018	Bemidji Hydro - General Budget (2018)	11/30/2018	\$12,000.00
Production	P02800.016	FERC Hydro Re-Licensing	12/20/2020	\$223,755.56
Production	P04101.078	PC Upgrades (2018)	12/1/2018	\$15,092.00
Production	P04101.088	Conveyor Belt #2 Replacement	8/1/2016	\$75,460.00
Production	P05103.038	Miscellaneous Tools and Equipment (2018)	12/20/2018	\$4,200.00
Production	P05103.118	HVAC replacement 2018	12/20/2018	\$7,000.00
Production	P05103.148	MCC and Load Center Replacements - 2018	12/20/2018	\$262,500.00
Production	P05103.158	Replace 8IK Sootblowers - Rotation (2018)	11/30/2018	\$161,000.00
Production	P05103.288	Replace One Plant Vehicle (2018)	5/31/2018	\$11,200.00
Production	3362	Luverne Wind Farm - Vintage Class Subscription (Software Upgrade)	12/20/2018	\$330,000.00
Production	P02140.018	Jamestown Peaking Plant - General Budget (2018)	12/10/2018	\$75,000.00
Production	P04101.018	BSP - Contingency Budget (2018)	12/20/2018	\$134,750.00
Production	P04101.028	IK Sootblower Replacement (2018)	10/1/2018	\$101,062.50
Production	P05103.068	Scissorlift replacement	5/31/2018	\$7,000.00
Production	P05103.078	OPGW Microwave System Replacement	9/30/2019	\$140,000.00
Production	P05103.098	Inverter replacement, D03	12/20/2018	\$21,000.00
Production	P05103.717	COY - Bottom Ash and Economizer Ash Retrofit (2017-2019)	9/30/2019	\$787,500.00
Production	5387	Overspeed Protection Aux Turbines (2018-2019)	7/31/2025	\$157,500.00
Production	P05103.268	Mower replacement #8270	4/30/2018	\$5,250.00
Production	P05103.278	Roof Replacement - Coal Galley 8th & 10th	9/30/2018	\$68,250.00
Production	P06160.018	Wind Farm Major Component (2018)	12/20/2018	\$750,000.00
		Total Production		\$92,160,015.43
Transmission	4266	Roberts County 115/41.6 kV Substation	9/20/2018	\$1,000,000.00
Transmission	4552	Milbank - General Transmission - Replace	12/20/2018	\$26,336.00
Transmission	T05032.068	Proactive - Worst Performing 41.6 kV Lines	12/20/2018	\$359,516.00
Transmission	T05048.048	69 & 41.6 kV poles in deep water (2018)	12/15/2018	\$240,000.00
Transmission	4452	Bemidji - General Transmission - Replace	12/20/2018	\$45,484.00
Transmission	4466	Devils Lake - General Transmission - Replace	12/20/2018	\$45,482.00
Transmission	4911	Neché/Pembina Load Break Switches	6/1/2018	\$23,500.00
Transmission	T05033.118	Transmission Substation - General Replace (2018)	11/30/2018	\$30,000.00
Transmission	T05048.028	Storm Work Order - Transmission - 69 kV & Above	12/20/2018	\$183,750.00
Transmission	T06033.028	Substation Battery Purchases (2018)	10/31/2018	\$65,000.00
Transmission	4459	Crookston - General Transmission - Replace	12/20/2018	\$39,499.00
Transmission	4514	Jamestown - General Transmission - Replace	12/20/2018	\$28,728.00
Transmission	4562	Morris - General Transmission - Replace	12/20/2018	\$32,321.00
Transmission	4583	Proactive Relay Upgrade (2018)	11/30/2018	\$200,000.00
Transmission	T03031.027	Hensel - Drayton 115 kV Line #2	9/25/2017	\$180,000.00
Transmission	4535	Wahpeton - General Transmission - Replace	12/20/2018	\$32,321.00
Transmission	T03008.035	Max-Ryder 41.6 kV line upgrades	11/30/2018	\$750,000.00
Transmission	4378	Max/Neal - Install Arresters on 41.6kV Line	10/31/2018	\$55,000.00
Transmission	4472	Rugby - General Transmission - Replace	12/20/2018	\$28,727.00
Transmission	T05008.037	Bottineau - Replace 41.6kV Line to Downtown Sub	10/31/2018	\$150,000.00
Transmission	T05046.048	Circuit Breaker Replacement Program (2018)	7/30/2018	\$320,000.00
Transmission	T02031.018	H081 - CapX Brooking Interconnect	9/30/2017	\$4,500.00
Transmission	T02031.05	BSSE - Big Stone South-Ellendale 345 kV Transmission Line	3/20/2019	\$30,559,298.00
Transmission	T03031.028	Donaldson 115 kV Sub - Install 115 kV Breaker for the Drayton Line and 115 kV Capacitor Bank	11/30/2020	\$369,000.00
Transmission	T05032.038	HV Transmission Line - Small Units of Property	12/20/2018	\$200,000.00
Transmission	T05032.048	Replace/Fix Damaged Structures	12/20/2018	\$175,000.00
Transmission	4504	Fergus Falls - General Transmission - Replace	12/20/2018	\$59,851.00
Transmission	T02031.04	BSAT - Big Stone South - Brookings	9/15/2017	\$609,749.00
Transmission	T03014.028	MILBANK-41.6KV-SW233-234-INSTALL STATIC ON 3102 FRAMED POLES	2/28/2018	\$10,300.00
Transmission	T05032.028	Rejected Pole Replacement	12/20/2018	\$507,000.00
Transmission	T05046.028	System Engineering - General Budget (2018)	8/30/2018	\$20,000.00
Transmission	T05048.038	Interrupters added to switches (2018)	9/30/2018	\$75,000.00
Transmission	4521	Wahpeton (Jamestown) - General Transmission - Replace	12/20/2018	\$19,154.00
Transmission	T03035.213	Clearbrook West to Bagley West 115 kV Line	6/30/2019	\$10,374,540.00
Transmission	T03035.254	Winger - Thief River Falls 230 kV Line	12/15/2023	\$1,226,100.00
Transmission	T05008.027	Turtle Lake/Mercer - Rebuild 41.6 kV Line (2017-2021)	11/30/2021	\$250,000.00
Transmission	T05032.058	Repair/Replace Existing Transmission Switches	10/31/2018	\$150,000.00
		Total Transmission		\$48,445,156.00
		Total Capital		\$172,723,255.83

Otter Tail Power Company
Case No. PU-17-398
Exhibit RCS-3
Copies of OTP's Confidential Responses to Data Requests
Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
ND-PSC-15.17	OTP provided copies of its OTP Key Performance Award Plan, OTP Management Plan, and OTC Executive Annual Incentive Plan.	Yes	13	2 - 14
ND-PSC-15.18	Amount of incentive compensation associated with the OTP Key Performance Plan, the OTP Management Plan, and the OTC Executive Annual Incentive Plan included in the test year by account and how the amount were derived; Collective Bargained employees are not eligible to participate in the OTP Key Performance Plan, the OTP Management Plan, or the OTC Executive Annual Incentive Plan.	Yes	2	15 - 16
ND-PSC-15.21	OTP included costs for the Executive Survivor and Supplemental Retirement Plan for the 2018 test year; Total OTP amount of 2018 ESSRP cost reported in FERC 926 for the 2018 test year; Amount of 2018 ESSRP cost included in OTP's requested North Dakota jurisdictional revenue requirement; Provision of comparable ESSRP cost by FERC balance for each calendar year 2015, 2016, and 2017; Identification by job title and company all current OTP and affiliated company employees and executives included in the ESSRP; Identification by former highest job title and pre-retirement company affiliation for all retired OTP and affiliated company employees and executives that are included in the ESSRP; Corporate executives that are participants in the ESSRP are covered under a Severance Plan and/or Employment contract in which removal of the ESSRP or any other benefit could represent a material change in their benefits and potentially trigger severance benefits. (Only Attachments 5 and 6 included)	Yes	4	17 - 20
ND-PSC-15.26	Identification of test year, filing date, and rate effective date for OTP's last two rate cases; Rate case expense incurred for the most recent rate cases in North Dakota and Minnesota; Rate expense requested in South Dakota's recently filed rate case; Identification of which cases were litigated and which were settled; Identification of stage at which settled cases were settled; Explanation of why OTP normalized rate case expense over a three-year period instead of another period; OTP claims it has not included any rate case expenses in rate base.	Yes	3	21 - 23
Total Pages Including This Page			23	

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Response to Data Request ND-PSC-15.17

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OTTER TAIL POWER COMPANY

Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/02/2018

Responding Witness: Peter Wasberg, Director, Human Resources and Safety - (218) 739-8940

Data Request:

OTP Annual Incentive Plan. Refer to pages 3-5 of the direct testimony of Company witness Peter Wasberg.

- a. Please provide a complete copy of the OTP Key Performance Award Plan.
- b. Please provide a complete copy of the OTP Management Plan.
- c. Please provide a complete copy of the Otter Tail Corporation Executive Annual Incentive Plan.

Attachments: 3

Attachment 2 to DR ND-PSC-15.17_NOTPUBLIC.pdf

Attachment 1 to DR ND-PSC-15.17_NOTPUBLIC.pdf

Attachment 3 to DR ND-PSC-15.17_NOTPUBLIC.pdf

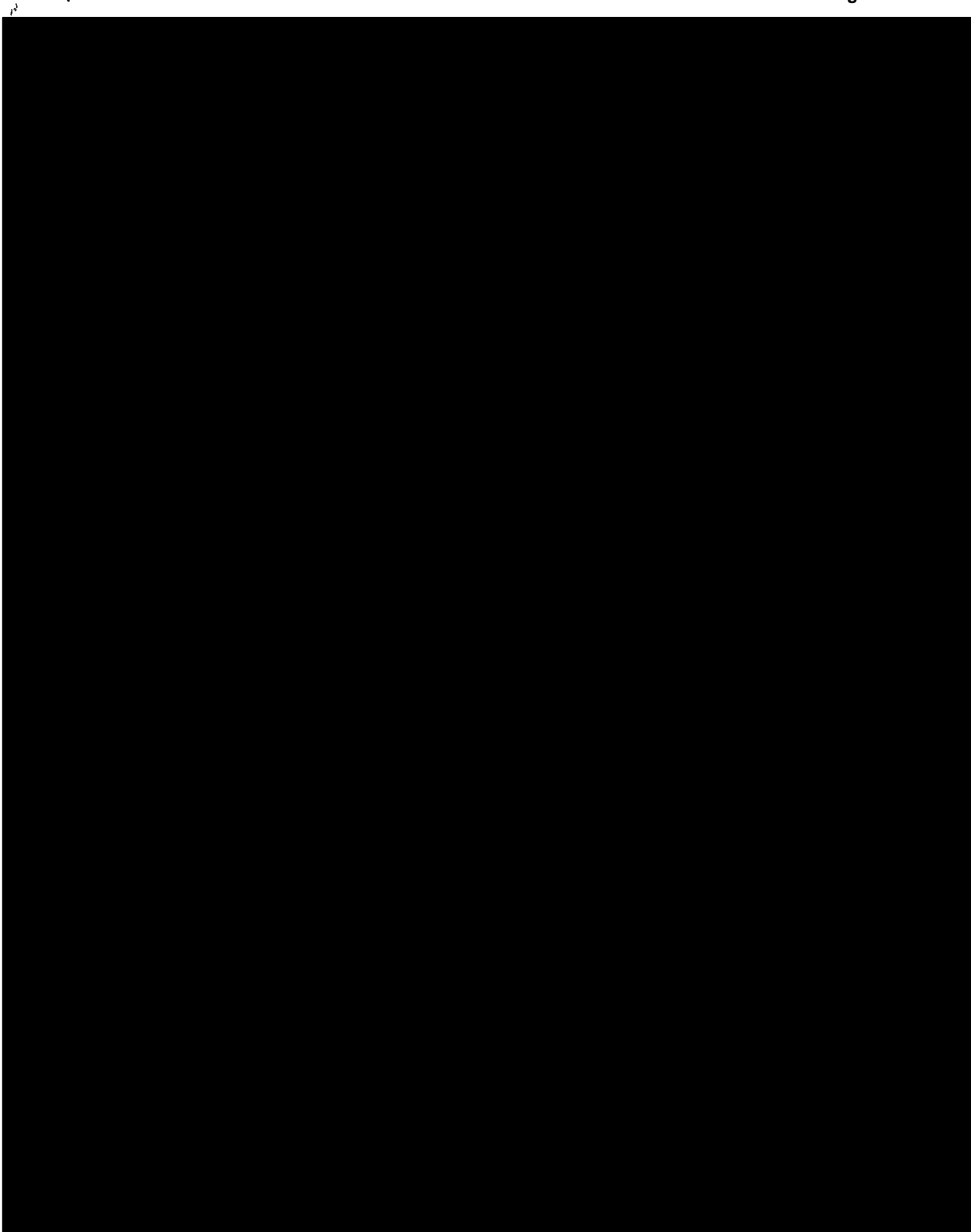
Response:

This response references schedules, attachments, and/or exhibits that that Otter Tail deems to be trade secrets, valuable or sensitive commercial or financial information, or information that is otherwise confidential or proprietary and subject to restrictions against unauthorized use and disclosure under North Dakota law and the Parties' Confidentiality Agreement. Such materials are noted as NOT PUBLIC.

- A. Please see Attachment 1 to DR ND-PSC-15.17_NOTPUBLIC for a complete copy of the OTP Key Performance Award Plan.
- B. Please see Attachment 2 to DR ND-PSC-15.17_NOTPUBLIC for a complete copy of the OTP Management Plan.
- C. Please see Attachment 3 to DR ND-PSC-15.17_NOTPUBLIC for a complete copy of the OTC Executive Annual Incentive Plan.

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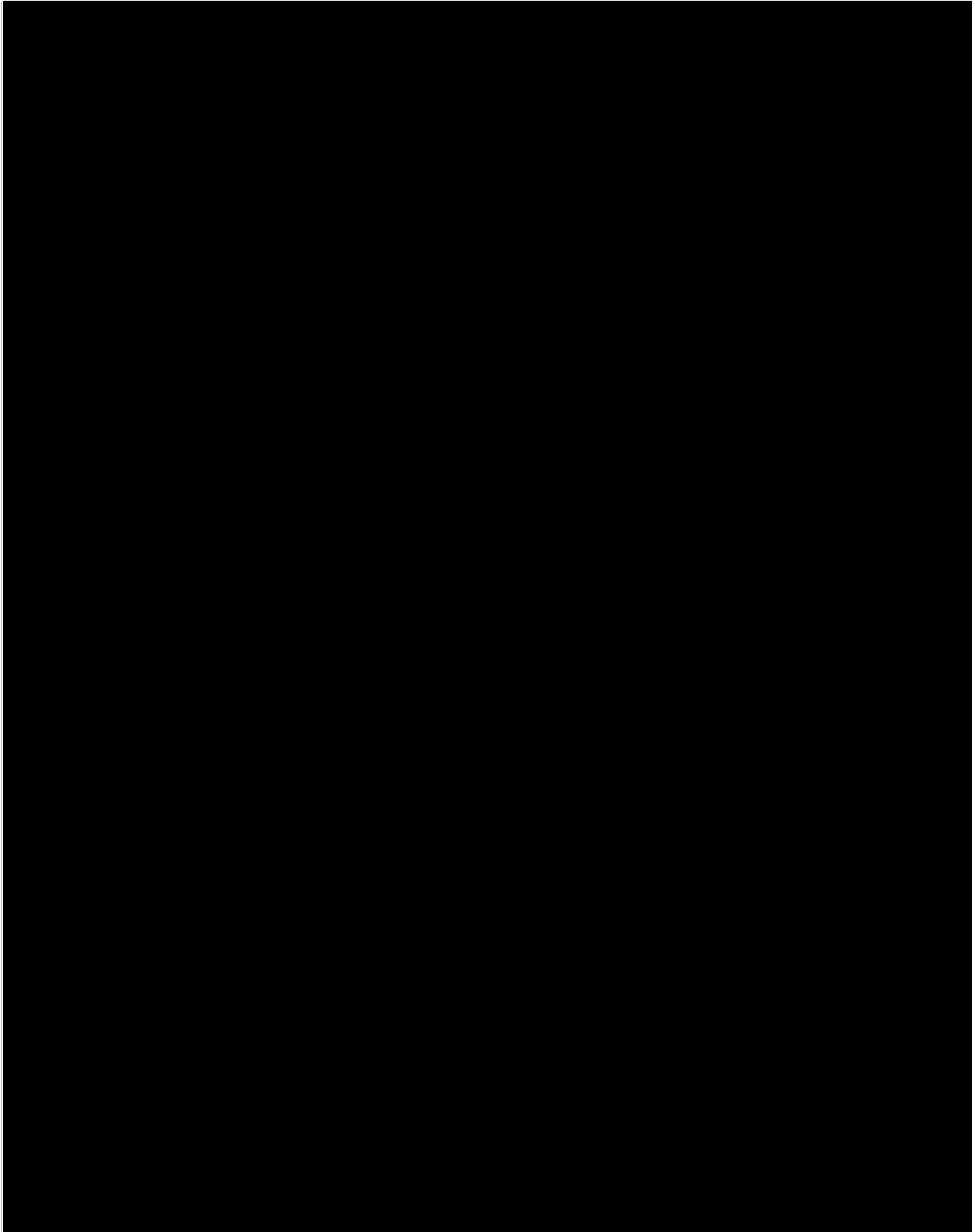
Case No. PU-17-398
Attachment 1 to DR ND-PSC-15.17
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**Case No. PU-17-398
Attachment 1 to DR ND-PSC-15.17
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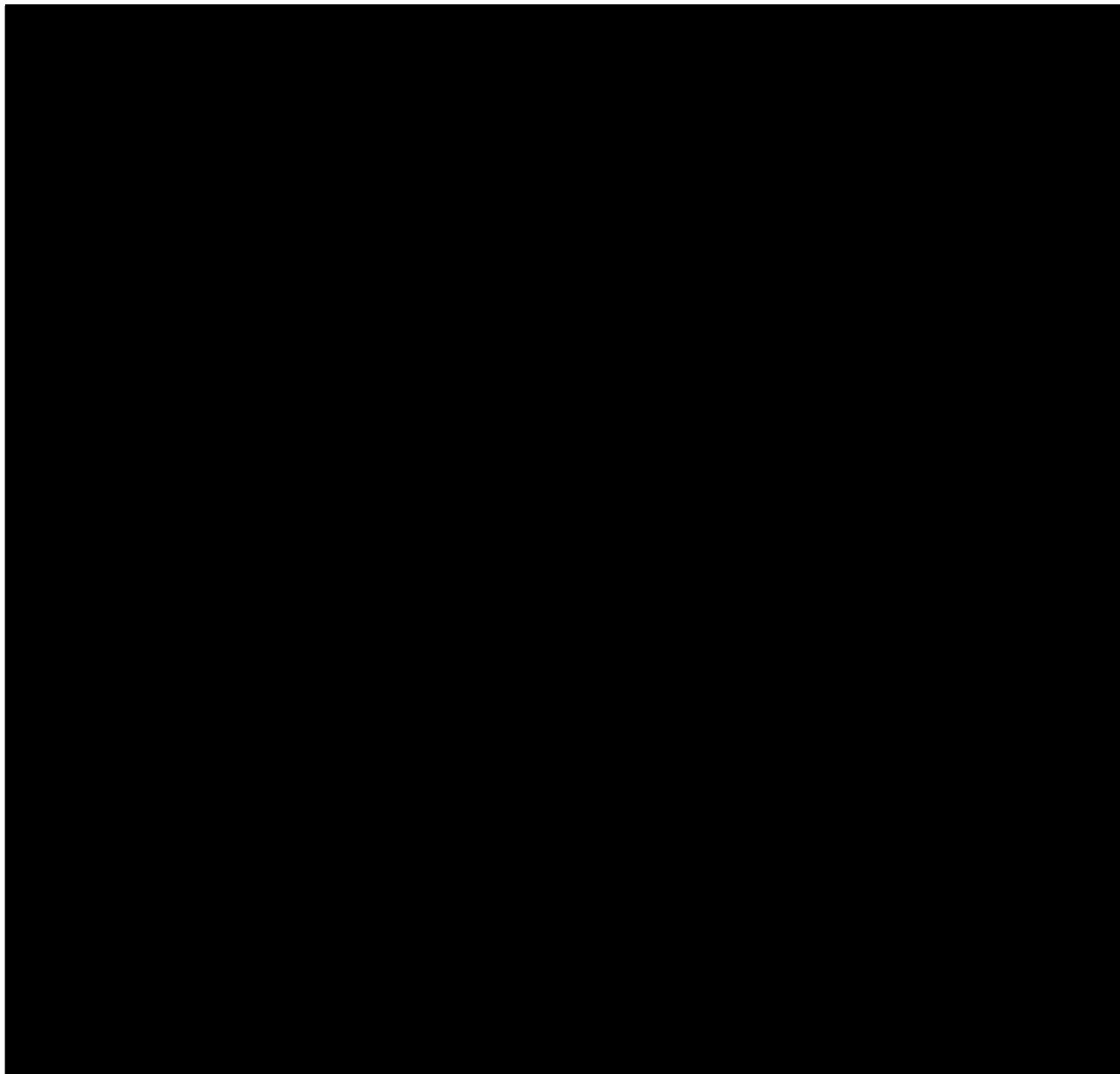
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Case No. PU-17-398

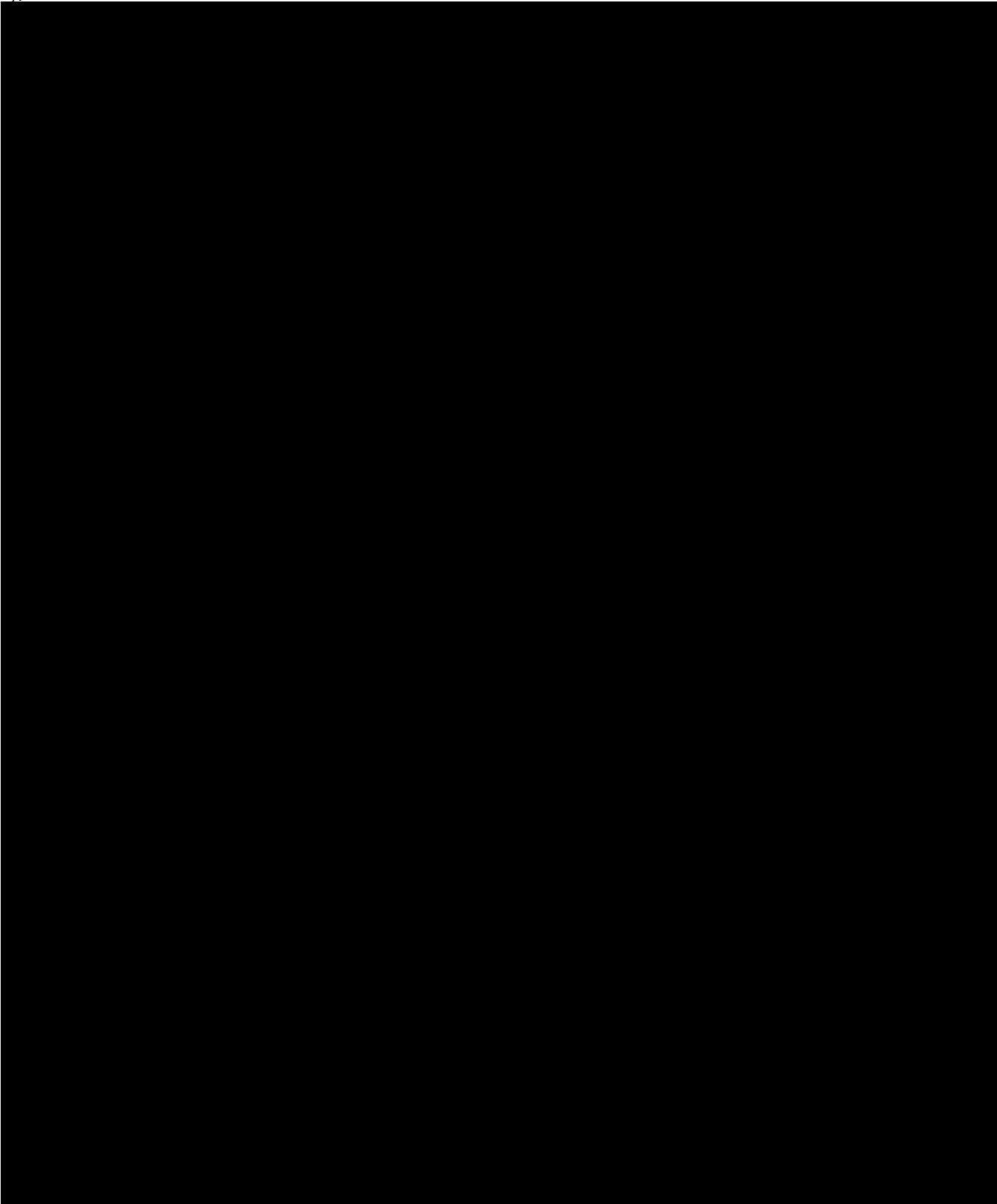
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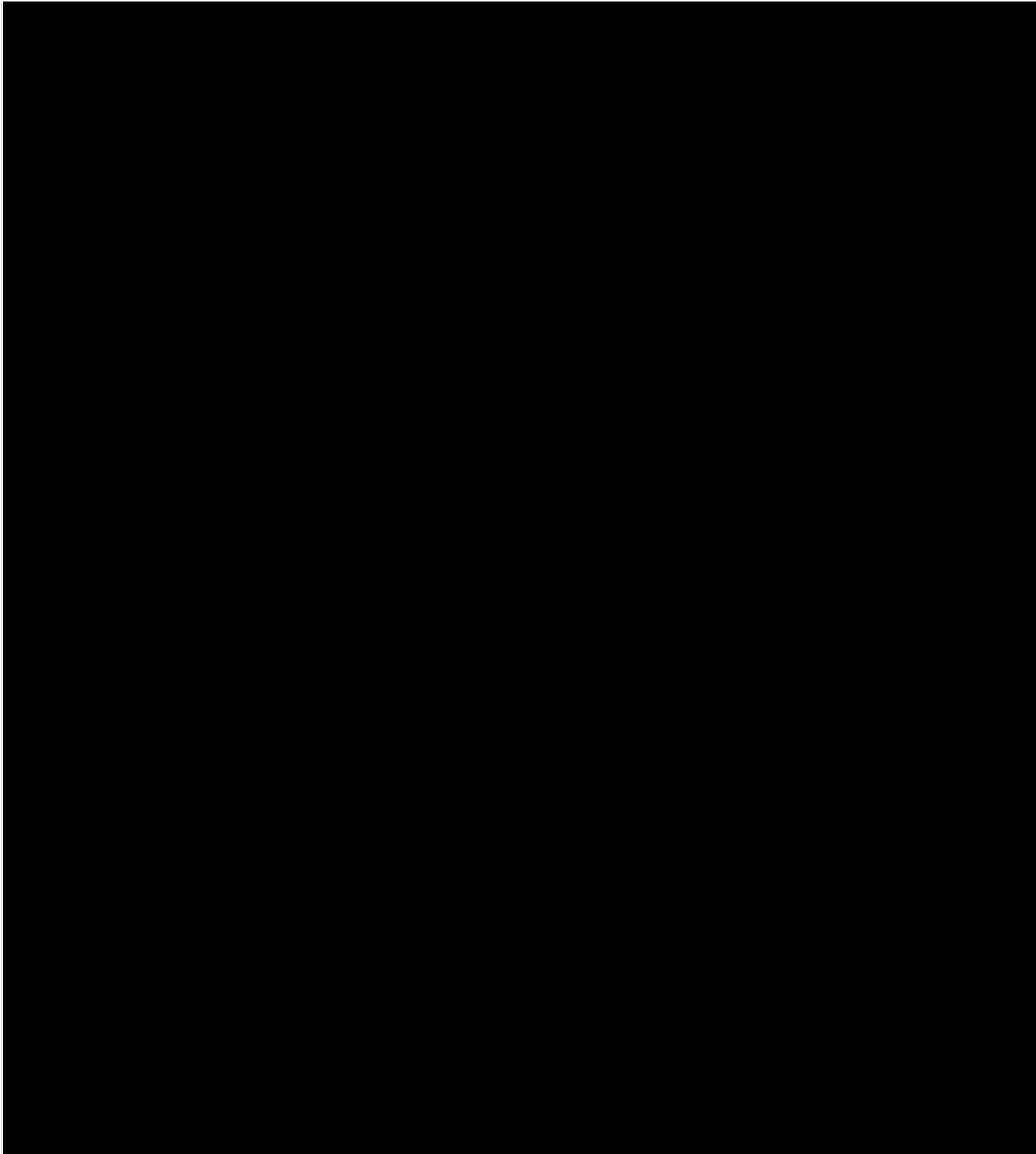
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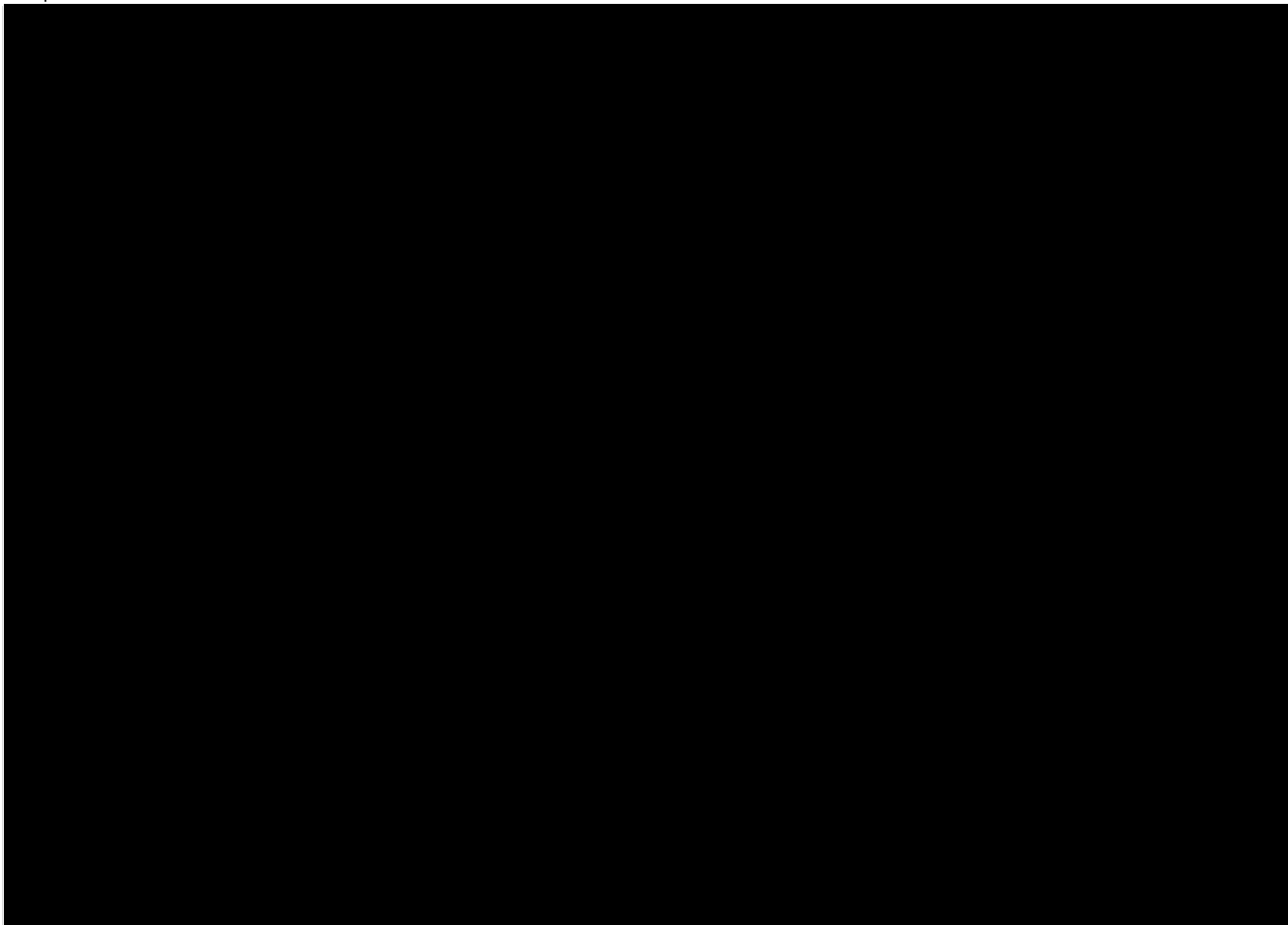
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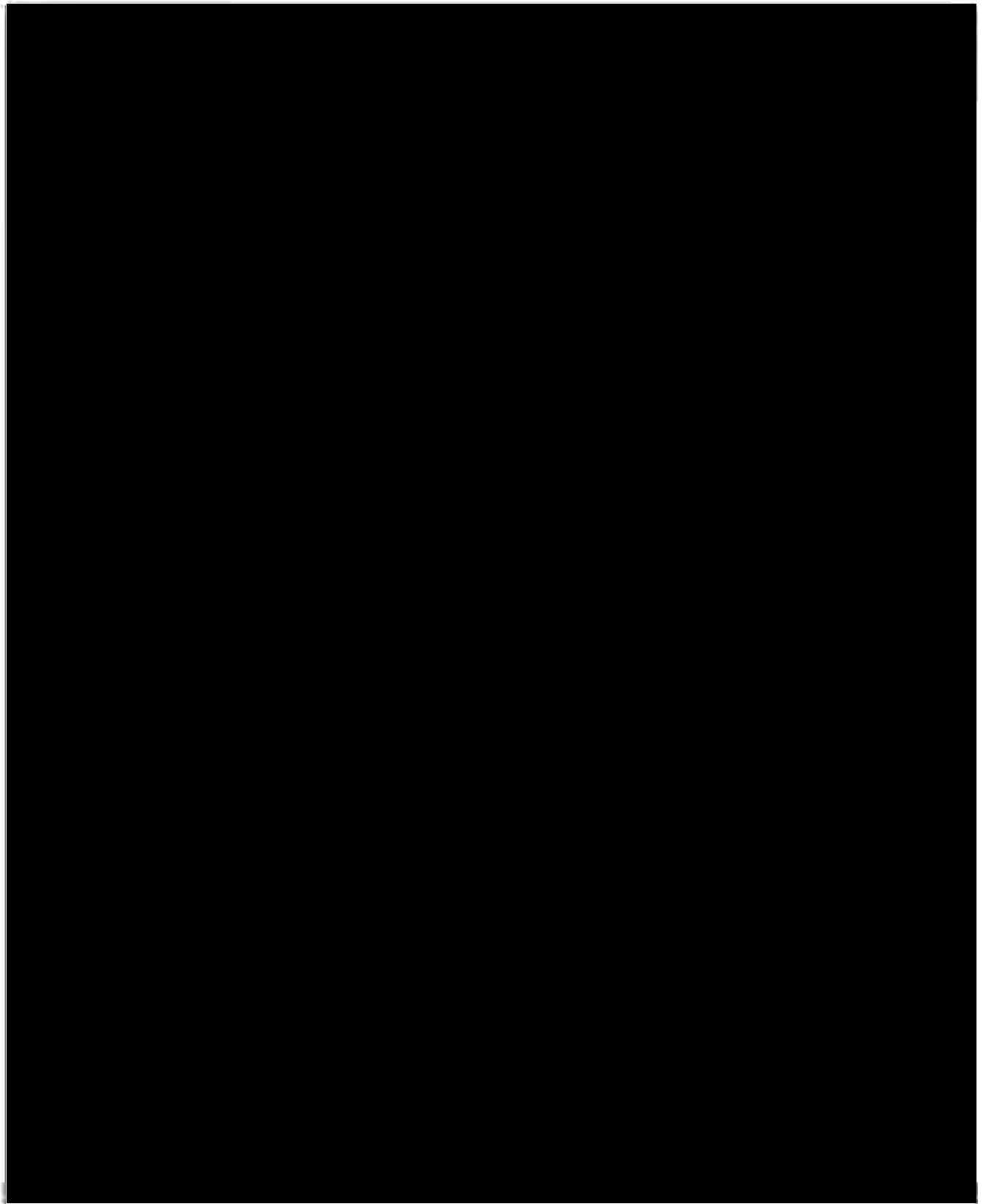
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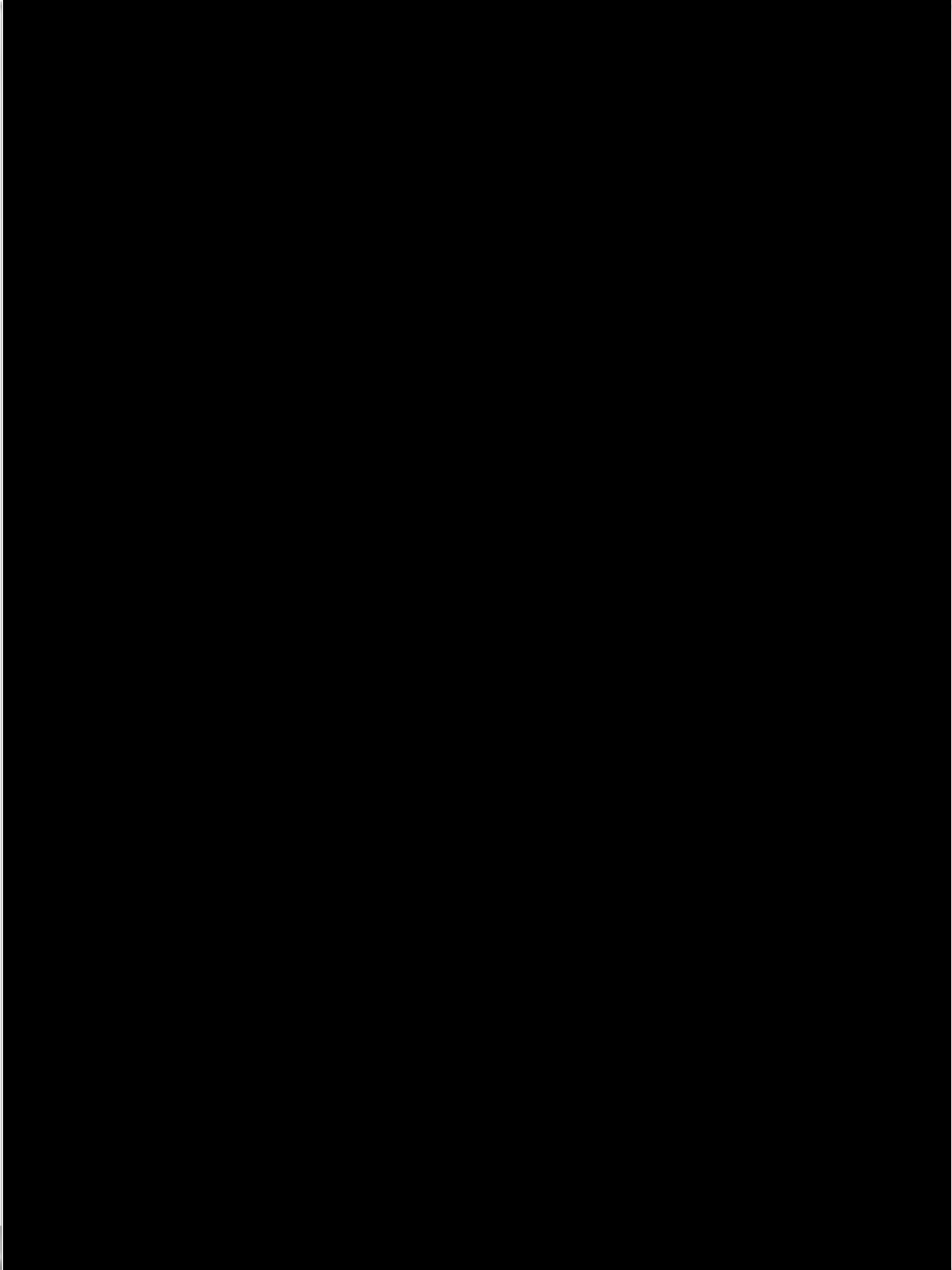
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Attachment 3 to DR ND-PSC-15.17

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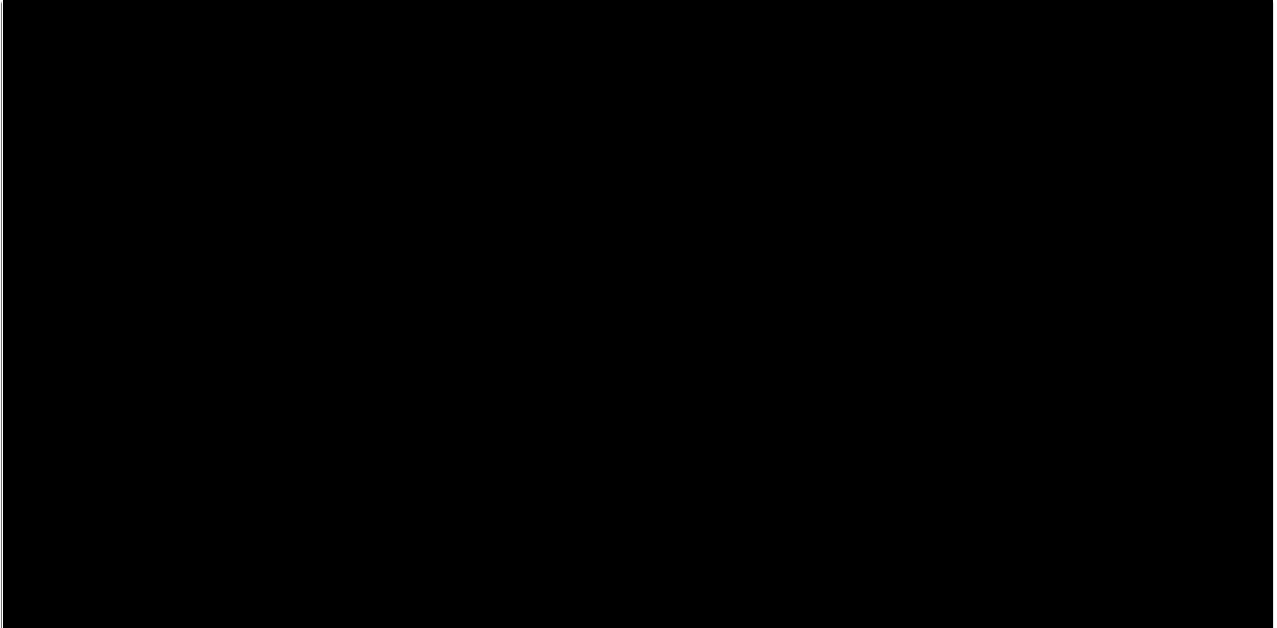


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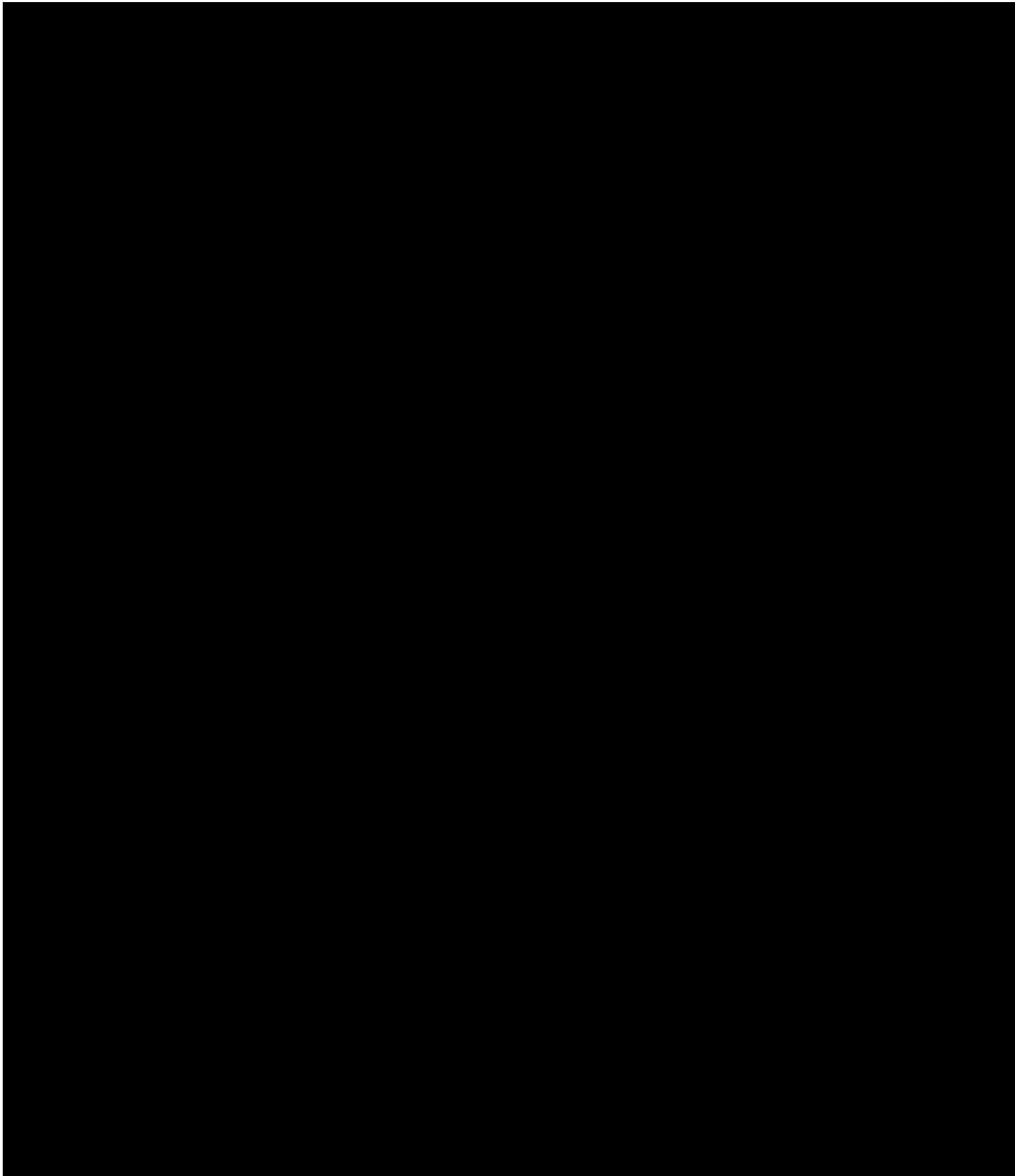
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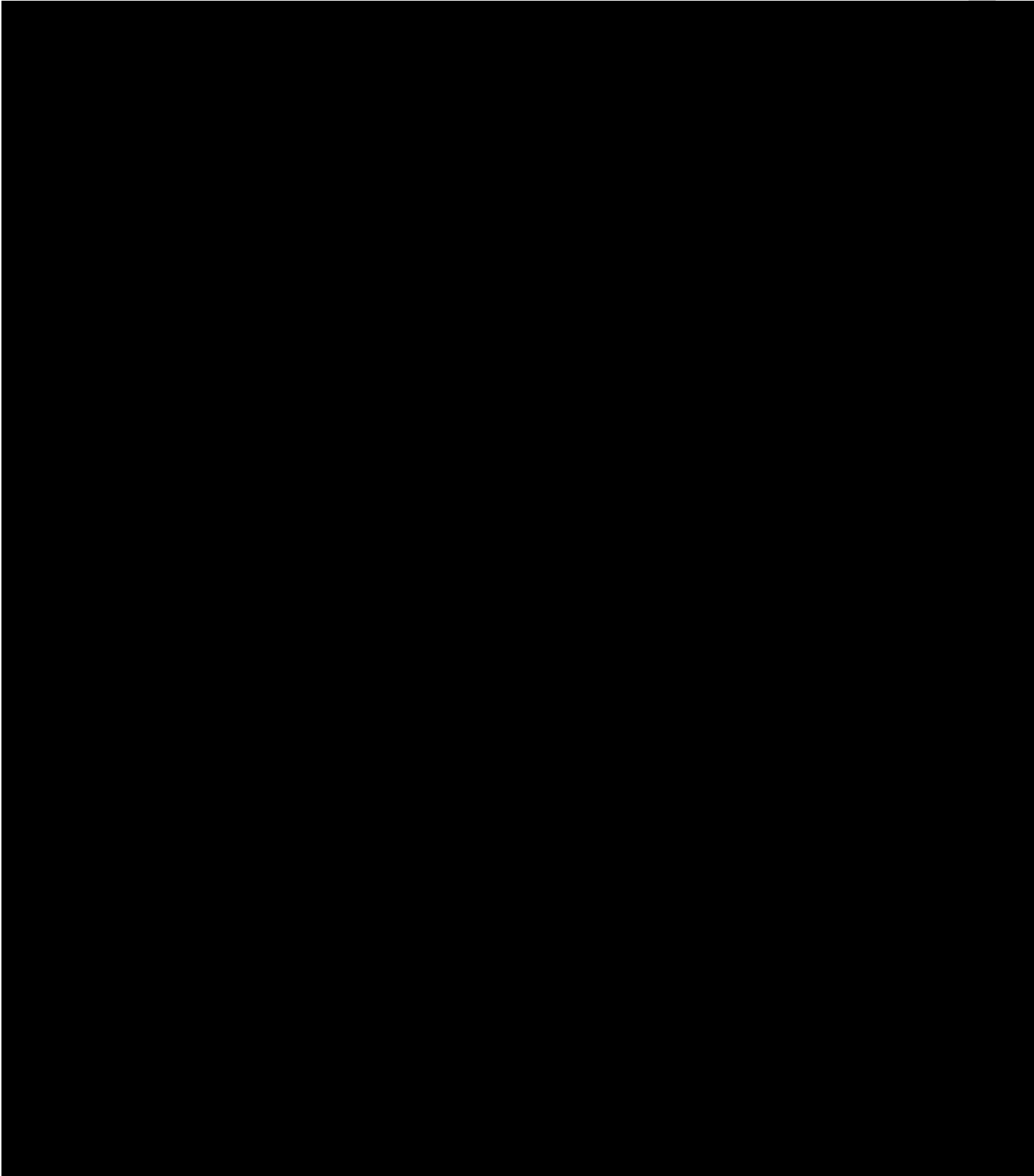
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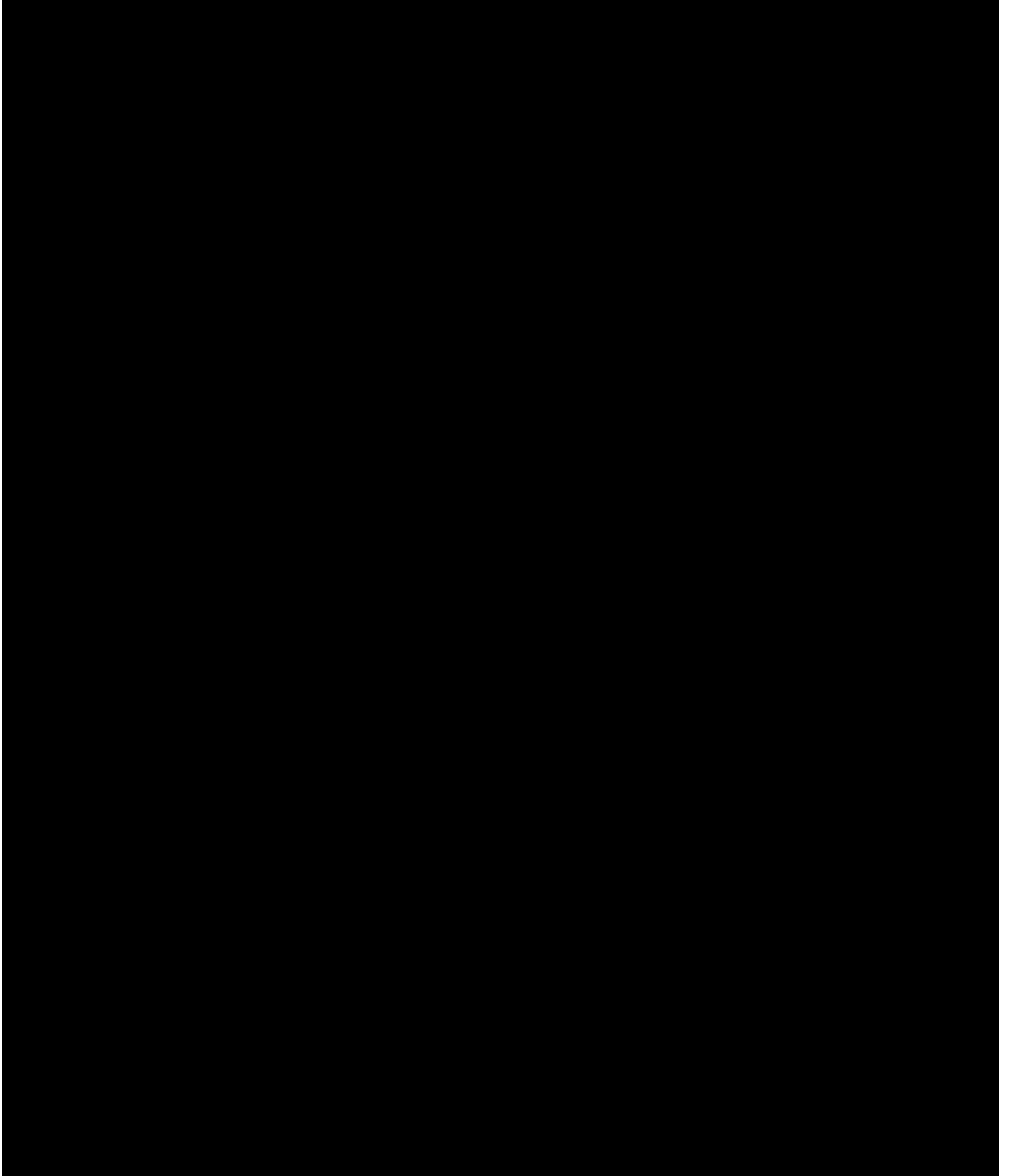
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Response to Data Request ND-PSC-15.18

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OTTER TAIL POWER COMPANY

Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/04/2018

Responding Witness: Peter Wasberg, Director, Human Resources and Safety - (218) 739-8940

Data Request:

OTP Annual Incentive Plan. Refer to page 17 of the direct testimony of Company witness Peter Wasberg.

- a. Please identify the dollar amount of incentive compensation associated with the OTP Key Performance Plan that is included in the test year ending December 31, 2018 by account and show how this amount was derived. Show detailed calculations.
- b. Please identify the dollar amount of incentive compensation associated with the OTP Management Plan that is included in the test year ending December 31, 2018 by account and show how this amount was derived. Show detailed calculations.
- c. Please identify the dollar amount of incentive compensation associated with the Otter Tail Corporation Executive Annual Plan that is included in the test year ending December 31, 2018 by account and show how this amount was derived. Show detailed calculations.
- d. Are any of the amounts of incentive compensation that were identified in response to parts a, b or c, above, related to union contracts? If so, identify, quantify and explain such amounts.

Attachments: 0

Response:

This response references schedules, attachments, and/or exhibits that that Otter Tail deems to be trade secrets, valuable or sensitive commercial or financial information, or information that is otherwise confidential or proprietary and subject to restrictions against unauthorized use and disclosure under North Dakota law and the Parties' Confidentiality Agreement. Such materials are noted as NOT PUBLIC.

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Response to Data Request ND-PSC-15.21

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OTTER TAIL POWER COMPANY

Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/04/2018

Responding Witness: Peter Wasberg, Director, Human Resources and Safety - (218) 739-8940

Data Request:

Supplemental Executive Retirement Program (SERP).

- a. Has the Company included any amount of SERP cost in the Company's requested revenue requirement for the test year ending December 31, 2018? If "yes" provide the following information:
- b. Provide the 2018 SERP cost in total and by FERC account.
- c. Provide the amount of 2018 SERP cost included in the Company's requested North Dakota jurisdictional revenue requirement.
- d. Provide the comparable SERP cost by FERC account for each calendar year, 2015, 2016 and 2017.
- e. Provide all actuarial studies, reports and estimates used for SERP for the years 2015 through 2018.
- f. Identify by job title and company all current OTP and affiliated company employees and executives that are included in the SERP.
- g. Identify by former highest job title and pre-retirement company affiliation for all retired OTP and affiliated company employees and executives that are included in the SERP.
- h. Are any of the SERP amounts related to employment contracts with current or former executives? If so, explain fully and provide a copy of the employment agreements.

Attachments: 13

Attachment 1 to DR ND-PSC-15.21_NOTPUBLIC.pdf

Attachment 2 to DR ND-PSC-15.21_NOTPUBLIC.pdf

Attachment 3 to DR-ND-PSC-15.21_NOTPUBLIC.pdf

Attachment 4 to DR ND-PSC-15.21_NOTPUBLIC.pdf

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Response to Data Request ND-PSC-15.21

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- Attachment 5 to DR ND-PSC-15.21_NOTPUBLIC.pdf
- Attachment 6 to DR ND-PSC-15.21_NOTPUBLIC.pdf
- Attachment 7 to DR ND-PSC-15.21_NOTPUBLIC.pdf
- Attachment 8 to DR ND-PSC-15.21_NOTPUBLIC.pdf
- Attachment 9 to DR ND-PSC-15.21_NOTPUBLIC.pdf
- Attachment 10 to DR ND-PSC-15.21_NOTPUBLIC.pdf
- Attachment 10a to DR ND-PSC-15.21_NOTPUBLIC.pdf
- Attachment 11 to DR ND-PSC-15.21_NOTPUBLIC.pdf
- Attachment 12 to DR ND-PSC-15.21_NOTPUBLIC.pdf

Response:

This response references schedules, attachments, and/or exhibits that that Otter Tail deems to be trade secrets, valuable or sensitive commercial or financial information, or information that is otherwise confidential or proprietary and subject to restrictions against unauthorized use and disclosure under North Dakota law and the Parties' Confidentiality Agreement. Such materials are noted as NOT PUBLIC.

- A. Yes. OTP has included costs for the Executive Survivor and Supplemental Retirement Plan (ESSRP) for the 2018 Test Year.
- B. \$1,426,000 (OTP Total) was reported in FERC 926 – Employee Pensions and Benefits for the 2018 Test Year.
- C. The North Dakota jurisdictional revenue requirement was \$577,665 for the 2018 Test Year.
- D. See table below:

ESSRP Cost (OTP Total)			
FERC Account	2015	2016	2017
926 – Employee Pensions and Benefits	\$1,478,792	\$1,465,095	\$1,438,457

- E. See Attachment 1 – 4 to DR ND-PSC-15.21_NOT_PUBLIC.
- F. See Attachment 5 to DR ND-PSC-15.21_NOT_PUBLIC.
- G. See Attachment 6 to DR ND-PSC-15.21_NOT_PUBLIC.
- H. The Corporate executives that are participants in the ESSRP are covered under a Severance Plan and or Employment Contract. Removal of the ESSRP or any other benefit could represent a material change in their benefits and potentially trigger severance benefits. Please see Attachments 7-12 to DR ND-PSC-15.21_NOT_PUBLIC.

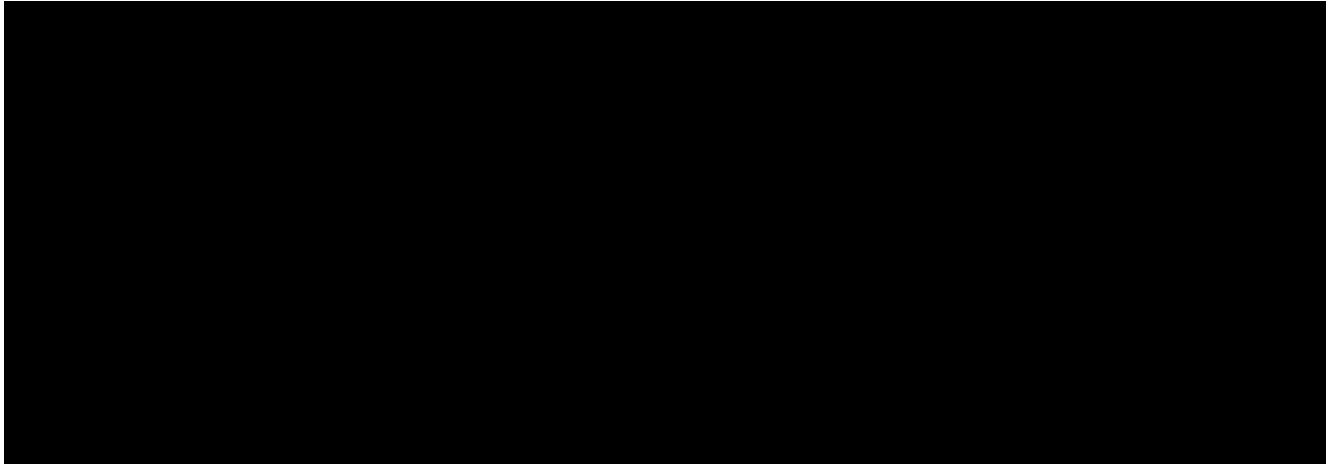
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Case No. PU-17-398

Attachment 5 to DR ND-PSC-15.21

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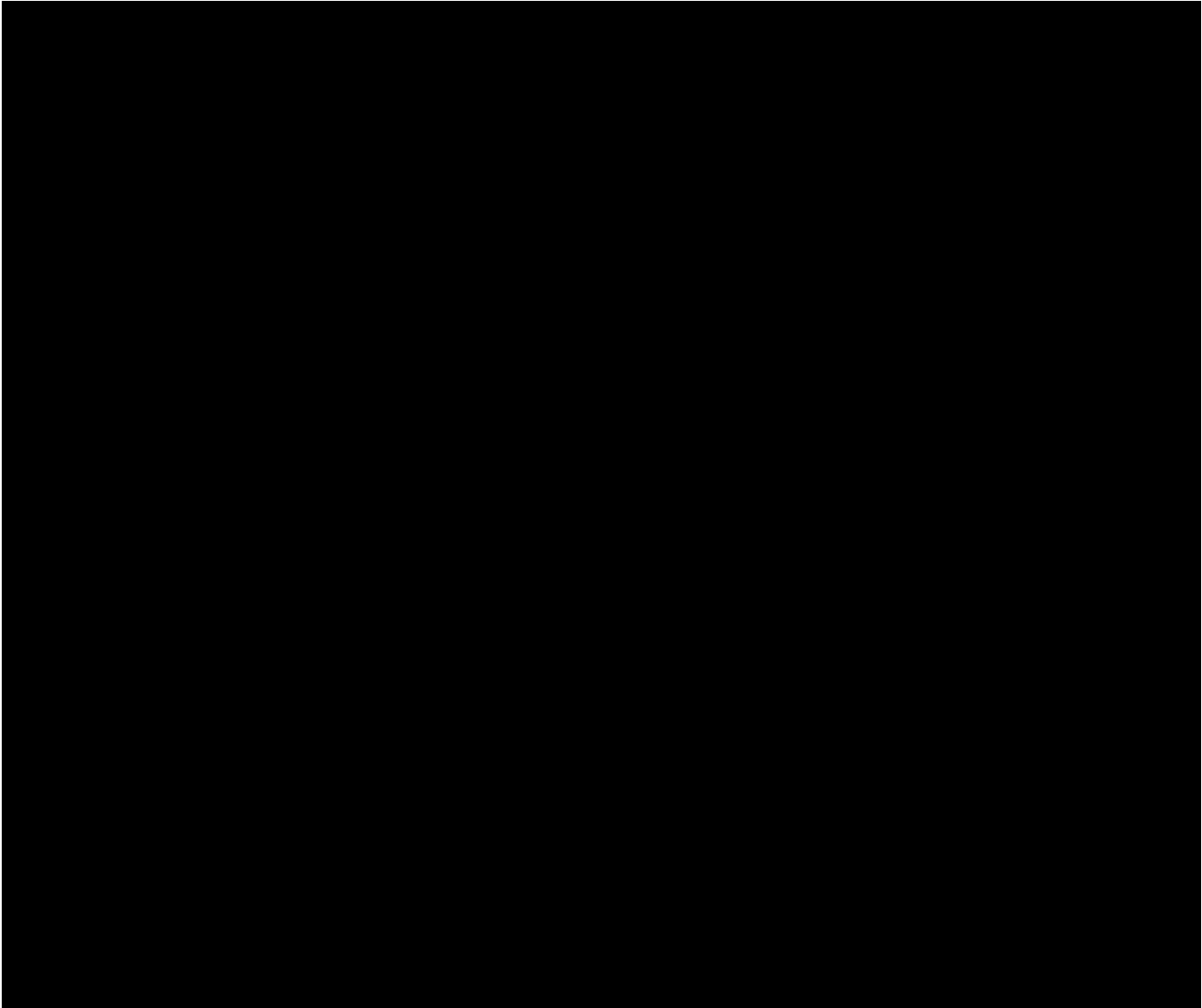
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Case No. PU-17-398

Attachment 6 to DR ND-PSC-15.21

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Response to Data Request ND-PSC-15.26

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OTTER TAIL POWER COMPANY

Case No: PU-17-398

Response to: North Dakota Public Service Commission

Analyst: Victor Schock

Date Received: 04/20/2018

Date Due: 05/04/2018

Date of Response: 05/04/2018

Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Rate Case Expense.

- a. Identify the test year, filing date and rate effective date for the Company's last five rate cases.
- b. Provide the level of rate case expense incurred for the last five rate cases broken down by payee or type of activity.
- c. Indicate which cases were settled and which were litigated. For the settled cases, also indicate at which stage they were settled (e.g., before rebuttal, after rebuttal, before hearings, after hearings, etc.).
- d. Explain fully and in detail why the Company normalized rate case expense over the period it is proposing versus some other period.
- e. Has the Company included any rate case expense in rate base? If so, explain fully why and identify by amount and account.

Attachments: 0

Response:

Otter Tail deems all or portions of the following attachments marked as NOT PUBLIC to be trade secrets, valuable or sensitive commercial or financial information, or information that is otherwise confidential or proprietary and subject to restrictions against unauthorized use and disclosure under North Dakota law and the Parties' Confidentiality Agreement. Such materials are noted as NOT PUBLIC.

- a. OTP's last ND rate case was filed November 3, 2008 using a historic 2007 Test Year (PU-08-862). Final rates from that case went into place December 1, 2009. Prior to that, OTP's next most recent ND rate case was filed in 1983.

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Response to Data Request ND-PSC-15.26
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b. Expenses incurred in OTP’s most recent ND rate case are provided in the Table 1 below.

Table 1: PU-08-862 Rate Case Expenses	
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TOTAL	\$392,253.95

Expenses from earlier ND cases (1983 and earlier) are unavailable and would not be comparable to modern figures.

Expenses for OTP’s most recent Minnesota rate case (MN Docket No. E017/GR-15-1033) are provided in Table 2 below:

Table 2: E017/GR-15-1033 Rate Case Expenses	
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TOTAL	\$2,852,032.08

Because similar projects and rate base additions occurred, as well as similar increases in expenses, much of the testimony developed in the Minnesota case was used to benefit the filing prepared for this North Dakota case.

OTP recently filed a rate increase request in South Dakota (EL18-021) on April 20, 2018. That request includes rate case expenses of \$550,000 amortized over three years.

c. OTP’s most recent ND rate case (2008) was settled after all direct testimony was filed, but before rebuttal testimony was filed. OTP’s 1983 rate case went to full hearings.

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Response to Data Request ND-PSC-15.26

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- d. OTP proposes to amortize rate case expenses over a period of three years, as addressed in the Direct Testimony of OTP witness Mr. Stuart D. Tommerdahl (at page 46). Mr. Tommerdahl includes that OTP believes we will likely file our next rate case in three years. It is appropriate to collect the costs of conducting the rate case over the time frame in which the rates established are expected to be in place.
- e. OTP has not included any rate case expenses in rate base.

Description	Total Company Amount	North Dakota Jurisdictional Amount
ECRR Projects		
Big Stone Plant AQCS	\$ 192,985,866	\$ 70,290,056
HLP MATS	\$ 6,460,514	\$ 2,353,073
Total	\$ 199,446,380	\$ 72,643,129
Source: Exhibit__(BCH-1), Schedule 2		

Description	Total Company Amount	North Dakota Jurisdictional Amount
RRAR Projects		
Langdon Wind Project	\$79,417,900	\$29,843,126
Ashtabula Wind Project	\$116,261,976	\$43,688,146
Luverne Wind Project	72,996,881	\$27,430,280
Total	\$268,676,757	\$100,961,553
Source: Exhibit__(BCH-1), Schedule 2		

Line No.	Description	Total Company Amount	North Dakota Jurisdictional Amount
	TCRR Projects		
1	CAPX 2020: Fargo	\$81,428,592	\$23,856,947
2	CAPX 2020: Bemidji	16,331,201	\$5,885,328
3	Cass Lake-Nary-Helga-Bemidji	7,039,948	\$975,736
4	Rugby Wind Interconnection	394,399	\$26,613
5	Casselton – Buffalo 115 kV Project	13,509,407	\$2,743,099
6	CAPX 2020: Brookings - Hampton	26,322,129	\$2,114,671
7	MVP: Big Stone Area Transmission	73,597,018	\$565,385
8	Ramsey 230/115 kW Transformer Upgrade	416,398	\$164,889
9	Karlstad, MN Capacitor Bank Project	1,103,974	\$437,161
10	Oakes Area Transmission Improvements	7,010,020	\$2,775,887
11	Hankinson Transformer Addition	828,844	\$328,213
12	NERC Compliance	14,078,440	\$5,574,900
13	Summit Transformer	853,991	\$338,171
14	Spiritwood Station Interconnection	720,137	\$285,166
15	Rugby Breaker Station	1,824,862	\$722,624
16	Granville Jct Breaker Station	1,015,655	\$402,188
17	Total Plant In Service	\$246,475,014	\$47,196,977
Source: Exhibit__(BCH-1), Schedule 2			

Description	Actual Payroll Expense	Budgeted Payroll Expense	Variance	Percentage Difference
OTP Total Company 2016 Payroll Expense	\$ 63,329,041	\$65,897,249	\$ (2,568,208)	-3.90%
OTP Total Company 2017 Payroll Expense	\$ 65,265,663	\$ 69,119,559	\$ (3,853,896)	-5.58%
Average Variance Percentage				-4.74%
Source: ND-PSC-15.02 and ND-PSC-15.04				

Description	Actual Payroll Expense	Budgeted Payroll Expense	Variance	Percentage Difference
OTP Total Company Payroll Expense - January 2018	\$ 5,211,656	\$ 5,391,402	\$ (179,746)	-3.33%
OTP Total Company Payroll Expense - February 2018	\$ 5,689,745	\$ 6,227,437	\$ (537,692)	-8.63%
OTP Total Company Payroll Expense - March 2018	\$ 5,939,477	\$ 6,077,170	\$ (137,693)	-2.27%
Total 2018 First Quarter	\$ 16,840,878	\$ 17,696,009	\$ (855,131)	-4.83%
Source: ND-PSC-15.07				