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-23-342

Exhibit___

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

Rebuttal Testimony and Schedules of

AMBER M. GRENIER

**PUBLIC DOCUMENT –
NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED**

November 4, 2024

TABLE OF CONTENTS

ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My name is Amber M. Grenier.[1] I am employed by Otter Tail Power Company (OTP or the Company).

Q. DID YOU PREPARE DIRECT TESTIMONY AND SUPPLEMENTAL DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed Direct Testimony addressing 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 addressed the treatment of generator interconnection procedures projects (GIPs) and proration of accumulated deferred income tax (ADIT) in the 2024 Test Year.

In my Supplemental Direct Testimony, I explained certain revisions being made to OTP's 2024 Test Year revenue requirement and associated revenue deficiency. I also sponsored the Class Cost of Service Study (CCOSS) for the revised 2024 Test Year revenue requirement and presented revised class revenue responsibilities.

Q. ARE YOU ADOPTING THE DIRECT TESTIMONY AND SUPPLEMENTAL DIRECT TESTIMONY OF ANY OTHER OTP WITNESSES?

A. Yes. I am adopting the direct testimony and supplemental direct testimony of OTP witness Mr. David G. Prazak, who has since retired.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony provides two updates related to the 2024 Test Year revenue requirement and revenue deficiency: (1) calculation of the Jurisdictional Cost of Service Study (JCOSS) E1 allocation factor; and (2) 2024 Test Year other electric revenues.

I also respond to recommendations included in the October 4, 2024 Direct Testimony of the following witnesses: (1) Karl Pavlovic on behalf of the North Dakota Public Service Commission (Commission) Advocacy Staff; (2) Dante Mugrace on behalf of Advocacy Staff; and (3) Kavita Maini on behalf of the

[1] Since filing Direct Testimony and Supplemental Direct Testimony, I have changed my name from Amber M. Stalboerger.

Midwest Large Energy Consumers (MLEC). Specifically, I address the following issues:

- Revenue and Cost Impacts of Large Commercial Sales Changes;
- Allocation of Midcontinent Independent System Operator (MISO) Revenues;
- Multi-Value Projects (MVPs) Operations & Maintenance (O&M) Expense;
- CCOSS Distribution Cost Classification Using Minimum Size System Study;
- Class Revenue Responsibility;
- Section 5.02 Special Facilities Charge Rate;
- Large General Service (LGS) Winter Prices; and
- LGS Primary and Secondary Intra-Class Revenue Apportionment.

II. UPDATES TO 2024 TEST YEAR REVENUE REQUIREMENT

A. JCOSS E1 Allocation Factor

Q. PLEASE DESCRIBE THE REASON FOR THE REVISION TO THE JCOSS E1 ALLOCATION FACTOR.

A. The JCOSS E1 allocation factor typically only includes the non-interruptible portion of all customer loads. After filing Direct Testimony, OTP determined that a portion of interruptible load was inadvertently included in the JCOSS E1 factor. Removing the interruptible load reduces the JCOSS E1 factor by approximately 0.10 percent and decreases the 2024 Test Year revenue deficiency by approximately $80,000 (OTP ND).

Q. IS THIS CONSISTENT WITH HOW OTP HAS CALCULATED THE JCOSS E1 ALLOCATION FACTOR IN PRIOR CASES?

A. Yes. The revised JCOSS E1 allocation factor is calculated in the same manner as occurred in OTP's last North Dakota rate case. The only change is the underlying data that goes into the calculation.

Q. HAS OTP INCLUDED THE JCOSS E1 ALLOCATION FACTOR REVISION IN THE CALCULATION OF THE 2024 TEST YEAR BASE RATE REVENUE REQUIREMENT?

A. Yes, the revised JCOSS E1 allocation factor is reflected in the Rebuttal Testimony 2024 Test Year base rate revenue requirement presented by OTP witness Ms. Christy L. Petersen.

Q. WILL THERE BE A CORRESPONDING REVISION TO THE CCOSS E1-8760 FACTOR?

A. Yes, a similar, *de minimis* revision will be made to the CCOSS E1-8760 factor. Similar to the JCOSS E1 allocation factor, the CCOSS E1-8760 factor typically only includes the non-interruptible portion of all customer loads. OTP has excluded the portion of interruptible load present in the Direct Testimony CCOSS E1-8760 allocator.

B. Other Electric Revenues (Advocacy Staff – Mugrace)

Q. DID ADVOCACY STAFF INCLUDE A RECOMMENDATION REGARDING CALCULATION OF 2024 TEST YEAR OTHER ELECTRIC REVENUES?

A. Yes. Mr. Mugrace recommended that revenue from late fees, connections, rent, integrated transmission deficiency payments, miscellaneous service, and other miscellaneous revenues reflect a three-year average. [2] In total, the recommendation increases 2024 Test Year present revenue by approximately $1.7 million (OTP ND).

Q. DOES OTP AGREE WITH THIS RECOMMENDATION?

A. In part. I acknowledge that these types of revenues can fluctuate year-to-year and that averaging these revenues may be an appropriate method to arrive at a normal, ongoing amount for purposes of setting rates. That averaging, however, needs to exclude revenue recovered through other mechanisms, and exclude non-recurring revenues that would not be expected to be present in the test year or the period over which rates will be in effect.

Q. WHY SHOULD REVENUE RECOVERED THROUGH OTHER MECHANISMS AND NON-RECURRING REVENUES BE EXCLUDED FROM THE THREE-YEAR AVERAGE?

A. Revenue recovered through other mechanisms should be excluded in order to properly focus on base rates. For example, sales for resale revenues consist of asset-based sales credited directly to customers through OTP's Energy Adjustment Rider (EAR). An increase to these revenues results in a decrease in the EAR revenues, resulting in no change to the 2024 Test Year revenue requirement.

---

[2] Mugrace Direct at 15:13-25.

Non-recurring revenue should also be excluded from the average because the entire purpose of using an average is to avoid the effects of anomalous events that are not expected to occur in the future. An example of this is one-time minimum contract payments.

Q. HAVE YOU PREPARED A REVISED CALCULATION OF THE THREE-YEAR AVERAGE OF THE OTHER OPERATING REVENUES ADDRESSED BY MR. MUGRACE?

A. Yes. Exhibit___(AMG-3), Schedule 1 provides an updated three-year average of other electric revenue, excluding revenue recovered through other mechanisms and non-recurring revenues. As shown therein, the three-year average is approximately $3.8 million (OTP ND), or approximately $0.4 million (OTP ND) greater than the amount included in the Supplemental Direct calculation of the 2024 Test Year revenue deficiency.

Q. HAS OTP INCLUDED THIS ADJUSTMENT IN THE CALCULATION OF THE 2024 TEST YEAR BASE RATE REVENUE DEFICIENCY?

A. Yes. This adjustment is reflected in the Rebuttal Testimony 2024 Test Year base rate revenue deficiency presented by Ms. Petersen.

III. CONTESTED ISSUES

A. Revenue and Cost Impacts of Large Commercial Sales Changes (MLEC-Maini)

Q. WHAT IS MS. MAINI'S RECOMMENDATION REGARDING LARGE LOADS?

A. Ms. Maini recommends adjusting the sales forecast to include an annualized amount of North Dakota Soybean Processors, LLC (ND Soy) load.[3]

Q. WHAT IS OTP'S POSITION REGARDING THIS RECOMMENDATION?

A. OTP witness Mr. Bruce G. Gerhardson explains in his Rebuttal Testimony that OTP does not support including the ND Soy load in the 2024 Test Year. Rather, OTP recommends this load change, and others, be addressed through the sales adjustment proposal. OTP witness Ms. Tammy K. Mortenson provides additional detail regarding the ND Soy load in her Rebuttal Testimony.

[3] Maini Direct at 12:13-14.

Q. HAS OTP RECEIVED INFORMATION REGARDING OTHER LARGE COMMERCIAL LOADS?

A. Yes. Ms. Mortenson explains in her Rebuttal Testimony that OTP has learned information regarding two other Large Commercial customers that could result in Large Commercial load being greater than the amount included in the 2024 Test Year sales forecast.

Q. HAVE YOU ESTIMATED THE IMPACT ON THE 2024 TEST YEAR REVENUE DEFICIENCY OF INCLUDING THESE LOADS?

A. Yes. If included, the load additions would have two impacts on the 2024 Test Year revenue deficiency. First, the additional sales from the loads would increase present revenues and therefore decrease the revenue deficiency (all else being equal). Second, the additional load would make North Dakota a larger part of our integrated system, resulting in changes to JCOSS allocation percentages and costs allocated to the North Dakota retail jurisdiction, increasing the revenue deficiency (all else being equal). In total, including the three loads would decrease the 2024 Test Year non-fuel base rate revenue deficiency by approximately $0.39 million (OTP ND).

Table 1
Revenue and Allocator Effect on 2024 Test year Non-Fuel Base Rate Revenue Deficiency
($ Millions)

Component	Total
Present Non-Fuel Revenue	$3.60
Costs Due to Allocator Changes	$3.31
Operating Income Deficiency	$0.30
Incremental Taxes	$0.09
Net Effect to 2024 Test Year Non-Fuel Base Rate Revenue Deficiency	**$0.39**

Q. PLEASE DISCUSS THE RESULTS SHOWN IN TABLE 1 FOR ND SOY.

A. ND Soy takes service pursuant to OTP's Economic Development Rate Rider – Large General Service (Section 14.13). This service arrangement was approved by the Commission in its October 27, 2022 Order in Case No. PU-22-322. Under the terms of the approved Electric Service Agreement (ESA), ND Soy receives an economic development discount for a five-year period, after which time, it will take service under standard rates. Thus, we would expect revenue from this customer to increase over time as economic development discounts decrease.

Q. DOES THE NATURE OF THESE CUSTOMERS' ENERGY USE AFFECT COST ALLOCATION?

A. Yes. The three customers do not have significant controllable loads. Collectively, the customers are expected to add 16 MW to the D1 and D2 JCOSS allocators. This is in contrast to APLD Hosting, LLC, a wholly owned affiliate of Applied Digital, Inc. ("Applied") (formerly known as Applied Blockchain), who has significant load control capability and had a disproportionately small impact on D1 and D2 allocators. And as a result, the addition of Applied reduced the 2024 Test Year revenue deficiency, as discussed in my Direct Testimony.

Q. DOES THE ADDITION OF THESE LOADS INCREASE THE TOTAL COSTS BEING ALLOCATED IN THE JCOSS?

A. No. The JCOSS is allocating costs for the 2024 Test Year. The increase in costs shown in Table 1 above reflects the fact that the load growth (should it materialize) will mean North Dakota is a larger portion of the overall OTP system.

Q. WHAT IS YOUR CONCLUSION REGARDING THE REVENUE AND COST IMPACTS OF THE POTENTIAL LARGE COMMERCIAL SALES CHANGES?

A. As explained by Mr. Gerhardson, OTP does not support including these sales changes in the 2024 test year. If they are included, however, then I recommend that the effect be reflected in both revenues and costs. Doing so would decrease the 2024 Test Year non-fuel base rate revenue deficiency by approximately $0.39 million (OTP ND).

B. Allocation of MISO Revenues (Advocacy Staff – Pavlovic)

Q. WHAT DID MR. PAVLOVIC RECOMMEND REGARDING ALLOCATION OF MISO REVENUES?

A. Mr. Pavlovic states the MISO revenues are delivered using the totality of OTP's electric plant and therefore should be allocated in the JCOSS using the Net Electric Plant in Service (NEPIS) allocation factor.[4]

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The revenues in question derive from MISO Schedules 7, 8, 9, 26, and 26A. These all are revenues associated with transmission investment, not the totality of OTP's electric plant.

Q. HOW IS TRANSMISSION INVESTMENT ALLOCATED IN THE JCOSS?

A. Transmission investment is allocated using OTP's D2 transmission demand allocation factor, which measures each jurisdiction's contribution to OTP's average annual six-hour transmission peak demand.

Q. DID MR. PAVLOVIC ACCEPT THIS ALLOCATION OF TRANSMISSION INVESTMENT IN THE JCOSS?

A. Yes. While Mr. Pavlovic disagrees with two JCOSS allocation methodologies, allocation of transmission investment was not one of them.

Q. DO BASIC ACCOUNTING PRINCIPLES PROVIDE FOR REVENUE ALLOCATION TO FOLLOW ALLOCATION OF THE UNDERLYING INVESTMENT?

A. Yes. Basic accounting principles would allocate the revenues with the investments.

Q. WHAT WOULD BE THE EFFECT OF ALLOCATING TRANSMISSION INVESTMENT ON THE NEPIS ALLOCATOR?

A. North Dakota has a larger share of the NEPIS allocator than it does the D2 allocator. Therefore, if investment were to be allocated on the same basis as associated revenue (rather than having revenue follow investment) and Mr. Pavlovic's recommendation regarding revenue allocation was adopted, it would result in an increase in transmission investment cost allocation to the North

[4] Pavlovic Final Direct at 9:1-4.

Dakota jurisdiction that would more than offset the addition revenues under his approach.

Q. WAS THE ORIGINAL ALLOCATION OF MISO REVENUES ON THE NEPIS ALLOCATOR IN ERROR?

A. Yes. I explained in my Supplemental Direct Testimony that the Direct Testimony JCOSS allocated MISO revenues to jurisdictions based on the NEPIS allocation factor,[5] which was an error. While we regret the oversight, that is not a reasonable basis to continue forward using the NEPIS allocator.

Q. HOW ARE MISO REVENUES ACTUALLY CREDITED TO CUSTOMERS?

A. As explained in OTP's response to Discovery Request ND-PSC-1105, a copy of which is provided as Exhibit___(AMG-3), Schedule 2, MISO revenues are credited to customers through the Transmission Cost Recovery (TCR) rider.

Q. HOW ARE MISO REVENUES ALLOCATED IN THE TCR RIDER?

A. MISO revenues are allocated to the jurisdictions using the D2 factor in the TCR rider. This means that adopting Mr. Pavlovic's recommendation would result in more revenue being allocated to North Dakota in the JCOSS than OTP actually is recovering in the rider.

Q. SHOULD THE COMMISSION ADOPT MR. PAVLOVIC'S RECOMMENDATION?

A. No. His recommendation is inconsistent with allocation of the underlying investment generating the revenue, as well as how MISO revenues are allocated when credited to customers.

C. Multi-Value Projects O&M (MLEC-Maini)

Q. WHAT IS MS. MAINI'S RECOMMENDATION REGARDING ALLOCATION OF MVP O&M COSTS?

A. Ms. Maini recommends that the Company directly assign the O&M costs associated with MVP projects to the FERC jurisdiction.[6]

---

[5] Stalboerger Supplemental Direct at 2:14-30.

[6] Maini Direct at 11:1-9. OTP is a joint owner of two MVP Projects: (1) Big Stone Area Transmission – Brookings (BSAT-Brookings); and (2) Big Stone Area Transmission – Ellendale (BSAT-Ellendale).

Q. HAS OTP INCURRED ANY O&M COSTS TO DATE FOR ITS MVP PROJECTS?

A. No. Ms. Maini testifies that she expects OTP to incur O&M costs associated with the MVP projects, including labor, external services, and legal functions.[7] To date, all labor, external services, and legal costs have been capitalized as part of the development and construction of the MVP projects. The non-retail portion of the capitalized costs are excluded from retail rate base, as discussed by Ms. Petersen in her Direct Testimony.[8]

Q. WILL THE NON-RETAIL PORTION OF FUTURE MVP O&M COSTS BE EXCLUDED FROM RETAIL RATES?

A. Yes. OTP has created separate accounting structures for future MVP O&M costs, and the non-retail portion will be excluded from retail rates, similar to the treatment of MVP capital costs. But with no O&M costs having yet been incurred (or included in the 2024 budget or 2024 Test Year), there is no adjustment to be made at this time.

D. CCOSS Distribution Cost Classification Using Minimum Size System Study (Advocacy Staff – Pavlovic)

Q. WHAT IS MR. PAVLOVIC'S RECOMMENDATION REGARDING CLASSIFICATION OF DISTRIBUTION COSTS IN THE CCOSS?

A. Mr. Pavlovic recommends that primary and secondary portions of distribution plant and associated operation and maintenance (O&M) accounts[9] be classified using only demand allocation factors.[10]

Q. DO YOU AGREE WITH MR. PAVLOVIC'S RECOMMENDATION THAT DISTRIBUTION PLANT BE CLASSIFIED AS DEMAND-RELATED?

A. No. I disagree with Mr. Pavlovic's recommendation. First, the underlying premise is unreasonable and fails to recognize that the addition of customers is a driver of certain distribution system costs. Second, classifying distribution plant as purely demand-related is not supported by the National Association of Regulatory Utility Commissioners Cost Allocation (NARUC) Manual. Third, Mr. Pavlovic's

---

[7] Maini Direct at 9:22-23.
[8] Petersen Direct at 26:4-10.
[9] The associated FERC accounts are 364, 365, 366, 367, 368 and 369 for distribution plant and 580-581, 583-584, 588, 590, 593-595, and 598 for associated O&M accounts.
[10] Pavlovic Direct at 12:12-16, 18:22-19:2.

recommendation deviates from how OTP and other utilities in North Dakota have traditionally classified distribution system costs.

Q. PLEASE DESCRIBE WHY THE PREMISE OF MR. PAVLOVIC'S RECOMMENDATION IS UNREASONABLE.

A. As explained in the NARUC Manual, costs can be classified into customer-, demand-, or energy-related. Distribution plant costs do not include energy-related costs, only customer- and demand-related costs. Customer-related costs are those that vary based on the number of customers, and demand-related costs are those that vary based on demand imposed on the system.[11]

Mr. Pavlovic's recommendation that primary and secondary distribution plant costs be classified as one hundred percent demand-related is unreasonable because it ignores the fact that distribution plant costs also are driven in part by the number of customers. For instance, a distribution system that must serve one hundred residential customers spread over several blocks will require more distribution plant components than a single commercial customer with the same amount of peak demand. In this case, the distribution system serving the residential customers requires additional poles and conductors, and potentially additional transformers to reach all of the customers. This example illustrates that at least a part of distribution system costs vary based on the number of customers. Accordingly, any method that classifies the primary and secondary distribution system costs as one hundred precent demand-related is not based on the principles of cost causation.

Q. HOW DOES THE NARUC MANUAL RECOMMEND DISTRIBUTION ASSETS BE CLASSIFIED?

A. The NARUC Manual recommends that distribution plant be classified as both demand- and customer-related, as shown in Table 6-1 below.[12] Specifically, it recognizes that the number of poles, conductors, transformers, and services are directly related to the number of customers on the utility's system. It therefore recommends that distribution plant be classified as demand- and customer-related costs or purely customer-related costs.

[11] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual at 22 (Jan. 1992) (NARUC Manual).
[12] NARUC Manual at 87.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

Q. DOES THE NARUC MANUAL PROVIDE ANY RECOMMENDATIONS FOR THE CLASSIFICATION OF DISTRIBUTION PLANT?

A. Yes. The NARUC Manual recommends two methods to classify the distribution system into demand-related and customer-related components: the Minimum-Size Method and the Minimum-Intercept Method.[13] The Minimum-Size Method, also referred to as the Minimum Size System Method, involves determining the minimum size of the distribution system. Once determined, the costs associated with the minimum size distribution system are classified as customer-related costs. Demand-related costs are the difference between total investment and

[13] NARUC Manual at 90-92.

customer-related costs. The Minimum Intercept Method, also referred to as the Zero-Intercept Method, similarly classifies distribution plant costs as either demand- or customer-related. This method identifies the portion of the distribution plant related to a no-load situation and classifies the costs related to the no-load situation as customer-related.

Q. WHAT METHOD DID OTP USE TO CLASSIFY DISTRIBUTION PLANT?

A. OTP uses Minimum Size System Method for the classification of distribution plant.[14] The Minimum Size System Method follows cost causation principles, is supported by the NARUC Manual, and has traditionally been relied upon by utilities in North Dakota. As such, I continue to recommend the use of the Minimum Size System Method for the classification of OTP's distribution system.

Q. PLEASE DESCRIBE OTP'S APPLICATION OF THE MINIMUM SIZE SYSTEM METHOD.

A. As described above, the Minimum Size System Method determines the minimum size for each component currently installed to serve the minimum loading requirements and then assumes that a least size distribution system can be built to serve the minimum load requirements.[15] OTP calculates the average cost of the minimum size pole, conductor, cable, transformer, and service currently installed using the Handy Whitman Index. This minimum system cost is classified as customer-related and allocated according to the number of customers per jurisdiction. Costs beyond those classified as customer-related in this method are classified as demand-related.

Q. IS THE MINIMUM SIZE SYSTEM METHOD USED BY OTHER UTILITIES IN NORTH DAKOTA?

A. Yes. Mr. Pavlovic states "...there is no basis in theory or practice supporting the use of the minimum-size system method to classify and allocate primary and secondary plant and associated O&M expense accounts in regulatory cost studies."[16] This statement is not true. The minimum system approach is used across the industry and has been relied upon for years in North Dakota. OTP has

---

[14] Stalboerger Direct, Exhibit__ (AMS-1), Schedule 2 at 15-19.
[15] NARUC Manual at 90-92.
[16] Pavlovic Direct at 10:8-10.

traditionally applied this method in North Dakota rate cases.[17] Both Montana-Dakota Utilities Co. and Northern States Power Company, doing business as Xcel Energy, have used the Minimum System Method with refinements to include the Zero Intercept Method for certain sub-functions.[18]

Q. DOES OTP USE THE MINIMUM SYSTEM METHOD WHEN ALLOCATING TOTAL SYSTEM COSTS TO RETAIL JURISDICTIONS?

A. Yes. The classification of distribution costs into demand-related and customer-related costs is part of the jurisdictional allocation process that occurs in in the JCOSS. And that classification is performed using the Minimum Size System Method.

Q. DOES MR. PAVLOVIC RECOMMEND USE OF THE MINIMUM SYSTEM METHOD IN THE JCOSS?

A. It is unclear. Mr. Pavlovic testifies "I recommend that OTP's JCOSS and CCOSS without minimum size system be used as the basis for both class revenue allocation and tariff rate design."[19]

Q. WHAT IS THE EFFECT OF CHANGING THE CLASSIFICATION OF DISTRIBUTION COSTS IN THE JCOSS?

A. If distribution costs are classified as entirely demand-related (as recommended by Mr. Pavlovic), it would increase costs allocated to the North Dakota retail jurisdiction by approximately $1.0 million.

---

[17] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota*, Case No. PU-17-398, Direct Testimony and Schedules of Gina S. Ice, Exhibit__(GSI-1), Schedule 2 at 17-22 (Nov. 2, 2017); *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-08-862, Direct Testimony and Schedules of Peter J. Beithon, Exhibit__(PJB-1), Schedule 11 B at 24-31 (Nov. 3, 2008).

[18] *Montana-Dakota Utilities Co. 2022 Electric Rate Increase Application*, Case No. PU-22-194, Rebuttal Testimony of Ronald J. Amen at 7 (Feb. 28, 2023); *Northern States Power Company 2021 Electric Rate Increase Application*, Case No. 20-441, Revised Direct Testimony of Michael A. Peppin, Exhibit___(MAP-1), Revised Schedule 2 at 6 (Mar. 26, 2021); *Montana-Dakota Utilities Co., a Division of MDU Resources Group, Inc. 2016 Electric Rate Increase Application*, Case No. PU-16-666, Direct Testimony of Bruce R. Chapman at 12 (Oct. 14, 2016); *Northern States Power Company 2013 Electric Rate Increase Application*, Case No. PU-12-813, Direct Testimony of Michael A. Peppin, Exhibit ___ (MAP-1), Schedule 2 at 6 (Dec. 18, 2012); *Northern States Power Company 2011 Electric Rate Increase Application*, Case No. PU-11-55, Direct Testimony of Michael A. Peppin, Exhibit ___ (MAP-1), Schedule 2 at 6 (Dec. 20, 2010).

[19] Pavlovic Direct at 4:15-17.

Q. IS THERE ANY REASONABLE BASIS TO CLASSIFY DISTRIBUTION COSTS AS ENTIRELY DEMAND-RELATED IN THE CCOSS BUT PARTIALLY DEMAND-RELATED AND PARTIALLY CUSTOMER-RELATED IN THE JCOSS?

A. No.

Q. WHAT DO YOU CONCLUDE REGARDING THE CLASSIFICATION OF OTP'S DISTRIBUTION SYSTEM?

A. For the reasons listed above, I continue to recommend the use of the Minimum Sized System Method for the classification of OTP's distribution system and associated O&M costs, and that Mr. Pavlovic's recommendation that the distribution system be classified as entirely demand-related costs be rejected.

E. Class Revenue Responsibility (Advocacy Staff – Pavlovic; MLEC – Maini)

Q. PLEASE SUMMARIZE THE CLASS REVENUE RESPONSIBILITY RECOMMENDATIONS OF THE PARTIES.

A. Both Mr. Pavlovic and Ms. Maini present alternatives to the Company's recommended class revenue responsibilities. Mr. Pavlovic uses the Advocacy Staff recommended revenue requirement, which presents challenges for direct comparison of absolute class revenue responsibility percentages. As a result, I prepared a comparison of the relative class increase for each party.

Table 2
Comparison of Recommended Relative Class Revenue Increases

	Source:	Stalboerger Supplemental Direct Table 1	Maini Table 7	Pavlovic Direct Table 5
Line No.	**Class**	**OTP Ratio of Class Proposed to Total Proposed Increase**	**MLEC Ratio of Class Proposed to Total Proposed Increase**	**Staff Ratio of Class Proposed to Total Proposed Increae**
1	Residential	1.284	1.480	1.150
2	Farms	1.287	1.200	1.305
3	General Service	1.196	1.000	0.933
4	Large General Service	0.900	0.640	0.604
5	Irrigation	1.338	1.600	7.687
6	Lighting	(0.563)	0.400	(0.641)
7	OPA	1.432	1.600	2.113
8	Controlled Service Deferred Load	0.074	1.100	9.443
9	Controlled Service Interruptible	0.072	1.100	1.692
10	Controlled Service Off-Peak	0.098	1.100	(1.564)
11	Total	1.000	1.000	1.000

Q. WHAT ARE YOUR OBSERVATIONS REGARDING TABLE 2?

A. First, OTP and MLEC generally follow similar patterns across the classes, though MLEC's recommendations result in more revenue being collected from the Residential class and less revenue being collected from the LGS class, as compared to OTP. Mr. Pavlovic on the other hand, presents substantially different recommendations for some smaller classes, particularly the controlled service classes.

Q. DO YOU HAVE CONCERNS WITH MR. PAVLOVIC'S RECOMMENDATIONS?

A. Yes. Mr. Pavlovic's recommendations are based, in part, on his CCOSS recommendations, which I disagree with for the reasons discussed above. More fundamentally, I have significant concerns regarding unintended consequences associated with his recommendations for the Controlled Service classes.

Q. PLEASE DESCRIBE THE CONTROLLED SERVICE CLASSES.

A. The rate schedules within the Controlled Service classes all provide for some form of control by OTP, meaning we are able to interrupt service to those customers under stated conditions. These are valuable tools for both system planning and system operation. For example, 4,886 North Dakota customers utilize our Water Heating – Controlled Service Rider (Section 14.01), which is part of the Controlled Service Deferred Load class. This allows us to control on average approximately 4.42 megawatts (MW).

Q. HOW WOULD MR. PAVLOVIC'S RECOMMENDATION AFFECT CONTROLLED SERVICE DEFERRED LOAD CUSTOMERS?

A. Mr. Pavlovic's recommendation would increase Controlled Service Deferred Load class rates by 56 percent (based on the Company's Supplement Direct revenue requirement). That would violate our objectives of maintaining reasonable rate continuity and mitigating disproportionate or abrupt rate impacts.[20] And if implemented, the cost increases could cause customers to no longer utilize the service, reducing load control resources and requiring replacement with other resources that have their own costs.

Q. DO CONTROLLED SERVICE DEFERRED LOAD CUSTOMERS ALSO TAKE SERVICE UNDER OTHER RATE SCHEDULES?

A. Yes. The Controlled Service Deferred Load services are specific to certain equipment (e.g., water heater). Customers utilizing a Controlled Service Deferred Load service generally take service under another rate schedule, for example Residential service. Therefore, Mr. Pavlovic's recommendations will have broader effects, extending to other customers.

Q. DOES OTP CONTINUE TO SUPPORT ITS RECOMMENDED RELATIVE INCREASES SHOWN IN TABLE 2, ABOVE?

A. Yes. Our recommended relative increases are consistent with our objectives of maintaining reasonable rate continuity and mitigating disproportionate or abrupt rate impacts. Importantly, they avoid dramatic and unintended consequences for our Controlled Service offerings that would occur under Mr. Pavlovic's recommendations. Also, as compared to MLEC's recommendations, OTP's approach has a lesser impact on residential customers that fall under our Residential service and our Controlled Service offerings.

---

[20] Stalboerger Direct at 20:1-3.

F. Special Facilities Charge Rate (Advocacy Staff – Pavlovic)

Q. PLEASE DESCRIBE OTP'S SPECIAL FACILITIES CHARGE RATE.

A. The Section 5.02 – Special Facilities consists of two retail rate schedules: Sections 11.02 – Irrigation and 14.02 – Bulk Interruptible Service.[21] The Section 5.02 rate is used to collect costs from customers who have requested unique extensions and certain non-standard equipment, to ensure that those costs are not passed on to other customers.

The Section 5.02 tariff currently states that when a customer wants to arrange for installation of Special Facilities, they must execute an agreement or service form to establish the payments. Once the costs under the agreement are calculated, customers pay a percentage of the equipment costs, much like a rental agreement as it is OTP-owned and maintained, for as long as the customer requires the equipment for service.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE SECTION 5.02 TARIFF MIGHT BE USED?

A. Yes. One example of the Section 5.02 tariff is an irrigation customer who requires metering or other infrastructure to be installed on an irrigator. This type of equipment is unique for each customer as the service extension is customized to meet the sizing of the irrigator pump and its location (distance) from the Company's distribution lines. The extensions can be relatively expensive and could cost up to tens of thousands of dollars. The customer's electricity billing will be handled under the irrigation rate. Because irrigation customers only operate for less than 7 months a year, and have unique electrical equipment needs, their payment schedules also are different from our typical customers (e.g. residential). For these reasons, the special equipment, and those costs for unique equipment requests are recovered through the Section 5.02 tariff.

Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING TO THE SPECIAL FACILITIES CHARGE RATES.

A. In this case we propose to modernize and standardize the way that the percentage payments are calculated. We propose to establish a new calculation that incorporates the following cost components:

---

[21] Prazak Direct at 53:4-28.

1. Operations and Maintenance expense for distribution function assets, including allocated administrative and general expenses to support distribution function assets.
2. General and Common Depreciation Expenses allocated to support distribution function assets.
3. Taxes other than income taxes for distribution function assets.
4. Depreciation expense for distribution assets.
5. Income taxes.
6. Return on rate base calculated with the approved capital structure.[22]

Q. WHY IS OTP PROPOSING THESE CHANGES?

A. The changes more accurately recover the specific costs at issue. The costs are caused by individual customers, so it is important to ensure that the rate is designed to recover all of the costs from that customer, and to do so in a fair and predictable way. The updated calculation will accomplish these goals.

Q. DOES MR. PAVLOVIC SUPPORT THESE CHANGES?

A. No. Mr. Pavlovic recommended that the Commission reject OTP's proposed revisions to Section 5.02 because he characterizes it as a "formula rate."

Q. IS THE SECTION 5.02 RATE A "FORMULA RATE," AS THAT PHRASE IS COMMONLY USED IN THE INDUSTRY?

A. No. Mr. Prazak referred to the Section 5.02 rate as a "formula rate" because the rate includes the use of a mathematical formula, as many rates do. Our proposal for the Section 5.02 is not similar to formula rate proposals that are sometimes used in other jurisdictions. For example, the proposal does not include a regular escalator, or specific increases over time. We are proposing only to update the percentage of project costs recovered annually, using standard factors, and apply the updated percentage to ensure accurate recovery of costs from customers.

Q. HAVE YOU PREPARED AN EXAMPLE OF THE OPERATION OF THE REVISED SECTION 5.02 RATE?

A. Yes. Exhibit___(AMG-3), Schedule 3 is an example of the revised Section 5.02 calculation.

---

[22] Prazak Direct at 53:15-25.

Q. DID OTP INCLUDE REVISED TARIFF LANGUAGE AS PART OF ITS INITIAL FILING?

A. Yes. Tariff revisions were included in Volume 2C, specifically in Section 5.02 itself, as well as in revised Electric Service Agreement and Irrigation Electric Service Agreement templates (Section 1.05).

Q. WHAT IMPACT DOES OTP ANTICIPATE THE PROPOSED CHANGES TO THE SPECIAL FACILITIES CHARGE RATES TO HAVE ON CUSTOMERS?

A. The change we propose to the rate will have minimal impact on customers overall but will be an improvement for customers who make use of the rate. Both current ratepayers and new customers who use the rate will be assured that the special facilities will be charged accordingly with annually updated rate information in the year of the special facilities investment. Additionally, as seen in Volume 3, Schedule E-2, page 5 of 9, for Irrigation services provided under schedules 11.01 and 11.02 subject to the special facility charge, the proposed revenues included in the 2024 Test Year is $10,354. The Bulk Interruptible service in schedule 14.12 does not currently have any customers.

Q. DOES OTP CONTINUE TO SUPPORT THE PROPOSED REVISIONS TO THE SPECIAL FACILITIES CHARGE RATE?

A Yes. The revisions ultimately will improve the accuracy of the cost recovery of these unique costs. Further, I believe OTP has provided adequate information to address Mr. Pavlovic's concerns.[23]

G. LGS Rate Design Winter Prices (MLEC – Maini)

Q. WHAT CONCERN DID MS. MAINI EXPRESS REGARDING LGS WINTER PRICES?

A. Mr. Maini noted that she was concerned about the changes in the LGS winter energy and demand charges.[24]

[23] Pavlovic Direct at 28:16-29:2.
[24] Maini Direct at 25:3-4.

Q. HOW DID OTP DEVELOP THE LGS WINTER ENERGY AND DEMAND CHARGES?

A. As explained in OTP's Direct Testimony, we set demand charges 20 percent higher than marginal capacity costs.[25] This is an intentional decision in order to increase the amount of costs recovered through demand charges.

Q. IS THIS CONSISTENT WITH MS. MAINI'S TESTIMONY IN OTHER OTP RATE CASES?

A. Yes. In our last North Dakota rate case, Ms. Maini supported the Company's proposal to increase the portion of LGS revenue recovered through demand charges.[26] In our last Minnesota rate case, Ms. Maini testified "My overarching goal, however, is to recover more costs from the demand charges to provide the proper pricing signals to customers that building infrastructure is expensive. As discussed earlier, this rate design should also help mitigate the issue of fixed cost recovery from volumetric billing determinants."[27]

Q. IS THERE A REASON FOR WINTER DEMAND CHARGES TO HAVE INCREASED MORE THAN SUMMER DEMAND CHARGES?

A. Yes. Summer marginal capacity costs have decreased since OTP's last North Dakota rate case, while winter capacity costs have increased.[28] As a result, the proposed LGS rate design for secondary and primary customers generally holds summer demand charges constant, while increasing winter demand charges.[29]

Q. IS THERE A REASON FOR WINTER ENERGY CHARGES TO HAVE INCREASED MORE THAN SUMMER ENERGY CHARGES?

A. Yes. Marginal summer energy costs have increased since OTP's last North Dakota rate case, but not by as much as winter energy costs.[30]

[25] Prazak Direct at 20:5-6.
[26] *See* Case No. PU-17-398, Maini Direct at 30:1-6 ("OTP has substantially increased the demand charges compared to existing rates, while comparatively lowering the energy charges. … I support the Company's proposal to increase the demand charges while reducing the energy charges.")
[27] Minnesota Public Utilities Commission Docket No. E107/GR-20-179, Maini Direct at 38:14-17.
[28] Prazak Direct at 5:32-35.
[29] Prazak Direct at 29:1-4 (Table 9).
[30] Prazak Direct at 5:27-31.

Q. DOES OTP CONTINUE TO SUPPORT THE PROPOSED LGS RATE DESIGN?

A. Yes. The proposed rate design, including winter demand and energy charges, is informed by the 2024 Marginal Cost Study. Further, the proposal moves more cost recovery to demand charges, which Ms. Maini has supported in prior cases.

H. LGS Intra-Class Revenue Allocation (MLEC – Maini)

Q. PLEASE SUMMARIZE MS. MAINI'S TESTIMONY REGARDING INTRA-LGS CLASS REVENUE ALLOCATION.

A. Ms. Maini supports the Company's proposed allocation between SLGS and non-SLGS subgroups within the LGS class.[31] She expresses "concern," however, that the allocation of revenue between LGS primary and secondary subgroups within the LGS class is "not directly consistent with the Company's [CCOSS] results."[32]

Q. DID OTP USE THE CCOSS TO DEVELOP INTRA-LGS CLASS REVENUE RESPONSIBILITIES?

A. Generally, yes. OTP's Direct Testimony explains that LGS intra-class revenue responsibility is based on the overall class level increase.[33] The LGS class increase is informed by the CCOSS results, but reflects other factors too, as discussed above.

Q. DID OTP EVALUATE THE COST RESPONSIBILITY DIFFERENTIAL BETWEEN LGS-SECONDARY AND LGS-PRIMARY CUSTOMERS?

A. Yes. As discussed in my Direct Testimony, OTP had discussions with MLEC and developed a way to separate the LGS class CCOSS results into secondary, primary and transmission sub-classes.[34]

Q. WHAT DID THAT EVALUATION SHOW?

A. As explained in our response to Discovery Request ND-MLEC-701, a copy of which is provided as Exhibit___(AMG-3), Schedule 4, the CCOSS and 2024 Marginal Cost Study voltage differentials were very similar. Further, the embedded cost responsibility for LGS-Primary and LGS-Secondary sub-classes, which was provided in Attachment 1 to Discovery Request ND-MLEC-701, showed LGS-Secondary cost responsibility of approximately 71.57 percent and LGS-Primary cost responsibility of approximately 28.43 percent. These values are generally

[31] Maini Direct at 22:8-10.
[32] Maini Direct at 22:13-14.
[33] Prazak Direct at 9:14-19 (Table 2).
[34] Stalboerger Direct at 25:3-6.

consistent with the proposed intra-LGS class revenue allocation, as shown in the table below.

Table 3
Comparison of CCOSS-Indicated Cost Responsibility and Proposed Intra-LGS Class Revenue Responsibility

LGS Subclass	Cost Responsibility	Revenue Responsibility[35]
LGS Secondary	71.57%	70.35%
LGS Primary	28.43%	29.61%

Q. DOES OTP CONTINUE TO SUPPORT ITS PROPOSED INRA-LGS CLASS REVENUE ALLOCATION?

A. Yes. The proposed allocation generally is aligned with embedded sub-class cost responsibilities and is a reasonable basis for designing rates.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[35] *See* Supplemental Direct Volume 3, Schedule E-1.

Line No.	Description	2024	2022	2023	Total Company Average	ND Share Average	Adjustment to ND Share
1	Late Charges (450) - DA	$ 316,187	$ 326,087	$ 335,982	$ 326,085	$ 326,085	$ 9,898
2	Connection Fees (452.1) - DA	$ 136,812	$ 136,860	$ 138,683	$ 137,452	$ 137,452	$ 640
3	Rent From Electric Property (includes Hoot Lake) - NEPIS	$ 435,931	$ 945,169	$ 939,659	$ 773,586	$ 291,695	$ 127,319
4	Other Misc. Electric Revenue - NEPIS	$ 1,395,880	$ 1,828,068	$ 2,070,882	$ 1,764,943	$ 665,504	$ 139,162
5	Integrated Transmission Deficiency Payments (456.3) - NEPIS	$ 848,757	$ 920,934	$ 841,253	$ 870,315	$ 328,168	$ 8,129
6	Miscellaneous Services (452.0) - NEPIS	$ -	$ 22,552	$ 23,723	$ 15,425	$ 5,816	$ 5,816
7	Other Electric Revenue - MISO Schedule - D2	$ 8,751,510	$ 10,782,790	$ 7,922,165	$ 9,152,155	$ 3,587,205	$ 157,034
8	Other Electric Revenue - MISO Schedule - GIPS - D2	$ (3,935,218)	$ (3,935,217)	$ (4,080,009)	$ (3,983,481)	$ (1,561,333)	$ (18,917)
9	Total	$ 7,949,860	$ 11,027,242	$ 8,192,338	$ 9,056,480	$ 3,780,592	$ 429,081

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: ND Public Service Commission
Analyst: Karl Pavlovic
Date Received: September 10, 2024
Date Due: September 24, 2024
Date of Response: September 24, 2024
Responding Witness: Amber Grenier, Manager, Regulatory Economics, 218-739-8728

Data Request:
Refer to the Supplemental Direct Testimony of Amber M. Stalboerger, page 2 lines 14-17, referencing "MISO revenues," the Transmission Cost Recovery (TCR) Rider and the D2 allocation factor in witness Stalboerger's Supplemental Direct Testimony. Please provide

a. the referenced Transmission Cost Recovery Rider and evidence supporting the assertion that the Transmission Cost Recovery Rider includes MISO revenues,

b. the cost causation that supports allocating the MISO revenues using the D2 allocation factor in witness Stalboerger's Supplemental Direct Testimony.

Attachments: 0

Response:

a) Please see Otter Tail's November 2, 2023 Supplemental Filing in Case No. PU-23-306. Table 2 of the filing shows crediting of MISO Schedule 9, 26, 37, 38, 26A and MVP ARR Revenue. Also see Attachments 7, 9, 10, 11, and 12 of Otter Tail's November 2, 2023 Supplemental Filing in Case No. PU-23-306.

b) MISO Schedule 26 and 26A recover transmission investments through MISO's MTEP process from other MISO participants. The retail share of these investments (the cost of which are charged back to load serving entities through Schedules 26 and 26A) is allocated to North Dakota customers using the D2 allocation factor, which is designed to allocate transmission related costs. Allocating the revenues associated with these investments using the D2 allocation factor matches the revenues with the costs reflected in MISO Schedule 26 and 26A.

   Because MISO Schedules 7, 8, and 9 are for transmission services, allocating these revenues using the D2 allocation factor is appropriate.

For the 12 months ended 12/31/ 23

	(1)	(2)	(3)
Line No.	**Cost Component**	**Distribution**	**Allocator**
1	Gross Distribution Plant - Total	654,605,387	
2	Net Distribution Plant - Total	390,367,770	
3	**Operations and Maintenance expense for distribution function assets, including allocated administrative and general expenses to support distribution function assets**		
4	Total O&M Allocated to Distribution	37,307,950	
5	Annual Allocation Factor for O&M		5.70%
6	**General and Common Depreciation Expenses allocated to support distribution function assets**		
7	Total G&C Depreciation Expense	2,148,907	
8	Annual Allocation Factor for G&C Depreciation Expense		0.33%
9	**Taxes other than income taxes for distribution function assets**		
10	Total Other Taxes	3,846,248	
11	Annual Allocation Factor for Other Taxes		0.59%
12	**Depreciation expense for distribution assets**		
13	Total Distribution Depreciation Expense	14,840,562	
14	Distribution Depreciation Expense Factor		2.27%
15	**Annual Allocation Factor for Expense**		**8.88%**
16	**Income Taxes**		
17	Total Income Taxes	7,444,651	
18	Annual Allocation Factor for Income Taxes		1.91%
19	**Return on rate base calculated with the approved capital structure**		
20	Return on Rate Base	31,216,270	
21	Annual Allocation Factor for Return on Rate Base		8.00%
22	**Annual Allocation Factor for Return**		**9.90%**
		Total	**18.79%**

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumers
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: August 12, 2024
Responding Witnesses: Amber Stalboerger, Manager, Regulatory Economics, 218-739-8728

Data Request:
Refer to Ms Amber Stalboerger direct testimony regarding the 2018 rate case CCOSS compliance item discussed on pages 24-25 of her direct testimony.

a. Please provide the working papers that support the finding that the marginal and embedded cost study produced a similar allocation of costs between the secondary and primary LGS service levels.
b. Please provide a comparison of the results between the embedded costs and marginal costs for voltage differentials between secondary and primary service for the LGS class.

Attachments: 2
Attachment 1 to ND-MLEC-701_PUBLIC
Attachment 2 to ND-MLEC-701_PUBLIC

Response:

Attachment 1 to ND-MLEC-701 is trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, Attachment 1 to ND-MLEC-701 is a live excel version (with formulae intact) of Otter Tail's class cost of service study model, which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Further, Attachment 1 to ND-MLEC-701 contains trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, the data marked as NOT PUBLIC in Attachment 1 to ND-MLEC-701 contains customer-specific energy usage information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

Attachment 2 to ND-MLEC-701 contains trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, the data marked as NOT PUBLIC in Attachment 2 to ND-MLEC-701 contains customer-specific energy usage information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

a. Please see Attachments 1 and 2 to ND-MLEC-701.
b. The table below provides a comparison of the results between the embedded costs and marginal costs for voltage differential between secondary and primary service for the LGS class.

	Embedded Cost	Marginal Cost
LGS Secondary	72%	75%
LGS Primary	28%	25%