Before the North Dakota Public Service Commission
State of North Dakota

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-

Exhibit___

CAPITAL BUDGET PROCESS, RATE BASE, REVENUE REQUIREMENT AND ADJUSTMENTS

Direct Testimony and Schedules of

TYLER A. AKERMAN

November 2, 2017

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Tyler Akerman. I am employed by Otter Tail Power Company (OTP) as Manager of the Business Planning/Regulatory Accounting department.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I graduated from Minnesota State University Moorhead with a Bachelor of Science degree with majors in Finance and Accounting. I started my current position as Manager, Business Planning/Regulatory Accounting in October 2015. My primary responsibilities include being accountable for all budgeting, financial planning, and forecasting as required by OTP and Otter Tail Corporation for use in strategic planning and decision making. In addition, I am responsible for managing the production of official company budgets and monthly forecasts, for leading the work group that prepares the jurisdictional cost of service studies for the three jurisdictions in which OTP provides service (Minnesota, North Dakota, and South Dakota) and providing other regulatory and financial analysis on an as needed basis. I have been employed by OTP since October 2012. Prior to beginning my current position in October 2015, I was a Financial Analyst in the Business Planning/Regulatory Accounting Department. A copy of my resume is included as Exhibit___(TAA-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony supports OTP's financial schedules and the determination of a revenue deficiency for the 2018 Test Year. More specifically, I have determined that OTP has a revenue deficiency of $15,715,320 for the 2018 Test Year. I support the additional financial data provided as part of this Application. I will discuss the development of the Capital Budget, Rate Base, and Income Statement which is being proposed for use in setting rates in this proceeding, including explaining the financial

impact of all Test Year adjustments and providing support for some of the Test Year adjustments.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. I explain the Jurisdictional Cost of Service Study (JCOSS), Test Year Revenue Deficiency, Financial Data Provided, Capital Budget Process, Rate Base, Adjustments to Rate Base, Income Statement, and Adjustments to the Income Statement.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I discuss the selection of the 2018 Test Year, and in Section IV, I discuss the JCOSS. In Section V, I discuss the Test Year revenue deficiency, and in Section VI, I discuss the financial data provided. In Section VII, I discuss the Capital Budget process; in Section VIII, I discuss Rate Base; and in Section IX, I discuss adjustments to Rate Base. In Section X, I discuss the Income Statement, and in Section XI, I discuss adjustments to the Income Statement. In Section XII, I present my conclusion.

III. 2018 TEST YEAR

Q. WHAT TEST YEAR IS OTP PROPOSING IN THIS CASE?

A. OTP is proposing a forecast 2018 Test Year that is a based primarily on OTP's 2018 Operations and Maintenance (O&M) Budget and 2018 Capital Expenditure Budget, with adjustments. The 2018 Test Year is a "future test year" as defined in N.D. Cent. Code § 49-05-04.1.1C as "any consecutive twelve-month period ending no later than twenty-four months after the date new schedules are filed."

Q. WHY HAS OTP PROPOSED A FORECAST TEST YEAR IN THIS CASE?

A. OTP has proposed the forecast 2018 Test Year because the 2018 Test Year will lead to rates that most reasonably reflect OTP's ongoing costs. OTP is in a period of significant capital expenditures and is experiencing other increasing costs. The forecast 2018 Test Year better reflects those costs than would a historic test year.

Q. DOES OTP'S FORECAST 2018 TEST YEAR MEET THE REQUIREMENTS FOR USE OF A FORECAST TEST YEAR?

A. Yes. In accordance with N.D. Cent. Code § 49-05-04.1, my Direct Testimony, the Direct Testimonies of other OTP witnesses, and the additional financial information in Volume 3, Supporting Information and Volume 5, Budget Documentation, affirm and demonstrate that OTP's forecast 2018 Test Year is reasonable, reliable, and in good faith. All basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the Commission to test the appropriateness of the forecast. The accounting treatment that has been applied to anticipated events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred.

Q. HAVE OTHER NORTH DAKOTA UTILITIES USED FORECAST TEST YEARS FOR GENERAL RATE CASE PROCEEDINGS?

A. Yes. Xcel Energy and Montana-Dakota Utilities use forecast test years for their general rate case proceedings.

IV. JURISDICTIONAL COST OF SERVICE STUDY

Q WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. The purpose of this section of my Direct Testimony is to explain OTP's JCOSS.

Q. WHAT IS THE PURPOSE OF A JCOSS?

A. A JCOSS determines the portion of a multijurisdictional utility's total company costs and revenues that should be recognized in a specific jurisdiction. In this case, the JCOSS determined the portion of OTP's total company costs and revenues that should be recognized in the North Dakota jurisdiction for the 2018 Test Year revenue requirement.

Q. WHY IS A JCOSS NECESSARY FOR OTP?

A. OTP serves retail customers in Minnesota, North Dakota, and South Dakota. In addition, wholesale and wheeling service is provided to some municipal utilities, and those

services are regulated by the Federal Energy Regulatory Commission (FERC), as are transmission services. Costs that are incurred to meet the requirements of a particular jurisdiction are directly assigned to that jurisdiction. Costs that cannot be directly assigned to a specific jurisdiction are allocated to jurisdictions based upon allocation factors included in the JCOSS. In this way, the JCOSS is used to determine what portion of the total costs incurred by OTP should be recovered from our North Dakota customers.

Q. IS IT IMPORTANT THAT ALL OF A UTILITY'S STATE JURISDICTIONS USE THE SAME JURISDICTIONAL ALLOCATION PROCEDURES FOR THE JCOSS?

A. Yes. By having uniform jurisdictional allocation procedures in all its state jurisdictions, OTP is able to recover its cost of providing retail service across its entire service territory, no more, and no less. The allocation procedures used by OTP were approved by the Commission in OTP's last North Dakota rate case, (Case No. PU-08-862).

Q. DO ALL OTP'S JURISDICTIONS USE THE SAME JURISDICTIONAL ALLOCATION PROCEDURES FOR OTP'S JCOSS?

A. Yes. The Minnesota Public Utilities Commission (MPUC) and South Dakota Public Utilities Commission (SD PUC) have approved the same jurisdictional allocation procedures for OTP's JCOSS that the Commission has approved for OTP's JCOSS.

Q. HOW WAS OTP'S JCOSS DEVELOPED?

A. The JCOSS was developed using procedures contained in the OTP Jurisdictional and Class Cost of Service Study and Rate Design Process Overview Manual, a copy of which is attached as Exhibit __ (TAA-1), Schedule 2. This is the same process that was used and approved by the Commission in OTP's North Dakota last rate case.

Q. WHAT ARE THE GENERAL STEPS FOR PREPARING OTP'S JCOSS?

A. The JCOSS involves the following steps: functionalization, classification and allocation. Functionalization is the process by which costs are arranged according to the utility function they serve, such as production, transmission, distribution, etc. Classification is

the arrangement of costs within a function by the service characteristic to which they most closely apply or relate, in order to facilitate their allocation based on these service characteristics. Allocation, in the JCOSS, is the process of distributing costs to each jurisdiction. I discuss the functionalization and classification steps in more detail below. OTP witness Ms. Gina S. Ice discusses jurisdictional allocations and OTP's Cost Allocation Procedures Manual (CAPM) in her Direct Testimony.

Q. IS FUNCTIONALIZATION OF COSTS REQUIRED?

A. Yes. The assignment of costs to each function: Production, Transmission, Distribution, Customer Service, Administrative and General generally follow the accounting categories defined in the FERC Uniform System of Accounts (USOA). At times, however, there are exceptions. When there are exceptions, the purpose of functionalization, not the accounting treatment, determines the distribution of the functional costs for the cost of service study. For example, lines and substations can fulfill production, transmission or distribution functions. Additional details regarding OTP's functionalization procedures are included in the CAPM.

Q. HOW WERE COSTS CLASSIFIED IN THE JCOSS?

A. Classification approaches differ across different functional categories. For example, fixed production plant is classified into energy-related and demand-related subcategories using the equivalent peaker method. OTP has used the equivalent peaker method to classify fixed production plant costs since 1980. Additional details regarding classification procedures are available in the CAPM.

Q. WHAT IS YOUR CONCLUSION RELATED TO OTP'S JCOSS?

A. The results of the JCOSS are appropriate for determining the 2018 Test Year revenue requirement.

V. TEST YEAR REVENUE DEFICIENCY

Q. WHAT IS THE BASIS OF OTP'S 2018 TEST YEAR JURISDICTIONAL REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. OTP's 2018 Test Year jurisdictional revenue requirement and revenue deficiency in this case is based on OTP's 2018 Budget Year, with adjustments.

Q. WHAT IS THE 2018 TEST YEAR JURISDICTIONAL REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. OTP's overall jurisdictional revenue requirement for the 2018 Test Year is $163,787,270 (including $2,787,168 of revenue requirements that will be left in the Transmission Cost Recovery Rider (TCRR)), and the 2018 Test Year revenue deficiency is $15,715,320. The 2018 Test Year revenue deficiency represents a 10.61 percent overall increase in retail revenues compared to projected 2018 retail revenues at current rates.

Q. HAVE YOU PREPARED A SUMMARY OF THE 2018 REVENUE DEFICIENCY?

A. Yes. Exhibit___(TAA-1), Schedule 3 and Volume 3, Schedule A-1 is a summary of the 2018 Test Year revenue deficiency. Line 1 shows average total Rate Base of $354 million. Line 4 shows the total amount available for return of $18.4 million, which is determined at present rate levels. Line 5 shows the 5.21 percent overall rate of return (ROR) earned before any rate increase. Line 6 shows the 7.97 percent required ROR, which is the basis for the requested rate increase. Line 7 shows the required operating income of $28.2 million, which was determined by multiplying the 7.97 percent required ROR by the $354 million Rate Base. Line 8 shows the $9.8 million income deficiency which is the difference between the required operating income of $28.2 million (on Line 7) less the $18.4 million of available return (on Line 4). The $15.7 million revenue deficiency on Line 10 is determined by multiplying the $9.8 million income deficiency (on Line 8) by the 1.607756 gross-revenue conversion factor. The calculation of the gross revenue conversion factor is provided in Volume 3, Schedule F-2.

Q. HAVE YOU COMPARED OTP'S EARNED OVERALL ROR TO ITS REQUIRED OVERALL ROR SINCE 2016?

A. Yes. OTP's earned ROR was lower than OTP's required ROR in 2016 and will be lower than OTP's required ROR in both 2017 and 2018 at current rates. Exhibit___(TAA-1), Schedule 4 and Volume 3, Schedule A-2 is a Jurisdictional Financial Summary for 2016 Actual Year, 2017 Current Period (projected), 2018 Base Year (projected), and the 2018 Test Year. Exhibit___(TAA-1), Schedule 4 and Volume 3, Schedule A-2 shows: (1) the overall ROR for 2016 Actual Year was 7.80 percent and the required ROR was 8.22 percent; (2) the projected overall ROR for 2017 Current Period is 7.63 percent and the projected required ROR is 8.12 percent; (3) the projected overall ROR for 2018 Base Year is 5.58 percent and the projected required ROR is 7.97 percent; and (4) the projected overall ROR for the 2018 Test Year is 5.21 percent and the required ROR was 7.97 percent.

VI. FINANCIAL DATA PROVIDED

Q. HAS OTP PROVIDED ADDITIONAL SUPPORTING FINANCIAL DATA AS PART OF THIS APPLICATION?

A. Yes. Additional supporting financial data is included in Volume 3, Supporting Information. The Volume 3, Supporting Information provides the information required under N.D. Cent. Code §§ 49-05-04 and 49-05-04.1(2).

Q. PLEASE PROVIDE AN OVERVIEW OF THAT FINANCIAL DATA.

A. OTP is providing additional financial data with this filing for 2016 Actual Year, 2017 Current Period, 2018 Base Year, and 2018 Test Year. Separate Rate Base and Income Statement bridge schedules that identify Traditional and Rate Case Adjustments for the 2018 Test Year have also been provided. Additional information for Rate Base and Income Statement are in Volume 3, Supporting Information.

Q. PLEASE DESCRIBE THE INFORMATION AVAILABLE FOR 2016 AND 2017.

A. 2016 is the most recent year for which 12 months of actual information is available. Information for 2017 reflects a combination of actual information (January through July) and projected information (August through December).

Q. PLEASE IDENTIFY THE FINANCIAL SCHEDULES PROVIDED AS PART OF THE FILING.

A. There are seven financial schedules, which have alphabetical headings, A through G. These are in Volume 3, Supporting Information, under the tab, Supporting Financial Information. I am sponsoring the information contained in all sections except Section D, Cost of Capital, Section E, Schedule E-1 and E-2, Rate Design and Section G, Schedules 1, 2, 3 and 4, Commission Policy Information. I will briefly describe the sections I am sponsoring.

Q. PLEASE DESCRIBE FINANCIAL SCHEDULE A-2.

A. Schedule A-2 is the Jurisdictional Financial Summary of OTP, as allocated to North Dakota, for the 2016 actual year, the 2017 Current Period, the 2018 Base Year, and the 2018 Test Year, as adjusted.

Q. PLEASE EXPLAIN FINANCIAL SCHEDULE B-1.

A. Schedule B-1 is the rate base summary of OTP, as allocated to North Dakota, for the 2016 actual year, the 2017 Current Period, the 2018 Base Year, and the 2018 Test Year, as adjusted.

Q. WHAT IS SHOWN ON FINANCIAL SCHEDULE C-1?

A. Schedule C-1 is the operating income summary of OTP, as allocated to North Dakota, for the 2018 Base Year and the 2018 Test Year, as adjusted. The Electric Revenues are the revenues from sales of electricity to OTP's North Dakota customers under rate schedules presently on file with the Commission. The North Dakota allocated share of OTP's Other Operating Revenues from other services provided by OTP has been added to

electric revenues. Operating Expenses are deducted from the electric revenues to arrive at Net Operating Income Before Income Taxes. Total Income Tax Expense is deducted from Net Operating Income Before Income Taxes to arrive at Net Operating Income After Income Taxes.

Q. WHAT IS SHOWN ON FINANCIAL SCHEDULE D-1?

A. Schedule D-1 is a Cost of Capital Summary showing the required RORs for 2016, 2017, and 2018. The 2018 Test Year required ROR is 7.97 percent, along with the amounts of common equity and the amounts and costs of long term debt and short-term debt. The 10.30 percent return on equity (ROE) reflected in the 2018 Test Year cost of capital is supported in the Direct Testimony of OTP witness Mr. Robert B. Hevert. The 7.97 percent overall ROR is supported by the Direct Testimony of OTP witness Mr. Kevin G. Moug.

Q. WHAT IS SHOWN ON FINANCIAL SCHEDULE E-1?

A. Schedule E-1 shows the operating revenue under the present and proposed rates by rate schedule. Schedule E-1 indicates that on an annual basis the proposed rates will produce additional revenues of $15,715,320 for the North Dakota jurisdiction. OTP witness Mr. David G. Prazak sponsors this Schedule in his Direct Testimony.

Q. WHAT DOES FINANCIAL SCHEDULE F-2 SHOW?

A. Schedule F-2 shows the development of the gross revenue conversion factor. This factor is used on Schedule A-1 to convert the 2018 Test Year income deficiency to the 2018 Test Year revenue deficiency.

Q. WHAT IS INCLUDED IN FINANCIAL SECTION G?

A. Section G of Volume 3 includes information regarding advertising expense. OTP witness Mr. Bryce C. Haugen supports this information in his Direct Testimony.

VII. CAPITAL BUDGET PROCESS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will provide an overview of the process used to develop the OTP Capital Budget. I will identify the participants in the Capital Budget, and describe the processes used in developing the Capital Budget. OTP witness Ms. Christine L. Petersen sponsors testimony which describes the OTP O&M Budget process.

Q. WHAT SYSTEM DOES OTP USE FOR CAPITAL BUDGETING?

A. The Capital Budget is developed using a software package called "Power Plant." OTP has used Power Plant since 2012. After the Capital Budget is developed in Power Plant, the information is loaded into Utilities International (UI) to develop the cost of service study.

Q. PLEASE IDENTIFY THE SIGNIFICANT PARTICIPANTS IN CAPITAL EXPENDITURE BUDGETING PROCESS FOR OTP.

A. The OTP Capital Budget is developed, maintained, and updated by the Fixed Assets Accounting Department. Several other groups within OTP also have significant roles in the OTP Capital Budgeting process, including the Business Areas within OTP. Sponsors of individual projects and the Vice Presidents of the Business Areas and the Department Managers within the Business Areas have significant roles.

OTP also has a Capital Budget Committee. The Capital Budget Committee is comprised of managers from various Business Areas. The Capital Budget Committee plays a significant role in prioritizing capital projects and determines if projects can be deferred, removed, or need to be kept in the year for which they are forecasted.

The OTP Chief Financial Officer (CFO) and OTP President also have significant roles. Annual targets for OTP's Routine capital projects (which I will define below) are determined by the CFO and President. Approval of a specific project by the OTP Board of Directors or the Otter Tail Corporation Board of Directors may also be required, depending on the level of spending involved in a project. The overall Capital Budget

requires approval of the OTP Board of Directors and the Otter Tail Corporation Board of Directors.

Q. WHAT ARE THE CATEGORIES OF PROJECTS IN OTP'S CAPITAL BUDGETS?

A. OTP's Capital Budgets are made up of Routine and Non-Routine projects.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF ROUTINE PROJECTS.

A. Routine projects are typically lower cost projects with construction timelines that typically do not span more than one year. Routine projects are projects done in the normal course of business that help maintain the functionality of an asset, support typical customer growth, address minor compliance requirements, and maintain system reliability. Routine projects also include projects related to serving new customers by building new facilities or upgrading existing facilities.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF NON-ROUTINE PROJECTS.

A. Non-Routine capital projects are typically higher cost projects that are not done on a yearly basis and for which the construction duration normally spans more than one year. Non-Routine projects are typically done to address major compliance requirements and/or adding a significant transmission or generation asset.

Q. WHAT IS THE PLANNING HORIZON FOR OTP CAPITAL BUDGETS?

A. The OTP Capital Budget normally covers a horizon from the current year to five years into the future. OTP annual Capital Budgets are developed in the context of a Five-Year Capital Budget. Each year, the Five-Year Capital Budget is revisited and extended for an additional year.

Q. PLEASE SUMMARIZE THE INITIAL STEPS IN DEVELOPING OTP'S CAPITAL BUDGET.

A. OTP's Capital Budget process begins the first quarter of the year before the Budget Year (i.e. first quarter of 2017 for the OTP 2018 Capital Budget). The Capital Budget process

begins with identification of new projects for consideration or updating of projects previously submitted through a prior Capital Budget to be reconsidered for the upcoming Five-Year Capital Budget.

Project Sponsors (the managers responsible for projects) propose new projects. The Project Sponsors are required to identify: (1) the need for the project; (2) the work to be completed; (3) the benefits of the project; and (4) any alternatives that were considered. After new projects are proposed by the Project Sponsors, the proposed projects are reviewed by the Vice Presidents for the Business Areas responsible for the projects. At this stage, the Vice President determines whether the project is to be considered further or be denied for consideration in the Five-Year Capital Budget.

After all projects for further consideration have been identified, the Capital Budget Committee categorizes each project as either Routine or Non-Routine and prioritizes the projects. The objective of the Capital Budget Committee is to develop the best list of projects to include in the preliminary Five-Year Capital Budget in accordance with the Routine Capital Budget targets set for OTP. The Capital Budget Committee generally discusses all Routine projects greater than $250,000 in detail.

Q. PLEASE DESCRIBE FURTHER HOW POTENTIAL PROJECTS ARE PRIORITIZED.

A. After the Capital Budget Committee finalizes the list of projects to include in the preliminary Five-Year Capital Budget, the list is presented to the OTP Executive Team for approval. The presentation and approval by the OTP Executive Team generally occurs in the first half of May.

Q. WHAT HAPPENS AFTER THE CAPITAL BUDGET COMMITTEE HAS DEVELOPED THE LIST OF CAPITAL PROJECTS?

A. The list is returned to the Capital Budget Committee and shared with the respective Business Units. Smaller projects (generally less than $500,000) are presented and approved through the Business Area Vice President. Larger projects (generally greater than $500,000) are first presented to the Capital Budget Committee for further review.

Routine (and Non-Routine) capital projects over $1,000,000 generally require project review and approval from the OTP Executive Team.

The OTP President can approve Routine (and Non-Routine) capital projects up to $5,000,000. If the capital project is greater than $5,000,000, it requires approval by the OTP Board of Directors. The OTP Board of Directors can approve capital projects up to $15,000,000. Any capital project over $15,000,000 requires approval by the Otter Tail Corporation Board of Directors.

Q. HOW IS THE FIVE-YEAR CAPITAL SPENDING FORECAST FINALIZED?

A. During the fourth quarter of the year before the Budget Year, the Five-Year Capital Budget Forecast is updated and reviewed by the Capital Budget Committee. A further project-by-project review is then conducted by the OTP Executive Team. Thereafter, the OTP Board of Directors and the Otter Tail Corporation Board of Directors approve the total spending levels within the Five-Year Capital Budget.

Q. ARE NON-ROUTINE PROJECTS SUBJECT TO ADDITIONAL SCRUTINY IN THE CAPITAL BUDGET PROCESS?

A. Yes. Non-Routine projects (and a few Routine projects) are also subject to the Phase Review Process. There are three phases in the Phase Review Process. The first phase is the Development Phase. The Development Phase of the project secures funding to do the necessary research to determine the feasibility of the project. At this stage, there is no commitment to the project.

After the Development Phase, the Project Sponsor seeks approval and final commitment to proceed with construction. During the second phase, the Construction Phase, detailed project scopes and objectives are developed, agreements are negotiated, and vendors are chosen. Completion of these steps leads to construction of the project.

After the project is completed, there is a third, Post Project Review Phase. During the Post Project Review Phase, the project is reviewed. This review includes assessment of: (1) the performance of the project against the scope and objectives that had been

developed at the beginning of the project; (2) expenses of the project; and (3) lessons learned.

Q. AFTER PROJECT DEVELOPMENT BEGINS, WHAT STEPS DOES OTP TAKE TO MONITOR AND MANAGE COMPLETION OF THE PROJECT?

A. Capital spending is monitored and reported monthly by comparing actual cash-flows to budgeted cash-flows to ensure accuracy and accountability, and to quickly identify any issues which may arise throughout the construction process. The monitoring and reporting process includes preparation and circulation of reports that outline the actual versus budgeted capital spend for projects on a monthly and year to date basis for purposes of receiving answers for any outstanding questions that may arise.

Project updates are provided to Business Area Vice Presidents on a quarterly basis. Project updates include milestone schedules, budget summaries, major accomplishments, upcoming milestones/activities, deviations from project scope, and updated risk summaries.

Q. DOES OTP PERFORM REFORECASTING OF PROJECTS WHILE UNDER CONSTRUCTION?

A. Yes. Monthly reforecasting is performed for all Routine and Non-Routine projects. Monthly reforecasting of all Non-Routine projects is performed by Plan Sponsors. Monthly reforecasting of Routine projects is performed by the Fixed Assets Accounting Department.

More extensive quarterly reforecasting of Routine projects occurs in the second and third quarters. This process allows forecasts to be refreshed as the construction process is occurring and as progress removes levels of uncertainty.

The level of monthly reforecasting of Non-Routine projects makes additional quarterly reforecasting unnecessary.

Q. HAS OTP INSTITUTED ANOTHER PROCESS TO INCREASE ITS FOCUS ON MANAGEMENT OF CAPITAL EXPENDITURES

A. Yes. OTP has initiated a Project Management Initiative (PMI) to: (1) ensure the prudent execution of capital projects; (2) define consistent monthly reporting procedures and formats; and (3) engage OTP management to more closely monitor capital projects. The PMI is primarily focused on Routine and Non-Routine projects over $250,000. The intent of PMI is to develop a process that engages management in the review of more complex projects and that the requirements placed on those projects add value during the execution of the project.

Q. PLEASE SUMMARIZE THE PMI PROCESS.

A. The PMI is primarily driven by the Fixed Assets Accounting Department and Project Sponsors of projects selected for the PMI, with involvement by the Vice Presidents of Asset Management, Energy Supply, Customer Service and Information Technology (IT), as well as the General Counsel and the CFO. Reports on projects within the PMI include: (1) updates on the projects milestone schedules; (2) budget summaries; (3) major accomplishments within the last quarter; (4) upcoming milestones/activities in the next quarter; (5) deviations from project scope; and (6) updated risk summaries. Information is reviewed by OTP executives monthly and during quarterly meetings with Plan Sponsors.

Q. DOES THE OTP EXECUTIVE TEAM PROVIDE ADDED SUPERVISION OF SOME NON-ROUTINE PROJECTS?

A. Yes. Certain Non-Routine projects that span multiple years and have intensified risk or capital spending have also been incorporated into a review process at regularly scheduled staff meetings of the OTP Executive Team. For example, the CapX2020 transmission projects, Big Stone Air Quality Control System (AQCS) project, and the Multi-Value Project (MVP) transmission projects have been reviewed at regular intervals by the OTP Executive Team.

Q. HAS OTP PROVIDED FURTHER INFORMATION ON THE DEVELOPMENT OF ITS CAPITAL BUDGET RELATING TO THIS APPLICATION?

A. Further information about the development of OTP's Capital Budget is contained in Volume 5, Budget Documentation.

VIII. RATE BASE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will discuss the components of Rate Base for the 2018 Base Year and the 2018 Test Year. I will also address the Rate Base effects of transferring recovery of certain environmental, renewable, and transmission project costs from riders into base rates, as further discussed by Mr. Haugen in his Direct Testimony.

Q. WHAT RATE BASE FINANCIAL SCHEDULES HAS OTP PROVIDED?

A. OTP has provided Schedules B-1 through B-5 in Volume 3, Supporting Information, under Tab II, B.

Q. WHAT TIME PERIODS ARE SHOWN ON THOSE FINANCIAL SCHEDULES?

A. The Rate Base schedules show information for: 1) 2016 Actual Year; 2) 2017 Current Period; and 3) 2018, including the 2018 Base Year and 2018 Test Year.

Q. PLEASE BRIEFLY DESCRIBE THE RATE BASE FINANCIAL SCHEDULES INCLUDED IN VOLUME 3.

A. Schedule B-1, Rate Base Summary, summarizes the North Dakota electric utility Rate Base for each of the four time periods under discussion (2016 Actual Year, 2017 Current Period, the 2018 Base Year and the 2018 Test Year). Schedule B-2 shows average Utility Plant in Service, average Accumulated Depreciation, and net average Utility Plant in Service in detail by function and all remaining Rate Base components in total for the entire system and the North Dakota jurisdiction. Schedule B-2 provides the detail underlying the information in the summary Schedule B-1. Schedule B-3 is a bridge schedule showing changes from OTP's 2007 Case No. 08-862 to the 2018 Test Year.

Schedule B-4, pages 1 through 3, summarizes jurisdictional allocation factors by Rate Base component. Schedule B-5 shows the adjustments made to the 2018 Base Year data to develop the 2018 Test Year. This information is shown for the 2018 Base Year and 2018 Test Year. Schedule B-6 is a summary of approaches used and assumptions made in determining the average Base Rate Base for the 2018 Base Year.

Q. WHAT IS THE SOURCE OF THE 2016 ACTUAL YEAR RATE BASE INFORMATION?

A. The 2016 Actual Year information is taken from OTP's North Dakota jurisdictional cost of service study (JCOSS), which is the basis (including cash working capital) for reporting the earned regulated returns included in the 2016 North Dakota Annual Report filed with the Commission.

Q. WHAT IS THE SOURCE OF THE 2017 CURRENT PERIOD RATE BASE INFORMATION?

A. The 2017 Current Period is based on actual results through July 2017 and a forecast for August through December 2017. We will make full 2017 actual results available to stakeholders.

Q. WHAT IS THE SOURCE OF THE 2018 BASE YEAR RATE BASE INFORMATION CONTAINED IN THE FINANCIAL SCHEDULES?

A. The 2018 Base Year is based on prior years' data along with OTP's 2018 Capital Budget, and reflects Traditional Adjustments described in Section IX.A, below.

Q. WHAT IS THE AMOUNT OF THE 2018 BASE YEAR RATE BASE AND 2018 TEST YEAR RATE BASE?

A. As shown in Exhibit___(TAA-1), Schedule 5 and Volume 3, Schedule B-1, the 2018 Base Year North Dakota Jurisdictional Rate Base is $350.8 million and the 2018 Test Year Rate Base is $354.2 million. I will explain the differences between the 2018 Base

North Dakota Jurisdictional Rate Base and the 2018 Test Year Rate Base in Section IX of my Direct Testimony.

Q. PLEASE BRIEFLY DESCRIBE THE COMPONENTS OF THE RATE BASE.

A. Rate Base consists primarily of the capital expenditures made by a utility to obtain or construct plant, equipment, materials, supplies and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation expense and non-investor sources of capital (such as accumulated deferred income tax).

Q. HOW WERE THE 2018 BASE YEAR AND 2018 TEST YEAR RATE BASE AMOUNTS DEVELOPED?

A. OTP developed its 2018 Capital Budget, the 2018 Base Year, and 2018 Test Year based on simple averages. OTP adjusted for known and measurable changes along with "Traditional" regulatory adjustments to arrive at the 2018 Base Year. These adjustments were made to reflect recognized regulatory requirements and to "normalize" the budgeted financial information for one-time events that will not be recurring on an on-going basis. Other Rate Case Adjustments were made to develop the 2018 Test Year. I will discuss those adjustments in Section IX of my Direct Testimony.

Q. WHAT ARE THE MAJOR COMPONENTS OF THE 2018 TEST YEAR RATE BASE?

A. The 2018 Test Year Rate Base is generally comprised of the following major items:

- Net utility plant in service (which reflects accumulated depreciation);
- Construction work in progress;
- Cash working capital items; and
- Accumulated deferred income taxes.

A. NET UTILITY PLANT IN SERVICE

Q. WHAT DOES EXHIBIT___(TAA-1), SCHEDULE 7 AND VOLUME 3, SCHEDULE B-5 INCLUDE REGARDING UTILITY PLANT IN SERVICE?

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show Utility Plant In Service (by total and component) which is before depreciation, Accumulated Depreciation (by total and component), and Net Utility Plant In Service (by total and component). These are shown for OTP and the North Dakota Jurisdiction for the 2018 Base Year and the 2018 Test Year. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show OTP's North Dakota Jurisdictional Net Utility Plant in Service is $450.9 million for the 2018 Base Year and $453.6 million for the 2018 Test Year.

Q. WHAT DOES "UTILITY PLANT IN SERVICE" REPRESENT?

A. Utility Plant in Service is based upon the original cost of property from the books and records of OTP, adjusted to account for the projected additions and/or retirements described above in the Capital Budgeting Process.

Q. WHAT DOES "NET UTILITY PLANT" REPRESENT?

A. Net utility plant represents OTP's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in Rate Base at depreciated original cost, reflecting a simple average based on monthly balances from December 2017 through December 2018.

Q. WHAT DOES "UTILITY PLANT IN SERVICE" REPRESENT?

A. Utility Plant in Service is based upon the original cost of property from the books and records of OTP adjusted to account for the projected additions and/or retirements described above in the Capital Budgeting Process.

Q. DOES EXHIBIT___(TAA-1), SCHEDULE 7 AND VOLUME 3, SCHEDULE B-5 INCLUDE ALL COMPONENTS OF NET UTILITY PLANT?

A. Yes. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 include all components of Utility Plant in Service (Production, Transmission, Distribution, General, and Intangible) and the Accumulated Depreciation related to each of these components. The net of Utility Plant in Service and Accumulated Depreciation is the Net Utility Plant in Service. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show these amounts and adjustments, and the amounts and adjustments that are allocated to the North Dakota jurisdiction.

Q. DOES EXHIBIT___(TAA-1), SCHEDULE 7 AND VOLUME 3, SCHEDULE B-5 INCLUDE THE RATE BASE COMPONENTS DISCUSSED BY OTP WITNESSES?

A. Yes. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 include all the Rate Base components discussed by the other OTP witnesses, including the Big Stone AQCS and Hoot Lake MATS projects discussed in the Direct Testimony of OTP witness Mr. Kirk A. Phinney, and the investments currently recovered in riders that are being rolled into base rates discussed in the Direct Testimony of Mr. Haugen. I discuss the process of including the investments currently recovered in riders in Subsection VIII (E) of my Direct Testimony.

Q. PLEASE BRIEFLY DESCRIBE ACCUMULATED DEPRECIATION.

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 include Accumulated Depreciation for all the Utility Plant in Service components. The sum of the 2018 Base Year North Dakota Jurisdiction Accumulated Depreciation for these components is negative ($304.2 million) and negative ($304.8 million) for the 2018 Test Year.

B. CONSTRUCTION WORK IN PROGRESS

Q. WHAT IS THE AMOUNT OF CONSTRUCTION WORK IN PROGRESS (CWIP) INCLUDED IN EXHIBIT___(TAA-1), SCHEDULE 7 AND VOLUME 3, SCHEDULE B-5?

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show that OTP's North Dakota Jurisdictional CWIP is $272,000 for the 2018 Base Year and for the 2018 Test Year.

Q. PLEASE EXPLAIN CWIP.

A. CWIP consists of two parts: 1) Short-Term and; 2) Long-Term. Short-Term CWIP applies to small rebuilds, increasing capacity of lines, upgrading lines, and similar types of activity which benefit existing customers. These are construction projects which cost less than $10,000 and require less than 30 days to complete. The Commission has ruled in our previous cases that Short-Term CWIP could be included in Rate Base. Long-Term CWIP is all CWIP that is not defined as Short-Term CWIP. Long-Term CWIP has not been included in Rate Base.

Q. HAS OTP REMOVED ANY REIMBURSABLE AMOUNTS FROM ITS CWIP BALANCE?

A. Yes, the CWIP balance (and thus Rate Base) does not include amounts which are reimbursable by government entities, as occurs in limited cases where lines must be moved because of highway work, or by customers (contribution in aid of construction).

C. WORKING CAPITAL

Q. PLEASE EXPLAIN THE WORKING CAPITAL INCLUDED IN EXHIBIT___(TAA-1), SCHEDULE 7 AND VOLUME 3, SCHEDULE B-5.

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show all the working capital elements, including materials and supplies, fuel stocks, prepayments and customer advances/deposits, and cash working capital, including OTP's North Dakota Jurisdictional amounts for the 2018 Base Year and 2018 Test Year.

Q. PLEASE EXPLAIN MATERIALS AND SUPPLIES.

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show OTP's North Dakota Jurisdictional Materials and Supplies for the 2018 Base Year and 2018 Test Year is $8.3 million. OTP's accounting records provide the materials and supplies inventory at the generating plants, central stores, and at various locations throughout OTP's service territory. The dollar amount used to calculate revenue requirements is based on a simple average.

Q. PLEASE EXPLAIN FUEL STOCKS?

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show OTP's North Dakota Jurisdictional Fuel Stocks for the 2018 Base Year and 2018 Test Year is $4.4 million. Fuel Stocks is based on the simple average of inventory balances for fuel stocks. Fuel stocks include coal stockpiles and fuel oil for OTP's generating plants.

Q. PLEASE DESCRIBE THE PREPAYMENTS

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show OTP's North Dakota Jurisdictional Prepayments for the 2018 Base Year and 2018 Test Year are negative ($13.2 million). Four separate items are grouped together under the line item of Prepayments. The four items are: 1) pre-paid insurance; 2) pre-paid pension; 3) post-retirement benefits liability; and 4) post-employment benefits liability. The amounts for each item are developed using simple averages.

Q. PLEASE DESCRIBE CASH WORKING CAPITAL.

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show OTP's North Dakota Jurisdictional Cash Working Capital for the 2018 Base Year and 2018 Test Year is $3.7 million. Cash Working Capital represents a determination of cash working capital requirements for operation, maintenance, and other expenses. I will explain the adjustment to Cash Working Capital in Section IX of my Direct Testimony.

Q. HOW WERE CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. The cash working capital requirements included in Rate Base is based on a Lead Lag Study prepared by OTP using calendar year 2014 financial data. This study analyzes the lapse of time between the average day on which OTP incurs expenses to serve its customers and the average day on which cash is received from customers in payment of that service. Ms. Ice explains the Lead Lag Study in her Direct Testimony.

D. ACCUMULATED DEFERRED INCOME TAXES

Q. WHAT IS THE AMOUNT OF ACCUMULATED DEFERRED INCOME TAXES (ADIT) INCLUDED IN EXHIBIT___(TAA-1), SCHEDULE 7 AND VOLUME 3, SCHEDULE B-5?

A. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show OTP's North Dakota Jurisdictional ADIT for the 2018 Base Year is ($103.2 million) and ($102.5 million) for the 2018 Test Year. These amounts reflect a simple average of the beginning and prorated ending 2018 Test Year ADIT balances. Mr. Tommerdahl further explains the proration of the 2018 Test Year ADIT in his Direct Testimony.

E. RIDER ROLL-IN

Q. IS OTP PROPOSING TO MOVE ANY PROJECTS FROM RIDER RECOVERY TO BASE RATE RECOVERY IN THIS FILING?

A. Yes. OTP proposes to transfer recovery of certain costs presently recovered in the Environmental Cost Recovery Rider (ECRR), the TCRR, and Renewable Resource Adjustment Rider (RRAR) to base rates after this case. The Direct Testimony of Mr. Haugen provides additional information regarding OTP's proposal to roll the ECRR, TCRR, and RRAR projects into base rates.

Q. WHAT IS THE AMOUNT OF THE 2018 TEST YEAR PLANT IN SERVICE INCLUDED IN RATE BASE FOR ENVIRONMENTAL PROJECTS CURRENTLY RECOVERED IN THE ECRR?

A. The 2018 Test Year Utility Plant in Service included in Rate Base for the environmental projects currently recovered in the ECRR (collectively, the ECRR Projects) is $199.4 million (OTP Total), and $72.6 million (OTP ND).

Q. WHAT IS THE 2018 TEST YEAR PLANT IN SERVICE INCLUDED IN RATE BASE FOR TRANSMISSION PROJECTS CURRENTLY RECOVERED IN THE TCRR?

A. The 2018 Test Year Utility Plant in Service included in Rate Base for the transmission projects currently recovered in the TCRR (collectively, the TCRR Projects) is $246.5 million (OTP Total) and $47.2 million (OTP ND).

Q. WHAT IS THE 2018 TEST YEAR PLANT IN SERVICE INCLUDED IN RATE BASE FOR RENEWABLE PROJECTS CURRENTLY RECOVERED IN THE RRAR?

A. The 2018 Test Year Utility Plant in Service included in Rate Base for the renewable projects currently recovered in the RRAR (collectively, the RRAR Projects) is $268.7 million (OTP Total) and $101.0 million (OTP ND).

IX. ADJUSTMENTS TO RATE BASE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will identify and explain the Traditional and Rate Case Adjustments that are made to the 2018 Base Year Rate Base to arrive at the 2018 Test Year Rate Base.

Q. HAVE YOU PREPARED A LIST OF THE ADJUSTMENTS TO RATE BASE?

A. Yes. The Traditional Adjustments to Rate Base are reflected in Exhibit___(TAA-1), Schedule 6. The Rate Case Adjustments to Rate Base are reflected in Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5. The following is a list of the adjustments to Rate Base:

<u>Traditional Adjustments to Rate Base</u>

1. Jurisdictional AQCS Costs
2. Transmission Recovery

Test Year Adjustments to Rate Base

1. Normalize CISone Project;
2. ADIT Proration
3. Changes in Allocations Due to Effects of 2018 Test Year Adjustments;

A. TRADITIONAL ADJUSTMENTS TO RATE BASE

Q. HOW IS THE INFORMATION IN EXHIBIT___(TAA-1), SCHEDULE 6 AND IN THIS SECTION OF YOUR DIRECT TESTIMONY PRESENTED?

A. All the information in Exhibit___(TAA-1), Schedule 6 and in this section of my Direct Testimony is presented in terms of North Dakota jurisdictional amounts.

1. Jurisdictional AQCS Costs

Q. PLEASE SUMMARIZE THE JURISDICTIONAL ADJUSTMENT TO DIRECT ASSIGN AQCS COSTS.

A. The MPUC did not allow OTP to include the cost of the baghouse portion of the AQCS project in the Minnesota ECRR, while both the Commission and the SD PUC did allow that recovery. As a result, it was necessary to directly assign to the North Dakota jurisdiction Allowance for Funds Used During Construction (AFUDC) accruing on the unrecovered bag house project costs during construction. This adjustment reduces Total Net Plant in Service by $1,399,687, Exhibit___(TAA-1), Schedule 6, and reduces Total Average Rate Base by $1,399,687, as shown on Exhibit___(TAA-1), Schedule 6.

2. Transmission Recovery

Q. PLEASE SUMMARIZE THE ADJUSTMENT FOR TRANSMISSION RECOVERY.

A. The non-retail portion of OTP's investments in the MVP transmission projects are directly assigned to the FERC jurisdiction. This direct assignment: (1) reduces Total Plant in Service by $50,100,785; (2) increases Accumulated Depreciation by $1,749,778; (3) reduces CWIP by $37,926,380; and (4) increases Accumulated Deferred Income Taxes by $8,626,466; and (5) reduces Total Average Rate Base by $77,650,922, all as shown on Exhibit___(TAA-1), Schedule 6.

B. TEST YEAR ADJUSTMENTS TO RATE BASE

Q. HOW IS THE INFORMATION IN EXHIBIT___(TAA-1), SCHEDULE 7 AND VOLUME 3, SCHEDULE B-5 AND IN THIS SECTION OF YOUR DIRECT TESTIMONY PRESENTED?

A. All the information in Exhibit___(TAA-1), Schedule 7, Volume 3, Schedule B-5 and in this section of my Direct Testimony is presented in terms of North Dakota jurisdictional amounts.

1. Normalize CISOne Project

Q. DID YOU NORMALIZE 2018 TEST YEAR PLANT IN SERVICE FOR THE CSIONE PROJECT?

A. Yes. Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 show the adjustment to Plant in Service for OTP's CISOne project that will go into service during the 2018 Test Year. The adjustment: (1) removes the project and any 2018 AFUDC from CWIP; (2) annualizes the project in Plant in Service; and (3) includes any accumulated depreciation and the associated depreciation expense for this project. Mr. Tommerdahl explains the basis for this adjustment in his Direct Testimony.

Q. PLEASE SUMMARIZE THE CUMULATIVE ADJUSTMENTS MADE FOR THE CISONE PROJECT.

A. The adjustments made for the CISOne project are set forth in Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5 and include: (1) a $3,272,488 increase to Intangible Plant in Service; (2) a $557,102 increase to Intangible Accumulated Depreciation; (3) a $2,715,386 increase to Intangible Net Plant in Service; and (4) a $2,715,386 increase to Total Average Rate Base. The corresponding impacts on the 2018 Test Year Income Statement are explained in Section XI of my Direct Testimony.

2. ADIT Proration

Q. PLEASE SUMMARIZE THE ADJUSTMENT FOR PRORATION OF ADIT.

A. The adjustment for the proration of ADIT is required by Internal Revenue Service (IRS) Regulation §1.167(l)-1(h)(6), which provides that ratemaking procedures and adjustments

must be consistent with normalization accounting. This requirement is described in the Direct Testimony of Mr. Tommerdahl. The Rate Base adjustment for the proration of the ADIT decreases the ADIT balance by $806,647, which increases the Rate Base by $806,647, as shown in Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5.

3. Effect of Test Year Adjustments on Allocations

Q. DO THE 2018 TEST YEAR ADJUSTMENTS CAUSE IMPACTS TO ALLOCATIONS?

A. Yes. The impacts are due to changes in the allocators that result from the other financial adjustments made to the 2018 Test Year. They are the result of calculations within the Cost of Service model itself. For example, any adjustment to Net Plant in Service will have a direct impact on the Net Electric Plant in Service (NEPIS) allocation factor calculated as a percentage of total system Net Plant. The allocation percentage is simultaneously recalculated each time an adjustment to Net Plant in Service occurs, thereby providing the most up-to-date factor possible.

As a result, anything that is allocated on NEPIS is simultaneously re-calculated on a jurisdictional basis as well. The impacts include: (1) minor changes ($9,658 decrease) to Prepayments and Customers Advances and Deposits ($268 decrease); (2) a $54,333 decrease in Cash Working Capital; and (3) a $48,685 increase in ADIT. The net effect is a $112,946 decrease to Total Average Rate Base, all as shown in Exhibit___(TAA-1), Schedule 7 and Volume 3, Schedule B-5.

X. INCOME STATEMENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section of my Direct Testimony, I will discuss the Income Statement and explain the Income Statement schedules for the 2018 Base Year and the 2018 Test Year. I will also address the Income Statement effects of rolling certain ECRR, TCRR and RRAR costs into base rates. Mr. Haugen discusses the substance of this proposal in his Direct Testimony.

A. SUMMARY OF FINANCIAL SCHEDULES

Q. WHAT INCOME STATEMENT FINANCIAL SCHEDULES HAS OTP PROVIDED?

A. OTP has provided Income Statement Schedules C-1 through C-8 Volume 3, Supporting Information.

Q. WHAT TIME PERIODS ARE SHOWN ON THESE SCHEDULES?

A. Those Income Statement schedules show information for: 1) 2016 Actual Year; 2) 2017 Current Period; and 3) 2018, including the 2018 Base Year and the 2018 Test Year.

Q. WHAT IS THE SOURCE OF THE 2016 BASE YEAR INCOME STATEMENT INFORMATION?

A. The source of the 2016 Actual Year Income Statement information is OTP's North Dakota JCOSS, which is the basis for reporting the earned ROR and ROE included in the 2016 North Dakota Jurisdictional Report filed with the Commission. The sources of the 2016 Actual Year information for the Income Statement are the same as for the Rate Base.

Q. WHAT IS THE SOURCE OF THE 2017 CURRENT PERIOD INCOME STATEMENT INFORMATION?

A. The 2017 Current Period is based on actual results through July 2017 and a forecast for August through December 2017. We will make full 2017 actual results available to stakeholders. The sources of the 2017 Current Period information for the Income Statement is the also the same as for the Rate Base.

Q. WHAT IS THE SOURCE OF THE 2018 BASE YEAR INCOME STATEMENT INFORMATION?

A. The sources of the 2018 Base Year information for the Income Statement are the same as for the Rate Base. The 2018 Base Year is based on OTP's 2018 Budget and reflects Traditional Adjustments described in Section XI.A, below.

B. SUMMARY OF TEST YEAR INCOME STATEMENT

Q. WHAT ARE THE 2018 BASE YEAR AND 2018 TEST YEAR TOTALS AVAILABLE FOR RETURN?

A. As shown in Exhibit___(TAA-1), Schedule 8 and Volume 3, Schedule C-3, the 2018 Base Year Total Available for Return (which is Net Income) is $19.6 million and the 2018 Test Year Total Available for Return is $18.4 million.

Q. PLEASE BRIEFLY DESCRIBE WHAT IS INCLUDED IN THE INCOME STATEMENT.

A. The Income Statement is composed primarily of: (1) Operating Revenues (which includes both retail revenues and other operating revenues); (2) Operating Expenses (which includes O&M expenses for the various operating segments, Administrative and General expenses, depreciation expense, and general taxes, including property taxes); (3) Income Tax Expense; and (4) Total Available for Return (which is Net Income).

Q. HOW WAS THE 2018 BASE YEAR INCOME STATEMENT DEVELOPED?

A. The 2018 Base Year Income Statement was developed using the 2018 budget for revenues and operation and maintenance expense, adjusted to remove the revenues and expenses that are part of "Traditional" regulatory adjustments. These adjustments were made to reflect recognized regulatory requirements and to "normalize" the budgeted financial information for one-time events that will not be recurring on an on-going basis. Other Rate Case Adjustments were made to develop the 2018 Test Year. I will discuss those adjustments in Section XI of my Direct Testimony.

Q. WHAT ARE THE MAJOR COMPONENTS OF THE INCOME STATEMENT THAT YOU WILL DISCUSS?

A. The major components of the Income Statement I will discuss are:

- Revenues;
- O&M Expenses;
- Depreciation Expense;

- Taxes; and
- Net Income.

Q. FOR WHICH OF THESE AREAS DO YOU AND OTHER OTP WITNESSES PROVIDE THE PRIMARY EXPLANATIONS?

A. I will provide the primary explanation of the Revenues and Depreciation Expense included in the 2018 Test Year. Other OTP witnesses will provide the primary explanation of O&M expenses.

C. TEST YEAR REVENUES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY?

A. This section describes how revenues were determined for purposes of calculating the 2018 Test Year base rate revenue requirement. The major components of Revenues are Retail Revenues and Other Revenues.

1. Retail Revenues

Q. WHAT IS THE AMOUNT OF RETAIL REVENUE INCLUDED IN EXHIBIT___(TAA-1), SCHEDULE 8 AND VOLUME 3, SCHEDULE C-3?

A. Exhibit___(TAA-1), Schedule 8 and Volume 3, Schedule C-3 show that OTP's North Dakota Jurisdictional Retail Revenue is $148.0 million for the 2018 Base Year and $148.1 for the 2018 Test Year.

Q. HOW WAS RETAIL REVENUE DETERMINED?

A. Retail revenue in the 2018 Budget and Test Year was determined on a calendar month basis using the projected sales forecast (as described in the Direct Testimony of OTP witness Mr. Brian H. Draxten) applied to current tariffs. Mr. Draxten explains how sales kWh in this forecast were developed. The same revenue calculation was used to determine the revenue requirement deficiency filed in the JCOSS for this rate case filing.

2. Other Electric Operating Revenue

Q. WHAT IS THE AMOUNT OF OTHER ELECTRIC OPERATING REVENUE INCLUDED IN EXHIBIT___(TAA-1), SCHEDULE 8 AND VOLUME 3, SCHEDULE C-3?

A. Exhibit___(TAA-1), Schedule 8 and Volume 3, Schedule C-3 show that OTP's North Dakota Jurisdictional Other Electric Operating Revenue Retail Revenue is $10.0 million for 2018 Base Year and 2018 Test Year.

Q. WHAT ARE THE COMPONENTS OF OTHER ELECTRIC OPERATING REVENUE?

A. Other Electric Operating Revenue includes items such as: 1) Midcontinent Independent System Operator (MISO) transmission related revenues 2) revenue from Integrated Transmission Agreements; 3) revenues from plant operations and steam sales; and 4) other miscellaneous revenues.

a) <u>MISO Revenues</u>

Q. ARE MISO REVENUES INCLUDED IN THE 2018 TEST YEAR?

A. Yes. Pursuant to MISO's Transmission and Energy Market Tariff and the MISO Transmission Owners Agreement, OTP receives revenues from several sources for use of its transmission system and related services that it provides. These sources of revenue include, but are not limited to the following: Schedule 1 - Scheduling, System Control & Dispatch; Schedule 2 - Reactive Supply & Voltage Control; Schedule 7 - Firm Transmission Service; Schedule 8 - Non-Firm Transmission Service; Schedule 9 - Network Integrated Transmission Service; and Schedule 11 - Pass-Through Revenue.

Q. IS REVENUE FROM OTHER MISO SERVICES INCLUDED IN THE 2018 TEST YEAR?

A. Yes. Revenue from other MISO services in the amount of $7,836,212 is included in the 2018 Test Year.

b) Integrated Transmission Agreement Revenues

Q. WHAT IS AN INTEGRATED TRANSMISSION AGREEMENT (ITA)?

A. An ITA is an agreement to jointly plan and construct a common transmission system with discrete ownership of individual facilities with reciprocal usage rights granted to each party. OTP has ITAs with the following entities: Minnkota Power Cooperative (Minnkota), Great River Energy (Great River), and East River Electric Power Cooperative (East River). Each of these agreements has been approved by FERC.

Q. PLEASE DESCRIBE THE ITA REVENUES THAT OTP RECEIVES.

A. OTP receives transmission revenue from other utilities through ITAs for joint use of defined transmission systems. Charges to Minnkota, Great River and East River for the scheduling and dispatch services provided by OTP under the ITAs are based on OTP's costs associated with system control and dispatching, including operating, maintenance, and fixed costs. Minnkota, Great River, and East River each pay their pro rata share of the system control and dispatching, operating, and maintenance expenses based on the respective joint use facilities owned by each party and OTP.

Q. ARE COSTS AND USAGE BALANCED UNDER THE ITAS?

A. Yes. One of the objectives of each ITA is to make sure each utility shares in the costs of the transmission system proportionate to usage. The proportion of investment to usage of the joint transmission system is determined each year for each of the ITAs. If a utility is deficient in its investment relative to the investment by the other party, it makes deficiency payments until the investment is equalized. The deficiency payments are payments by the underinvested utility of the carrying cost of the utility that is more than fully invested.

Q. IS REVENUE FROM THESE ITAS INCLUDED IN THE 2018 TEST YEAR?

A. Yes. Revenue from ITAs in the amount of $639,990 is included in the 2018 Test Year.

c) Plant Operator and Steam Revenues

Q. DOES OTP RECEIVE COMPENSATION AS THE PLANT OPERATOR FOR THE TWO JOINTLY OWNED GENERATING UNITS, BIG STONE AND COYOTE?

A. Yes. OTP operates the Big Stone Plant and Coyote Station on behalf of itself and its ownership partners (Minnkota, Northwestern, and Montana-Dakota Utilities for Big Stone and Minnkota, Northwestern, Montana-Dakota Utilities, and Northwestern Municipal Power Agency for Coyote Station). As the plant operator, OTP provides services for which it is compensated by its partners. The services include: scheduling and operations of the plants for both the day-ahead and real-time market; acting as the meter data management agent for all partners of the plants; settlement reconciliation of unit dispatches and actual generation; providing accounting reports and records to the partners; scheduling generator outages; communicating directly with the MISO generator dispatch desk; and providing and maintaining reliable communications between MISO, the plants, and the OTP control center.

Q. IS PLANT OPERATION REVENUE INCLUDED IN THE 2018 TEST YEAR?

A. Yes. Plant operation revenue in the amount of $138,170 is included in the 2018 Test Year.

Q. DOES OTP RECEIVE REVENUE FROM THE SALE OF STEAM?

A. Yes. Big Stone supplies steam to an ethanol plant near the Big Stone Plant.

Q. IS REVENUE FROM STEAM SALES INCLUDED IN THE 2018 TEST YEAR?

A. Yes. Revenue from steam sales is included in the amount of $782,847 in the 2018 Test Year.

d) Other Revenues

Q. ARE ALL OTHER SOURCES OF OTHER ELECTRIC OPERATING REVENUES ALSO INCLUDED IN THE 2018 TEST YEAR?

A. Yes. While I will not address all the other sources of Other Electric Operating Revenues, they are included in the 2018 Test Year.

Q. IS OTHER REVENUE INCLUDED IN THE 2018 TEST YEAR?

A. Yes. Other Revenue is included in the amount of $788,245 in the 2018 Test Year.

D. DEPRECIATION EXPENSE

Q. WHAT IS THE AMOUNT OF DEPRECIATION EXPENSE INCLUDED IN EXHIBIT___(TAA-1), SCHEDULE 8 AND VOLUME 3, SCHEDULE C-3?

A. Exhibit___(TAA-1), Schedule 8 and Volume 3, Schedule C-3 show OTP's North Dakota Jurisdictional Depreciation Expense is $20.7 million for the 2018 Base Year and $21.4 million for the 2018 Test Year.

Q. HOW WERE TEST YEAR DEPRECIATION EXPENSES DETERMINED?

A. The depreciation expense in the 2018 Test Year reflects the remaining lives and salvage percentage parameters as determined in our 2017 depreciation study and filed with the MPUC in Docket No. E017/D-17-652. These parameters are applied against the forecasted 2017 ending plant in service and accumulated depreciation balances to determine forecasted depreciation rates for the 2018 Test Year. These forecasted depreciation rates are applied against the 2018 Test Year plant in service balances to yield our 2018 Test Year depreciation expense.

E. INCOME TAXES

Q. WHAT IS THE AMOUNT OF INCOME TAX EXPENSE INCLUDED IN EXHIBIT___(TAA-1), SCHEDULE 8 AND VOLUME 3, SCHEDULE C-3?

A. Exhibit___(TAA-1), Schedule 8 and Volume 3, Schedule C-3 show OTP's North Dakota Jurisdictional Income Tax Expense is $4.0 million for the 2018 Base Year and $5.1 million for the 2018 Test Year.

Q. HOW WERE OTP'S INCOME TAX EXPENSES CALCULATED?

A. OTP's Federal and North Dakota income tax expenses are based solely on the regulated income and expense items included in the revenue requirement calculation using the "stand-alone" method. The stand-alone method determines the jurisdictional regulated income tax expense based solely on allowable regulated income and expense items. The current income tax expense calculation utilizes straight-line depreciation rates to determine depreciation expense as part of the current income tax expense calculation while modified accelerated income tax depreciation (MACRS) rates and a special bonus depreciation provision were used to determine deferred income taxes (which are treated as a reduction to Rate Base).

XI. ADJUSTMENTS TO INCOME STATEMENT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my Direct Testimony, I will describe the Traditional Adjustments and Rate Case Adjustments that have been made to determine the 2018 Base Year Income Statement and the 2018 Test Year Income Statement. The Traditional Adjustments to the Income Statement are reflected in Exhibit___(TAA-1), Schedule 9 attached to my Direct Testimony. The Rate Case Adjustments to the Income Statement are reflected in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8.

Q. HAVE YOU PREPARED A BRIDGE SCHEDULE SHOWING ALL ADJUSTMENTS YOU MADE TO ARRIVE AT THE 2018 TEST YEAR INCOME STATEMENT?

A. Yes. Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8, is a bridge schedule that includes a list of all the Income Statement adjustments made to the 2018 Base Year in developing the 2018 Test Year. Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8 also identifies the impact each adjustment has on the operating Income Statement.

Q. HAVE YOU PREPARED A LIST OF THE ADJUSTMENTS TO THE INCOME STATEMENT MADE FOR THE 2018 TEST YEAR?

A. Yes. The following is a list of Traditional Adjustments (necessary to arrive at the 2018 Base Year) and Rate Case Adjustments (necessary to arrive at the 2018 Test Year):

Traditional Adjustments to Income Statement:

1. Advertising Expense
2. Economic Development Costs
3. Incentive Compensation
4. SPP Schedule 9 and 11 Expenses
5. Transmission Recovery
6. Wholesale Asset Based Margins

Test Year Adjustments to Income Statement

1. Normalize CISOne Project
2. Rate Case Expense
3. Normalize Plant Outage
4. Removal of Production Tax Credits
5. Economic Development
6. Prorate ADIT for Riders
7. Allocation Changes due to Test Year Adjustments

A. TRADITIONAL ADJUSTMENTS TO INCOME STATEMENT

Q. HOW IS THE INFORMATION IN EXHIBIT___(TAA-1), SCHEDULE 9 AND IN THIS SECTION OF YOUR DIRECT TESTIMONY PRESENTED?

A. All the information in Exhibit___(TAA-1), Schedule 9 and in this section of my Direct Testimony is presented in terms of North Dakota jurisdictional amounts.

1. Advertising Expense

Q. HAVE YOU MADE ADJUSTMENTS WITH RESPECT TO ADVERTISING EXPENSES?

A. Yes. The adjustment for Advertising Expenses: (1) decreases Total O&M Expenses by $225,857; (2) increases Total Income Taxes by $85,379; and (3) increases Net Operating Income by $140,479, all as shown on Exhibit___(TAA-1), Schedule 9. Mr. Haugen discusses the basis for this adjustment in his Direct Testimony.

2. Economic Development Costs

Q. HAVE YOU MADE ADJUSTMENTS WITH RESPECT TO ECONOMIC DEVELOPMENT EXPENSES?

A. Yes. The adjustment for Economic Development Costs: (1) decreases Total O&M Expenses by $68,871; (2) increases Total Income Taxes by $26,035; and (3) increases Net Operating Income by $42,837, all as shown on Exhibit___(TAA-1), Schedule 9. Mr. Tommerdahl discusses the basis for this adjustment in his Direct Testimony.

3. Incentive Compensation

Q. HAVE YOU MADE ADJUSTMENTS WITH RESPECT TO INCENTIVE COMPENSATION?

A. Yes. The adjustments with respect to Incentive Compensation reflect the cap of 25 percent of salary for each employee and are described in the Direct Testimony of Mr. Wasberg. The adjustment for incentive compensation: (1) decreases Total O&M Expenses by $205,563; (2), increases Total Income Taxes by $77,707; and (3) increases Net Operating Income by $127,856, all as shown on Exhibit___(TAA-1), Schedule 9.

4. SPP Schedule 9 and 11 Expenses

Q. HAVE YOU MADE ADJUSTMENTS WITH RESPECT TO SPP SCHEDULE 9 AND 11 EXPENSES?

A. Yes. The adjustment for SPP Schedule 9 and 11 expenses: (1) decreases Total O&M Expenses by $469,227; (2) increases Total Income Taxes by $177,377; and (3) increases Net Operating Income by $291,850, all as shown on Exhibit___(TAA-1), Schedule 9. These adjustments are needed to reflect OTP's recovery of the North Dakota portion of

SPP Schedule 9 and 11 expenses in the TCRR and to reflect a direct assignment of the Minnesota portion of the expenses.

5. Transmission Recovery

Q. HAVE YOU MADE ADJUSTMENTS WITH RESPECT TO TRANSMISSION RECOVERY?

A. Yes. The adjustment for Transmission Recovery: (1) decreases Total Operating Revenues by $10,764,133; (2) decreases Total O&M Expenses by $6,424; (3) decreases Total Depreciation Expense by $872,002; (4) decreases Total Income Taxes by $3,494,303; and (5) decreases Net Operating Income by $5,749,396, all as shown on Exhibit___(TAA-1), Schedule 9. Mr. Haugen discusses the basis for this adjustment in his Direct Testimony.

6. Wholesale Asset Based Margins

Q. IS AN ADJUSTMENT NECESSARY FOR WHOLESALE ASSET BASED MARGINS?

A. Yes. In OTP's last rate case (Case No. PU-08-862), parties agreed to credit (through the Fuel Clause Adjustment (FCA)) 85 percent of all asset based margins that were achieved by OTP. It was recognized that passing the credits directly through the FCA as they are realized ensures that neither customers nor OTP will be disadvantaged by a non-representative margin forecast in the 2007 Test Year. Also, the parties recognized that by sharing the gains on asset based sales, OTP will have an incentive to maximize the benefit from these sales.

Q. HAVE YOU MADE ADJUSTMENTS WITH RESPECT TO WHOLESALE ASSET BASED MARGINS?

A. Yes. The adjustment for Wholesale Asset Based Margins reduces the total revenues and expenses to the required 85 percent. The adjustment for Wholesale Asset Based Margins: (1) decreases Total Operating Revenues by $31,996; (2) decreases Total O&M Expenses by $33,119; (3) increases Total Income Taxes by $425; and (4) increases Net Operating Income by $699, all as shown on Exhibit___(TAA-1), Schedule 9.

B. TEST YEAR ADJUSTMENTS TO THE INCOME STATEMENT

Q. HOW IS THE INFORMATION IN EXHIBIT___(TAA-1), SCHEDULE 10 AND VOLUME 3, SCHEDULE C-8 AND IN THIS SECTION OF YOUR DIRECT TESTIMONY PRESENTED?

A. All the information in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8 and in this section of my Direct Testimony is presented in terms of North Dakota jurisdictional amounts.

1. Normalize CISOne Project

Q. HAVE YOU MADE AN INCOME STATEMENT ADJUSTMENT TO NORMALIZE THE CISONE PROJECT TO CORRESPOND TO THE RATE BASE ADJUSTMENT?

A. Yes. The adjustment to the Income Statement for Normalized Plant in Service: (1) increases Depreciation Expense by $709,039; (2) decreases Total Income Taxes by $268,027; and (3) decreases Total Available for Return by $441,012, all as shown in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8. This adjustment is discussed in Mr. Tommerdahl's Direct Testimony.

2. Rate Case Expense Adjustment

Q. WHAT IS THE AMOUNT OF RATE CASE EXPENSE INCLUDED IN THE 2018 TEST YEAR?

A. The total amount over rate case expense is $775,000 amortized over three years for a 2018 Test Year amount of $257,871.

Q. HAVE YOU MADE AN ADJUSTMENT FOR THE RATE CASE EXPENSE?

A. Yes. The adjustment for rate case expense: (1) decreases Total Operating Expenses by $517,129; (2) increases Total Income Taxes by $195,483; and (3) increases Total Available for Return by $321,646, all as shown in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8. This adjustment is also discussed in Mr. Tommerdahl's Direct Testimony.

3. Normalize Plant Outage

Q. HAVE YOU MADE AN ADJUSTMENT TO THE INCOME STATEMENT TO NORMALIZE PLANT OUTAGE MAINTENANCE COSTS IN THE 2018 TEST YEAR?

A. Yes. The adjustment for plant outage expense: (1) decreases Total Operating Expenses by $347,737; (2) increases Total Income Taxes by $131,450; and (3) increases Total Available for Return by $216,287, all as shown in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8.

Q. DESCRIBE HOW OTP PLANS FOR O&M EXPENSES RESULTING FROM MAJOR PLANT OUTAGES AT ITS GENERATION FACILITIES?

A. OTP has two generating facilities (Big Stone Plant and Coyote Station) that are on three-year schedules for major plant outages. These outages facilitate larger repairs and allow for other maintenance. Having a three-year schedule for larger repairs and maintenance is necessary to maintain a reliable system.

Q. DOES OTP HAVE A MAJOR PLANT OUTAGE SCHEDULED TO OCCUR DURING THE 2018 TEST YEAR?

A. Yes. OTP has a plant outage scheduled for the Big Stone Plant in 2018. Ms. Petersen identified this plant outage in her Direct Testimony.

Q. WAS AN ADJUSTMENT MADE RELATED TO THE PLANT OUTAGE O&M EXPENSES?

A. Yes. An adjustment was made because O&M expenses would be overstated for a normal year if left unadjusted. The adjustment takes into account the actual 2016 Coyote Station O&M expenses as well the budgeted 2018 Big Stone Plant O&M expenses. One third of the total for the two plant outages is compared to 2018 budgeted plant outage expense. The adjustment normalizes the 2018 plant outage expense to the level it would be if the plant outage costs were expensed each year.

4. Removal of Production Tax Credits

Q. HAVE YOU MADE AN ADJUSTMENT TO THE INCOME STATEMENT TO REFLECT THE REMOVAL OF PRODUCTION TAX CREDITS (PTCS)?

A. Yes. The adjustment for PTC removal: (1) increases Total Income Taxes by $1,156,403; and (2) decreases Total Available for Return by $1,156,403, all as shown in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8. This adjustment is explained in the Direct Testimony of Mr. Haugen.

5. Economic Development

Q. HAVE YOU MADE AN ADJUSTMENT TO THE INCOME STATEMENT RELATED TO ECONOMIC DEVELOPMENT?

A. Yes. The adjustment for economic development: (1) increases Total Operating Expenses by $200,000; (2) decreases Total Income Taxes by $75,603; and (3) decreases Total Available for Return by $124,397, all as shown in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8. This adjustment is explained in Mr. Tommerdahl's Direct Testimony.

6. Prorate ADIT for ND Riders

Q. HAVE YOU MADE AN ADJUSTMENT TO THE INCOME STATEMENT TO REFLECT THE PRORATION OF ADIT IN THE RIDERS?

A. Yes. The adjustment for the proration of ADIT corresponds to the Rate Base adjustment and is required by IRS Regulation Section 1.167(l)-1(h)(6), which provides that ratemaking procedures and adjustments must be consistent with normalization accounting. This normalization requirement is described in the Direct Testimony of Mr. Tommerdahl. The adjustment for ADIT proration for the ND Riders: (1) increases Total Operating Revenues by $34,877; (2) increases Total Income Taxes by $13,184; and (3) increases Total Available for Return by $21,693, all as shown in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8.

7. Effect of Test Year Adjustments on Allocations

Q. HAVE YOU MADE AN ADJUSTMENT TO THE INCOME STATEMENT TO REFLECT THE EFFECT OF TEST YEAR ADJUSTMENTS ON ALLOCATIONS?

A. Yes. The adjustment to reflect the effect of Test Year adjustments on allocations: (1) increases Total Operating Revenue by $7,046; (2) increases Total Operating Expenses by $5,106; (3) decreases Total Income Tax expense by $33,439; (4) increases Total Available for Return by $35,379, all as shown in Exhibit___(TAA-1), Schedule 10 and Volume 3, Schedule C-8.

XII. CONCLUSION.

Q. WHAT IS YOUR CONCLUSION?

A. OTP has demonstrated the 2018 Test Year revenue deficiency of $15,715,320 has been appropriately determined and all necessary adjustments have been made. As a result, the 2018 Test Year revenue deficiency of $15,715,320 should be recovered in base rates.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Mr. Tyler A. Akerman, CPA, CGMA
Manager, Business Planning/Regulatory Accounting
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8298

CURRENT RESPONSIBILITIES: (October 2015 to Present)

Provide leadership in budgeting, financial planning, and forecasting as required by OTP and Otter Tail Corporation for use in strategic planning and decision making. In addition, this position is responsible for managing the production of official company budgets and monthly forecasts, for leading the work group which prepares the jurisdictional cost of service studies for the three jurisdictions in which OTP provides service (Minnesota, North Dakota, and South Dakota) and providing any other regulatory and financial analysis on an as needed basis.

PREVIOUS POSITIONS:

Otter Tail Power Company

2015 – Present	Manager, Business Planning/Regulatory Accounting
2012 – 2015	Financial Analyst, Business Planning/Regulatory Accounting

City of Fergus Falls

2006 – 2012	Accountant, Finance

EDUCATIONAL / CERTIFICATIONS

Moorhead State University-Moorhead, B.S.
Majors in Accounting and Finance
Minor in Business and Professional Communications

Certified Public Accountant (CPA)
Chartered Global Management Accountant (CGMA)

Otter Tail Power Company

Jurisdictional and Class Cost of Service Study

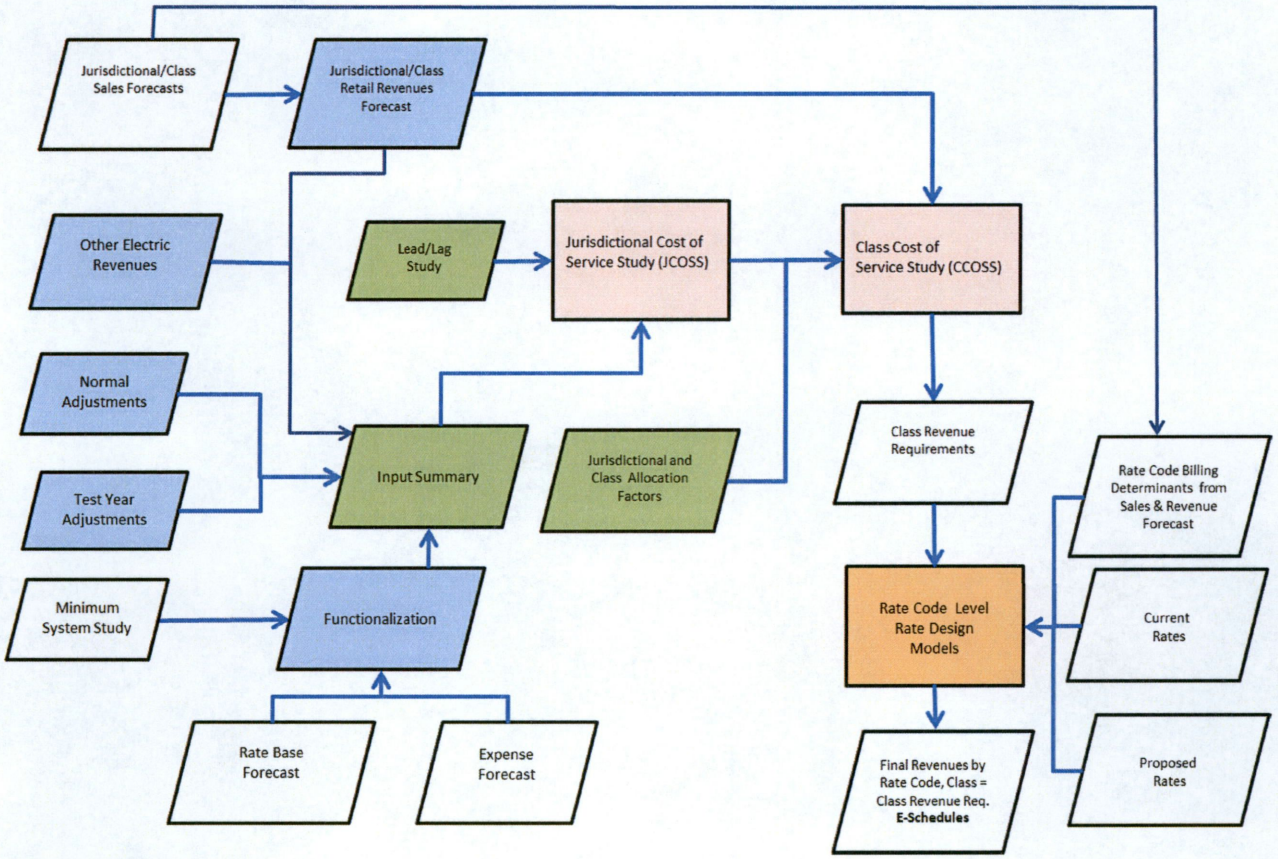
And

Rate Design

Process Overview Manual

1. Introduction:

The purpose of this document is to provide an overview of the various inputs of data which feed into Otter Tail Power's (OTP) Jurisdictional Cost of Service Study (JCOSS) and Class Cost of Service Study (CCOSS) models to determine OTP's revenue requirement upon which subsequent customer class revenue requirements and related rate designs are completed. Flow charts are provided along with descriptive narratives and tables to provide further clarity in how information included in OTP's rate case filing flows from one step in the process to the next. Below is a high-level overview of key components within the overall process that leads to the determination of revenue requirements and corresponding rates necessary to collect the required revenues from the respective customer classes.

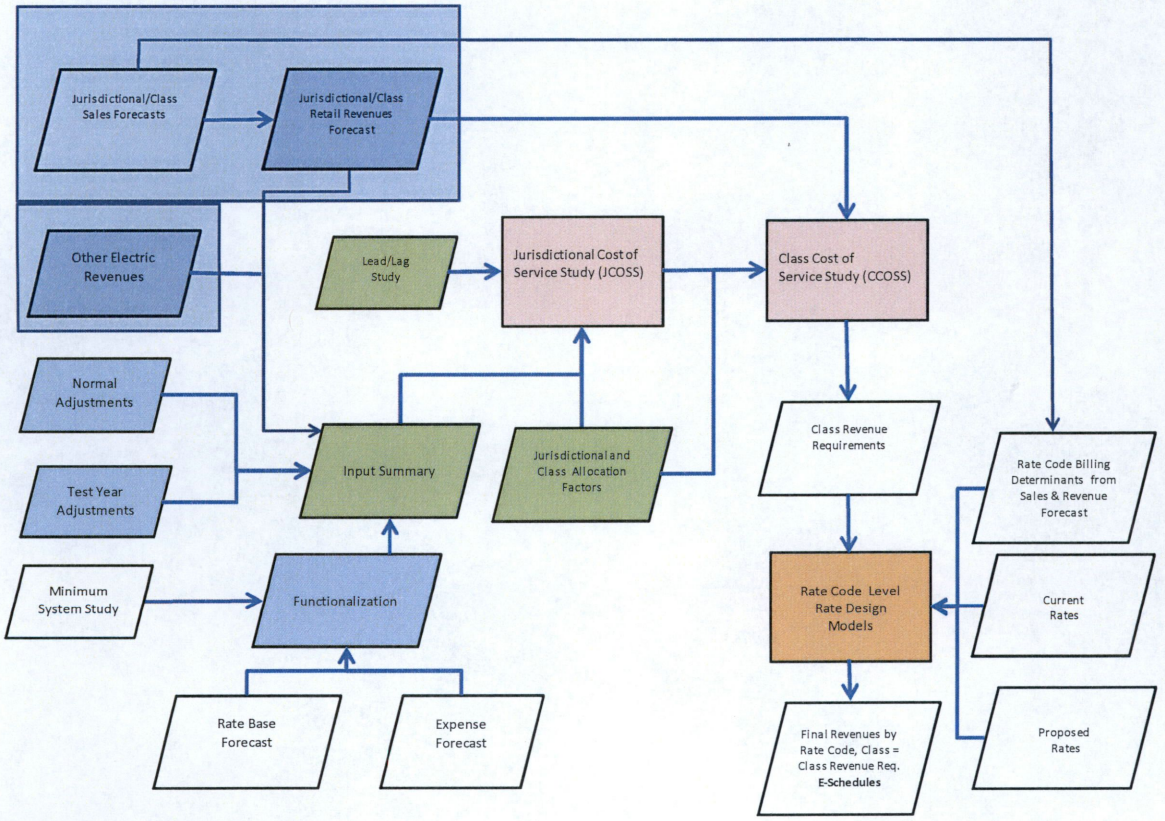


The balance of this document will review in general terms, the various components identified above, describing the flow of data between those components. The descriptions provided are assumed in the context of a forecast test year.

Retail Sales & Revenue Forecast

In summary, the development of the kWh sales forecast at a class and jurisdictional level is the initial step in determining the retail base rate revenue forecast. The kWh sales forecasts and associated billing determinants then serve as inputs into the process which derives forecasted class and jurisdictional revenues based on existing base rate design. Additional revenues from various rate riders make up the balance of revenues associated with kWh sales, as itemized in Work Paper B-1. Total Jurisdictional revenues flow into the Input Summary, which subsequently feeds into the JCOSS. Class Revenues serve as an input in the CCOSS. Billing determinants developed in the process of creating the sales and revenue forecasts, ultimately serve as inputs into the final rate design models used to develop rates to collect the required revenues. These steps will be explained in more detail later in this document.

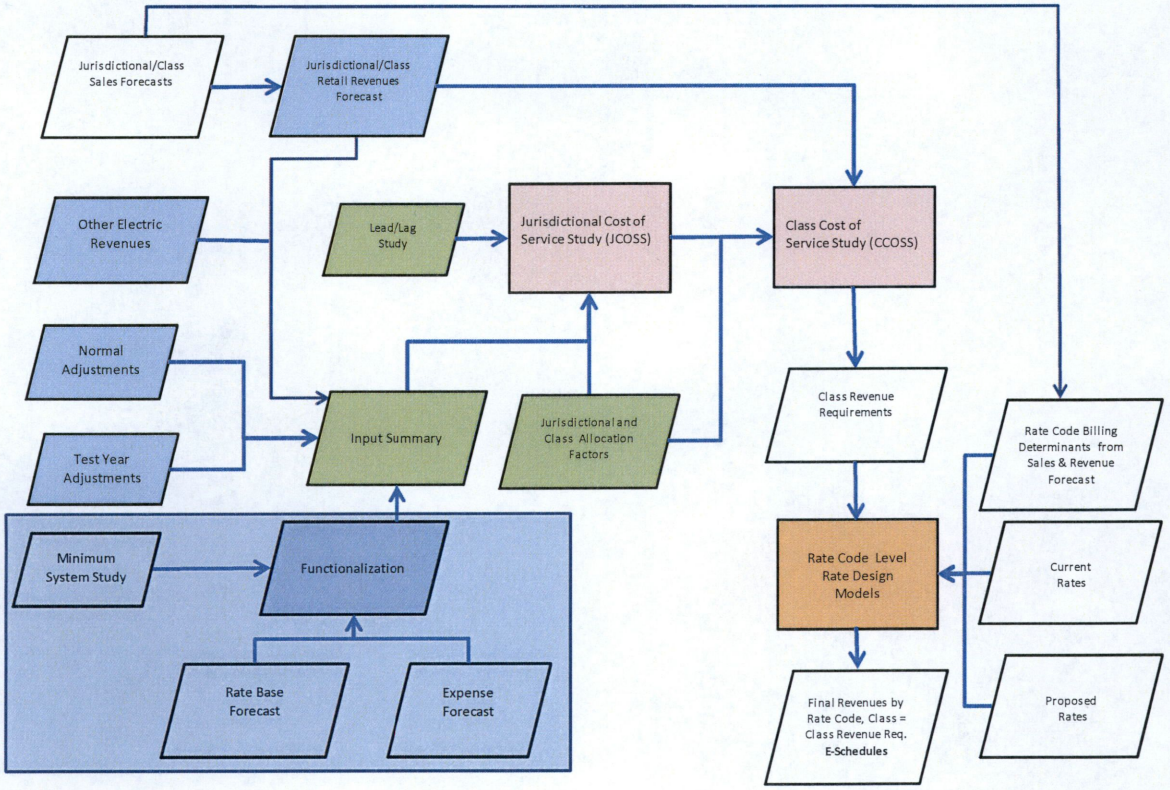
Other Electric Revenues and Sales for Resale are listed in Work Papers B-2 and B-3 and also flow into the Input Summary. These revenues, combined with the forecasted retail revenues, yield total jurisdictional and company revenues.



Functionalization (Volume 4A)

The **Functionalization Schedule, found in Volume 4A** of the rate case filing, is the schedule which takes total company rate base and expense information as accounted for under Federal Energy Regulatory Commission (FERC) accounting rules, and aggregates those amounts into functional cost categories:

production; transmission; distribution; customer accounting and collecting, and customer service and information. In addition, this schedule further "classifies" the information within each function, based on key service characteristics: demand, energy, customers and meters. These classifications have further sub-characteristics such as type of demand or energy, voltage level, or type of customer or meter. These service characteristics or sub-characteristics provide the basis for further cost allocations within the JCOSS and CCOSS. OTP's Cost Allocation Procedures Manual (CAPM) provides further detail on how each class of costs gets allocated jurisdictionally and subsequently to the various classes within each jurisdiction.



Functionalization Pages:

Pages 1-3 is the input section of the Functionalization schedule, where the FERC account balances are entered and amounts are aggregated based on functional area.

Page 4 of the Functionalization schedule takes the distribution rate base and distribution expense balances from pages 1-3 of the Functionalization schedule and allocates those costs to the following classifications for distribution rate base and expenses:

- Primary Demand
- Secondary Demand
- Primary Customer
- Secondary Customer
- Street Lights
- Area Lights
- Meters
- Load Management

The classifications of these costs are based on allocation factors developed from the Minimum System Study. Details of the process to develop the Minimum System Study are found in Appendix A-1 of OTP's CAPM.

Page 4 of the Functionalization schedule also includes an input section on lines 2 and 3 for the Base/Peak split allocation factors which allocate Production Plant rate base and expense amounts between Base Demand and Peak Demand, Base Demand and Base Energy Categories. The calculation of the Base/Peak split factors is found in Cost of Service Workpapers C-1 and C-1a, following the methodology described in pages 3 and 4 of OTP's CAPM.

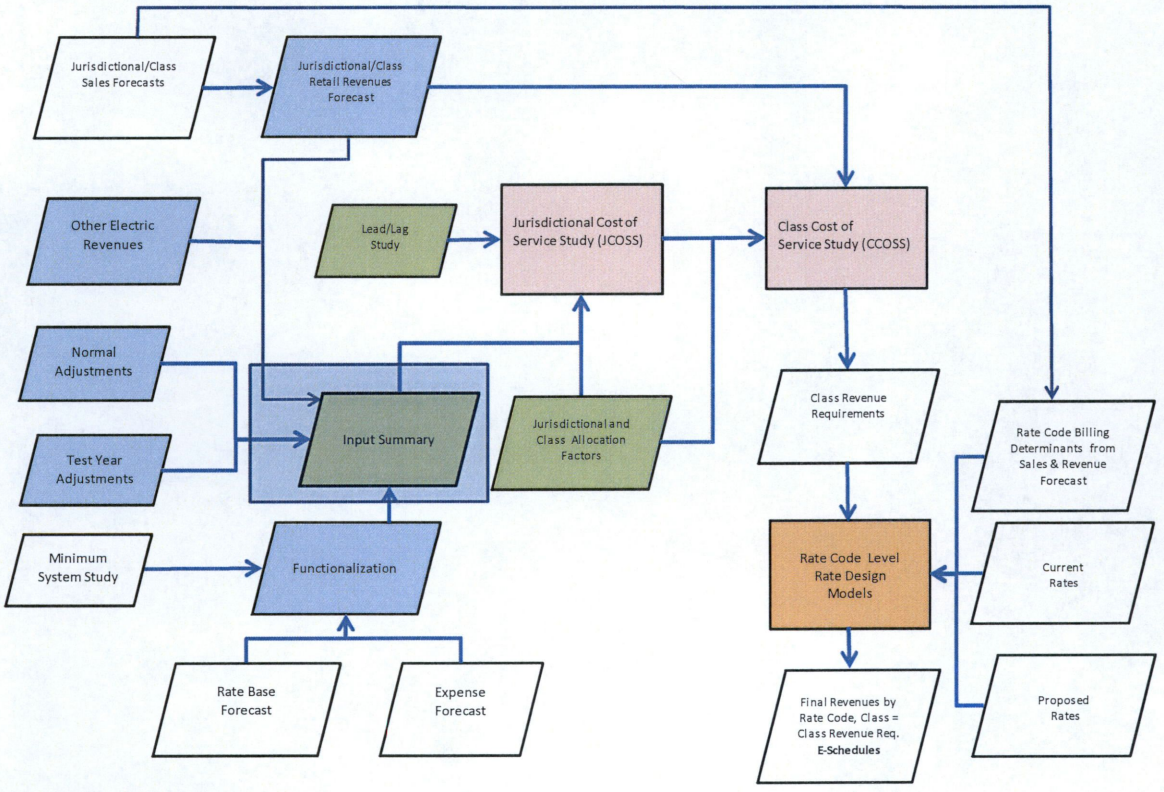
Pages 5 and 6 of the Functionalization schedule summarize the allocations of costs from pages 1-4, into the respective cost categories that align with the categorical breakdowns ultimately included in OTP's JCOSS and CCOSS. The Rate Base and Expense amounts are first entered into the JCOSS Input Summary, which is described in the next section below.

Input Summary (Volume 4A)

The purpose of the Input Summary, found in Volume 4A is to aggregate Total Company cost information (operating statement as well as rate base items) that has been categorized in the Functionalization schedule, as well as incorporate Total Company Revenue amounts and other Company data quantified in other Workpapers, into a single schedule. This schedule serves as the staging schedule from which much of the company financial information is entered into the JCOSS model.

The amounts which have been functionalized and classified by service characteristics are included in Column A of the Input Summary, as well as revenues and certain other rate base items computed in their respective source document workpapers. All data in the Input Summary is footnoted to the source document / work paper of origin. The Input Summary then incorporates into the adjacent columns to the right, adjustments which are necessary for computation of the JCOSS.

A more detailed description of the various sections of the Input Summary is included following the graphic below.



Input Summary Schedules

The **Input Summary** is divided into two primary sections; Rate Base components and Operating Statement components. Further breakdowns of the Input Summary schedules are identified below:

1. **A – Summary** Schedules - These pages include all the **rate base** related accounts and associated adjustments. The A-Summary schedules are broken down further into two sections:
    a. **A-Summary 1** - This is a bridge schedule which starts with Total Company Simple Average rate base amounts in Column A. These amounts originate from the Functionalization schedule as well as amounts from work paper schedules, as footnoted in the Input summary schedule. Subsequent columns in the schedule incorporate the Normal Adjustments necessary to determine OTP's Total Company Unadjusted amounts in the last column of the schedule. These amounts reflect the values that would be input into the JCOSS Model to compute OTP's Unadjusted JCOSS based on currently approved methodologies and normal adjustments.

    b. **A-Summary 2** - This is a bridge schedule which starts with Total Company Unadjusted amounts in Column A as computed in the A-Summary 1. Subsequent columns in the A-Summary 2 schedule incorporate the Test Year Adjustments necessary to determine OTP's Total Company Adjusted amounts in the last column of the schedule. These amounts reflect the values that would be input into the JCOSS Model to compute OTP's Test Year JCOSS.

2. **B - Summary** – These pages include all **operating statement** amounts and associated adjustments. The B-Summary schedules are broken down further into two sections:

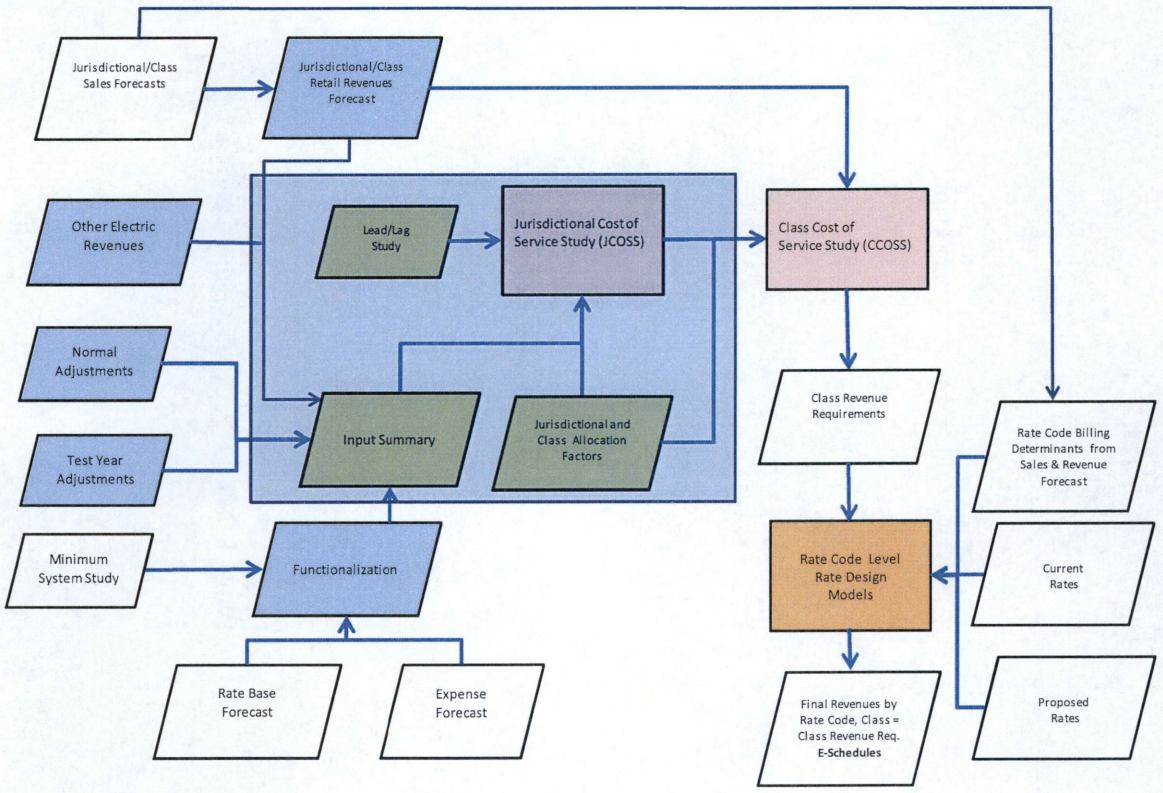
    a. **B-Summary 1** - This is a bridge schedule which starts with Total Company annual Operating Statement amounts in Column A. These amounts originate from the Functionalization schedule as well as amounts from work paper schedules, as footnoted in the Input summary schedule. Subsequent columns in the B-Summary-1 schedule incorporate the Normal Adjustments necessary to determine OTP's Total Company Unadjusted amounts in the last column of the schedule. These operating statement amounts reflect the values that would be input into the JCOSS Model to compute OTP's Unadjusted JCOSS based on currently approved methodologies and normal adjustments.

    b. **B-Summary 2** - This is a bridge schedule which starts with Total Company Unadjusted Operating Statement amounts in Column A as computed in the A-Summary-1. Subsequent columns in the B-Summary 2 schedule incorporate the Test Year Adjustments necessary to determine OTP's Total Company Adjusted amounts in the last column of the schedule. These amounts reflect the values that would be input into the JCOSS Model to compute OTP's Test Year JCOSS.

Jurisdictional Cost of Service Study Model (JCOSS)

The purpose of JCOSS model is to compute OTP's total Available for Return and compare that amount to the current authorized/proposed return and computes incremental amount of revenue surplus or deficiency necessary to meet that authorized return. The key Inputs into the JCOSS are:

1. Input Summary Amounts
2. Lead-Lag Study Amounts
3. Jurisdictional Allocation Factors



The **JCOSS is found in Volume 4A for the Test Year**. The following table aligns the JCOSS Pages to the respective Input Summary, Lead-Lag, and Allocation Factor Schedules. All Summary pages in the JCOSS model have references to the respective detailed sections of the JCOSS.

JCOSS Page	Description	Source	Source Pages
1-1	**JCOSS Summary of Deficiency**	JCOSS Detail Pages	Pages 2, 7, 17
2-1	**Rate Base Summary**	JCOSS Detail Pages	Pages 3, 4, 5, 6
3-1	Total Plant in Service	Input Summary A-2	Page 1
4-1	Accumulated Depreciation Plant Held for Future Use	Input Summary A-2	Page 2 Page 2
5-1	CWIP Materials & Supplies, Fuel Stocks Prepayments Customer Advances Cash Working Capital	Input Summary A-2	Page 3 Page 4 Page 4 Page 4 Page 4 Page 4
6-1	Accumulated Deferred Income Taxes	Input Summary A-2	Page 4
7-1	**Operating Statement Summary**	JCOSS Detail Pages	Pages 8,9,10,11,12
8-1	Operating Revenues	Input Summary B-2	Page 1
9-1	Production Expenses Transmission Expenses Distribution Expenses Customer Accounting Expenses	Input Summary B-2	Page 2 Page 2 Page 2 Page 2
10-1	Customer Service & Information Expenses Sales Expenses Admin & General Expenses	Input Summary B-2	Page 2 Page 3 Page 3
11-1	Depreciation Expense	Input Summary B-2	Page 4
12-1	General Taxes Investment Tax Credits Deferred Income Taxes Current Income Taxes- Federal Current Income Taxes –MN Current Income Taxes – ND AFDC	Input Summary B-2 Input Summary B-2 Input Summary B-2 JCOSS Detail JCOSS Detail JCOSS Detail Input Summary	Page 4 Page 4 Page 4 Page 13-1 Page 14-1 Page 14-1 Page 5
13-1	Federal Income Taxes	JCOSS Calculation	Page 13-a
14-1	Minnesota State Income Tax Expense North Dakota State Income Tax Expense	JCOSS Calculation	Page 14-a
15-1	Jurisdictional Allocation Factors	Required Schedules C-9	Page 4
16-1	Secondary Allocation Factors	JCOSS Calculation Required Schedules – C-9	Page 16-a Page 5
17-1	Capital Structure – Requested	Required Schedules – D-1-a	Page 17-1 Page 17-a
18-1	Cash Working Capital Revenue Lead Days	Lead Lag Study Required Schedules – B-2-e	Summary – Page 1 Page 1
19-1	Cash Working Capital - MN Calculation Expense Lag Days	Lead Lag Study Required Schedules – B-2-e	See Reference tables on next page Page 3
20-1	Cash Working Capital - ND Calculation Expense Lag Days	Lead Lag Study Required Schedules – B-2-e	See Reference tables on next page Page 3
21-1	Cash Working Capital - SD Calculation Expense Lag Days	Lead Lag Study Required Schedules – B-2-e	See Reference tables on next page Page 3
22-1	Cash Working Capital - FERC Calculation Expense Lag Days	Lead Lag Study Required Schedules – B-2-e	See Reference tables on next page Page 3
23-1	Cash Working Capital- Total Company	JCOSS Calculation	Sum of Jurisdictional totals 19-1 to 22-1

Lead-Lag Study Reference Table

The following table provides a cross reference of the various Lead-Lag study values found in the JCOSS to the respective page in the Lead-Lag Study.

JCOSS Page 18-1

Line No.	Revenue Lead Days from Service to Collection	Revenue Lead Days	Lead Lag Study Page	Notes:
23	Computer Maintained Billings	43.4	1	
24	Manually Maintained Billings	41.3	1	
25	Cost of Energy Adjustment Revenues	127.7	37	
26	Sales for Resale	23.1	40	
27	Rent from Electric Property	-92.4	42	
28	Miscellaneous	34.9	51	
29	ITA Deficiency Payments	48.4	56	
30	Wheeling	35.8	60	
31	Load Control and Dispatch	27.9	1	Line 21
32	Rent from Electric Property - Big Stone	39.9		Calculated in COSS
33	Rent from Electric Property - Coyote	39.9		Calculated in COSS
34	Profit on Materials and Supplies	39.9		Calculated in COSS
35	Miscellaneous Services	39.9		Calculated in COSS
36	Loan Pool Interest	39.9		Calculated in COSS

JCOSS Page 20-1

Line No.	Item	Expense Lag Days	Lead Lag Study Page	Notes:
3	Fuel - Coal	15.5	69	
5	Fuel - Oil	11.2	69	
7	Purchased Power	31.6	69	
9	Labor and Associated Payroll Expense	15.1	69	
11	All Other O&M Expense	13.1	69	Line 19
13	Property Taxes (Excl Coal Conversion Taxes)	299.5	157	Calculated in COSS
15	Coal Conversion Taxes	33.3	171	
17	Federal Income Taxes	0.0	172	
19	State Income Taxes	0.0	172	
21	Incremental Federal Income Taxes	0.0	172	
23	Incremental State Income Taxes	0.0	172	
25	Bank Balances	n/a		
27	Special Deposits	n/a		
29	Working Funds	n/a		
31	Tax Collections Avail - FICA Withholding	0.0	175	
33	Tax Collections Avail - Federal Withholding	0.0	175	
35	Tax Collections Avail - State Withholding- MN	1.9	175	
37	Tax Collections Avail - State Withholding- ND	69.1	175	
39	Tax Collections Available - State Sales Tax	23.8	175	
41	Tax Collections Available - Franchise Taxes	0	175	

JCOSS pages 1-a to 18-a contain the jurisdictional breakdowns of the JCOSS information as listed on pages 1-1 to 18-1 on the table above.

Allocation Factors

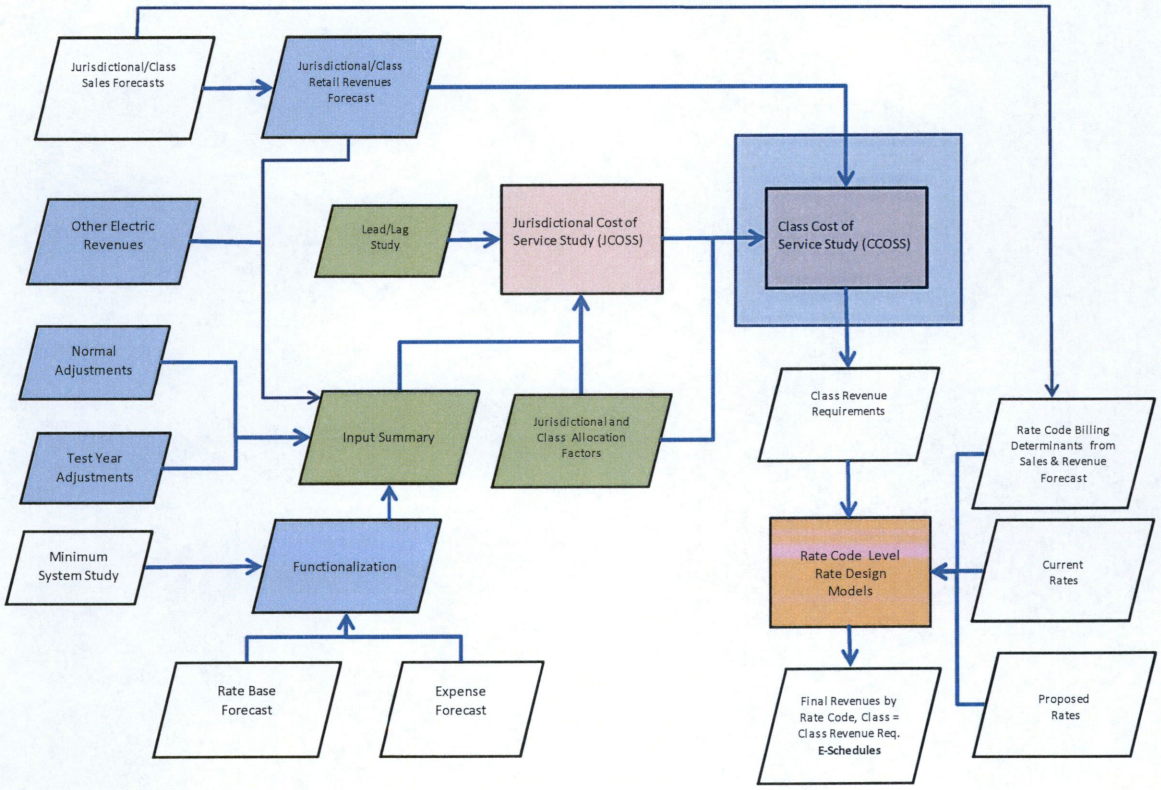
As reflected in the flow chart and listed on page 15-1 of the CCOSS, jurisdictional allocation factors are applied to various costs (rate base and expense) to allocate total company costs to the jurisdiction. Details on both jurisdictional and class allocation factors are outlined in OTP's Cost Allocation Procedures Manual and in OTP's Forecast Cost Allocation Procedures Manual Supplement. Required schedules C-9 and Work Papers Volume 4, C-3 provide additional detail as well.

JCOSS Summary

The results of the JCOSS, as summarized on page 1-1, is the determination of a (surplus) or deficiency in revenue needed to achieve the rate of return authorized or requested within the jurisdiction. The respective **jurisdictional amounts** within the study **serve as the primary inputs** into the **CCOSS model**, with allocations of those costs and associated class revenue requirements distributed to each customer class.

Class Cost of Service (Volume 4A)

OTP's CCOSS model establishes the revenue requirements for each of OTP's 10 customer classes based on the allocation of jurisdictional costs using the **class allocation factors detailed on page 15-2** and the **secondary class allocation factors detailed on page 16-2**.



The **key inputs** into the CCOSS model are:

1. Current North Dakota Class Revenues
2. JCOSS North Dakota results – Pages 1-1 to 16-1
3. Class Allocation Factors
    a. Primary Allocators by class (D Factors, E8760 Factors, C Factors) Page 15-2
    b. Secondary – Page 16-2

The CCOSS pages 1-2 to 16-2 align with the pages 1-1 to 1-16 of the JCOSS.

The **key output** of the CCOSS is the determination of **class revenue requirements** based on the embedded costs and revenues attributable to each class. The CCOSS serves as a guide in the determination of proposed class rate increases necessary to collect the jurisdictional revenue increase required. The Summary of each class's deficiency is provided on page 1-2 of the CCOSS.

Class	CCOSS Output	Source
Residential	Class Revenue Deficiency	CCOSS Page 1-2
Farms	Class Revenue Deficiency	CCOSS Page 1-2
General Service	Class Revenue Deficiency	CCOSS Page 1-2
Large General Service	Class Revenue Deficiency	CCOSS Page 1-2
Irrigation	Class Revenue Deficiency	CCOSS Page 1-2
Outdoor Lighting	Class Revenue Deficiency	CCOSS Page 1-2
OPA	Class Revenue Deficiency	CCOSS Page 1-2
Controlled Service Water Heating	Class Revenue Deficiency	CCOSS Page 1-2
Controlled Service Interruptible	Class Revenue Deficiency	CCOSS Page 1-2
Controlled Service Deferred	Class Revenue Deficiency	CCOSS Page 1-2
Total Jurisdiction	**Sum of Class Revenue Deficiencies**	**Ties to JCOSS Deficiency Page 1-1**

Rate Design (Volume 3 Section E)

The JCOSS determines the jurisdictional revenue requirement and related deficiency in revenue. The CCOSS determines each class's responsibility for that deficiency based on the embedded costs included in the studies. Ultimately, the company develops a proposal for each class's share of the overall jurisdictional revenue requirement to eliminate the deficiency and develops proposed rates within each class to collect that deficiency. **Total Test Year Current and Proposed Revenues by Class are provided in Volume 3 Schedule E-1.**

Class	Current Revenues	Source	Proposed Revenues	Source	Class Revenue Increase
Residential	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Farms	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
General Service	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Large General Service	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Irrigation	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues

Outdoor Lighting	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
OPA	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Controlled Service Water Heating	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Controlled Service Interruptible	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Controlled Service Deferred	Class Revenue	CCOSS	Class Proposed Revenue	Company Proposal	Difference between Current and Proposed Revenues
Total Jurisdictional	**Total Current Revenue**	JCOSS	**Total Revenue Required**	JCOSS	**Total Increase in Revenue**

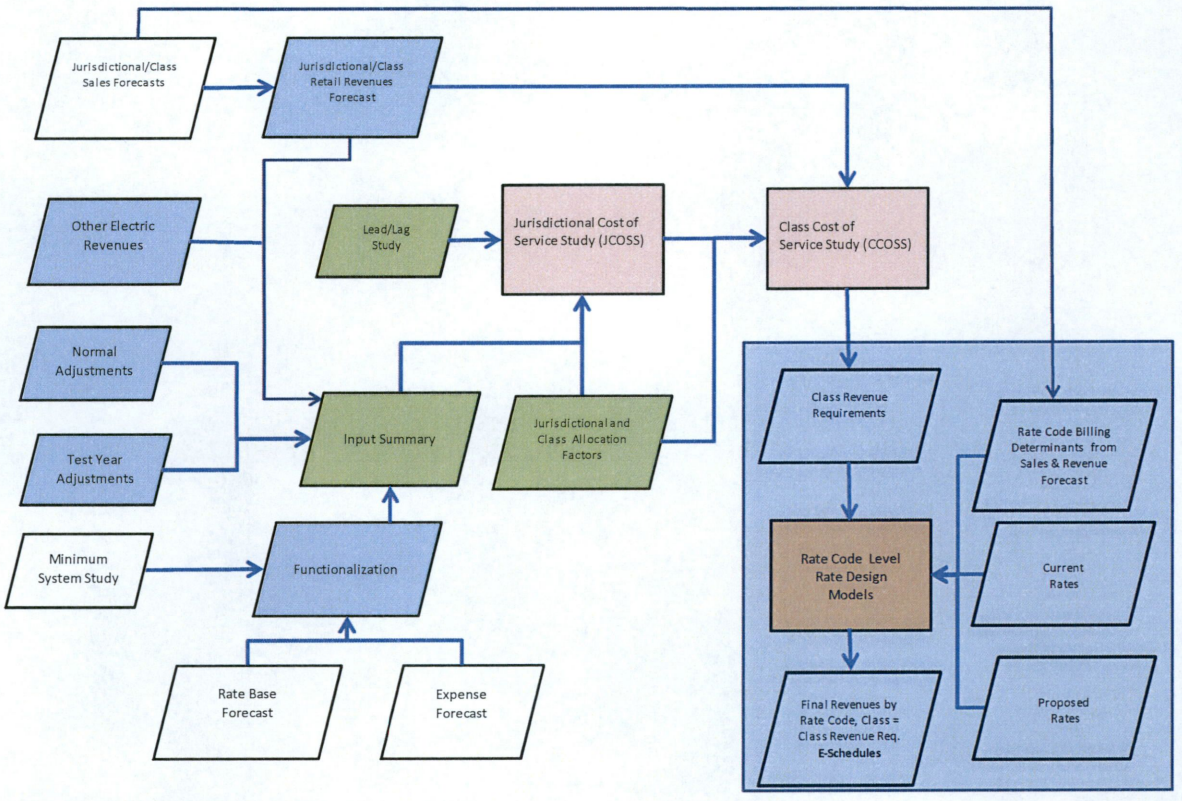
Following the development of proposed class revenue responsibilities, the next step in the process is rate design.

Key Components / Inputs in the Rate Design Process

The purpose of the rate design process is to develop new rates and associated rate structures that result in the collection of the proposed class revenue requirement based on the billing determinants included in the forecast. Rate design is completed at a rate code level. Class revenue requirements are distributed to the rate code level. The allocation of class revenue to rate code level is completed using an Equivalent Percent of Marginal Cost (EPMC) allocation.

The following inputs are key to completing rate design in the rate design models at a rate code level:

1. **Billing Determinants** – These are the various billing determinants which were developed and included in the Sales and Revenue forecast process. Billing determinants include such things as forecasted kWhs, kW, number of customers, and number of meters. The sales and revenue forecast process develops billing determinates at a rate group level and then further allocates those determinants to a rate code level.
2. **Current Rates**- Current rates applied to the billing determinants yield the current level of revenues for the particular rate code. The result of this is the calculation of current revenues from existing rates.
3. **Proposed Rates-** Based on forecasted billing determinants described above, proposed rates are adjusted to yield the total revenue required from that rate to meet its contribution to the class revenue requirement.



Key Outputs of Rate Design Process:

The **key output of the Rate Design process** is a **new set of proposed rates** that within their respective customer class, collects the amount of revenue equal to the proposed class revenue requirement. The sum of revenues derived by all rates across all classes equals the total jurisdictional revenue requirement. As noted earlier, the **results of the rate design** process are **summarized in Volume 3 Schedule E-1. Details of the changes from current rates to proposed rates are found in Volume 3 Schedule E-2.**

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULES
SUMMARY OF REVENUE REQUIREMENTS - 2018 TEST YEAR

Case No. PU-17-
Exhibit ___(TAA-1), Schedule 3

Line No.	Description	(A) 2018 Test Year
1	Average Rate Base	$354,191,795
2	Operating Income (Before AFUDC)	$18,454,393
3	Allowance for Funds Used During Construction (AFUDC)	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$18,454,393
5	Overall Rate of Return (Line 4 / Line 1)	5.21%
6	Required Rate of Return	7.97%
7	Operating Income Requirement (Line 1 x Line 6)	$28,229,086
8	Income Deficiency (Line 7 - Line 4)	$9,774,693
9	Gross Revenue Conversion Factor	1.607756
10	Revenue Deficiency (Line 8 x Line 9)	$15,715,320
11	Retail Related Revenues Under Present Rates	$148,071,951
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	10.61%

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
JURISDICTIONAL FINANCIAL SUMMARY SCHEDULES
SUMMARY OF REVENUE REQUIREMENTS - JURISDICTIONAL

Line No.	Description	(A) 2016 Actual Year	(B) 2017 Current Period	(C) 2018 Base Year	(D) 2018 Test Year
1	Average Rate Base	$350,541,961	$346,427,485	$350,782,707	$354,191,795
2	Operating Income (Before AFUDC)	$27,340,344	$26,444,364	$19,581,198	$18,454,393
3	Allowance for Funds Used During Construction (AFUDC)	$0	$0	$0	$0
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$27,340,344	$26,444,364	$19,581,198	$18,454,393
5	Overall Rate of Return (Line 4 / Line 1)	7.80%	7.63%	5.58%	5.21%
6	Required Rate of Return	8.22%	8.12%	7.97%	7.97%
7	Operating Income Requirement (Line 1 x Line 6)	$28,814,549	$28,129,912	$27,957,382	$28,229,086
8	Income Deficiency (Line 7 - Line 4)	$1,474,205	$1,685,548	$8,376,184	$9,774,693
9	Gross Revenue Conversion Factor	1.607756	1.607756	1.607756	1.607756
10	Revenue Deficiency (Line 8 x Line 9)	$2,370,162	$2,709,950	$13,466,858	$15,715,320
11	Retail Related Revenues Under Present Rates	$143,879,019	$147,985,448	$148,037,074	$148,071,951
12	Percent Increase Needed in Overall Revenue (Line 10 / Line 11)	1.65%	1.83%	9.10%	10.61%

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE SUMMARY

Case No. PU-17-
Exhibit ___ (TAA-1), Schedule 5
Page 1 of 1

Line No.	(A) Description	(B) 2016 Actual Year	(C) 2017 Current Period	(D) 2018 Base Year	(E) 2018 Test Year
1	Electric Plant in Service	$713,874,704	$731,453,923	$755,122,657	$758,395,144
2	Less: Accumulated Depreciation	(275,833,971)	(289,379,585)	(304,195,201)	(304,752,302)
3	Net Electric Plant in Service	$438,040,733	$442,074,338	$450,927,457	$453,642,842
	Other Rate Base Components:				
4	Plant Held for Future Use	13,093	13,021	13,044	13,044
5	Construction Work in Progress	5,734,954	1,460,258	271,748	271,747
6	Materials and Supplies	7,832,359	7,943,851	8,275,549	8,275,549
7	Fuel Stocks	4,030,121	3,967,123	4,430,805	4,430,805
8	Prepayments	(6,646,069)	(9,822,113)	(13,189,483)	(13,199,141)
9	Customer Advances	(396,682)	(376,292)	(365,614)	(365,882)
10	Cash Working Capital	2,847,470	2,909,136	3,656,607	3,602,273
11	Accumulated Deferred Income Taxes	(100,914,018)	(101,741,837)	(103,237,405)	(102,479,443)
12	TOTAL	$350,541,961	$346,427,485	$350,782,707	$354,191,794

Note: The 2018 Base Year is based on 2018 budgeted financial information. The 2018 Test Year is the 2018 Base Year with proposed adjustments to arrive at the Test Year.

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
TRADITIONAL ADJUSTMENTS TO RATE BASE SCHEDULE

Line No.	Description	(A) Jurisdictional AQCS Adjustment	(B) Transmission Recovery Adjustment
1	**Plant in Service**		
2	A/C 101 & 106 - Direct MN		
3	A/C 101 & 106 - Direct ND	471,573	
4	A/C 101 & 106 - Direct SD		
5		471,573	
6	*Production Plant*		
7	A/C 101 & 106 - Base Demand (E1)	(1,497,297)	
8	A/C 101 & 106 - Peak Demand (D1)	(373,963)	
9	A/C 101 & 106 - Base Energy (E2)		
10	*Subtotal A/C 101 & 106*	(1,871,260)	-
11			
12	A/C 114 - Base Demand (E1)		
13	A/C 114 - Peak Demand (D1)		
14	A/C 114 - Base Energy (E1)		
15	*Subtotal A/C 114*	-	-
16			
17	*Total Production Plant*	(1,399,687)	-
18			
19	*Transmission Plant*		
20	A/C 101 & 106 (D2)		(50,100,785)
21	A/C 101 & 106 (Direct FERC)		
22	A/C 114 (D2)		
23	*Total Transmission Plant*	-	(50,100,785)
24			
25	*Distribution Plant*		
26	Primary Demand (D3)		
27	Secondary Demand (D4)		
28	Primary Customer (C2)		
29	Secondary Customer (C3)		
30	Streetlighting (C4)		
31	Area Lighting (C5)		
32	Meters (C6)		
33	Load Management (C9)		
34	*Total Distribution Plant*	-	-
35			
36	*General Plant*		
37	Production (P10)		
38	Transmission (D2)		
39	Distribution (P60)		
40	Customer Accounts (OXC)		
41	Customer Service & Info (OXI)		
42	Load Management (C9)		
43	*Total General Plant*	-	-
44			
45	*Intangible Plant (P90)*	-	-
46			
47	**Total Plant in Service**	**(1,399,687)**	**(50,100,785)**
48			
49	**Accumulated Depreciation**		
50	*Production Plant*		
51	Base Demand (E1)		
52	Peak Demand (D1)		
53	Base Energy (E2)		
54	*Total Production Plant*	-	-
55			
56	Transmission Plant (D2)		1,749,778
57	Transmission Plant - Direct FERC		
58	*Total Transmission Plant*	-	1,749,778
59			
60	Distribution Plant (P60)	-	-
61			
62	General Plant (P90)	-	-
63			
64	Intangible Plant (P90)	-	-
65			
66	**Total Accumulated Depreciation**	**-**	**1,749,778**
67			
68	**Total Net Plant in Service**	**(1,399,687)**	**(48,351,007)**
69			
70	**Plant Held for Future Use**		
71	Production Plant (P10)		
72	Transmission Plant (D2)		
73	Distribution Plant (P60)		
74	General Plant (P90)		
75	Intangible Plant (P90)		
76	**Total Plant Held for Future Use**	-	-

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
TRADITIONAL ADJUSTMENTS TO RATE BASE SCHEDULE

Line No.	Description	(A) Jurisdictional AQCS Adjustment	(B) Transmission Recovery Adjustment
77			
78	**Const Work-in-Progress - Direct Assigned**		
79	Production Plant - Dierct MN		
80	Production Plant - Dierct ND		
81	Production Plant - Direct SD		
82	Production Plant - Direct FERC		
83	Transmission Plant - Direct MN		
84	Transmission Plant - Direct ND		
85	Transmission Plant - Direct SD		
86	Transmission Plant - Direct FERC		
87	Distribution Plant - Direct MN		
88	Distribution Plant - Direct ND		
89	Distribution Plant - Direct SD		
90	Distribution Plant - Direct FERC		
91	General Plant - Direct MN		
92	General Plant - Direct ND		
93	General Plant - Direct SD		
94	General Plant - Direct FERC		
95	Intangible Plant - Direct MN		
96	Intangible Plant - Direct ND		
97	Intangible Plant - Direct SD		
98	Intangible Plant - Direct FERC		
99	**Total CWIP - Major Projects - Direct Assigned**	-	-
100			
101	**Const Work-in-Progress - Short-Term**		
102	Production Plant (P10)		
103	Transmission Plant (D2)		
104	Distribution Plant (P60)		
105	General Plant (P90)		
106	Intangible Plant (P90)		
107	**Total CWIP - Short-Term**	-	-
108			
109	**Const Work-in-Progress - Long Term**		
110	Production Plant (AFUDC Projects P10)		
111	Production Plant (Rider Projects)		
112	Transmission Plant (AFUDC Projects)		(37,926,380)
113	Transmission Plant (Rider Projects)		
114	Distribution Plant (P60)		
115	General Plant (P90)		
116	Intangible Plant (P90)		
117	**Total CWIP - Long Term AFUDC Projects**	-	**(37,926,380)**
118	**Total CWIP - Long Term Rider Projects**	-	-
119			
120	**Total Construction Work-in-Progress**	-	**(37,926,380)**
121			
122	**Materials & Supplies**		
123	Production (P10)		
124	Transmission (D2)		
125	Distribution (P60)		
126	**Total Materials and Supplies**	-	-
127			
128	**Fuel Stocks**		
129	Coal Stocks (E1)		
130	Fuel Oil Stocks (D1)		
131	**Total Fuel Stocks**	-	-
132			
133	**Prepayments (NEPIS)**	-	-
134			
135	**Customer Advances & Deposits**		
136	Customer Advances & Deposits (NEPIS)		
137	Customer Deposits (Direct MN)		
138	**Total Customer Advances & Deposits**	-	-
139			
140	**Cash Working Capital**	-	-
141			
142	**Accumulated Deferred Income Taxes**		
143	*Items SD Flows Through*		
144	Federal (NPMNR)		8,626,466
145	Minnesota (NPISM)		
146	North Dakota (NPISN)		
147	*Subtotal*	-	8,626,466
148	*All Other*		
149	Federal (NEPIS)		
150	Federal (Direct FERC)		
151	Minnesota (NPISM)		
152	North Dakota (NPISN)		
153	*Subtotal*	-	-
154			
155	**Total Accumulated Deferred Income Taxes**	-	**8,626,466**

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
TRADITIONAL ADJUSTMENTS TO RATE BASE SCHEDULE

Line No.	Description	(A) Jurisdictional AQCS Adjustment	(B) Transmission Recovery Adjustment
156			
157	**Unamortized Rate Case Expenses**		
158	Minnesota		
159	North Dakota		
160	South Dakota		
161	FERC		
162	**Total Unamortized Rate Case Expenses**	-	-
163			
164	**Total Average Rate Base**	**$ (1,399,687)**	**$ (77,650,922)**

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
RATE BASE SCHEDULES
RATE BASE ADJUSTMENTS
2018 Base Year versus 2018 Test Year

Line No.	Description	(A) 2018 Base Year	(B) Normalize Plant in Service	(C) Prorate ADIT	(D) Changes in Allocations due to Effect of Test Year Adjustments	(E) 2018 Test Year
	Utility Plant in Service:					
1	Production	$330,519,064			$1	$330,519,065
2	Transmission	$153,826,931			($1)	$153,826,930
3	Distribution	$228,593,947			($0)	$228,593,947
4	General	$36,403,979			($0)	$36,403,979
5	Intangible	$5,778,736	$3,272,488		($0)	$9,051,224
6	**TOTAL Utility Plant in Service**	$755,122,657	$3,272,488	$0	($1)	$758,395,144
	Accumulated Depreciation					
7	Production	($142,605,271)			($1)	($142,605,272)
8	Transmission	($48,351,303)			$0	($48,351,302)
9	Distribution	($98,387,400)			$0	($98,387,399)
10	General	($14,025,311)			$0	($14,025,311)
11	Intangible	($825,917)	($557,102)		$0	($1,383,019)
12	**TOTAL Accumulated Depreciation**	($304,195,201)	($557,102)	$0	$0	($304,752,302)
13	**NET Utility Plant in Service**					
14	Production	$187,913,793	$0	$0	$1	$187,913,793
15	Transmission	$105,475,629	$0	$0	($1)	$105,475,628
16	Distribution	$130,206,548	$0	$0	$0	$130,206,548
17	General	$22,378,669	$0	$0	($0)	$22,378,668
18	Intangible	$4,952,819	$2,715,386	$0	($0)	$7,668,205
19	**NET Utility Plant in Service**	$450,927,457	$2,715,386	$0	($1)	$453,642,842
20	Big Stone Plant capitalized items	$0			$0	$0
21	Utility Plant Held for Future Use	$13,044			$0	$13,044
22	Construction Work in Progress	$271,748			($0)	$271,747
23	Materials and Supplies	$8,275,549			$0	$8,275,549
24	Fuel Stocks	$4,430,805			$0	$4,430,805
25	Prepayments	($13,189,483)			($9,658)	($13,199,141)
26	Customer Advances	($365,614)			($268)	($365,882)
27	Cash Working Capital	$3,656,607			($54,334)	$3,602,273
28	Accumulated Deferred Income Taxes	($103,237,405)		$806,647	($48,685)	($102,479,443)
29	**Total Average Rate Base**	$350,782,707	$2,715,386	$806,647	($112,946)	$354,191,794

Column references to adjustment workpapers:
(B) W/P 2018 ND TY-01
(C) W/P 2018 ND TY-06

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME SCHEDULES
STATEMENT OF OPERATING INCOME - 2018 TEST YEAR

Case No. PU-17-
Exhibit ___(TAA-1), Schedule 8
Page 1 of 1

Line No.	Description	(A) 2018 Base Year Total Utility	(B) 2018 Test Year 2018 Base Year ND Jurisdiction	(C) Adjustments	(D) 2018 Test Year ND Jurisdiction
	OPERATING REVENUES				
1	Retail Revenue	$390,016,076	$148,037,074	$34,877	$148,071,951
2	Other Electric Operating Revenue	$58,232,545	$10,040,248	7,046	$10,047,294
3	**TOTAL OPERATING REVENUE**	$448,248,621	$158,077,321	$41,923	$158,119,244
	OPERATING EXPENSES				
4	Production Expenses	$161,876,335	$60,104,536	($347,737)	$59,756,799
5	Transmission Expenses	$35,311,843	$13,507,453	0	$13,507,453
6	Distribution Expenses	$16,917,384	$7,680,921	0	$7,680,921
7	Customer Accounting Expenses	$13,849,926	$6,091,579	0	$6,091,579
8	Customer Service and Information Expenses	$11,097,740	$1,382,509	0	$1,382,509
9	Sales Expenses	$273,627	$22,472	200,000	$222,472
10	Administration and General Expenses	$50,400,273	$20,112,229	-515,613	$19,596,616
11	Charitable Contributions	$0	$0	0	$0
12	Depreciation Expense	$54,316,572	$20,716,262	709,039	$21,425,301
13	General Taxes	$15,375,197	$4,902,302	3,590	$4,905,891
14	**TOTAL OPERATING EXPENSES**	$359,418,897	$134,520,262	$49,279	$134,569,541
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$88,829,724	$23,557,059	($7,356)	$23,549,703
16	**INCOME TAX EXPENSE**				
17	Investment Tax Credit	($4,487,336)	($1,681,974)	$1,155,767	($526,207)
18	Deferred Income Taxes	$2,599,820	$1,321,609	-4,226	$1,317,383
19	Income Taxes	$21,246,187	$4,336,226	(32,092)	$4,304,134
20	**TOTAL INCOME TAX EXPENSE**	$19,358,671	$3,975,861	$1,119,450	$5,095,310
21	**NET OPERATING INCOME**	$69,471,053	$19,581,199	($1,126,806)	$18,454,393
22	Allowance for Funds Used During Construction	2,027,574	0	0	0
23	**TOTAL AVAILABLE FOR RETURN**	$71,498,627	$19,581,199	($1,126,806)	$18,454,393

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
TRADITIONAL ADJUSTMENTS TO INCOME STATEMENT SCHEDULE

Line No.	Description	(A) Advertising Expenses	(B) Economic Development Costs	(C) Incentive Compensation	(D) SPP Schedule 9 and 11 Expense	(E) Transmission Recovery Adjustment	(F) Wholesale Asset Based Margins
1	**Operating Revenues**						
2	Sales of Electricity - Minnesota (Direct MN/R10)						
3	Sales of Electricity - North Dakota (Direct ND/R10)						
4	Sales of Electricity - South Dakota (Direct SD/R10)						
5	Sales of Electricity - FERC (Direct SD/R10)						
6	Total Retail Sales	-	-	-	-	-	-
7							
8	**Other Operating Revenues**						
9	**Other Sales for Resale**						
10	Municipalities (Direct FERC)						
11	Non-Asset Wholesale Transactions (D2)						
12	All Other Transactions						
13	Base Demand (E1)						
14	Peak Demand (D1)						
15	Base Energy (E2)						(31,996)
16	Peak Energy (D1)						
17	**Total Other Sales for Resale**	-	-	-	-	-	**(31,996)**
18							
19	**Other Electric Revenues**						
20	Late Fees - Minnesota (Direct MN/C1)						
21	Late Fees - North Dakota (Direct ND/C1)						
22	Late Fees - South Dakota (Direct SD/C1)						
23	*Subtotal Late Fees*	-	-	-	-	-	-
24	Connection Fees - Minnesota (Direct MN/C1)						
25	Connection Fees - North Dakota (Direct ND/C1)						
26	Connection Fees - South Dakota (Direct SD/C1)						
27	*Subtotal Connection Fees*	-	-	-	-	-	-
28	Rent from Electric Property (NEPIS)						
29	Rent from Electric Property - Big Stone (NEPIS)						
30	Rent from Electric Property - Coyote (NEPIS)						
31	*Subtotal Rent from Electric Property*	-	-	-	-	-	-
32	Other Miscellaneous Electric Revenue (NEPIS)						
33	Other Miscellaneous Electric Revenue (Direct MN/C1)						
34	Other Miscellaneous Electric Revenue (Direct ND/C1)						
35	Other Miscellaneous Electric Revenue (Direct SD/C1)						
36	*Subtotal Other Miscellaneous Electric Revenue*	-	-	-	-	-	-
37	Integrated Transmission Deficiency Payments (NEPIS)						
38	Miscellaneous Services (NEPIS)						
39	Wheeling - All Jurisdictions (NEPIS)						
40	*Subtotal Miscellanous Services*	-	-	-	-	-	-
41	Load Control & Dispatching, MAPP & MISO (NEPIS)					(10,764,133)	
42	Load Control & Dispatching, MAPP & MISO (Direct FERC)						
43	*Subtotal Load Control & Dispatching, MAPP & MISO*	-	-	-	-	(10,764,133)	-
44	Loan Pool Interest - Minnesota (Direct MN/C1)						
45	Loan Pool Interest - North Dakota (Direct ND/C1)						
46	Loan Pool Interest - South Dakota (Direct SD/C1)						
47	*Subtotal Loan Pool Interest*	-	-	-	-	-	-
48	**Total Other Electric Revenues**	-	-	-	-	**(10,764,133)**	-
49							
50	**Total Other Operating Revenues**	-	-	-	-	**(10,764,133)**	**(31,996)**
51							

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
TRADITIONAL ADJUSTMENTS TO INCOME STATEMENT SCHEDULE

Line No.	Description	(A) Advertising Expenses	(B) Economic Development Costs	(C) Incentive Compensation	(D) SPP Schedule 9 and 11 Expense	(E) Transmission Recovery Adjustment	(F) Wholesale Asset Based Margins
52	**Total Operating Revenues**	-	-	-	-	(10,764,133)	(31,996)
53							
54	**Operating Expenses**						
55	**Production Expenses**						
56	*Production Expenses Excl Purchased Power*						
57	Base Demand (E1)						
58	Peak Demand (D1)						
59	Base Energy (E2)						(33,119)
60	Peak Energy (D1)						
61	Total Excluding Purchased Power	-	-	-	-	-	(33,119)
62							
63	*Purchased Power*						
64	Base Demand (E1)						
65	Peak Demand (D1)						
66	Base Energy (E2)						
67	Peak Energy (D1)						
68	Total Purchased Power	-	-	-	-	-	-
69	**Total Production Expenses**	-	-	-	-	-	(33,119)
70							
71	Transmission Expenses (D2)				(469,227)	(6,424)	
72	Transmission Expenses (Direct FERC)						
73	**Total Transmission Expenses**	-	-	-	(469,227)	(6,424)	-
74							
75	**Distribution Expenses**						
76	Primary Demand (D3)						
77	Secondary Demand (D4)						
78	Primary Customer (C2)						
79	Secondary Customer (C3)						
80	Streetlighting (C4)						
81	Area Lighting (C5)						
82	Meters (C6)						
83	Load Management (C9)						
84	**Total Distribution**	-	-	-	-	-	-
85							
86	**Customer Accounting Expenses**						
87	Meter Reading (C7)						
88	Other (C8)						
89	**Total Customer Accounts**	-	-	-	-	-	-
90							
91	**Customer Service & Info Expenses**						
92	Conservation & DSM Rebates - MN (Direct MN/E2)						
93	Conservation & DSM Rebates - ND (Direct ND/E2)						
94	Conservation & DSM Rebates - SD (Direct SD/E2)						
95	Other (C1)						
96	**Total Customer Serv & Infomation Exp**	-	-	-	-	-	-
97							
98	**Sales Expenses**						
99	Off-Peak Development - MN (Direct MN/C1)						
100	Off-Peak Development - ND (Direct ND/C1)		(68,871)				
101	Off-Peak Development - SD (Direct SD/C1)						
102	Other (C1)	(635)					
103	**Total Sales Expenses**	**(635)**	**(68,871)**	-	-	-	-

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
TRADITIONAL ADJUSTMENTS TO INCOME STATEMENT SCHEDULE

Line No.	Description	(A) Advertising Expenses	(B) Economic Development Costs	(C) Incentive Compensation	(D) SPP Schedule 9 and 11 Expense	(E) Transmission Recovery Adjustment	(F) Wholesale Asset Based Margins
104							
105	**Administrative & General Expenses**						
106	*Salaries, Supplies, Pensions & Benefits*						
107	Production (OXPD)			(69,992)			
108	Transmission (D2)			(29,423)			
109	Distribution (OXD)			(54,625)			
110	Customer Accounts (OXC)			(42,084)			
111	Customer Service & Info (C1)			(9,440)			
112	*Total A&G Salaries, Supp, Pensions & Benefits*	-	-	(205,563)	-	-	-
113	Load Management (C9)						
114	Outside Services (A/C 923) (NEPIS)						
115	Property Insurance (A/C 924) (NEPIS)						
116	Injuries & Damages (A/C 925) (NEPIS)						
117	Regulatory Commission Exp (A/C 928) - MN (Direct MN/R10)						
118	Regulatory Commission Exp (A/C 928) - ND (Direct ND/R10)						
119	Regulatory Commission Exp (A/C 928) - SD (Direct SD/R10)						
120	Regulatory Commission Exp (A/C 928) - FERC (Direct FERC/R10)						
121	*Total Regulatory Commission Expense* (2)	-	-	-	-	-	-
122	General Advertising (A/C 930.1) (C1) (1)	(225,223)					
123	Misc, Rents, Maintenance (P90) (1)						
124	**Total Administrative & General Expense**	**(225,223)**	-	**(205,563)**	-	-	-
125							
126	**Charitable Contributions (& Cust Dep Int)**						
127	Minnesota Only (Direct MN/C1)						
128	North Dakota Only (Direct ND/C1)						
129	South Dakota Only (Direct SD/C1)						
130	**Total Charitable Contributions (& Cust Dep Int)**	-	-	-	-	-	-
131							
132	**Total O & M Expenses**	**(225,857)**	**(68,871)**	**(205,563)**	**(469,227)**	**(6,424)**	**(33,119)**
133							
134	**Depreciation Expense**						
135	Production						
136	Base Demand (E1)						
137	Peak Demand (D1)						
138	Base Energy (E2)						
139	*Total Production*	-	-	-	-	-	-
140	Transmission (D2)					(872,002)	
141	Transmission (Direct FERC)						
142	*Total Transmission* (2)	-	-	-	-	(872,002)	-
143	Distribution (P60)						
144	General (P90)						
145	Intangible (P90)						
146	**Total Depreciation Expense**	-	-	-	-	**(872,002)**	-
147							
148	**Big Stone Expense Offsets**						
149	Minnesota (Direct MN)						
150	North Dakota (Direct ND)						
151	South Dakota (Direct SD)						
152	FERC (Direct FERC)						
153	**Total Big Stone Expense Offsets**	-	-	-	-	-	-
154							
155	General Taxes (NEPIS)					(642,008)	

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
TRADITIONAL ADJUSTMENTS TO INCOME STATEMENT SCHEDULE

Line No.	Description	(A) Advertising Expenses	(B) Economic Development Costs	(C) Incentive Compensation	(D) SPP Schedule 9 and 11 Expense	(E) Transmission Recovery Adjustment	(F) Wholesale Asset Based Margins
156	General Taxes (Direct FERC)						
157	**Total General Taxes**	-	-	-	-	(642,008)	-
158							
159	**Total Operating Expense Before Tax**	(225,857)	(68,871)	(205,563)	(469,227)	(1,520,434)	(33,119)
160							
161	**Net Operating Income Before Tax**	225,857	68,871	205,563	469,227	(9,243,699)	1,123
162							
163	**Wind Investment Tax Credit & Production Tax Credit**						
164	Amortization of Prior Year' Credit (EPIS) (4)						
165	Production Tax Credits (EPIS) (5)						
166	Investment Tax Credits (EPIS)						
167	Debits Utilized (EPIS)						
168	**Total Wind Investment Tax Credit & Production Tax Credit**	-	-	-	-	-	-
169							
170	Federal (NEPIS)						
171	Minnesota (NPISM)						
172	North Dakota (NPISN)						
173	*Subtotal*	-	-	-	-	-	-
174	**Total Deferred Income Taxes**	-	-	-	-	-	-
175							
176	**Current Income Taxes**						
177	Federal Income Taxes						
178	Minnesota Income Taxes (Direct MN)						
179	North Dakota Income Taxes (Direct ND)						
180	**Total Current Income Taxes**	85,379	26,035	77,707	177,377	(3,494,303)	425
181							
182	**Total Income Taxes**	85,379	26,035	77,707	177,377	(3,494,303)	425
183							
184	**Net Operating Income**	140,479	42,837	127,856	291,850	(5,749,396)	699
185							
186	Allowance for Funds Used During Construction						
187	Allowance for Funds Used During Construction - MN Only						
188	Allowance for Funds Used During Construction - SD Only						
189	**Total Allowance for Funds Used During Construction** (7)	-	-	-	-	-	-
190							
191	**Total Available for Return**	$ 140,479	$ 42,837	$ 127,856	$ 291,850	$ (5,749,396)	$ 699

OTTER TAIL POWER COMPANY
Electric Utility - State of North Dakota
OPERATING INCOME SCHEDULES
OPERATING INCOME STATEMENT ADJUSTMENTS SCHEDULE

Line No.	Description	(A) 2018 Base Year	Projected Changes (B) Normalize CISOne Project	(C) Rate Case Expense	(D) Normalize Plant Outage	(E) Removal of PTC's	(F) Economic Development	(G) Prorate ADIT for ND Riders	(H) Changes in Allocations due to Effect of Test Year Adjustments	(I) 2018 Test Year
	OPERATING REVENUES									
1	Retail Revenue	$148,037,074						$34,877	$0	$148,071,951
2	Other Electric Operating Revenue	$10,040,248							$7,046	$10,047,294
3	**TOTAL OPERATING REVENUE**	$158,077,321	$0	$0	$0	$0	$0	$34,877	$7,046	$158,119,244
	OPERATING EXPENSES									
4	Production Expenses	$60,104,536			($347,737)				($0)	$59,756,799
5	Transmission Expenses	$13,507,453							$0	$13,507,453
6	Distribution Expenses	$7,680,921							$0	$7,680,921
7	Customer Accounting Expenses	$6,091,579							$0	$6,091,579
8	Customer Service and Information Expenses	$1,382,509							$0	$1,382,509
9	Sales Expenses	$22,472					200,000		$0	$222,472
10	Administration and General Expenses	$20,112,229		(517,129)					$1,516	$19,596,616
11	Charitable Contributions	$0							$0	$0
12	Depreciation Expense	$20,716,262	709,039						$0	$21,425,301
13	General Taxes	$4,902,302							$3,590	$4,905,891
14	**TOTAL OPERATING EXPENSES**	$134,520,262	$709,039	($517,129)	($347,737)	$0	$200,000	$0	$5,106	$134,569,542
15	**NET OPERATING INCOME BEFORE INCOME TAXES**	$23,557,059	($709,039)	$517,129	$347,737	$0	($200,000)	$34,877	$1,940	$23,549,702
16	**INCOME TAX EXPENSE**									
17	Investment Tax Credit	($1,681,974)				$1,156,403			($636)	($526,207)
18	Deferred Income Taxes	$1,321,609							($4,226)	$1,317,383
19	Income Taxes	$4,336,226	(268,027)	195,483	131,450	0	(75,603)	13,184	($28,578)	$4,304,134
20	**TOTAL INCOME TAX EXPENSE**	$3,975,861	($268,027)	$195,483	$131,450	$1,156,403	($75,603)	$13,184	($33,439)	$5,095,310
21	**NET OPERATING INCOME**	$19,581,199	($441,012)	$321,646	$216,287	($1,156,403)	($124,397)	$21,693	$35,379	$18,454,392
22	Allowance for Funds Used During Construction	0								0
23	**TOTAL AVAILABLE FOR RETURN**	$19,581,199	($441,012)	$321,646	$216,287	($1,156,403)	($124,397)	$21,693	$35,379	$18,454,392

Column references to adjustment workpapers:
(B) W/P 2018 ND TY-01
(C) W/P 2018 ND TY-02
(D) W/P 2018 ND TY-03
(E) W/P 2018 ND TY-04
(F) W/P 2018 ND TY-05
(G) W/P 2018 ND TY-06