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-23-

Exhibit___

ALLOCATORS, CLASS COST OF SERVICE,
REVENUE ALLOCATION AND OTHER REGULATORY ITEMS

Direct Testimony and Schedules of

AMBER M. STALBOERGER

November 2, 2023

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Prefiled Direct Testimony and Schedules of Amber M. Stalboerger - Volume 2A
Otter Tail Power Company

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ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My name is Amber M. Stalboerger. I am employed by Otter Tail Power Company (OTP or the Company).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Manager of Regulatory Analysis. I am responsible for providing leadership in areas of financial analysis related to setting rates and overall cost recovery, cost allocation methodologies, cost of energy, and cost of service study analysis.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit___(AMS-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony addresses a variety of regulatory and cost allocation issues, including development of jurisdictional and class allocation factors and the mechanics of the Company's proposal to address changes in sales volumes between rate cases. I also address the treatment of generator interconnection procedures projects (GIPs) and proration of accumulated deferred income tax (ADIT) in the 2024 Test Year. I sponsor and present the results of OTP's 2024 Test Year Class Cost of Service Study (CCOSS) and OTP's proposed class revenue responsibilities. Finally, I address one CCOSS compliance issue from OTP's last North Dakota rate case (Case No. PU-17-398).

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

A. The allocation factors OTP uses in its Jurisdictional Cost of Service Study (JCOSS) and CCOSS are reasonable and appropriate for determining the 2024 Test Year revenue requirement and calculating class cost responsibilities. OTP's overall approach for addressing changes in sales between rate cases also is just and reasonable, as is the proposed treatment of GIPs and ADIT proration in the 2024 Test Year. The Company's CCOSS is an appropriate, but not exclusive, guide for establishing class revenue responsibilities. Ultimately, considering the CCOSS and other relevant factors, OTP's proposed class revenue responsibilities are reasonable and should be adopted.

III. JURISDICTIONAL AND CLASS ALLOCATORS

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

A. In this section of my Direct Testimony, I introduce and discuss the allocation factors OTP uses in its jurisdictional and class cost of service studies.

Q. WHAT IS THE ROLE OF JURISDICTIONAL AND CLASS ALLOCATORS IN THE RATEMAKING PROCESS?

A. Jurisdictional allocators are used to allocate system costs among jurisdictions and class allocators are used to allocate jurisdictional costs among customer classes.

Q. WHY ARE JURISDICTIONAL AND CLASS ALLOCATORS NECESSARY?

A. OTP operates an integrated electrical system that serves customers across multiple jurisdictions. This integrated system design takes advantage of economies of scale to provide least-cost energy solutions for all our customers. Because OTP operates as one system, costs of investment in the system and the expenses necessary to operate the system need to be allocated among the jurisdictions. Costs allocated to each jurisdiction need to be further allocated to customer classes in order to design rates.

Q. HOW DO THESE ALLOCATIONS OCCUR?

A. OTP uses the JCOSS to allocate system costs and revenues to various jurisdictions in which it provides service, as described in more detail by OTP witness Ms. Christy L. Petersen. OTP then uses the CCOSS to allocate jurisdictional costs and revenues, which I describe in more detail below.

Q. WHAT ALLOCATORS DID OTP USE IN ITS TEST YEAR JCOSS AND CCOSS?

A. Table 1 below identifies the main allocators used in the 2024 Test Year JCOSS and CCOSS. The OTP Cost Allocation Procedures Manual (CAPM), included as Exhibit___(AMS-1), Schedule 2, provides additional detail regarding the development of each allocator.

Table 1
JCOSS and CCOSS Allocators

Cost Function	Classification	JCOSS Allocator[1]	CCOSS Allocator[2]
Production Plant	Base Demand	E1	E1-E8760
	Peak Demand	D1	D1
	Base Energy (Wind)	E2	E2-E8760
Transmission Plant	Demand-Related	D2	D2
Distribution Plant	Demand-Related (Primary)	D3	D3
	Demand-Related (Secondary)	D4	D4
	Customer-Related (Primary)	C2	C2
	Customer-Related (Secondary)	C3	C3
	Street Lighting	C4	C4
	Area Lighting	C5	C5
	Meters	C6	C6
	Load Management	C9	C9

Q. HAS OTP CHANGED THE CAPM SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. No, not materially. Schedule 2, identifies, in redline, the CAPM content changes from the CAPM presented in OTP's last North Dakota rate case.

Q. DID OTP USE THESE SAME ALLOCATORS IN ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. We used the same energy, demand, and customer allocation factors outlined in the CAPM for cost allocations in this case as we did in our last North Dakota rate case. As discussed below, however, we are proposing certain refinements to how the D1, D2, and E1-8760 allocators are calculated for class allocation purposes.

Q. ARE THE ALLOCATORS USED IN THE CURRENT CASE BASED ON FORECASTED INFORMATION?

A. Yes. OTP is using a forecast 2024 Test Year in this case and developed the allocation factors based on forecast information. The process of developing the forecast-based allocators is described in Exhibit___(AMS-1), Schedule 3, which is a supplement to the CAPM.[3]

[1] *See* Volume 3, Supporting Information, Schedule B-5.
[2] *See* Volume 3, Supporting Information, Schedule E-3.
[3] Similar to Schedule 2, Schedule 3 shows revisions to the CAPM supplement in redline format.

A. Jurisdictional Allocation Factors

Q. DOES OTP USE THE SAME JURISDICTIONAL ALLOCATION METHODOLOGIES ACROSS ALL OF ITS JURISDICTIONS?

A. Yes. Each of our jurisdictions has approved the same jurisdictional cost allocation methodology.

Q. IS IT IMPORTANT TO MAINTAIN CONSISTENCY IN JURISDICTIONAL ALLOCATION METHODOLOGIES ACROSS JURISDICTIONS?

A. Yes. Maintaining consistency in cost allocation across jurisdictions helps minimize the potential for any over- or under-recovery of costs from an overall system perspective.

Q. HOW DO THE JCOSS ALLOCATION FACTORS COMPARE TO OTP'S LAST NORTH DAKOTA RATE CASE?

A. Table 2 below compares the 2024 Test Year JCOSS allocation factors to those used in the 2018 Test Year from OTP's last North Dakota rate case.

Table 2
Comparison of JCOSS Allocation Factors

Cost Function	Classification	JCOSS Allocator[4]	2018 Test Year	2024 Test Year	Change
Production Plant	Base Demand	E1	35.65831%	43.87388%	8.21558%
	Peak Demand	D1	39.84045%	39.48493%	-0.35553%
	Base Energy (Wind)	E2	37.57734%	44.98105%	7.40371%
Transmission Plant	Demand-Related	D2	39.59894%	39.19520%	-0.40371%
Distribution Plant	Demand-Related (Primary)	D3	45.87051%	46.52141%	0.65090%
	Demand-Related (Secondary)	D4	48.02088%	48.69979%	0.67891%
	Customer-Related (Primary)	C2	44.77088%	43.71010%	-1.06078%
	Customer-Related (Secondary)	C3	44.78375%	43.71399%	-1.06976%
	Street Lighting	C4	43.58121%	41.67331%	-1.90790%
	Area Lighting	C5	51.76290%	54.51687%	2.75398%
	Meters	C6	44.67973%	44.58005%	-0.09968%
	Load Management	C9	43.55054%	43.69288%	0.14234%

[4] *See* Volume 3, Supporting Information, Schedule B-5.

Q. WHAT IS CONTRIBUTING TO THE GENERAL INCREASE IN THE E1 AND E2 JCOSS ALLOCATION FACTORS?

A. The increase in the JCOSS E1 and E2 allocation factors is the result of relative growth in OTP's North Dakota sales (as compared to other jurisdictions served by OTP), primarily due to the addition of APLD Hosting, LLC, a wholly owned affiliate of Applied Digital, Inc. ("Applied") (formerly known as Applied Blockchain) as a full-service customer in 2022.

Q. PLEASE DESCRIBE OTP'S SERVICE TO APPLIED.

A. OTP received a Certificate of Public Convenience and Necessity (CPCN) to provide service to Applied in 2021.[5] Applied started taking service under OTP's Super Large General Service Tariff, Electric Rate Schedule Section 10.06 (SLGS) and began operating at full capacity in late 2022. Applied is OTP's largest North Dakota customer (by sales) and second largest customer (by sales) across all jurisdictions served by OTP.

Q. PLEASE DESCRIBE THE SLGS RATE.

A. The SLGS rate, which was approved in OTP's last North Dakota rate case, is designed to attract high load factor large/commercial customers into OTP's service territory. Customers that meet eligibility criteria have access to individual contract pricing based on OTP's marginal cost of service. The Commission approved Applied's individual contract pricing in Case No. PU-21-366.

Q. HAS OTP ANALYZED APPLIED'S CONTRIBUTION TO MEETING ITS NORTH DAKOTA COST OF SERVICE?

A. Yes. During its approval of OTP providing service to Applied under the SLGS rate, the Commission requested that OTP annually assess Applied's contribution to meeting its North Dakota cost of service.[6] OTP provided its first assessment covering calendar year 2022 as part of its annual report filing in Case No. PU-23-249. That assessment confirmed that Applied made a net contribution to system costs. OTP's second assessment covering calendar year 2023 will be provided as part of its next annual report filing.

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[5] *See* PU-21-365, Order on Electric Service Area Agreement and Certificate of Public Convenience and Necessity (Sept. 21, 2021). Other cases addressing OTP's service to Applied include Case Nos. PU-21-364 and PU-21-366.

[6] Section 10.06, Terms and Conditions, Paragraph 9 requires OTP to provide the Commission annual compliance updates to the marginal cost model used for SLGS pricing.

Q. HAVE YOU EVALUATED APPLIED'S IMPACT ON THE 2024 TEST YEAR REVENUE DEFICIENCY?

A. Yes. As discussed by Ms. Petersen, the 2024 Test Year revenue requirement is $223.3 million, resulting in a $40.7 million base rate revenue deficiency. Both of these values reflect OTP's service to Applied under the Commission-approved SLGS pricing and jurisdictional allocators reflecting anticipated 2024 sales to Applied. Removing both the costs (including the effect on jurisdictional allocations) and revenues associated with OTP's service to Applied *increases* the 2024 Test Year revenue deficiency by approximately $2.0 million. This confirms that OTP's service to Applied continues to benefit other North Dakota customers.

Q. HOW ARE WIND GENERATING RESOURCES TREATED IN THE JCOSS?

A. As discussed in the CAPM, wind generation is a non-dispatchable resource with operating characteristics that are different from other production facilities. OTP uses the Midcontinent Independent System Operator's (MISO) capacity accreditation to classify wind production plant into base energy and peak demand components.

Q. HAS MISO RECENTLY CHANGED HOW IT ACCREDITS WIND CAPACITY?

A. Yes. On February 16, 2023, the Federal Energy Regulatory Commission (FERC), approved revisions to MISO's Energy and Operating Reserve Market Tariff (MISO Tariff).[7] Those revisions implement a seasonal resource adequacy construct whereby Load Serving Entities (LSEs), including OTP, are required to have enough resources (generation, purchased capacity, load management resources) to cover expected customer demand and contingencies for each season (summer, winter, fall, spring). Previously, MISO only required LSEs to meet planning reserve margins during the summer season. With the adoption of a seasonal resource adequacy construct, MISO has changed how it accredits wind capacity, looking to production during all seasons, not just the summer. As a result, OTP's wind facilities have higher accredited capacity under the new construct.

Q. WHAT IS THE EFFECT OF MISO'S NEW RESOURCE ADEQUACY RULES ON THE CLASSIFICATION OF WIND PRODUCTION PLANT?

A. Table 3, below, shows the capacity accreditation factors for each of OTP's wind facilities for each season. Winter capacity factors are higher than summer capacity

[7] *See Midcontinent Independent System Operator, Inc.*, Docket Nos. ER22-495-002, ER22-495-003, Order Addressing Arguments Raised on Rehearing and on Compliance, 182 FERC ¶ 61,096 (Feb. 16, 2023).

factors. Thus, the change to MISO's resource adequacy rules increases each facility's accredited capacity and thus, the portion of wind production plant classified as peak demand.

Table 3
OTP Wind Facility MISO Capacity Accreditation

Wind Facility	Summer	Fall	Winter	Spring	Average
Ashtabula	2.19%	4.32%	7.16%	2.74%	4.10%
Ashtabula III	3.19%	4.65%	9.81%	3.51%	5.29%
Langdon	1.83%	3.34%	6.45%	2.88%	3.62%
Luverne	2.80%	4.48%	7.94%	2.99%	4.55%
Merricourt	9.25%	10.62%	20.45%	15.37%	13.92%
Total	19.25%	27.40%	51.83%	27.49%	**31.49%**

Q. WHAT IS THE BASE RATE REVENUE REQUIREMENT IMPACT OF APPLYING MISO'S NEW RESOURCE ADEQUACY RULES ON THE CLASSIFICATION OF WIND PRODUCTION PLANT?

A. Applying the MISO resource adequacy rules to the classification of wind production plant decreased the 2024 Test Year revenue requirement by approximately $0.5 million.

B. Class Allocation Factors

Q. HOW DO THE CCOSS ALLOCATION FACTORS COMPARE TO OTP'S LAST NORTH DAKOTA RATE CASE?

A. Table 4 below shows the differences between the 2024 Test Year CCOSS allocation factors and those used in the 2018 Test Year from OTP's last North Dakota rate case.

Table 4
Change in CCOSS Allocation Factors

Class Allocator	Residential	Farm	General Service	Large General Service	Irrigation
Generation Demand (D1)	0.3242%	-0.5525%	-0.6271%	0.6994%	0.0000%
Transmission Demand (D2)	0.3242%	-0.5525%	-0.6271%	0.6994%	0.0000%
Primary Demand (D3)	-0.3845%	-1.7545%	-0.2645%	-2.9564%	0.0567%
Secondary Demand (D4)	-4.7396%	-1.6865%	-0.8935%	-1.6533%	0.0813%
Energy (E1-8760)	-11.6701%	-0.7336%	-7.2854%	21.2278%	0.0000%
Energy (E2-8760)	-8.2183%	-0.5254%	-6.9565%	20.8154%	0.0076%
Total Retail Customers (C1)	-0.4304%	0.1419%	0.6118%	-0.0023%	-0.0085%
Retail Service Locations (C2)	0.3317%	-0.0998%	-0.3975%	0.1460%	-0.0836%
Secondary Service Locations (C3)	0.3250%	-0.1000%	-0.4015%	0.1569%	-0.0836%
Street Lighting (C4)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Area Lighting (C5)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Meter (C6)	0.9508%	-0.2907%	0.4991%	-0.2271%	-0.0101%
Meter Reading (C7)	-9.2398%	-0.0758%	9.7264%	0.0024%	0.0486%
System Service Locations (C8)	0.3340%	-0.0997%	-0.3969%	0.1429%	-0.0836%
Load Management (C9)	-0.3498%	0.0725%	0.0749%	0.0002%	-0.0129%

Class Allocator	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interuptible	Controlled Service Off-peak
Generation Demand (D1)	-0.5274%	0.1177%	0.7144%	0.1004%	-0.2490%
Transmission Demand (D2)	-0.5274%	0.1177%	0.7144%	0.1004%	-0.2490%
Primary Demand (D3)	-0.2675%	0.1069%	6.9893%	0.6678%	-2.1932%
Secondary Demand (D4)	-0.2049%	0.0268%	10.7942%	0.6740%	-2.3985%
Energy (E1-8760)	-0.6124%	-0.2984%	0.1318%	0.0000%	-0.7598%
Energy (E2-8760)	-0.4898%	-0.2137%	0.3319%	-3.4460%	-1.3052%
Total Retail Customers (C1)	0.0736%	0.0590%	-0.0353%	-0.3460%	-0.0638%
Retail Service Locations (C2)	0.0452%	0.0682%	0.0075%	-0.0082%	-0.0095%
Secondary Service Locations (C3)	0.0452%	0.0681%	0.0075%	-0.0083%	-0.0095%
Street Lighting (C4)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Area Lighting (C5)	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Meter (C6)	0.1174%	-0.0393%	-0.3998%	0.1665%	-0.7668%
Meter Reading (C7)	0.3547%	1.0084%	-0.2784%	-0.9856%	-0.5609%
System Service Locations (C8)	0.0452%	0.0682%	0.0075%	-0.0082%	-0.0095%
Load Management (C9)	0.0055%	0.0000%	3.1345%	0.4968%	-3.4217%

Q. DO YOU HAVE ANY PRELIMINARY OBSERVATIONS REGARDING TABLE 4?

A. Yes. As discussed below, OTP has reorganized the rate schedules that comprise the controlled services classes (Controlled Service, Controlled Service Deferred, and Controlled Service Interruptible) since its last North Dakota rate case, so the values for those classes in the table above are not directly comparable to those of the previous case. OTP witness Mr. David G. Prazak discusses this issue in more detail in his Direct Testimony.

Q. WHAT IS CONTRIBUTING TO THE GENERAL INCREASE IN THE E1-E8760 AND E2-8760 CCOSS ALLOCATION FACTORS FOR THE LARGE GENERAL SERVICE CLASS?

A. The primary contributor to the increase in the E1-E8760 and E2-E8760 allocation factors for the Large General Service (LGS) class is the addition of Applied as a full-service customer in 2022. That class is now significantly larger (by sales volume) than it was during our last North Dakota rate case and therefore has a larger share of the E1-8760 and E2-8760 allocators.

Q. HAS THERE BEEN A CORRESPONDING INCREASE TO THE D1 AND D2 ALLOCATION FACTORS FOR THE LGS CLASS?

A. No. One of the unique aspects of Applied's operations is that it can rapidly reduce its load in response to OTP load control signals.[8] This flexibility allowed OTP to add Applied as a customer without needing to acquire an amount of additional capacity comparable to its energy amount. Applied's flexibility also is considered in calculation of the D1 and D2 allocation factors (for both jurisdictional and class purposes), which is why there has not been a corresponding increase to those factors.

Q. PLEASE DISCUSS THE CHANGES TO THE PROCESS OF CALCULATING THE CCOSS D1 AND D2 ALLOCATION FACTORS.

A. OTP has set the D1 and D2 allocation factors for the Controlled Service classes to zero kilowatts (kW). Setting these classes to zero kW reflects OTP's ability to completely turn off these loads during high priced periods, as well as during OTP's peak. These classes are considered a low-cost resource and prevent OTP from needing to obtain additional capacity.

Q. PLEASE DISCUSS THE CHANGE TO THE CALCULATION OF THE E1-8760 ALLOCATION FACTOR.

A. Historically, the E1-E8760 allocator was calculated based on applying a 10/24ths factor to forecasted annual kilowatt hours (kWhs) for water heating and deferred loads. We have refined the calculation to better weigh the avoided capacity costs realized by those levels of service that could be controlled.

[8] *See* Case No. PU-21-336, Informal Presentations of OTP and Applied (Sept. 1, 2021).

The refinement excludes kWhs related to up to 14 hours of control for water heating and deferred loads based on the highest priced 14 of 24 hours using forecasted marginal hourly capacity costs. Schedule 3 further describes the process for the development of this forecasted factor.

IV. SALES ADJUSTMENT PROPOSAL

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

A. In this section of my Direct Testimony, I discuss the mechanics of OTP's sales adjustment proposal. OTP witness Mr. Bruce G. Gerhardson supports this proposal in his Direct Testimony.

Q. WHAT IS THE SALES ADJUSTMENT PROPOSAL DESIGNED TO ADDRESS?

A. Mr. Gerhardson explains that OTP potentially could see significant changes in sales between rate cases. The sales adjustment proposal is designed to address the impacts of such changes on revenues and jurisdictional cost allocations.

Q. IS OTP'S PROPOSAL LIMITED TO BASE RATES?

A. No. Mr. Gerhardson explains the proposal has two elements: one focusing on base rates and one focusing on riders. Regarding base rates, OTP proposes to create a new mandatory rider, called the Sales Adjustment Rider, which would capture the effect of sales changes on base rate jurisdictional cost allocations and revenues. OTP also requests that the Commission authorize OTP to update jurisdictional allocators used to develop rider revenue requirements between rate cases. These changes would occur as part of annual rider filings, as discussed below.

Q. PLEASE EXPLAIN HOW THE SALES ADJUSTMENT RIDER WOULD WORK.

A. Again, as discussed above, the Sales Adjustment Rider is intended to capture the effect of sales changes on base rate jurisdictional cost allocations and revenues. The starting point will be the 2024 Test Year JCOSS for the authorized revenue requirement from this case. OTP will then remove all 2024 Test Year rider costs and revenues. This will form the baseline for comparison (the Sales Adjustment Rider Baseline JCOSS).

Concurrently with the filing of OTP's 2024 annual report (made in the second quarter of 2025) and continuing at the time of filing each annual report thereafter until OTP's next North Dakota rate case, OTP will prepare a JCOSS that captures the effects of differences between actual sales and the amounts included in the 2024 Test Year. Specifically, the filing will include a JCOSS that begins with the Sales Adjustment Rider Baseline JCOSS, but then incorporates the effects of actual sales for the calendar year on allocation factors, base revenues and working capital. This JCOSS will be the Comparison JCOSS. The only differences between the Sales Adjustment Rider Baseline JCOSS and the Comparison JCOSS would be the impact of sales on allocation factors, base revenues and associated working capital: all other aspects would be identical. The difference between the Sales Adjustment Rider Baseline JCOSS and the Comparison JCOSS would be the amount credited to, or collected from, customers through the Sales Adjustment Rider.

Q. HOW WILL THE SALES ADJUSTMENT RIDER AMOUNTS BE CREDITED TO OR COLLECTED FROM CUSTOMERS?

A. The Sales Adjustment Rider would become a new mandatory rider. Sales Adjustment Rider amounts would be credited to or collected from customers on a per-kWh basis.

Q. HAS OTP PREPARED A PROPOSED SALES ADJUSTMENT RIDER TARIFF SHEET?

A. Yes. A proposed Sales Adjustment Rider tariff sheet is provided as Exhibit___(AMS-1), Schedule 4. The tariff sheet describes other mechanics of the Sales Adjustment Rider, including applicable tracker and true-up adjustment provisions.

Q. HOW WILL OTP'S PROPOSAL IMPACT OTHER RIDERS?

A. As discussed by Mr. Gerhardson, OTP intends its overall proposal to address the effects of between-rate-case sales changes on revenues and cost allocations. OTP's other riders already capture revenue effects of between-rate-case changes in sales volumes through annual updates (which incorporate forecasted sales for the applicable recovery period) and true-up adjustments (which capture differences between forecasted sales and actual sales). This process would be unchanged under OTP's proposal. Those riders, however, currently do not accommodate the effects of sales changes on jurisdictional cost allocations.

OTP proposes to change the operation of its riders by allowing for annual updates to jurisdictional cost allocations. Specifically, at the time OTP makes its annual rider filings it would: (1) calculate proposed rider revenue requirements utilizing jurisdictional allocators based on the same sales volumes used to develop the projected rider rates; and (2) include within the true-up calculation amounts due to differences between the jurisdictional allocators used to calculate the prior year's annual revenue requirement and allocators based on actual sales during that year. This is similar to the current process used for the Energy Adjustment Rider.

V. GENERATOR INTERCONNECTION PROCEDURES PROJECTS

Q. WHAT ARE GENERATOR INTERCONNECTION PROCEDURES PROJECTS?

A. Generator Interconnection Procedures Projects, or GIPs, are upgrades to OTP's transmission facilities that are located beyond a generator's point of interconnection with the MISO transmission grid. New generators typically require upgrades of the existing transmission system beyond the point (downstream) of the point of interconnection.

Q. WHAT TYPES OF UPGRADES ARE INCLUDED IN THE GIPS CATEGORY?

A. GIPs involve things that result in an increase to transmission system capacity or that interconnect new generation, such as: (1) replacing structures to increase line clearances; (2) replacing existing conductors with larger conductors; (3) adding new or replacing existing substation equipment; (4) constructing new substations or switch stations; and (5) building new transmission lines or modifying existing transmission lines to interconnect with new switching stations or substations.

Q. HAS OTP BEEN REQUIRED TO MAKE MANY TRANSMISSION UPGRADES BEYOND THE POINT OF INTERCONNECTION?

A. Yes. With the significant number of wind generation projects coming online in North Dakota, Minnesota, and South Dakota, OTP's transmission facilities have required many upgrades in order to interconnect new generators, even if the point of interconnection of the new generator is not on OTP's transmission system.

Q. HOW MUCH HAS OTP INVESTED IN GIPS TO DATE?

A. By the end of 2024, OTP will have approximately $42.8 million (OTP Total) / $16.8 million (OTP ND) of transmission rate base investment for GIPs made in connection with approximately 20 different generating facilities, including Merricourt Wind and Astoria Station.

Q. PLEASE DISCUSS THE RATEMAKING TREATMENT FOR GIPS UNDER THE MISO TARIFF.

A. Under the MISO Tariff, the entire cost of facilities that are specific to the generator itself and provide the initial point of interconnection to the MISO transmission system are paid for in advance by the generator.

The MISO tariff also provides two alternatives to be elected by a transmission owner (TO) for the types of transmission improvements included in OTP's GIPs: (1) pre-funding by the generator; or (2) TO Provided Funding. The TO may elect pre-funding, which requires full payment by the generator in advance of network upgrades being constructed. TO Provided Funding allows TOs (including OTP) to elect to provide funding for network upgrades to the TO's transmission system that are required to transmit energy from the new generators.[9] If the TO elects TO Provided Funding, the generator is required to pay for 100 percent of transmission network upgrades to facilities of 230 kilovolts (kV) or below, and 90 percent of upgrades to facilities of 345 kV or above. The remaining 10 percent of upgrades to facilities of 345 kV or above are allocated to utilities throughout the MISO region.[10]

Q. HOW DOES THE GENERATOR PAY FOR TRANSMISSION OWNER PROVIDED FUNDING?

A. Under the MISO Tariff, the generator pays the TO the cost of TO Provided Funding over a 20-year period at a formula rate established under the MISO Tariff.[11]

Q. DOES OTP'S TRANSMISSION OWNER PROVIDED FUNDING OF GIPS PROVIDE FINANCIAL BENEFITS TO OTP CUSTOMERS?

A. Yes. The MISO Tariff provisions for Transmission Owner Provided Funding provide for recovery of costs over a 20-year period rather than over the 40 to 60-year useful life of the GIPs as they are depreciated. This increases revenues during the 20-year repayment period.

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[9] *Order Accepting Tariff Revisions*, 171 FERC ¶ 61,075 (2020) [*hereinafter* FERC Transmission Owner Provided Funding Order].
[10] FERC Transmission Owner Provided Funding Order, ¶ 2.
[11] FERC Transmission Owner Provided Funding Order, ¶¶ 35, 49.

Q. WHAT IS THE CURRENT STATUS OF THE MISO TARIFF PROVISIONS RELATED TO RATEMAKING FOR THE GIPS?

A. On December 2, 2022, the United States Courts of Appeals, District of Columbia Circuit issued its opinion in Case No. 20-1453 remanding the MISO Tariff provisions to FERC for additional support.[12] FERC has not acted on the remand as of yet, meaning there is significant uncertainty regarding the ratemaking treatment of these projects.

Q. GIVEN THIS UNCERTAINTY, HAS OTP INCLUDED THE GIPS INVESTMENTS IN THE 2024 TEST YEAR?

A. Except for investments related to Merricourt Wind and Astoria Station, the 2024 Test Year does not include GIPs investments. There are too many uncertainties regarding the ultimate ratemaking treatment for these projects to include them in the 2024 Test Year. Merricourt Wind and Astoria Station GIPs are included in the 2024 Test Year because there are no intercompany revenue payments associated with those projects due to OTP being owner of both the generator and transmission facilities.

VI. ACCUMULATED DEFERRED INCOME TAX PRORATION

Q. WHAT WILL YOU DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. In this section, I will explain the Federal ADIT Proration that is required in order to meet normalization requirements, as explained by the Internal Revenue Service (IRS) in a Private Letter Ruling issued by the IRS to OTP. I also will explain how OTP has applied these requirements to the 2024 Test Year for both final rates and interim rates in this case and provide a discussion of the financial effects of doing so.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE BASIC PRINCIPLES OF INCOME TAX NORMALIZATION.

A. Income tax normalization is an approach to determining the regulated rates for a utility that is required by the Internal Revenue Code (IRC) and IRS Regulations as a precondition of the utility being allowed to use accelerated and bonus depreciation for determining its federal income taxes. Under normalization, the

[12] *American Clean Power Ass'n v. Federal Energy Regulatory Commission*, 54 F.4th 722 (D.C. Cir 2022).

income tax expense reflected in regulated rates is determined using straight-line depreciation and the difference between the straight-line income tax expense and the current income tax payable under accelerated and bonus depreciation is determined as ADIT, which reduces rate base.

Q. IS THE USE OF INCOME TAX NORMALIZATION A COMMON PRACTICE FOR UTILITIES AND REGULATORY AGENCIES?

A. Yes. The Commission and virtually every state regulatory agency, along with virtually every utility, use income tax normalization and have done so consistently for many years.

Q. DOES THE TREATMENT OF ADIT THAT IS PART OF INCOME TAX NORMALIZATION LEAD TO LOWER RATES FOR CUSTOMERS?

A. Yes. ADIT leads to substantial reductions in rate base. In this case, ADIT reduces OTP's 2024 Test Year rate base by approximately $371.7 million (OTP Total) / $175.8 million (OTP ND).[13] This reduction in rate base, in turn, leads to a reduction in the revenue requirement.

Q. IS A UTILITY REQUIRED TO PRORATE FEDERAL ADIT IF IT USES A FORWARD-LOOKING TEST YEAR?

A. Yes. IRS Regulation Section 1.167(l)-1(h)(6) provides that ratemaking procedures and adjustments must be consistent with normalization accounting. This regulation sets procedures a utility must use to normalize the impact on rate making if the utility wants to use accelerated depreciation methods to determine its federal income taxes. The monthly changes to the Federal deferred taxes balance, as calculated by the utility, must be prorated prior to computing the average of beginning and ending balances for ADIT.

When a utility utilizes a forecast test year to determine depreciation, the IRS requires that "the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period."[14] The prorated amount of any increase or decrease during the future portion of the period is determined by multiplying the increase or

[13] Petersen Direct, Schedule 6. Note, because proration is not required for the 2024 Test Year, these amounts are not prorated.
[14] Treas. Reg. § 1.167(l)-1(h)(6)(ii).

decrease by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period.[15]

Q. WHAT HAPPENS IF OTP FAILS TO COMPLY WITH THIS REGULATION?

A. If a utility does not comply with this regulation, the utility would be at serious risk of losing the ability to claim accelerated depreciation in its federal income tax filings. Losing accelerated depreciation would significantly increase rate base due to the elimination of the ADIT offset to rate base.

Q. HAS OTP OBTAINED A SPECIFIC PRIVATE LETTER RULING FROM THE IRS REGARDING ITS OBLIGATIONS WITH RESPECT TO ADIT PRORATION?

A. Yes. OTP obtained a private letter ruling dated June 26, 2017, addressing the requirements for ADIT proration (the Otter Tail PLR) and the IRS released a public version of the Otter Tail PLR on September 29, 2017.

Q. DID THE OTTER TAIL PLR PROVIDE DIRECTION AS TO HOW TO PRORATE ADIT IN ORDER TO COMPLY WITH NORMALIZATION REQUIREMENTS?

A. Yes. The Otter Tail PLR directs that, in order to comply with normalization requirements, ADIT proration is to be based on the date rates become effective (relative to the dates of the test year used to compute those rates). The Otter Tail PLR also determined how ADIT proration must be applied for both final rates and for interim rates and interim rate refunds.

Q. PLEASE EXPLAIN HOW THE EFFECTIVE DATES OF RATES AFFECT THE REQUIREMENTS.

A. The principle is that if rates become effective and are in effect during the time when the basis for the rates is forecast, proration must be applied. If rates become effective or are in effect after the forecast period, proration is no longer necessary. For example, if a rate (including an interim or final rate) goes into effect as of January 1 of a forecast January 1 to December 31 test year, ADIT proration is applied to the entire Test Year period (because the entire period is deemed a future period). If the rate goes into effect at some other date in the test year, ADIT proration must be applied in setting rates for the period from the effective date of

[15] *Id.*

the rate to December 31. If the rate goes into effect after the conclusion of the test year, ADIT proration need not be applied to that rate.

Q. HOW DO THESE REQUIREMENTS APPLY TO THE FINAL RATES IN THE CURRENT CASE?

A. As I explained, to comply with normalization requirements, the rate must be computed by applying ADIT proration to only the portion of the test year that follows the date of implementation of the rates. If it is assumed that final rates will be implemented as of August 1, 2024, ADIT Proration would be required only for the period from August 1, 2024 through December 31, 2024. Changes in ADIT balances from January 1, 2024 to July 31, 2024 are not prorated, but the incremental monthly changes to ADIT from August 1, 2024 to December 31, 2024 are prorated.

Q. HAS OTP PRORATED FEDERAL ADIT IN THE 2024 TEST YEAR?

A. No. The 2024 Test Year revenue requirement is calculated as if final rates go into effect January 1, 2025, so no proration has been applied.

Q. WHAT IS THE FINANCIAL IMPACT IF FINAL RATES GO INTO EFFECT BEFORE JANUARY 1, 2025?

A. Assuming final rates are implemented as of August 1, 2024, the impact of applying proration to Federal ADIT decreases ADIT and increases the net rate base amount by approximately $2.3 million (OTP Total) / $0.9 million (OTP ND), resulting in an increase in the revenue requirement of approximately $0.09 million (OTP ND) as shown in Exhibit___(AMS-1), Schedule 5. This is the approach that is required under the Otter Tail PLR if final rates go into effect in 2024, as I explained above.

Q. HOW IS ADIT PRORATION COMPUTED FOR INTERIM RATES?

A. Interim rates are proposed to become effective January 1, 2024. Interim rates are computed based on a January 1, 2024 to December 31, 2024 Test Year. Because interim rates are computed based on an entirely future test period as defined by the IRS, proration is applied to all incremental changes to ADIT balances from January 1, 2024 to December 31, 2024.

Q. WHAT IS THE IMPACT OF PRORATING FEDERAL ADIT IN INTERIM RATES?

A. The impact of applying proration to the additional Federal ADIT attributable to the 2024 Test Year amounts for purposes of computing interim rates increases the net rate base amount by approximately $3.6 million (OTP Total) / $1.4 million (OTP ND), resulting in an increase in the revenue requirement of approximately $0.13 million (OTP ND). These calculations are also shown in Schedule 5. If interim rates are in effect for only a portion of 2024, the actual impact will be less, and the interim effect will be limited to a one-time effect. This is the approach that is required under the Otter Tail PLR, as I have also explained.

VII. CLASS COST OF SERVICE STUDY AND CLASS REVENUE RESPONSIBILITY

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I explain OTP's 2024 Test Year CCOSS and present OTP's proposed class revenue responsibilities. The 2024 Test Year CCOSS is included in Volume 3, Supporting Information. A one-page summary of the CCOSS results is provided as Exhibit___(AMS-1), Schedule 6.

A. CCOSS

Q. WHAT COSTS ARE MEASURED BY THE CCOSS?

A. OTP's CCOSS is an embedded cost study, meaning it measures the 2024 Test Year cost of service for the North Dakota jurisdiction and all costs are fully distributed to classes.

Q. DOES OTP ALSO USE A MARGINAL COST STUDY?

A. Yes. Mr. Prazak discusses the marginal cost study and its use in his Direct Testimony.

Q. ARE THE CCOSS AND THE MARGINAL COST STUDY USED FOR DIFFERENT PURPOSES?

A. Yes. OTP uses the CCOSS to inform the development of inter-class revenue responsibilities. As discussed in more detail by Mr. Prazak, OTP uses the marginal cost study to guide intra-class revenue responsibilities (i.e., by rate schedule) and to develop rate elements (i.e., energy charges, demand charges, etc...).

Q. WAS THE CCOSS PREPARED USING THE SAME GENERAL CCOSS METHODOLOGY AS WAS USED IN OTP'S LAST NORTH DAKOTA RATE CASE?

A. Yes. The proposed CCOSS was prepared using the same basic cost classification and allocation methodology used in OTP's last North Dakota rate case.

Q. HAS OTP REVISED ITS CCOSS CUSTOMER CLASSES SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. OTP revised its controlled services classes to better group like-customers. Mr. Prazak discusses the reasoning for the change in his Direct Testimony.

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2024 CCOSS.

A. Table 5 below compares the present revenue responsibilities [Column B] and cost responsibilities [Column C] of OTP's customer classes, as calculated in the CCOSS. As shown in Table 5, the revenue responsibility of the Residential class currently is below its CCOSS-indicated cost responsibility. Conversely, the revenue responsibility of the Large General Service class is greater than its CCOSS-indicated cost responsibility.

Table 5
Comparison of Present Revenue Responsibility and Cost Responsibility

	A	B	C	D
Line No.	**Class**	**Present Revenue Responsibility**	**CCOSS Cost Responsibility**	**Difference**
1	Residential	27.88%	31.09%	3.22%
2	Farms	1.44%	1.49%	0.05%
3	General Service	21.07%	21.04%	-0.03%
4	Large General Service	39.71%	36.55%	-3.16%
5	Irrigation	0.05%	0.07%	0.02%
6	Lighting	1.73%	1.18%	-0.54%
7	OPA	0.74%	0.94%	0.19%
8	Controlled Service Deferred Load	1.30%	1.96%	0.66%
9	Controlled Service Interruptible	5.69%	5.44%	-0.25%
10	Controlled Service Off-Peak	0.39%	0.23%	-0.16%

B. Class Revenue Responsibilities

Q. PLEASE SUMMARIZE HOW OTP USED THE CCOSS IN THE DEVELOPMENT OF OTP'S RECOMMENDED CLASS REVENUE RESPONSIBILITIES.

A. The CCOSS is the primary guide for setting the class revenue responsibilities. However, determining the appropriate class revenue responsibilities is not as simple as setting them to equal the results of the CCOSS. It is necessary to consider other objectives, particularly the objective of maintaining reasonable rate continuity, and mitigating disproportionate or abrupt rate impacts. A more complete discussion of the rate design considerations applied by OTP is contained in Mr. Prazak's Direct Testimony.

Q. HOW DOES OTP PROPOSE TO ALLOCATE TOTAL REVENUE TO CUSTOMER CLASSES?

A. Absent a rate case, OTP estimates 2024 class revenues (including riders) are approximately $206.0 million, as shown in Column B of Table 6 below. OTP's proposed 2024 Test Year revenues are approximately $223.3 million as shown in Column C of Table 6. The total net dollar increase for OTP's North Dakota customers is $17.4 million (Column D), or 8.43 percent (Column E).

Based on a consideration of all of OTP's rate design objectives, OTP proposes the distribution of revenue responsibilities contained in Table 6. This distribution of revenue responsibilities results in a reasonable movement toward class cost responsibility (as calculated in the proposed CCOSS) without producing unreasonable bill impacts.

Table 6
Proposed Revenue Allocation and Net Bill Impact

	A	B	C	D	E
Line No.	Class	Total Present Revenues	Total Proposed Revenues	Net Bill Increase	Net Bill Impact
1	Residential	$ 58,596,832	$ 64,807,623	$ 6,210,791	10.60%
2	Farms	$ 3,035,105	$ 3,357,543	$ 322,438	10.62%
3	General Service	$ 44,329,329	$ 49,019,629	$ 4,690,300	10.58%
4	Large General Service	$ 79,991,537	$ 86,326,696	$ 6,335,159	7.92%
5	Irrigation	$ 105,695	$ 117,613	$ 11,918	11.28%
6	Lighting	$ 3,705,988	$ 3,215,029	$ (490,959)	-13.25%
7	OPA	$ 1,551,133	$ 1,738,362	$ 187,230	12.07%
8	Controlled Service Deferred Load	$ 2,666,277	$ 2,682,814	$ 16,537	0.62%
9	Controlled Service Interruptible	$ 11,230,365	$ 11,298,787	$ 68,422	0.61%
10	Controlled Service Off-Peak	$ 776,948	$ 783,351	$ 6,403	0.82%
11	Total	$ 205,989,209	$ 223,347,447	$ 17,358,238	8.43%

Q. PLEASE EXPLAIN HOW YOU ARRIVED AT THE TOTAL NET DOLLAR INCREASE IDENTIFIED IN TABLE 6.

A. OTP currently receives a certain amount of base rate and rider revenue from its North Dakota customers that it would continue to receive without a rate case. The combined total of these amounts is identified in Column B of Table 6. Like Column B, Column C (Total Proposed Revenues), also includes base rate and rider revenue. The detail for the base revenue amounts included in Columns B and C of Table 6 is provided in Exhibit___(AMS-1), Schedule 7. Mr. Prazak's proposed base rate design utilizes the base revenue of $155.0 million as provided in Schedule 7 (Column I, Line No. 11).

OTP witness Ms. Paula A. Foster explains that as part of this case, OTP proposes to move certain projects currently being recovered in riders into base rates. This is a shift in the recovery mechanism and does not result in a change to a customer's overall bill. Therefore, Table 6, Column B, which is the sum of the base and rider revenues, provides the appropriate base from which to measure the rate increase being proposed in this case. Table 6, Column C identifies the 2024 Test Year proposed revenues, which includes the shift in recovery mechanism between riders and base rates. The overall bill impact that customers will experience under OTP's proposal is shown in Table 6, Columns D and E.

Q. DOES OTP'S PROPOSAL GENERALLY MOVE CLASSES CLOSER TO COST RESPONSIBILITY?

A. Yes. OTP attempted to move classes closer to their CCOSS-indicated cost responsibilities, and as shown in Table 7, was able to do so for its two largest classes (by revenue) and several of the smaller customer classes. Table 7 below compares present revenue and cost responsibilities (as measured in the CCOSS) and OTP's proposed revenue responsibilities for all of OTP's customer classes.

Table 7
Comparison of Proposed Revenue Responsibility and Cost Responsibility

Line No.	Class A	Present Revenue Responsibility B	Cost Responsibility from CCOSS C	Proposed Revenue Responsibility D
1	Residential	27.88%	31.09%	29.07%
2	Farms	1.44%	1.49%	1.51%
3	General Service	21.07%	21.04%	21.88%
4	Large General Service	39.71%	36.55%	38.52%
5	Irrigation	0.05%	0.07%	0.05%
6	Lighting	1.73%	1.18%	1.58%
7	OPA	0.74%	0.94%	0.78%
8	Controlled Service Deferred Load	1.30%	1.96%	1.20%
9	Controlled Service Interruptible	5.69%	5.44%	5.06%
10	Controlled Service Off-Peak	0.39%	0.23%	0.35%

Q. PLEASE PROVIDE FURTHER CONTEXT FOR OTP'S PROPOSED REVENUE RESPONSIBILITY FOR THE RESIDENTIAL CLASS.

A. As shown in Table 7, the CCOSS indicates Residential class revenues would need to increase from 27.88 percent [Column B] to 31.09 percent [Column C] to bring the revenues for this class up to its cost level. To provide a reasonable balance of the cost of service and rate continuity objectives of rate design, OTP proposes increasing the Residential class revenue responsibility from 27.88 percent [Column B] to 29.07 percent [Column D].

Q. IF OTP'S RECOMMENDED REVENUE DISTRIBUTION IS ACCEPTED, WILL THERE STILL BE DIFFERENCES BETWEEN CLASS REVENUE RESPONSIBILITY AND COST RESPONSIBILITY?

A. Yes. OTP does not propose an unmoderated adherence to the results of the CCOSS. For this reason, differences remain between OTP's proposed class revenue responsibility and cost responsibilities identified by the CCOSS. For example, OTP's recommended revenue increase of approximately $6.2 million for the Residential class (shown above in Table 6, Column D) moves the Residential class closer to its cost responsibility. In order to be at its full cost responsibility, the Residential class revenues would need to increase by approximately $10.8 million, an additional $4.6 million of revenue responsibility compared to OTP's proposal. Table 8 below identifies the net bill impacts if revenue responsibility is based entirely on cost.

Table 8
Unmoderated Revenue Responsibilities

	A	B	C	D	E
Line No.	Class	Total Present Revenues	Total Proposed Revenues	Net Bill Increase	Net Bill Impact
1	Residential	$ 58,596,832	$ 69,445,591	$ 10,848,758	18.51%
2	Farms	$ 3,035,105	$ 3,337,900	$ 302,795	9.98%
3	General Service	$ 44,329,329	$ 46,990,988	$ 2,661,659	6.00%
4	Large General Service	$ 79,991,537	$ 81,636,850	$ 1,645,313	2.06%
5	Irrigation	$ 105,695	$ 166,449	$ 60,754	57.48%
6	Lighting	$ 3,705,988	$ 2,637,134	$ (1,068,854)	-28.84%
7	OPA	$ 1,551,133	$ 2,095,672	$ 544,539	35.11%
8	Controlled Service Deferred Load	$ 2,666,277	$ 4,375,580	$ 1,709,303	64.11%
9	Controlled Service Interruptible	$ 11,230,365	$ 12,145,104	$ 914,739	8.15%
10	Controlled Service Off-Peak	$ 776,948	$ 516,179	$ (260,769)	-33.56%
11	Total	$ 205,989,209	$ 223,347,447	$ 17,358,238	8.43%

Q. HOW MUCH OF THE RECOMMENDED INCREASE IN CLASS REVENUES IS TIED TO MOVING CLASSES CLOSER TO CLASS COST RESPONSIBILITY?

A. Table 9 below identifies the portion of the change in revenue responsibility due to the change in the revenue requirement and the portion due to the movement towards cost. For most classes, the recommended movement toward cost is a minor component of the overall change in revenue responsibility.

Table 9
Components of Change in Class Revenue Responsibility

	A	B		C		D	
Line No.	Class	Due to Change in Revenue Requirement		Due to Movement to Cost		Total Change in Class Revenue Responsibility	
1	Residential	$	3,667,775	$	2,543,015	$	6,210,791
2	Farms	$	190,689	$	131,749	$	322,438
3	General Service	$	2,726,181	$	1,964,120	$	4,690,300
4	Large General Service	$	8,692,032	$	(2,356,873)	$	6,335,159
5	Irrigation	$	6,641	$	5,277	$	11,918
6	Lighting	$	147,521	$	(638,480)	$	(490,959)
7	OPA	$	109,239	$	77,991	$	187,230
8	Controlled Service Deferred Load	$	242,754	$	(226,217)	$	16,537
9	Controlled Service Interruptible	$	1,471,707	$	(1,403,286)	$	68,422
10	Controlled Service Off-Peak	$	103,699	$	(97,296)	$	6,403
11	Total	$	223,347,447	$	(0)	$	17,358,238

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION WITH RESPECT TO CLASS REVENUE RESPONSIBILITY.

A. OTP's recommended class increases move rates closer to cost while moderating impacts, particularly to the Residential class. OTP's proposed class revenue responsibility proposal is appropriately based on the CCOSS results and rate design objectives, and it is therefore reasonable for setting rates in this case.

VIII. 2018 NORTH DAKOTA RATE CASE CCOSS COMPLIANCE ITEM

Q. PLEASE DESCRIBE THE CCOSS COMPLIANCE ITEM FROM OTP'S LAST NORTH DAKOTA RATE CASE.

A. The Settlement Agreement approved by the Commission in OTP's last North Dakota rate case required OTP, in consultation with MLEC, to investigate the feasibility of unbundling the embedded costs to serve LGS customers at the secondary, primary and transmission voltage service levels. The investigation was to primarily look into the feasibility of: (a) unbundling the distribution costs and (b) quantifying the loss differentials between secondary, primary, and transmission service respectively.[16]

[16] *See* Case No. PU-17-398, Settlement Agreement at 11 (July 6, 2018) (the Settlement Agreement). The Settlement Agreement was approved (with three modifications) by the Commission in its September 26,

Q. DID OTP INVESTIGATE THE FEASIBILITY OF UNBUNDLING THE EMBEDDED COSTS TO SERVE LGS CUSTOMERS?

A. Yes. OTP met with MLEC in August to discuss possible approaches to unbundling the embedded costs to serve LGS customers. Based on the discussion with MLEC, OTP was able to develop a way to separate the LGS class into secondary, primary, and transmission sub-classes.

Q. HOW DID OTP SEPARATE THE LGS CLASS INTO THE SECONDARY, PRIMARY, AND TRANSMISSION SUB-CLASSES?

A. We modified the CCOSS demand, energy and customer allocation factors to have separate allocations for LGS secondary, LGS primary and LGS transmission sub-classes. The demand and energy allocation factors account for voltage losses at each service level. These voltage losses were calculated in OTP's 2020 System Loss Study. OTP then applied these allocation factors to the costs allocated to the LGS class in the CCOSS. This is a similar method used to allocate costs from the JCOSS to the CCOSS.

Q. WHAT WERE THE RESULTS OF UNBUNDLING THE EMBEDDED COSTS TO SERVE?

A. The results showed the marginal cost study and the embedded cost study produced a similar allocation of costs between the secondary and primary LGS service levels.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

2018 Order on Settlement. The Settlement Agreement also provided that OTP and MLEC were to work together to attempt to identify a reasonable means of making available wind turbine maintenance data or some proxy thereof. OTP discussed this issue with MLEC. MLEC reviewed the item and concluded this issue is resolved.

Ms. Amber M. Stalboerger
Manager Regulatory Analysis, Regulatory Economics
Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8042

CURRENT RESPONSIBILITIES: (February 2023 to Present)

Provide leadership for financial analysis related to setting rates and overall cost recovery, including managing the financial analysis used to determine revenue requirements associated with various state cost recovery mechanisms. Manage regulatory analysis and review of state jurisdictional and class cost of service studies that determine utility revenue requirements and are used as a basis for rate design. Oversee the development of theories, methodologies, and procedures used to establish embedded cost allocations.

PREVIOUS POSITIONS:

Otter Tail Power Company

2023 - Present	Manager Regulatory Analysis, Regulatory Economics
2022 - 2023	Senior Data Analyst, Advanced Concepts
2021 - 2022	Supervisor, Regulatory Analysis, Regulatory Administration
2019 - 2020	Supervisor, DSM Administration, Market Planning
2014 - 2018	Evaluation Analyst, Market Planning
2013 - 2014	Internal Auditor II, Otter Tail Corporation
2008 - 2013	Rates Analyst, Regulatory Administration

EDUCATION

Minnesota State University Moorhead, Moorhead, MN
Bachelor of Science, Mathematics emphasis Actuarial Science
Bachelor of Arts, Mathematics
Bachelor of Science, Accounting

OTTER TAIL POWER COMPANY

Cost Allocations Procedures Manual

~~Revised October 2017~~Revised October 2023

INTRODUCTION

The general methodology used in this procedure manual is one of functionalization and classification. Functionalization is the process by which costs are arranged according to the major utility function they serve, such as production, transmission, etc. Classification is the arrangement of costs within a function by the service characteristic to which they most closely apply or relate, to facilitate their allocation based on these service characteristics.

The major functional areas used in this procedure manual are production, transmission, distribution, customer accounting and collecting, and customer service and information. The reason for using functions other than the three major ones (production, transmission, and distribution) is to provide a better base for eventual allocation of cost and to provide the flexibility necessary to handle certain cost items.

The principal service characteristics used in the classification process are demand, energy, number of customers, and number of meters. Sub-characteristics within each of these principal characteristics which allow a more precise division of cost, such as type of demand or energy, voltage level, or type of customer or meter were also used. These sub-characteristics provide added detail for a more accurate allocation of cost. The service characteristics or sub-characteristics provide the basis for determining allocation factors when allocation is necessary. Unless otherwise noted, all allocation factors described herein are used for both jurisdictional and class allocations.

The philosophy used to arrive at the service characteristics was to determine what characteristic or characteristics best describe or approximate the decisions made or factors considered when an expense is incurred or a plant investment is made. The amount of dollars to be allocated and the cost of determining or obtaining values for a service characteristic were also factors considered when determining the service characteristics to use.

There are ~~16~~ 17 service characteristics used in this study. They consist of four demand characteristics, ~~three~~ four energy or kilowatt-hour characteristics, and nine meter or customer characteristics. These service characteristics, which are used to develop allocation factors are:

1. GENERATION DEMAND FACTOR (D1) - this factor is determined based on contribution to Otter Tail's average annual six-hour system peak kW demand. Any loads for which Otter Tail is responsible for providing generation are included in this factor excluding interruptible, water heating, deferred, and off-peak loads when allocating jurisdictional amounts to the customer classes excluding controllable load. The hours ending 9:00, 10:00, and 11:00 a.m., and 6:00, 7:00, and 8:00 p.m. were averaged to arrive at the Generation Demand Factor.
2. TRANSMISSION DEMAND FACTOR (D2) - this factor is determined based on contribution to Otter Tail's average annual six-hour transmission peak kW demand. Any loads for which Otter Tail is responsible for providing transmission service are included in this factor excluding interruptible, water heating, deferred, and off-peak loads when allocating jurisdictional amounts to the customer classes. The hours used are the same as those for the Generation Demand Factor.
3. DISTRIBUTION PRIMARY DEMAND FACTOR (D3) - this factor is determined based on contributions to Otter Tail's average annual six-hour primary distribution peak kW demand

minus the 0.83 kW/customer already included in the minimum system portion of the primary customer component. (See Appendix A-1.) Any loads for which Otter Tail is responsible for providing primary distribution service are included in this factor. The hours used are the same as those for the Generation Demand Factor.

4. DISTRIBUTION SECONDARY DEMAND FACTOR (D4) - this factor is determined based on non-coincident kW demands at the secondary service level minus the 3.0 kW/customer already included in the minimum system portion of the secondary customer component. (See Appendix A-1.) Only loads served at voltages less than 2400 volts are included in this factor.
5. ENERGY FACTOR (E1) - this factor is based on kilowatt-hour (kWh) sales adjusted for line losses to the generation level excluding interruptible, irrigation, and $^{14}/_{24}$ths of water heating and deferred sales. It is only used for jurisdictional allocations.
6. ENERGY FACTOR (E2) - this factor is based on total kWh sales adjusted for line losses to the generation level. It is only used for jurisdictional allocations.

~~6.~~7. ENERGY FACTOR (E1-E8760) – this factor is based on hourly energy usage, to which are applied hourly marginal capacity costs to develop an hourly cost relationship excluding interruptible, irrigation, and water heating, and deferred sales in the highest priced 14 of 24 marginal capacity cost hours. It is only used to allocate jurisdictional amounts to the customer classes.

~~7.~~8. ENERGY FACTOR (E2-E8760) - this factor is based on hourly energy usage, to which are applied hourly marginal costs to develop an hourly cost relationship. It is only used to allocate jurisdictional amounts to the customer classes.

~~8.~~9. TOTAL RETAIL CUSTOMERS FACTOR (C1) - this factor is based on the total active retail customers served in each jurisdiction.

~~9.~~10. TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2) – a distribution service location is any point on the distribution system at which service is or can be provided including inactive and seasonal locations.

~~10.~~11. TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3) - this factor includes only those distribution service locations served or which can be served at secondary voltage (below 2400 volts).

~~11.~~12. STREETLIGHT FACTOR (C4) - this factor is based on the weighted installed cost of the streetlights in each jurisdiction.

~~12.~~13. AREA LIGHT FACTOR (C5) - this factor is based on the weighted installed cost of area lights in each jurisdiction.

~~13.~~14. METER FACTOR (C6) - this factor is based on the weighted installed cost of meters in service.

~~14.~~15. METER READING FACTOR (C7) - this factor is based on total weighted meter reading time.

~~15.~~16. TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8) - this factor is similar to the Total Distribution Service Locations Factor, except all locations on the system at which service can be or is provided are included.

~~16.~~17. LOAD MANAGEMENT FACTOR (C9) - this factor is based on the total number of locations that have radio load management receivers in each jurisdiction.

The methodology for applying the various procedures and allocators to system cost values to develop jurisdictional and class or group cost values is explained in detail on the following pages.

RATE BASE COMPONENTS

PRODUCTION PLANT IN SERVICE

The plant in service within this function was classified into preliminary demand and energy categories as follows:

1. DEMAND COST - this category includes all production plant (accounts 310- 346), except that related to the Big Stone Plant unit train.
2. BASE LOAD ENERGY COST - Big Stone unit train only.

The demand category was then reclassified into Base (Energy-Related) and Peak Demand categories based on the following formulas:

$$\text{Total Current Cost} = (\text{Existing Peaking Capacity [kW]})(\text{Current Peaking Unit Cost [\$/kW]}) + (\text{Existing Steam \& Hydro Capacity [kW]})(\text{Current Base Load Unit Cost [\$/kW]})$$

$$\text{Peaking Demand Factor} = \frac{(\text{Total Existing Plant Capacity})(\text{Current Peaking Unit Cost})}{\text{Total Current Cost}}$$

$$\text{Base (Energy-Related) Demand Factor} = 1 - \text{Peaking Demand Factor}$$

$$\text{\$ of Peak Demand} = (\text{Demand Cost}) \times (\text{Peaking Demand Factor})$$

$$\text{\$ of Base (Energy-Related) Demand} = (\text{Demand Cost}) \times (\text{Base Demand Factor})$$

This determination of Base and Peak Demand amounts is based on the premise that all plants are or can be used to supply system peak demands. However, base load plants (steam and hydro) are also used to supply the bulk of the energy used on the system. Therefore, the base load plants have a dual function of supplying both energy and demand. The above classification of production plant into base and peak categories recognizes this fact and assigns a portion of the base load plants to each of these functions. The underlying assumption is that the cost to supply a peak kW of demand capacity to the system is the cost of a kW of capacity from a peaking plant.

New unit costs in current year dollars were used to determine the peaking and base factors to provide an allocation method that separates costs based on present circumstances not on past circumstances. The use of current costs also eliminates any potential problems associated with the timing of plant additions, changes in load factors or changes in generation mix criteria which could lead to large short-term allocation factor variations.

The dollars in each category were then allocated based on the following:

BASE DEMAND - Energy Factor (E1)
PEAK DEMAND - Generation Demand Factor (D1)

BASE ENERGY - Energy Factor (E1)
PEAK ENERGY - Generation Demand Factor (D1)

3. Wind generation is a non-dispatchable production resource with operating characteristics different from other base load or peaking generation. The capacity factor for wind generation is determined by the Midwest Independent System Operator (MISO) as they accredit capacity on a four-season construct based on each generation site's production. While a majority of a wind turbine's output is energy, a portion of the investment is also needed to meet the system's peak demand. The most recent MISO accreditations are used to create a weighted average for each wind farm that results in a base/peak split. Wind generation investment is allocated based on the following factors:
   BASE ENERGY – Energy Factor (E2)
   PEAK DEMAND – Generation Demand Factor (D1)

TRANSMISSION PLANT IN SERVICE

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION PLANT IN SERVICE

The plant in service within this function was classified into the following categories:

1. Primary Demand (2400 volts and above)
2. Secondary Demand (below 2400 volts)
3. Primary Customer (2400 volts and above)
4. Secondary Customer (below 2400 volts)
5. Streetlighting
6. Area Lighting
7. Meters
8. Load Management

based on the following account-by-account methodology:

ACCOUNT 360 (LAND) - classified primary demand related (substation land).
ACCOUNT 360.1 (LAND RIGHTS) - classified primary demand related.
ACCOUNT 361 (STRUCTURES AND IMPROVEMENTS) - classified primary demand related.
ACCOUNT 362 (STATION EQUIPMENT) - classified primary demand related.
ACCOUNTS 364-369.1 - classified based on minimum size system (see Appendix A-1).
ACCOUNT 370 (METERS) - direct assignment to meters characteristic.
ACCOUNT 370.05 (SMART METERS) - direct assignment to meter characteristic.
ACCOUNT 370.1 (LOAD MANAGEMENT SWITCHES) - direct assignment to load management characteristic.
ACCOUNT 371 (INSTALLATION ON CUSTOMER'S PREMISES) - classified secondary customer related.
ACCOUNT 371.1 (~~RENTAL EQUIPMENT~~EV CHARGING STATIONS) - classified ~~primary~~

secondary demand and customer related.
ACCOUNT 371.2 (ALL OTHER PRIVATE LIGHTING) - direct assignment to area lighting.
ACCOUNT 373 (STREETLIGHTING AND SIGNAL SYSTEMS) - direct assignment to streetlighting.

The categories were then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3)
SECONDARY DEMAND - Distribution Secondary Demand Factor (D4)
PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2)
SECONDARY CUSTOMER - Total Secondary Distribution Service Locations Factor (C3)
STREETLIGHTING - Streetlight Factor (C4)
AREA LIGHTING - Area Light Factor (C5)
METERS - Metering Factor (C6)
LOAD MANAGEMENT - Load Management Factor (C9)

GENERAL PLANT IN SERVICE

General Plant in Service, except Account 397.3 (Radio Load Control Equipment), was functionalized into the following categories based on the labor ratios developed from data in FERC Form No. 1, Page 354, or similar data for a forecast year.

1. Production
2. Transmission
3. Distribution
4. Customer Accounting
5. Customer Service and Information

The amounts in the production, transmission, and distribution categories were then allocated using the gross plant in service ratios from the related plant in service functions. Customer Accounting and Customer Service and Information were allocated based on the expense ratios from the related expense functions. Account 397.3 directly assigned to Load Management category and allocated on the Load Management Factor (C9).

INTANGIBLE PLANT IN SERVICE

Intangible Plant in Service was allocated using the gross general plant in service ratios.

ACCUMULATED PROVISION FOR DEPRECIATION

PRODUCTION - Classification and allocation procedure is the same as that used for Production Plant in Service.

TRANSMISSION - Allocated based on gross plant in service ratios developed from the Transmission Plant in Service function.

DISTRIBUTION - Allocated based on gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - Allocated based on gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - allocated using the gross plant in service ratios developed from the Intangible Plant in Service function.

NET CAPITALIZED ITEMS - BIG STONE PLANT

Directly assigned to each jurisdiction. Allocated to classes or groups based on the gross Production Plant in Service ratio.

PLANT HELD FOR FUTURE USE

PRODUCTION - allocated using gross plant in service ratios developed from the Production Plant in Service function.

TRANSMISSION - allocated using the Transmission Demand Factor (D2).

DISTRIBUTION - allocated using gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - allocated using gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - allocated using gross plant in service ratios developed from the Intangible Plant in Service function.

CONSTRUCTION WORK IN PROGRESS (CWIP)

CWIP was separated into three parts or types: Major Projects, Short-Term, and Long-Term. The Major Projects section includes capital expenditures on which a current return is requested without an offset for Allowance For Funds Used During Construction (AFUDC). The Short-Term section are those projects with less than $10,000 cost or expected to be completed in less than 30 days. AFUDC is not accrued on short-term projects. The Long-Term section includes all other projects and AFUDC is accrued on this portion.

The CWIP of each type was functionalized as production, transmission, distribution, general, or intangible plant. The allocations are then based on the gross plant in service ratios for each individual function.

WORKING CAPITAL

MATERIALS AND SUPPLIES:

Materials and Supplies are separated into production, transmission, and distribution functions. The production portion includes materials and supplies at Big Stone and Coyote Plants as well as production repair parts. The remaining materials and supplies are split between transmission and distribution functions based on data from Page 227 of the latest FERC Form No. 1. The functional amounts are allocated on their respective gross plant in service ratios.

FUEL STOCKS:

COAL STOCKS - allocated using Energy Factor (E1).

FUEL OIL STOCKS - allocated using Generation Demand Factor (D1).

PREPAYMENTS - allocated based on total net plant in service ratios.

CUSTOMER ADVANCES - allocated based on total net plant in service ratios.

CASH WORKING CAPITAL - calculated separately for each jurisdiction. Allocated to customer class on total operating expenses for each jurisdiction (OX).

ACCUMULATED DEFERRED INCOME TAXES

Allocated using the total "net" plant in service ratios.

UNAMORTIZED BALANCE - SPIRITWOOD PLANT

Directly assigned to each jurisdiction. Allocated to customer class using the gross Production Plant in Service ratio.

UNAMORTIZED RATE CASE EXPENSE

Directly assigned to jurisdiction. Allocated to customer class on each jurisdiction's retail revenues (R10).

OPERATING REVENUES

RETAIL SALES

Directly assigned to each jurisdiction and class as billed.

WHOLESALE SALES

MUNICIPALITIES (SUPPLEMENTAL POWER ACCOUNTS 400.1-81, 400.2-81, and 400.3-81) - directly assigned to FERC jurisdiction and group as billed.

NONASSOCIATED UTILITIES, COOPERATIVES AND OTHER PUBLIC AUTHORITIES

The revenues from asset-based sales are classified as base demand, peak demand, base energy, and peak energy as follows:

1. All revenues from these sales, except those considered Participation or Peaking Power, are classified as Base Energy.
2. Demand charges for Peaking sales are classified as Peak Demand.
3. Demand charges for Participation Power sales are classified as follows:

   $ of Peak Demand = Market price ($/MW/Mo.) × capacity of the sale (MW)

   $ of Base Demand = Total Demand charges – $ of Peak Demand.
4. Energy charges for Participation Power sales are classified Base Energy.
5. Energy charges for Peaking Power sales are classified Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)
PEAK DEMAND - Generation Demand Factor (D1)
BASE ENERGY - Energy Factor (E2)
PEAK ENERGY - Generation Demand Factor (D1)

OTHER ELECTRIC REVENUE

ACCOUNT 450 (FORFEITED DISCOUNTS) - directly assigned to jurisdictions as collected. Allocated to classes (if required) based on Total Customers Factor (C1).

ACCOUNT 451 (CONNECTION FEES) - directly assigned to jurisdictions as collected. Allocated to classes (if required) based on Total Customers Factor (C1).

ACCOUNT 456.5 (WHEELING) - directly assigned to FERC groups as collected.

ACCOUNT 456.7 (RESIDENTIAL CONSERVATION SERVICE) - directly assigned to jurisdictions. Allocated to classes based on E8760 (Energy Factor).

ALL OTHER ACCOUNTS - allocated using total net plant in service ratios.

EXPENSE COMPONENTS

PRODUCTION EXPENSES

The expenses within this function, except those in Account 555, were classified into PRELIMINARY demand and energy categories as follows:

1. STEAM AND HYDRO (SH) DEMAND - this category includes all expenses in Accounts 500, 502-511, 535-543, and 556.
2. INTERNAL COMBUSTION (IC) DEMAND - this category includes all expenses in Accounts 546-554, except Account 547.
3. BASE ENERGY - includes Accounts 501, 512, 513, 514, 544, and 545.
4. PEAK ENERGY - includes Account 547.

The two demand categories (SH and IC) were then reclassified into BASE and PEAK Demand categories using the same methodology and formulas applied to those categories in Production Plant in Service.

The expenses in Account 555 (Purchased Power) are classified into base and peak demand and energy based on the following:

A. All expenses, except those for purchases labeled Participation or Peaking Power, were classified as Base Energy.
B. Demand charges for Peaking Power were classified as Peak Demand.
C. Demand Charges for Participation Power (including co-generators and shared customers) were classified as follows:

$$\begin{aligned}\text{\$ of Peak Demand} &= \text{MAPP Schedule H (peaking) rate (\$/MW/Mo.)}\\ &\times \text{capacity of the purchase (MW)}\\ &\times \text{number of months purchased.}\end{aligned}$$

$$\text{\$ of Base Demand} = \text{Total Demand Charges} - \text{\$ of Peak Demand.}$$

D. Energy charges for Participation Power were classified as Base Energy.
E. Energy charges for Peaking Power were classified as Peak Energy.

The jurisdictional allocations were then made as follows:

BASE DEMAND - Energy Factor (E1)
PEAK DEMAND - Generation Demand Factor (D1)
BASE ENERGY - Energy Factor (E2)
PEAK ENERGY - Generation Demand Factor (D1)

TRANSMISSION EXPENSES

Allocated using the Transmission Demand Factor (D2).

DISTRIBUTION EXPENSES

The expenses within this function were classified into the following categories:

1. Primary Demand (2400 volts and above)
2. Secondary Demand (below 2400 volts)
3. Primary Customer (2400 volts and above)
4. Secondary Customer (below 2400 volts)

5. Streetlights
6. Area Lights
7. Meters
8. Load Management

Based on the following account-by-account methodology:

OPERATION

ACCOUNT 580 (SUPERVISION AND ENGINEERING) - classified based on classification of Accounts 582-588.

ACCOUNT 581 (LOAD DISPATCHING) - classified based on classification of Accounts 583-589.

ACCOUNT 582 (STATION EXPENSE) - classified based on classification of related plant in service Account 362.

ACCOUNT 583 (OVERHEAD LINE EXPENSE) - classified based on the classification of related plant in service Accounts 364, 365, 368, and 369.

ACCOUNT 584 (UNDERGROUND LINE EXPENSE) - classified based on the classification of related plant in service Accounts 366, 367, and 369.1.

ACCOUNT 585 (STREETLIGHTING EXPENSE) - classified directly as streetlighting.

ACCOUNTS 586~~.1-586.5 & 586.9~~ (METER EXPENSES) - classified directly as meters.

~~ACCOUNTS 586.6-586.7 (METER EXPENSES) - classified directly as load management.~~

ACCOUNT 587 (~~CUSTOMER INSTALLATION~~OTHER EXPENSE) - classified secondary customer.

ACCOUNT 588 (MISCELLANEOUS EXPENSE) - classified based on classification of Accounts 582-587.

ACCOUNT 589 (RENTS) - classified based on classification of related plant in service Account 364.

MAINTENANCE

ACCOUNT 590 (SUPERVISION AND ENGINEERING) - classified based on classification of Accounts 592-596.

ACCOUNT 592 (STATION EQUIPMENT) - classified based on classification of related plant in service Account 362.

ACCOUNT 593 (OVERHEAD LINES) - classified based on classification of related plant in service Accounts 364, 365, and 369.

ACCOUNT 594 (UNDERGROUND LINES) - classified based on classification of related plant in service Accounts 366, 367, and 369.1.

ACCOUNT 595 (LINE TRANSFORMERS) - classified based on classification of related plant in service Account 368.

ACCOUNT 596 (STREETLIGHTING) - classified directly to streetlighting.

ACCOUNTS 597~~.1-597.2~~ (METERS) - classified directly to meters.

~~ACCOUNT 597.3 (METERS) - classified directly to load management.~~

ACCOUNT 598 (MISCELLANEOUS DISTRIBUTION PLANT) - classified based on classification of Accounts 592-597.

Each category was then allocated based on the following:

PRIMARY DEMAND - Distribution Primary Demand Factor (D3).
SECONDARY DEMAND - Distribution Secondary Demand Factor (D4).
PRIMARY CUSTOMER - Total Distribution Service Locations Factor (C2).
SECONDARY CUSTOMER - Total Secondary Distribution Service Locations Factor (C3).
STREETLIGHTING - Streetlight Factor (C4).
AREA LIGHTING - Area Light Factor (C5).
METERS - Meter Factor (C6).
LOAD MANAGEMENT - Load Management Factor (C9).

CUSTOMER ACCOUNTING AND COLLECTING EXPENSES

Expenses in this function were classified into two categories:

1. Meter Reading
2. Other Expenses

as specified by the following:

ACCOUNT 901 (SUPERVISION) - classified based on classification of Accounts 902-905.
ACCOUNT 902 (METER READING EXPENSE) - classified meter reading.
ACCOUNT 903 (CUSTOMER RECORDS AND COLLECTIONS) - classified other expense.
ACCOUNT 904 (UNCOLLECTIBLE ACCOUNTS) - classified other expense.
ACCOUNT 905 (MISCELLANEOUS CUSTOMER ACCOUNTING EXPENSES) - classified other expense.

The METER READING category was allocated using the Meter Reading Factor (C7) and the OTHER EXPENSES category using the Total System Service Locations Factor (C8).

CUSTOMER SERVICE AND INFORMATION EXPENSES

Conservation related programs and promotional rebates are directly assigned to jurisdiction and then allocated to class based on E8760 (Energy Factor). All other Customer Service and Information Expenses are allocated based on Total Customer Factor (C1).

SALES EXPENSES

Economic Development is directly assigned to jurisdiction and then allocated to class based on Total Customer Factor (C1). Account 913, Advertising, is assigned below the line. All other Sales Expenses are allocated based on Total Customer Factor (C1).

ADMINISTRATIVE AND GENERAL EXPENSES

ACCOUNTS 920 (SALARIES), 921 (SUPPLIES, ETC.), AND 926 (PENSIONS AND BENEFITS) - these accounts functionalized as: Production, Transmission, Distribution, Customer Accounting, or Customer Service, based on FERC labor ratios (FERC Form No. 1, Page 354, or comparable data for a forecast year). Functional categories were then allocated using the expense ratios from the related expense functions, except that in the Production category the energy-related expenses and buy/sell transactions were not included in the ratios. (Energy-related expenses and buy/sell transactions are excluded because they are mainly purchased fuel which requires a minimum of company labor.)

ACCOUNT 923 (OUTSIDE SERVICES) - allocated based on total net plant in service ratios.

ACCOUNTS 924 (PROPERTY INSURANCE) and 925 (INJURIES & DAMAGES) - ~~were~~ allocated based on the total net plant in service ratios.

ACCOUNTS 928 (REGULATORY COMMISSION EXPENSES) - directly assigned to each jurisdiction. Allocated to classes or groups based on total electric revenues from each class or group.

ACCOUNT 930.1 (GENERAL ADVERTISING) -– The majority of this account is assigned below the line. Any remaining amount is allocated based on Total Customers Factor (C1).

ACCOUNTS 930.2 (MISCELLANEOUS), 931 (RENTS), and ~~935.1-935.5 & 935.9~~935 (MAINTENANCE) - allocated based on the gross general plant in service ratios.

ACCOUNT 935.6 (MAINTENANCE) - directly assigned to load management and allocated on (C9).

DEPRECIATION EXPENSES

PRODUCTION - Classification and allocation procedure is the same as that used for Production Plant in Service.

TRANSMISSION - Allocated based on gross plant in service ratios developed from the Transmission Plant in Service function.

DISTRIBUTION - Allocated based on gross plant in service ratios developed from the Distribution Plant in Service function.

GENERAL - Allocated based on gross plant in service ratios developed from the General Plant in Service function.

INTANGIBLE - Allocated using the gross plant in service ratios developed from the Intangible Plant in Service function.

BIG STONE PLANT CAPITALIZED ITEMS EXPENSES

Directly assigned to each jurisdiction. Allocated to classes or groups based on the gross Production Plant in Service ratio.

OTHER EXPENSE - SPIRITWOOD AMORTIZATION

Directly assigned to each jurisdiction. Allocated to customer class using the gross Production Plant in Service ratio.

GENERAL TAXES

Allocated using total net plant in service ratios.

DEFERRED INCOME TAXES

Allocated using total net plant in service ratios.

INVESTMENT TAX CREDIT

Allocated using total gross plant in service ratios.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

Allocated based on long-term construction work in progress ratios.

INCOME TAXES

Income taxes are calculated for each jurisdiction separately.

APPENDIX A-1

DETERMINATION OF THE DEMAND & CUSTOMER COMPONENTS OF THE DISTRIBUTION SYSTEM

The customer component of the distribution system, that portion which varies with the number of customers, was determined by applying the minimum size system method. This method involves determining the minimum size unit currently being installed and using the average installed book cost of that unit to determine the customer component. However, our accounting system is such that, except for Account 368 (transformers), the only average installed book cost available is for all the units in an account regardless of size. To circumvent this problem, the following procedures were used:

1. The ~~Electric Distribution (ED) Department~~Delivery Planning Department specified what the minimum size unit for each account is and then provided information as to the type and quantity of material included in this unit and the amount of labor necessary to install it.
2. For each account that a customer component is required, the average age of the account was determined by using results of the recently completed depreciation study. This age is then subtracted from the study year to determine in what year the average unit was installed.
3. The average installed cost of the minimum size unit for the year indicated above was then determined. This was done by developing material, labor, transportation, and payroll costs for the year this unit was installed and applying them to the information supplied in No. 1, above.

The following pages describe how the dollars in each account were assigned to the various categories of cost using the data developed above and other figures from the various accounts.

Symbol Legend:

PSL = Poles for Streetlights
DSL = Dollars allocated to Streetlighting
DAL = Dollars allocated to Area Lighting
DPCC = Dollars allocated to Primary Customer Category
DPDC = Dollars allocated to Primary Demand Category
DSCC = Dollars allocated to Secondary Customer Category
DSDC = Dollars allocated to Secondary Demand Category
UPD = Units of Primary Distribution
USD = Units of Secondary Distribution

Account 364 (Poles): (All poles considered primary)

A. Average age of a pole.
B. Minimum size pole.
C. Installed cost of the minimum size pole of the age in "A."
D. Number of streetlights on separate poles. (Based on sample survey by Engineering Services.)
E. Number of area lights on separate poles. (Based on sample survey by Engineering Services.)

F. Number of poles in Account 364.
G. Total dollars in Account 364.

Dollar Allocations for Account 364

To Streetlighting = $D \times C^{*}$ = DSL

To Area Lighting = $E \times C^{*}$ = DAL

Customer Component = $(F - D - E) \times C$ = DPCC

Demand Component = DSL – DAL – DPCC = DPDC

*Cost of a minimum size pole was used because most streetlights are mounted on minimum size poles and those that are on larger poles are mounted on poles that do not have the usual framing (crossarms, etc.).

Account 365 (Overhead Conductor and Devices):

I. Primary

A. Average age of primary conductor.
B. Minimum size primary unit.
C. Average installed cost of a minimum size primary unit of the age in "A."
D. Average number of poles in a minimum size unit of primary conductor. (Estimated by ED Department.)
E. Total dollars in Account 365 considered primary (see note).
F. Total number of poles used for primary distribution. (Number of poles in Account 364 - Number of poles allocated to streetlighting and area lighting.)

$$\text{Number of units of primary distribution} = \text{UPD} = \frac{F}{D1}$$

Dollar Allocations for Account 365 Primary

Customer Component = $C \times$ UPD = DPCC

Demand Component = E – DPCC = DPDC

NOTE: All bare copper, aluminum, ACSR and iron wire are primary. 30% of WP copper, 80% of WP aluminum and 50% of the steel wire are primary. (Estimated by ~~ED Department~~Delivery Planning - exact percentages very difficult to determine.) All miscellaneous conductor and other equipment are primary.

II. Secondary

A. Average age of secondary conductor.
B. Minimum size secondary unit.
C. Average installed cost of a minimum size unit of the age in "A."

D. Number of units of secondary conductor (see note).
E. Total dollars in Account 365 considered secondary. (All conductor not primary - see primary section.)
F. Dollar value of duplex conductor in Account 365. (Duplex assumed to be used entirely for street and area lights.)
G. Percent of total number of lighting units (street and area lights) that are streetlights.

Dollar Allocations for Account 365 Secondary

To Streetlighting $= F \times G = DSL$

To Area Lighting $= F - DSL = DAL$

Customer Component $= C \times D = DSCC$

Demand Component $= E - F - DSCC = DSDC$

NOTE: Estimated by ~~ED Department~~Delivery Planning based on 250' of secondary for each five urban residential cottages, and urban commercial customers, 3,360' of secondary per unit.

Account 366 (Underground Conduit):

The percentages developed from the allocation of Account 367 will be applied to this account.

Account 367 (Underground Conductor and Devices):

I. Primary

A. Average age of primary unit.
B. Minimum size primary unit.
C. Average installed cost of a minimum size primary unit of the age in "A."
D. Number of feet of conductor in the minimum size primary unit.
E. Total dollars in Account 367 considered primary. (All conductor rated 5 kV and above, and all nonconductor items are considered primary.)
F. Total number of feet of primary conductor in Account 367.

$$\text{Number of units of primary distribution} = UPD = \frac{F}{D2}$$

Dollar Allocations for Account 367 Primary

Customer Component $= C \times UPD = DPCC$

Demand Component $= E - DPCC = DPDC$

II. Secondary

A. Average age of secondary unit.
B. Minimum size of secondary unit.
C. Average installed cost of a minimum size secondary unit of the age in "A."

D. Number of feet of conductor in the minimum size secondary unit.
E. Total dollars in Account 367 considered secondary. (All conductor rated 600 volts or less is secondary.)
F. Total number of feet of secondary conductor in Account 367 (see note).
G. Dollar value of duplex conductor in Account 367 (duplex conductor is assumed to be used entirely for street and area lights).
H. Percent of total number of lighting units (street and area lights) that is streetlights.

$$\text{Number of units of secondary distribution} = \text{USD} = \frac{\text{F}}{\text{D3}}$$

Dollar Allocations for Account 367 Secondary

To Streetlighting = G × H = DSL

To Area Lighting = G – DSL = DAL

Customer Component = C × USD = DSCC

Demand Component = E – G – DSCC = DSDC

NOTE: Includes all quadruplex and triplex cable and 1/3 of 600 volt single wire. (Duplex is for lighting only.)

Account 368 (Transformers): (All transformers classified secondary)

A. Average installed cost of minimum size 2400 V. overhead unit.*
B. Average installed cost of minimum size 7200 V. overhead unit.*
C. Average installed cost of minimum size 14400 V. overhead unit.*
D. Average installed cost of minimum size 2400 V. underground unit.*
E. Average installed cost of minimum size 7200 V. underground unit.*
F. Number of 2400 V. overhead units in the account.
G. Number of 7200 V. overhead units in the account.
H. Number of 14400 V. overhead units in the account.

*Overhead unit cost includes cost of appropriate cutout and arrester.

I. Number of 2400 V. underground units in the account.
J. Number of 7200 V. underground units in the account.
K. Total dollar value of Account 368.

Dollar Allocations for Account 368

Customer Component = (A × F) + (B × G) + (C × H) + (D × I) + (E × J) = DSCC

Demand Component = K – DSCC = DSDC

Account 369 (Overhead Services): (All services classified secondary)

A. Average age of a service.
B. Minimum size of a service.
C. Average installed cost of a minimum size service of the age in "A."
D. Total number of 3 and 4 services.
E. Dollar value of two-wire services (two-wire services are considered all customer component).
F. Total dollar value of Account 369.

Dollar Allocations for Account 369

Customer Component = $(C \times D) + E = DSCC$

Demand Component = $F - DSCC = DSDC$

Account 369.1 (Underground Services): (All services classified secondary)

A. Average age of an underground service.
B. Minimum size of an underground service.
C. Average installed cost of a minimum size three-wire service of the age in "A."
D. Total number of services in Account 369.1.
E. Total dollar value of Account 369.1.

Dollar Allocations for Account 369.1

Customer Component = $(C \times D) = DSCC$

Demand Component = $E - DSCC = DSDC$

Forecast Cost Allocation Factors Manual

Supplement to Otter Tail Power Company's Cost Allocation Procedure Manual

<u>**Revised October 2023**</u>

This Supplement describes the general processes used to develop forecasted demand, energy and customer cost allocation factors outlined in Otter Tail Power Company's Cost Allocation Procedures Manual.

Introduction:

Otter Tail Power Company ("OTP") operates as a single electrical system to serve customers in three states (Regulatory jurisdictions) – Minnesota, North Dakota, and South Dakota. OTP is subject to the statutes, rules and regulations that dictate the operation of a publicly owned electric utility within each state. Rates are state specific and subject to approval by the respective state's regulatory Commission.

OTP generally accounts for its costs (investment and expense) on a system basis. To determine a particular state's share of its cost of service, the company applies allocation factors to its system costs to further assign those costs to each jurisdiction. The current process OTP uses to allocate its costs is documented in OTP's Cost Allocation Procedure Manual ("CAPM").

Historically, OTP's general rate cases were based on cost of service studies that were developed using a historic test year. The associated cost allocation factors were based on historical information using a single annual coincident peak ("1 CP") for OTP's system. The current CAPM has been previously approved by each state, in OTP's most recent rate case within each state. Maintaining a consistent cost allocation process between jurisdictions is important. Using the same cost allocation methodology in all jurisdictions helps minimize the potential for material over or under-recovery of costs across jurisdictions that might occur if different cost allocation methodologies were used in each state.

In future rate cases, OTP will be using a forecast test year in Minnesota and North Dakota. This supplement to Otter Tail's Cost Allocation Procedures Manual, describes in general terms, the methodologies used to compute the forecast cost allocation factors to be used in a forecast test year.

Summary of Cost Allocation Factors:

OTP has ~~16~~ 17 different demand, energy and customer allocation factors that are used to allocate costs within the jurisdictional cost of service study. As noted earlier, these same factors are used across all ~~three~~ four jurisdictions OTP serves. Below is a summary of the 16 allocation factors as outlined in the CAPM:

1. GENERATION DEMAND FACTOR (D1)
2. TRANSMISSION DEMAND FACTOR (D2)
3. DISTRIBUTION PRIMARY DEMAND FACTOR (D3)
4. DISTRIBUTION SECONDARY DEMAND FACTOR (D4)
5. ENERGY FACTOR (E1)
6. ENERGY FACTOR (E2)
7. ~~6.~~7. ENERGY FACTOR (E1-E8760) (Class allocations only)
8. ~~7.~~8. ENERGY FACTOR (E2-E8760) (Class allocations only~~ – MN & ND~~)
9. ~~8.~~9. TOTAL RETAIL CUSTOMERS FACTOR (C1)
10. ~~9.~~10. TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2)
11. ~~10.~~11. TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3)
12. ~~11.~~12. STREETLIGHT FACTOR (C4)
13. ~~12.~~13. AREA LIGHT FACTOR (C5)
14. ~~13.~~14. METER FACTOR (C6)

~~14.~~15. METER READING FACTOR (C7)
~~15.~~16. TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8)
~~16.~~17. LOAD MANAGEMENT FACTOR (C9)

The rest of this document describes each allocation factor, (as described in the current CAPM) and the related methodology used to develop the forecast of that factor. In some explanations contained below related to the computations of D and E factors, references are made to manually forecasted customers. In some jurisdictions, certain customers are manually forecasted, exclusive from forecasts developed for all other customers. In most cases, these customers are forecasted separately due to size or certain operational characteristics. When the explanation specifically refers to manually forecasted customers, the explanation will specifically state "manually forecasted customers". All other references to forecasted data will refer to all other customers exclusive of the manually forecasted ones.

Forecast Allocation Factors Methodology:

1. **GENERATION DEMAND FACTOR (D1)** - This factor is determined based on contribution to Otter Tail's average annual six-hour system peak kW demand. Any loads for which Otter Tail is responsible for providing generation are included in this factor excluding interruptible, water heating, deferred, and off-peak loads when allocating jurisdictional amounts to the customer classes. The hours ending 9:00, 10:00, and 11:00 a.m., and 6:00, 7:00, and 8:00 p.m. were averaged to arrive at the Generation Demand Factor.

   Forecast Methodology for D1: The Forecasted D1 factors are computed using a ~~4~~5-step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

   a. Compute customers demand
   ~~a.~~b. Compute controlled service customers demand
   ~~b.~~c. Compute manually forecasted customers demand
   ~~c.~~d. Compute FERC demand
   ~~d.~~e. Compute total forecasted D1 Factors

   a. Compute customers demand: First, the historical allocation factors are re-computed excluding the manually forecasted customers. Next, annual Generation Demand (D1) and the Energy at the generation level (E2) factors are compiled in a spreadsheet, for the last five years. A Demand/Energy ratio is then computed for each customer class and state for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2 excluding the manually forecasted customers) to compute the Forecasted Generation Demand (Forecasted D1).

   b. Compute controlled services customers demand: Controlled services customers demand is set to zero for class allocation purposes only.

~~b.~~c. Compute manually forecasted customers demand: Manually forecasted customers demand is determined. In some cases, a fixed baseline demand agreed on by OTP and the customer is the level of demand used for those customers in the forecast.

~~c.~~d. Compute FERC demand: The FERC D1 factors are calculated by computing the average historical five-year D1 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.

~~d.~~e. Compute total forecasted D1 Factors: The manually forecasted demand is added to the corresponding forecasted demand for all other customers. Total demand by class is combined within each jurisdiction to determine each jurisdiction's total demand. Total system demand is the sum of the jurisdictional demands. The jurisdictional Generation Demand (D1) allocator is based on each jurisdiction's share of the total system demand.

2. **TRANSMISSION DEMAND FACTOR (D2)** - this factor is determined based on contribution to Otter Tail's average annual six-hour transmission peak kW demand. Any loads for which Otter Tail is responsible for providing transmission service are included in this factor excluding interruptible, water heating, deferred, and off-peak loads when allocating jurisdictional amounts to the customer classes. The hours used are the same as those for the Generation Demand Factor.

Forecast Methodology for D2: The Forecasted D2 factors are computed using a ~~4~~5-step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

a. Compute forecasted customers demand
~~a.~~b. Compute controlled service customer demand (class only)
~~b.~~c. Compute manually forecasted customer demand
~~c.~~d. Compute FERC demand
~~d.~~e. Compute total forecasted D2 Factors

a. Compute forecasted customers demand: First, the historical allocation factors for the previous five years are re-computed excluding the manually forecasted customers. Next, the annual transmission Demand (D2) and the Energy at the generation level (E2) are compiled in a spreadsheet, for the last five years. A Demand/Energy ratio is then computed for each customer class and jurisdiction for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2 excluding the manually forecasted customers), to compute the non-manually Forecasted Transmission Demand (Forecasted D2).

~~a.~~b. Compute controlled services customers demand: Controlled services customers demand is set to zero for class allocation purposes only.

~~b.~~c. Compute manually forecasted customer Demand: Manually forecasted customers demand is determined. In some cases, a fixed baseline demand agreed on by OTP and the customer is the level of demand used for those customers in the forecast.

~~c.~~d. Compute FERC demand: The FERC D2 factors are calculated by computing the average historical five-year D2 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.

~~d.~~e. Compute total forecasted D2 Factors: The manually forecasted demand is added to the corresponding demand from all other customers. Total demand by class is combined within each jurisdiction to determine each jurisdiction's total demand. Total system demand is the sum of the jurisdictional demands. The jurisdictional demand (D2) allocator is based on the jurisdiction's share of the total system demand.

3. **DISTRIBUTION PRIMARY DEMAND FACTOR (D3)** - this factor is determined based on contributions to Otter Tail's average annual six-hour primary distribution peak kW demand minus the 0.83 kW/customer already included in the minimum system portion of the primary customer component. (See Appendix A-1.) Any loads for which Otter Tail is responsible for providing primary distribution service are included in this factor. The hours used are the same as those for the Generation Demand Factor.

   Forecast Methodology for D3: The Forecasted D3 factors are computed using a 3-step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

   a. Compute non-FERC demand
   b. Compute the FERC demand
   c. Compute total forecasted D3 Factors

   a. Compute non-FERC demand: First, historical allocation factors for the previous five years are re-computed. Next, each year's Distribution Primary Demand (D3) and the Energy at the generation level (E2) are compiled in a spreadsheet, for the previous five years, and a Demand/Energy ratio is computed for each class and jurisdiction for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2) to compute the Distribution Primary Demand (Forecasted D3).
   b. Compute the FERC demand: The FERC D3 factors are calculated by computing the average historical five-year D3 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.
   c. Compute total forecasted D3 Factors: The non-FERC forecasted demand is added to the corresponding FERC forecasted demand. The entire system is summed up by class and the jurisdictional total is divided by the total system to get the Forecasted Distribution Primary Demand (D3) allocation factor.

4. **DISTRIBUTION SECONDARY DEMAND FACTOR (D4)** - this factor is determined based on non-coincident kW demands at the secondary service level minus the 3.0 kW/customer already included in the minimum system portion of the secondary customer component. (See Appendix A-1.) Only loads served at voltages less than 2400 volts are

included in this factor.

Forecast Methodology for D4: The Forecasted D4 factors are computed using a 3-step process that uses historical Demand/Energy Ratios and applies those ratios against forecast energy sales:

a. Compute non-FERC demand
b. Compute the FERC demand
c. Compute total forecasted D4 Factors

a. Compute non-FERC demand: The historical allocation factors are re-computed for the prior five year's Distribution Secondary Demand (D4) and the Energy at the generation level (E2) factors. These factors are compiled in a spreadsheet and a Demand/Energy ratio is computed for each class and state for each year. The average Demand/Energy ratio for the last five years is computed by class and state and then multiplied by the corresponding forecasted generation level Energy (Forecasted E2) to compute the non-manually forecast Distribution Secondary Demand factor. (Forecasted D4).
b. Compute the FERC demand: The FERC D4 factors are calculated by finding the average historical five-year D4 factor by class and multiplying that by the system Forecasted Energy at the Generation level (E2) by the corresponding class.
c. Compute total forecasted D4 Factors: The non-FERC forecasted demand is added to the corresponding FERC demand. The entire system is summed up by class and the jurisdictional total is divided by the total system to get the Forecasted Distribution Secondary Demand (D4) allocation factor.

5. **ENERGY FACTOR (E1)** - this factor is based on kilowatt-hour (kWh) sales adjusted for line losses to the generation level excluding interruptible, irrigation, and 14/24ths of ~~water heating and~~ deferred and off-peak sales. It is only used for jurisdictional allocations.

Forecast Methodology for E1: The Forecasted E1 factors are computed using a 4-step process:

a. Compute Energy at the meter level
b. Compute Energy at the generation level excluding interruptible, irrigation, and 14/24ths of ~~water heating and~~ deferred and off-peak sales
c. Compute FERC Energy
d. Compute total forecasted E1 Factors

a. Compute Energy at the meter level: The annual kWh Sales forecast at the rate group level is the initial dataset for developing this factor. Where applicable, the kWh energy forecast from manually forecasted customers are added to the appropriate rate group to calculate total energy sales at the meter by rate group.
b. Compute Energy at the generation level excluding interruptible, irrigation, and 14/24ths of ~~water heating and~~ deferred and off-peak sales: The meter level kWh energy forecast at

the rate group level above is converted to MWhs. The forecast amounts are then multiplied by the loss factor applicable for each respective rate group level forecast to arrive at the generation level energy forecast for each state. Interruptible and irrigation rates are excluded, and ~~water heating and~~ deferred and off-peak rates energy is multiplied by 10/24ths (excluding 14/24ths).

c. Compute FERC Energy: The FERC E1 Energy is calculated by summing up the 3 states E1 total for each forecasted year and multiplying that by the 5-year average of the historical FERC E1 factors.

d. Compute total forecasted E1 Factors: The generation level energy less interruptible, irrigation, and 14/24ths of ~~water heating and~~ deferred and off-peak energy is then summed by class (manually forecasted customers are summed with their appropriate class) and state for each year to reach the system level energy. Then each jurisdictional total is divided by the system total to get the forecasted Energy Factor (E1).

6. **ENERGY FACTOR (E2)** - this factor is based on total kWh sales adjusted for line losses to the generation level. It is only used for jurisdictional allocations.

Forecast Methodology for E2: The Forecasted E2 factors are computed using a 4-step process:

a. Compute Energy at the meter level
b. Compute Energy at the generation level
c. Compute FERC Energy
d. Compute total forecasted E2 Factors

a. Compute Energy at the meter level: The annual kWh Sales forecast at the rate group level is the initial dataset for developing this factor. Where applicable, the kWh energy forecast from manually forecasted customers are added to the appropriate rate group to calculate total energy sales at the meter by rate group.

b. Compute Energy at the generation level: The meter level kWh energy forecast at the rate group level above is converted to MWhs. The forecast amounts are then multiplied by the loss factor applicable for each respective rate group level forecast to arrive at the generation level energy forecast for each state.

c. Compute FERC Energy: The FERC E2 Energy is calculated by summing up the 3 states E2 total for each forecasted year and multiplying the state energy forecasts by the 5-year average of the historical FERC E2 factors.

d. Compute total forecasted E2 Factors: The generation level energy forecast by rate group is then summed to a class level, state level and system level (manually forecasted customers are added to the appropriate class and state) for each year. Each jurisdictional total is divided by the system total to get the respective jurisdictional Energy Factors (E2).

7. **ENERGY FACTOR (E1-E8760)** - This factor is based on hourly energy usage, to which are applied hourly ~~marginal~~ generation capacity costs to develop an hourly cost relationship. **This factor is only used to allocate jurisdictional amounts to the customer classes in Minnesota and North Dakota.**

~~**General Note on E8760 Factors:** The E8760[1] factors are developed in a manner upon which marginal energy prices are applied to energy usage which is comparable to the energy usage levels that included in the determination of the E1 and E2 factors. For example, the E8760 factor which replaces the E1 factor, excludes similar controllable or interruptible loads and irrigation, like the E1 factor does. As a result, there are two E8760 factors that are developed; one that mirrors the energy usage of all customers reflected in the E1 factor and one that mirrors the energy usage and customers reflected in the E2 factor. The two factors are identified as E1-E8760 and E2-E8760.~~

Forecast Methodology for E1-E8760: Forecasted E1-E8760 allocation factors are developed using a ~~4~~5-step process.

a. Develop customer load profiles
b. Apply load profiles to forecast sales and scale to generation levels
~~b.~~c. Compute sales for controlled loads and irrigation
~~c.~~d. Apply hourly ~~energy~~ generation capacity costs to forecasted hourly sales
~~d.~~e. Compute E1-E8760 factor ~~excluding controllable load and irrigation~~

a. Develop customer load profiles: Annual hourly kWh load survey data[2] is gathered for each customer load research group (which includes manually forecast customer data). Based on the annual hourly load research data, hourly "profiles" are developed by customer group as the basis to shape forecasted kWhs across all 8760 hours of the forecast year. Multiple profiles are developed based on applicable customer types.

b. Apply load profiles to forecast sales and scale to generation levels: Each month's hourly load shape developed in step a. is applied to the corresponding monthly kWh sales forecast for the respective customer group to distribute those sales across the hours of the month. This process applied to all twelve months of the year yields the distribution of the forecasted sales across all 8760 hours of the year. Within this step of the process, the forecast kWh sales are also calibrated to account for losses, which vary depending on customer type and service voltage level. The end result of this step is forecasted generation level kWh sales by customer class for all 8760 hours of the year.

~~b.~~c. Compute E1-E8760 Factors for controlled loads and irrigation: Interruptible and irrigation sales are excluded from the calculation of the E1-E8760 factors. Deferred and off-peak loads exclude the sales from the highest priced 14 hours each day.

~~c.~~d. Apply hourly ~~energy~~ generation capacity costs to hourly energy sales: Forecasted hourly

~~[1] In a leap year, calculations would be made using 8784 hours.~~
[2] OTP's load research by customer type is conducted on a system basis.

marginal ~~energy~~ generation capacity costs are multiplied against the forecasted hourly kWh sales developed in ~~the prior step~~steps b. and c. to compute total annual marginal revenues.

~~d.~~e. Compute E1-E8760 Factors: excluding Controllable load and irrigation: To compute the E1-E8760 allocation factors, the marginal ~~energy~~ generation capacity costs computed in step ~~e~~d. are aggregated to the class level. The class's marginal ~~energy~~ generation capacity ~~revenues~~ costs are divided by the total jurisdictional marginal ~~energy~~ generation capacity ~~revenues~~ costs to determine each class's allocation factor (percentage). The resultant set of factors (percentages) are converted back to equivalent kWhs by class and used in place of the ~~E2~~ E1 factor cost allocation in the class cost of service study. ~~Customers who are excluded from the calculation of the E1 factors are excluded from the calculation of the E1-E8760 factors (interruptible, irrigation, and 14/24ths of water heating and deferred sales).~~

8. ENERGY FACTOR (E2-E8760) – This factor is based on hourly energy usage, to which are applied hourly marginal costs to develop an hourly cost relationship. **This factor is only used to allocate jurisdictional amounts to the customer classes in Minnesota and North Dakota.**

Forecast Methodology for E2-E8760: Forecasted E2-8760 allocation factors are developed using a ~~4~~5-step process.

a. Develop customer load profiles
b. Apply load profiles to forecast sales and scale to generation levels
c. Apply hourly energy costs to forecasted hourly sales
~~c.~~d. Apply hourly energy costs to controllable loads
~~d.~~e. Compute E2-E8760 Factor

a. Develop customer load profiles: Annual hourly kWh load survey data[3] is gathered for each customer load research group (which includes manually forecast customer data). Based on the annual hourly load research data, hourly "profiles" are developed by customer group upon which to use to shape forecasted kWhs across all 8760 hours of the forecast year. Multiple profiles are developed based on applicable customer types.

b. Apply load profiles to forecast sales and scale to generation levels: Each month's hourly load shape developed in step a. is applied to the corresponding monthly kWh sales forecast for the respective customer group to distribute those sales across the hours of the month. This process applied to all twelve months of the year yields the distribution of the forecasted sales across all 8760 hours of the year. Within this step of the process, the forecast kWh sales are also calibrated to account for losses, which vary depending on customer type and service voltage level. The end result of this step is forecasted

[3] OTP's load research by customer type is conducted on a system basis.

generation level kWh sales by customer class for all 8760 hours of the year.

c. Apply hourly energy costs to hourly energy sales: Forecasted hourly marginal energy costs are multiplied against the forecasted hourly kWh sales developed in the prior step to compute total annual marginal ~~revenues~~costs.

~~c.~~d. Apply hourly energy costs to controllable loads: A strike-price is set on the hourly marginal energy cost for interruptible and deferred loads. If the hourly marginal energy costs exceeds the set strike-price, the hourly marginal energy cost is reduced by 90 percent. Forecasted hourly marginal energy costs are multiplied against the forecasted hourly kWh sales developed in step b. to compute total annual marginal costs.

~~d.~~e. Compute E2-E8760 Factors: To compute the E2-E8760 allocation factors, the marginal energy costs computed in steps c. and d. are aggregated to the class level. The class's marginal energy ~~revenues~~ costs are divided by the total jurisdictional marginal energy ~~revenues~~ costs to determine each class's allocation factor (percentage). The resultant set of factors (percentages) are converted back to equivalent kWhs by class and used in place of the E2 factor cost allocation in the class cost of service study.

~~8.~~9. **TOTAL RETAIL CUSTOMERS FACTOR (C1)** - this factor is based on the total distinct active retail customers served in each jurisdiction.

Forecast Methodology for C1: The Forecasted C1 factors are computed using a 4-step process:

a. Compute historical C1 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C1 factors

a. Compute historical C1 values: The historical C1 factors are computed.

b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~

c. Compute the FERC values: Remain the same as the most recent historical year.

d. Compute Forecasted C1 factors: To compute forecasted C1 values for each year, the prior year's C1 values are multiplied by the growth factor. The C1 values are summed by state/FERC and system. Each jurisdictional total is divided by the system total to yield the forecasted C1 Factor.

~~9.~~10. **TOTAL DISTRIBUTION SERVICE LOCATIONS FACTOR (C2)** – a distribution service location is any point on the distribution system at which service is or can be provided including inactive and seasonal locations.

Forecast Methodology for C2: The Forecasted C2 factors are computed using a 4-step process:

a. Compute historical C2 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C2 factors

a. Compute historical C2 values: The historical C2 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C2 factors: To compute forecasted C2 values for each year, the prior year's C2 values are multiplied by the growth factor. The C2 values are summed by jurisdiction and system. Each jurisdictional total is divided by the system total to yield the jurisdictional forecasted C2 factor.

~~10.~~11. **TOTAL SECONDARY DISTRIBUTION SERVICE LOCATIONS FACTOR (C3)** - this factor includes only those distribution service locations served or which can be served at secondary voltage (below 2400 volts).

Forecast Methodology for C3: The Forecasted C3 factors are computed using a 4-step process:

a. Compute historical C3 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C3 factors

a. Compute historical C3 values: The historical C3 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C3 factors: To get the Forecasted C3 values for each year, the prior year's C3 values are multiplied by the growth factor. The C3 values are summed by

jurisdiction and system. Then each jurisdictional total is divided by the system total to yield the forecasted C3 factor.

~~11.~~12. **STREETLIGHT FACTOR (C4)** - this factor is based on the weighted installed cost of the streetlights in each jurisdiction.

Forecast Methodology for C4: The most recent historical C4 factor is used as the forecasted C4 factor with no change.

~~12.~~13. **AREA LIGHT FACTOR (C5)** - this factor is based on the weighted installed cost of area lights in each jurisdiction.

Forecast Methodology for C5: The most recent historical C5 factor is used as the forecasted C5 factor with no change.

~~13.~~14. **METER FACTOR (C6)** - this factor is based on the weighted installed cost of meters in service.

Forecast Methodology for C6: The most recent historical C6 factor is used as the forecasted C6 factor with no change.

~~14.~~15. **METER READING FACTOR (C7)** - this factor is based on total weighted meter reading time.

Forecast Methodology for C7: The Forecasted C7 factors are computed using a 4-step process:

a. Compute historical C7 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Combine historical values and growth factor and computes Forecasted C7 factors

a. Compute historical C7 values: The historical C7 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C7 factors: To compute the Forecasted C7 values for each year, the prior year's C7 values are multiplied by the growth factor. The C7 values are summed by jurisdiction and system. Then each jurisdictional total is divided by the system total to

yield the Forecasted C7 Factor.

~~15.~~16. **TOTAL SYSTEM SERVICE LOCATIONS FACTOR (C8)** - this factor is similar to the Total Distribution Service Locations Factor, except all locations on the system at which service can be or is provided are included.

Forecast Methodology for C8: The Forecasted C8 factors are computed using a 4-step process:

a. Compute historical C8 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Combine historical values and growth factor and computes Forecasted C8 factors

a. Compute historical C8 values: The historical C8 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth Factors for each class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~
c. Compute the FERC values: Remain the same as the most recent historical year.
d. Compute Forecasted C8 factors: To compute the Forecasted C8 values for each year, the prior year's C8 values are multiplied by the growth factor. The C8 values are summed by jurisdiction and system. Then each jurisdictional total is divided by the system total to yield the forecasted C8 factor.

~~16.~~17. **LOAD MANAGEMENT FACTOR (C9)** - this factor is based on the total number of locations that have radio load management receivers in each jurisdiction.

Forecast Methodology for C9: The Forecasted C9 factors are computed using a 4-step process:

a. Compute historical C9 values
b. Compute Class Growth factor
c. Compute the FERC values
d. Compute Forecasted C9 factors

a. Compute historical C9 values: The historical C9 factors are computed.
b. Compute Class Growth factor: Customer growth factors for each class by state are computed by using historical meter counts. The percent difference in meter counts for each of the past 5 years is calculated for each class and state. The customer growth factor is the average percent difference over the last 5 years.~~Customer growth Factors for each~~

~~class by state are computed using the same method to develop the customer growth factor for the rate group level in the revenue forecast process.~~

c. Compute the FERC values: Remain the same as the most recent historical year.

d. Compute Forecasted C9 factors: To compute the forecasted C9 values for each year, the prior year's C9 values are multiplied by the growth factor. The C9 values are summed by jurisdiction and system. Then each jurisdiction is divided by the system total to yield the forecasted C9 factor.

Non-Legislative Version of

Tariff Sheet ND 13.13 - Sales Adjustment Rider

SALES ADJUSTMENT RIDER N

DESCRIPTION	RATE CODE
All Services	NSA

N
N
N

RULES AND REGULATIONS: Terms and conditions of this tariff and the General Rules and Regulations govern use of this rider. N N

APPLICATION OF RIDER: This rider is applicable to electric service under all of the Company's retail rate schedules as described in the Mandatory Riders – Applicability Matrix. N N

COST RECOVERY FACTOR: There shall be included on each North Dakota Customer's monthly bill a Sales Adjustment (SA) Rider charge, which shall be calculated before any applicable municipal payment adjustments and sales taxes as provided in the General Rules and Regulations for the Company's electric service. The following charges are applicable in addition to all charges for service being taken under the Company's standard rate schedules. N N N N N

Sales Adjustment - $0.000 per kWh

N

DETERMINATION OF SALES ADJUSTMENT RIDER: The Sales Adjustment (SA) Rider Factor shall be determined by dividing the effect of sales changes on base rate jurisdictional cost allocations and revenues from Otter Tail Power Company's most recent general rate case by the forecasted retail sales (kWh) subject to the SA Rider for a designated 12-month recovery period. For each recovery period, a true-up adjustment to the SA Tracker account will be calculated reflecting the difference between actual prior period SA recoveries and actual prior period recoveries. Any resulting over/under recovery will be reflected as a carryover balance and included in calculating the next SA Factor plus carrying charges or credits accrued at the rate of return approved in Otter Tail Power Company's most recent general rate case. N N N N N N N N N N

Forecasted retail sales used for calculating the SA Factor shall include the forecast of retail electric revenue collected through all applicable charges and credits under the Company's retail rate schedules in Sections 9, 10, 11, 12, and 14, except for Section 14.09 (**Tail***Winds*). **N N N**

The SA Factor may be adjusted annually with approval of the Commission. **N**

<u>MANDATORY AND VOLUNTARY RIDERS</u>: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders. **N N N N**

Otter Tail Power Company
Proration of Accumulated Deferred Income Tax for Final Rates Implemented August 1, 2024
Unadjusted Projected Fiscal Year 2024

Line No.	(A)	(B) 12/31/23	(C) 12/31/24	(D) Simple Average
1	**Accumulated Deferred Income Taxes**			
2	Non-Prorated:			
3	Federal (above the line including Wind)	(314,143,869)	(328,958,993)	(321,551,431)
4				
5	Prorated:			
6	Federal (above the line including Wind)	(314,143,869)	(324,310,973)	(319,227,421)
7				
8	**Adjustment to ADIT**			**2,324,010**
9				
10			NEPIS	37.8769%
11			North Dakota Share	880,263
12				
13			Rate Base Revenue Requirement Factor	10.38%
14			Test Year ND Revenue Requirement Impact	**91,409**

Otter Tail Power Company
Proration of Accumulated Deferred Income Tax for Interims
Unadjusted Projected Fiscal Year 2024

Line No.	(A)	(B) 12/31/23	(C) 12/31/24	(D) Simple Average
1	**Accumulated Deferred Income Taxes**			
2	Non-Prorated:			
3	Federal (above the line including Wind)	(314,143,869)	(328,958,993)	(321,551,431)
4				
5	Prorated:			
6	Federal (above the line including Wind)	(314,143,869)	(321,741,362)	(317,942,615)
7				
8	**Adjustment to ADIT**			**3,608,816**
9				
10			NEPIS	37.8177%
11			North Dakota Share	1,364,771
12				
13			Rate Base Revenue Requirement Factor	9.80%
14			Test Year ND Revenue Requirement Impact	**133,778**

Otter Tail Power Company
North Dakota Cost of Service Study
2024 Projected Test Year

Line No.	Item	Class Allocation Factors	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
1	Rate Base		661,733,555	205,126,967	10,826,081	147,590,894	226,405,626	578,900	13,293,092	6,108,235	15,571,307	35,235,809	996,643
2													
3	Total Available for Return		21,208,695	2,105,053	321,162	5,158,815	10,895,058	(10,923)	1,432,702	(78,072)	(286,637)	1,438,974	232,561
4													
5	Rate of Return Earned		3.21%	1.03%	2.97%	3.50%	4.81%	-1.89%	10.78%	-1.28%	-1.84%	4.08%	23.33%
6													
7	Rate of Return Requested		7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%
8													
9	Operating Income Required		51,946,084	16,102,467	849,847	11,585,885	17,772,842	45,444	1,043,508	479,496	1,222,348	2,766,011	78,236
10													
11	Total Available for Return		21,208,695	2,105,053	321,162	5,158,815	10,895,058	(10,923)	1,432,702	(78,072)	(286,637)	1,438,974	232,561
12													
13	Operating Income Defeciency		30,737,389	13,997,414	528,685	6,427,071	6,877,784	56,366	(389,194)	557,568	1,508,984	1,327,037	(154,324)
14													
15	Incremental Taxes		9,923,169	4,518,884	170,679	2,074,897	2,220,403	18,197	(125,646)	180,004	487,156	428,417	(49,822)
16													
17	Revenue Increase (Decrease) Required		40,660,558	18,516,298	699,364	8,501,967	9,098,187	74,564	(514,841)	737,572	1,996,140	1,755,453	(204,146)
18													
19	Percentage Increase		22.26%	36.36%	26.51%	22.09%	12.54%	81.15%	-16.33%	54.31%	83.89%	16.90%	-28.34%
20													
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25	Present Revenues		182,686,888	50,929,292	2,638,536	38,489,021	72,538,663	91,886	3,151,974	1,358,100	2,379,440	10,389,651	720,325
26	Revenue Increase (Decrease) Required		40,660,558	18,516,298	699,364	8,501,967	9,098,187	74,564	(514,841)	737,572	1,996,140	1,755,453	(204,146)
27	Revenue Responsibility		223,347,446	69,445,591	3,337,900	46,990,988	81,636,850	166,449	2,637,134	2,095,672	4,375,580	12,145,104	516,179
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Otter Tail Power Company
Base Revenue Responsibilities
2024 Base Revenues

	A	B	C	D	E	F	G	H	I	I
Line No.	**Class**	**Present Base Revenue**	**POET Sales moving into EAR**	**Change in Rider Revenues due to Changes in Allocation Factors**	**RRCR moving into base****	**TCR moving into base**	**GCR moving into base**	**AMDT moving into base**	**Net deficiency**	**Total Proposed Base Revenues**
1	Residential	36,934,037	(480,371)	592,636	5,020,393	1,278,967	1,161,634	206,546	6,210,791	50,924,632
2	Farm	1,830,773	(17,239)	32,727	251,924	77,410	58,291	8,944	322,438	2,565,269
3	General Service	27,366,763	(297,241)	457,062	3,765,812	1,022,544	871,345	180,607	4,690,300	38,057,192
4	Large General Service	38,106,045	931,990	(959,344)	5,243,594	985,090	1,213,279	10,911	6,335,159	51,866,724
5	Irrigation	54,144	131	(64)	7,451	3,585	1,724	1,050	11,918	79,939
6	Area / Street lighting	2,693,795	(39,218)	46,256	370,680	34,065	85,769	63,498	(490,959)	2,763,887
7	Other Public Authorities	820,854	(1,427)	11,454	112,954	47,854	26,136	6,090	187,230	1,211,143
8	Controlled Service Deferred Load	1,289,964	69,258	(6,944)	177,506	12,310	41,072	55,950	16,537	1,655,653
9	Controlled Service Interruptible	4,005,936	397,729	166,755	551,238	80,450	127,547	81,479	68,422	5,479,556
10	Controlled Service Off Peak	279,169	(32,156)	43,174	38,415	5,553	8,889	3,766	6,403	353,213
11	Total Present Revenues	113,381,480	531,458	383,711	15,539,967	3,547,829	3,595,685	618,840	17,358,238	154,957,208
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