Before the North Dakota Public Service Commission

State of North Dakota

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

Case No. PU-17-398

OAH File No. 20170622

Exhibit __

Class Revenue Responsibility and CCOSS

Rebuttal Testimony and Schedule of

Gina S. Ice

June 22, 2018

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ATTACHED SCHEDULES

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gina S. Ice. My business address is 215 S. Cascade St., Fergus Falls, MN 56538-0496.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Otter Tail Power Company (OTP) as Rates Analyst, Regulatory Administration.

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

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony replies to the Direct Testimony of Dr. David E. Dismukes filed on behalf of North Dakota Public Service Commission (the Commission) Advocacy Staff (Staff), the Direct Testimony of Ms. Kavita Maini and Mr. Larry L. Schedin filed on behalf of the Midwest Large Energy Consumers Group (MLEC) and the Direct Testimony of Mr. Steve W. Chriss filed on behalf of Walmart Inc. (Walmart).

II. SUMMARY OF REBUTTAL TESITMONY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Historically, the Commission has looked to cost to help guide the revenue allocation process. In this case, all parties agree that the Residential class is currently below cost. It is therefore reasonable for the Residential class revenue increase to be greater than the overall increase. OTP's proposed revenue allocation is the most reasonable approach in the record. Dr. Dismukes's recommended revenue allocation fails to follow his own stated methodology, while Ms. Maini's allocation, although cost-based, may not adequately reflect principles of gradualism and moderation.

OTP's Class Cost of Service Study (CCOSS) was prepared using the same basic principles and methodology as was used in OTP's last North Dakota rate case and previous North Dakota rate cases – at least as far back as 1982. Dr. Dismukes's observations regarding the CCOSS are not consistent with North Dakota or national practice. His recommendations should not be adopted.

III. CONTESTED ISSUES

A. Class Revenue Responsibility [MLEC-Maini; Staff-Dismukes; Walmart-Chriss]

Q. DID ALL PARTIES ALLOCATE THE SAME PROPOSED 2018 TEST YEAR REVENUES?

A. No. OTP and Dr. Dismukes make revenue allocations based on OTP's Initial Filing. Ms. Maini made her recommendation based on OTP's Supplemental Direct Testimony.

Q. IS IT POSSIBLE TO COMPARE THESE RECOMMENDATIONS?

A. Yes. OTP, Dr. Dismukes and Ms. Maini all recommend moving below-cost customer classes closer to their cost responsibilities.[1] Classes are moved closer to their cost responsibilities when the revenue increase percentage exceeds the overall revenue increase percentage. So the recommendations of OTP, Dr. Dismukes and Ms. Maini can be compared by looking at the relationship between the recommended class increase to the overall increase.

Q. HAVE YOU PREPARED A COMPARISON OF THE REVENUE RECOMMENDATIONS?

A. Yes. The table below compares the revenue recommendations of OTP, Dr. Dismukes and Ms. Maini. Columns A-C show the increase in class revenues recommended by each party. Columns D-F compare the recommended class increase to the overall increase. Columns G-I identify each party's resulting class revenue responsibility.

[1] Ice Direct, p. 12; Dismukes Direct, p. 55; Maini Direct, p. 24.

Table 1
Comparison of Recommended Revenue Responsibilities

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
Class	OTP Percent Increase	Dr. Dismukes Percent Increase	Ms. Mann Percent Increase	OTP Relative Increase	Dr. Dismukes Relative Increase	Ms. Mann Relative Increase	OTP Class Revenue Responsibility	Dr. Dismukes Class Revenue Responsibility	Ms. Maini Class Revenue Responsibility
Residential	13.70%	10.26%	11.00%	1.29	0.97	1.66	33.47%	32.47%	33.90%
Farms	13.70%	13.27%	11.00%	1.29	1.25	1.66	1.81%	1.81%	1.83%
General Service	8.27%	10.26%	3.96%	0.78	0.97	0.60	25.75%	26.23%	25.65%
Large General Service	8.26%	10.26%	1.68%	0.78	0.97	0.25	28.53%	29.07%	27.78%
Irrigation	19.00%	13.27%	15.00%	1.79	1.25	2.26	0.04%	0.04%	0.04%
Lighting	13.00%	13.27%	11.00%	1.23	1.25	1.66	1.98%	1.99%	2.02%
OPA	13.00%	13.27%	11.00%	1.23	1.25	1.66	0.83%	0.83%	0.85%
Controlled Service Water Heating	13.70%	13.27%	15.00%	1.29	1.25	2.26	0.75%	0.75%	0.79%
Controlled Service Interruptible	13.70%	13.27%	15.00%	1.29	1.25	2.26	5.83%	5.79%	6.12%
Controlled Service Deferred	8.26%	13.27%	5.71%	0.78	1.25	0.86	1.01%	1.02%	1.02%
	10.61%	10.62%	6.64%	1.00	1.00	1.00	100.00%	100.00%	100.00%

Q. WHAT ARE YOUR OBSERVATIONS REGARDING TABLE 1?

A. Dr. Dismukes treats all below-cost classes similarly, with uniform increases equal to 1.25 times the overall increase. OTP and Ms. Maini include more differentiation in their recommendations, with different magnitudes in the movement to cost for different classes. Finally, Ms. Maini recommends larger relative increases for below-cost classes than does OTP, likely due to her view of cost.

Q. DO THE PARTIES HAVE DIFFERENT VIEWS AS TO CUSTOMER COST RESPONSIBILITIES?

A. Yes. Dr. Dismukes and Ms. Maini both present alternative CCOSSs that influence their revenue responsibility recommendations.

Q. IS THE COMMISSION USED TO DEALING WITH COMPETING COST RECOMMENDATIONS?

A. Yes. In Case. No. PU-15-95, Staff provided the following testimony:

> The commission has recognized that the class cost of service study can be done in different ways resulting in different conclusions. The commission considers the CCOSS as a guide rather than a formulaic solution for designing rates. This is observed in a previous commission order, as follows:
>
> > We believe that both fully-distributed embedded class cost of service studies and long run incremental studies may provide useful guidance in designing rates. However, we will continue to use our own

> judgment considering the evidence, arguments and public policy in a particular case as to an appropriate rate design. We will avoid mechanical application of the results of any given cost study.[2]

Q. DO YOU BELIVE OTP'S VIEW ON COST IS SUPERIOR TO THAT OF DR. DISMUKES AND MS. MAINI?

A. Yes. While I recognize the Commission considers a variety of views on cost when allocating revenues, for the reasons discussed in Section III.B. below, I believe OTP's CCOSS is the superior CCOSS in this case and should be given the most weight in allocating revenue.

Q. ARE THERE ANY SIMILARITIES BETWEEN THE CCOSS OF OTP, DR. DISMUKES AND MS. MAINI THAT SHOULD INFLUENCE THE REVENUE ALLOCATION?

A. Yes. OTP, Dr. Dismukes and Ms. Maini all show that Residential class present revenue responsibility is below its cost responsibility, as calculated under their respective CCOSSs.[3]

Q. IS THERE ANY OTHER DATA THAT SUPPORTS THE CONCLUSION THAT THE RESIDENTIAL CLASS REVENUE RESPONSIBILITY IS BELOW ITS COST RESPONSIBILITY?

A. Yes. OTP has very low rates.[4] The data provided by Ms. Maini indicates Residential customers are benefited more by OTP's low rates than are industrial customers.[5] If the Residential class percentage increase is at the overall increase, there will be no change in the amount of the benefit of OTP's low rates that flows to Residential customers. And if the Residential class receives an increase that is less than the overall increase, Residential customers will capture even more of the benefits of OTP's low rates.

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[2] Case No. PU-15-95, Diller Direct, p. 12-13 (quoting Order in Case No. PU-91-112, Finding of Fact No. 76)).
[3] Ice Direct, p.11; Dismukes Direct, Exhibit DED-2 and DED-3, Maini Direct, p. 24.
[4] Gerhardson Direct, p. 9-10; Maini Direct, p. 13.
[5] Maini Direct, p. 13.

Q. DOES DR. DISMUKES FOLLOW HIS OWN REVENUE ALLOCATION METHODOLOGY?

A. No. Dr. Dismukes testifies that "each of the under-earning classes is assigned an increase that is 1.25 times the system average increase."[6] Dr. Dismukes's alternative CCOSS shows the Residential class with a relative rate of return of 0.94,[7] which according to Dr. Dismukes indicates the Residential class "is earning an amount less than the Company's overall rate of return."[8] Yet, Dr. Dismukes's revenue allocation shows the Residential class receiving a revenue increase that is 0.97 times the overall increase.[9]

Q. HAVE YOU ADJUSTED DR. DISMUKES REVENUE ALLOCATION TO BE CONSISTENT WITH HIS RECOMMENDATION FOR UNDER-EARNING CLASSES?

A. Yes. The table below shows the relative revenue increases applying Dr. Dismukes two-step approach to all under-earning classes, including the Residential class, as calculated in Dr. Dismukes alternative CCOSS and confirmed in the response to OTP information request ND-OTP-106, a copy of which is included as Exhibit___(GSI-3), Schedule 1.

[6] Dismukes Direct, p. 55.
[7] Dismukes Direct, Exhibit DED-3, p. 1.
[8] Dismukes Direct, p. 54.
[9] Dismukes Direct, Exhibit DED-7, p. 1.

Table 2
Adjusted Dismukes Revenue Responsibilities

	[A]	[B]	[C]	[D]	[E]	[F]
Class	Dr. Dismukes Percent Increase	Dr. Dismukes Percent Increase - ADJUSTED	Dr. Dismukes Relative Increase	Dr. Dismukes Relative Increase - ADJUSTED	Dr. Dismukes Class Revenue Responsbility	Dr. Dismukes Class Revenue Responsbility - ADJUSTED
Residential	10.26%	13.27%	0.97	1.25	32.47%	33.36%
Farms	13.27%	13.27%	1.25	1.25	1.81%	1.81%
General Service	10.26%	8.49%	0.97	0.80	26.23%	25.81%
Large General Service	10.26%	8.49%	0.97	0.80	29.07%	28.60%
Irrigation	13.27%	13.27%	1.25	1.25	0.04%	0.04%
Lighting	13.27%	13.27%	1.25	1.25	1.99%	1.99%
OPA	13.27%	13.27%	1.25	1.25	0.83%	0.83%
Controlled Service Water Heating	13.27%	13.27%	1.25	1.25	0.75%	0.75%
Controlled Service Interruptible	13.27%	13.27%	1.25	1.25	5.79%	5.79%
Controlled Service Deferred	13.27%	13.27%	1.25	1.25	1.02%	1.02%
	10.62%	10.62%	1.00	1.00	100.00%	100.00%

Q. WHAT ARE YOUR OBSERVATIONS OF TABLE 2?

A. As shown in Table 3, Dr. Dismukes's adjusted recommendation is very similar to OTP's relative recommended increases for many customer classes.

Table 3
Comparison of OTP and Adjusted Dismukes Revenue Responsibilities

	[A]	[B]	[C]	[D]	[E]	[F]
Class	OTP Percent Increase	Dr. Dismukes Percent Increase - ADJUSTED	OTP Relative Increase	Dr. Dismukes Relative Increase - ADJUSTED	OTP Class Revenue Responsibility	Dr. Dismukes Class Revenue Responsbility - ADJUSTED
Residential	13.70%	13.27%	1.29	1.25	33.47%	33.36%
Farms	13.70%	13.27%	1.29	1.25	1.81%	1.81%
General Service	8.27%	8.49%	0.78	0.80	25.75%	25.81%
Large General Service	8.26%	8.49%	0.78	0.80	28.53%	28.60%
Irrigation	19.00%	13.27%	1.79	1.25	0.04%	0.04%
Lighting	13.00%	13.27%	1.23	1.25	1.98%	1.99%
OPA	13.00%	13.27%	1.23	1.25	0.83%	0.83%
Controlled Service Water Heating	13.70%	13.27%	1.29	1.25	0.75%	0.75%
Controlled Service Interruptible	13.70%	13.27%	1.29	1.25	5.83%	5.79%
Controlled Service Deferred	8.26%	13.27%	0.78	1.25	1.01%	1.02%
	10.61%	10.62%	1.00	1.00	100.00%	100.00%

Q. DO YOU CONTINUE TO SUPPORT OTP'S RECOMMENDED RELATIVE INCREASES?

A. Yes. All parties agree that classes should be moved closer to their cost responsibilities. The question is how that should occur. Dr. Dismukes treats all under-earning classes similarly, without any consideration of the magnitude of the difference between present revenue responsibility and cost responsibility. Therefore, while his recommendation is similar to OTP's for certain classes, OTP's recommended relative increases are more precisely tailored to the class-by-class differences between revenue and cost responsibility. Conversely, while Ms. Maini appears to consider the magnitude of each class's under-earning, she recommends larger relative increases for many classes, likely due to her view on underlying cost responsibilities. I believe our view on cost is superior to that of Ms. Maini (as discussed below) and that our recommended relative increases are more consistent with the rate design principles of gradualism and moderation. I therefore continue to recommend the Commission adopt OTP's recommended relative increases, as shown in Column D of Table 1, above.

Q. HOW DOES OTP RECOMMEND ALLOCATING THE REBUTTAL TESTIMONY 2018 TEST YEAR PROPOSED REVENUES?

A. OTP witness Mr. Tyler A. Akerman explains that OTP's 2018 Test Year revenue deficiency is $10,105,973 million, which is a 6.91 percent increase over present revenues. Applying the relative increases shown in Column D of Table 1 above results in the recommended revenue allocations shown in the table below.

Table 4
Recommended 2018 Test Year Revenue Allocation

[A]		[B]	[C]	[D]	[E]	[F]
Line No.	Class	Total Present Revenues	Revenue Increase - Proposed	Class Increase % / Overall Increase %	Percent Increase (C/B)	Total Proposed Revenues (B+C)
1	Residential	$47,632,359	$4,249,316	1.29	8.92%	$51,881,675
2	Farms	$2,573,882	$229,618	1.29	8.92%	$2,803,500
3	General Service	$38,487,308	$2,069,538	0.78	5.38%	$40,556,846
4	Large General Service	$42,613,778	$2,292,063	0.78	5.38%	$44,905,841
5	Irrigation	$58,520	$7,240	1.79	12.37%	$65,760
6	Outdoor Lighting	$2,841,429	$240,534	1.23	8.47%	$3,081,963
7	OPA	$1,188,731	$100,629	1.23	8.47%	$1,289,360
8	Controlled Service Water Heating	$1,074,543	$95,861	1.29	8.92%	$1,170,404
9	Controlled Service Interruptible	$8,296,431	$740,130	1.29	8.92%	$9,036,561
10	Controlled Service Deferred	$1,506,746	$81,043	0.78	5.38%	$1,587,789
11	Total North Dakota	$146,273,727	$10,105,972		6.91%	$156,379,699

Q. IF THE ACTUAL REVENUE DEFICIENCY CHANGES, HOW WOULD THE COMMISSION SET CLASS REVENUE RESPONSIBILITIES?

A. OTP recommends the Commission multiply the overall, approved percentage increase by the values in Column D of Table 1 in order to arrive at the class-level revenue increases. For example, if the Commission approves an overall revenue increase of 6.5 percent, the revenue increase for the Residential class would be equal to 8.39 percent, which is 1.29 times 6.5 percent. This process would be repeated for each of the customer classes.

Q. CAN THE COMMISSION FOLLOW OTHER APPROACHES FOR ESTABLISHING CLASS REVENUE RESPONSIBILITIES?

A. Yes. The Commission could rely on the revenue percentages in Columns G-I of Table 1. The downside of this approach is that selecting a particular set of percentages will be tied to a particular calculation of cost. That being said, since the revenue percentages in Column G are associated with OTP's calculation of cost, OTP could support utilizing the percentages in Column G and not the proportional approach described above.

B. Class Cost of Service Study

1. Classification of Fixed Production Plant [MLEC-Maini]

Q. WHAT IS CLASSIFICATION?

A. Classification is the process of separating functionalized costs (i.e. production, transmission, distribution, etc.) into component parts: energy-related; demand-related and customer-related.[10]

Q. HOW DOES OTP CLASSIFY FIXED PRODUCTION PLANT?

A. OTP classifies fixed production plant into energy-related and demand-related components using the equivalent peaker method.[11] OTP utilizes this classification methodology in CCOSSs filed in North Dakota, South Dakota and Minnesota.

Q. WHAT IS THE THEORY BEHIND THIS CLASSIFICATION METHOD?

A. The NARUC Electric Cost Allocation Manual describes the theory behind the equivalent peaker method as follows:

> The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.[12]

Ultimately, the equivalent peaker method recognizes that intermediate and baseload plants provide both capacity and energy.

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[10] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, p. 20 (Jan. 1992).
[11] Ice Direct, Schedule 2, p. 4-5.
[12] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, p. 53 (Jan. 1992).

Q. IS THE EQUIVALENT PEAKER METHOD CONSISTENT WITH HOW OTP PLANS ITS SYSTEM?

A. Yes. The equivalent peaker method expressly recognizes that utilities have different needs (energy v. demand) and that they seek to meet those needs in the least-cost manner. Peaking plants generally have the lowest capital cost and the highest operating cost and typically are the least-cost means of procuring capacity. Intermediate and baseload plants have higher relative capital costs and lower relative operating costs: they are therefore generally the least-cost means of procuring energy. The equivalent peaker method recognizes the cost dynamics by treating any fixed production plant costs that exceed the cost of a peaking facility as being energy-related.

Q. DO OTHER NORTH DAKOTA INVESTOR-OWNED UTILITIES USE THE EQUIVALENT PEAKER METHOD?

A. Yes. Northern States Power Company (NSP) uses an equivalent peaker method to classify fixed production plant into energy-related and demand-related components.[13]

Q. DID PARTIES MAKE ANY RECOMMENDATIONS REGARDING THE CLASSIFICATION OF FIXED PRODUCTION PLANT?

A. Yes. Ms. Maini recommends classifying fixed production plant as 100 percent demand-related.[14]

Q. DO YOU HAVE ANY CONCERNS WITH MS. MAINI'S RECOMMENDATION?

A. Yes. Ms. Maini's recommendation does not reflect that baseload and intermediate plants meet both capacity and energy needs. It is also not consistent with how we plan our system. We incur the higher costs of baseload and intermediate plants precisely because they are the least-cost means of addressing energy needs of our customers. Ms. Maini's recommendation is premised on the assumption that OTP (and other utilities) only care

[13] Case No. 12-813, Peppin Direct, Schedule 2, p. 3; Case No. 07-776, Zins Direct, p. 7.
[14] Maini Direct, p. 16-18.

about peak demand, which is not the case. If it was, there would be no basis to ever incur the additional costs of baseload or intermediate generation.

Q. DOES OTP CONTINUE TO SUPPORT THE EQUIVALENT PEAKER METHOD OF CLASSIFYING FIXED PRODUCTION PLANT?

A. Yes.

2. Allocation of Energy-Related Fixed Production Plant [Staff-Dismukes; MLEC-Maini]

Q. WHAT IS ALLOCATION?

A. Allocation is the process of assigning classified costs to customer classes.[15]

Q. HOW DOES OTP ALLOCATE ENERGY-RELATED FIXED PRODUCTION PLANT COSTS TO CLASSES?

A. OTP allocates energy-related fixed production plant costs to classes using E8760 allocators. I described the development of the E8760 allocators in my Direct Testimony.[16]

Q. DID OTP IMPLEMENT THE E8760 ALLOCATION AS A RESULT OF A SETTLEMENT IN ITS LAST RATE CASE?

A. Yes. As noted in my Direct Testimony, the Commission's November 25, 2009 Order on Settlement in Case No. PU-08-862 and PU-08-742 approved a settlement which required the use of the E8760 allocator in future CCOSSs.[17]

Q. DID PARTIES PROVIDE COMMENTS ON THE USE OF THE E8760 ALLOCATOR?

A. Yes. Ms. Maini indicates that use of the E8760 allocator should be adopted.[18] Dr. Dismukes does not recommend a change in this case, but indicates different approaches may be appropriate in future cases.[19]

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[15] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, p. 22 (Jan. 1992).
[16] Ice Direct, p. 5-6.
[17] Ice Direct, p. 5.
[18] Maini Direct, p. 18.
[19] Dismukes Direct, p. 18.

Q. DO YOU CONTINUE TO SUPPORT USE OF THE E8760 ALLOCATOR?

A. Yes. While we acknowledge that development of the E8760 allocator is more data intensive,[20] it is ultimately a better reflection of cost-causation because it incorporates not only the differences in class usage throughout the day and year but also the actual costs when that usage occurs.[21]

3. Allocation of Transmission Expense [Staff-Dismukes]

Q. HOW DOES OTP ALLOCATE TRANSMISSION PLANT COSTS IN ITS CCOSS?

A. OTP allocates its transmission plant with the D2, demand-related allocation factor.

Q. HAS OTP CONSISTELY USED THIS FACTOR IN ITS CCOSS IN NORTH DAKOTA?

A. Yes. We have used the D2 factor to allocate transmission plant since at least 1982.

Q. DOES OTP USE THE SAME ALLOCATOR IN ITS CCOSS FILED IN SOUTH DAKOTA AND MINNESOTA?

A. Yes. OTP has consistently utilized the D2 factor in CCOSSs prepared for rate cases in North Dakota, South Dakota and Minnesota.

Q. DID PARTIES MAKE ANY RECOMMENDATIONS REGARDING THE ALLOCATION OF TRANSMISSION PLANT?

A. Yes. While Dr. Dismukes recommends that the Commission accept the Company's proposed jurisdictional allocations,[22] he recommends that OTP should use the 12 coincident peak (CP) methodology to allocate transmission plant costs in the CCOSS.[23]

[20] Dismukes Direct, p. 17-18.
[21] Ice Direct, p. 5; Maini Direct, p. 19.
[22] Dismukes Direct, p. 12.
[23] Dismukes Direct, p. 20-21.

Q. WHAT IS THE FIRST REASON GIVEN BY DR. DISMUKES SUPPORTING HIS RECOMMENDATION?

A. Dr. Dismukes contends that the Federal Energy Regulatory Commission (FERC) allocates transmission costs based on 12CP.[24]

Q. DOES FERC ALLOCATE COSTS TO CUSTOMER CLASSES?

A. No. The allocation referred to by Dr. Dismukes is the process by which FERC allocates *some* transmission costs among users of the transmission system, including OTP's retail customers. It is not an allocation of retail costs to customer classes, which is what happens in a CCOSS.

Q. IS 12CP THE ONLY METHOD USED BY FERC TO ALLOCATE TRANSMISSION COSTS?

A. No. FERC Order No. 888, which was cited by Dr. Dismukes in his Direct Testimony, includes the following passage:

> We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning. Moreover, we recognize that alternative allocation proposals may have merit and welcome their submittal by utilities in future rate applications. They will be evaluated on a case-by-case basis and decided on their merits.[25]

Midcontinent Independent System Operator (MISO) has been authorized to allocate the costs of Multi Value Projects (MVPs) to users of the transmission system based on total (MWh) usage, not on a coincident peak basis.[26]

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[24] Dismukes Direct, p. 19-21.

[25] *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities,* 75 FERC 61,080, FERC Order No. 888, p. 296-97 (Apr. 24, 1996).

[26] *Midwest Independent Transmission System Operator, Inc.*, 133 FERC 61,221, Order Conditionally Accepting Tariff Revisions (Dec. 16, 2010).

Q. PLEASE DESCRIBE THE PROCESS OF ALLOCATING TRANSMISSION COSTS TO CUSTOMER CLASSES.

A. The first step is the appropriate allocation of transmission costs to OTP's retail customers and to other users of the transmission system. This is done by FERC. The Jurisdictional Cost of Service Study (JCOSS) reflects FERC's determinations by directly assigning certain transmission costs to the FERC / wholesale jurisdiction. The remaining portion that is the responsibility of OTP's retail customers is then allocated across the North Dakota, South Dakota and Minnesota retail jurisdictions based on a D2 allocator. Finally, the costs that are allocated to the North Dakota retail jurisdiction are allocated to customer classes also based on a D2 allocator.

Q. IS OTP USING THE D2 ALLOCATOR TO ALLOCATE WHOLESALE TRANSMISSION COSTS TO NORTH DAKOTA RETAIL CUSTOMERS?

A. No. As discussed above, FERC decides what transmission expenses are the responsibility of OTP's retail customers and what expenses are the responsibility of other users of the transmission system. The D2 allocator is used to divide the portion of transmission expense FERC decides is the responsibility of OTP's retail customers among the North Dakota, South Dakota and Minnesota jurisdictions.

Q. DOES THE D2 ALLOCATOR REFLECT COST CAUSATION?

A. Yes. Because the D2 factor is based on the system's average annual transmission peak, the transmission system is able to meet its demand not only during peak times but can also meet its demand during at other times.

Q. DOES OTP AGREE WITH DR. DISMUKES RECOMMENDATION?

A. No. Neither FERC's allocation of transmission costs nor his assertions regarding planning support a change in allocator.

4. Classification of Distribution System [Staff-Dismukes]

Q. HOW DID OTP CLASSIFY THE DISTRIBUTION SYSTEM IN ITS CCOSS?

A. The classification process is described in OTP's Cost Allocation Procedure Manual.[27] OTP separates the distribution system into demand-related and customer-related components using the minimum size method, sometimes also called the minimum system method.

Q. HAS OTP CONSISTENTLY USED THE MINIMUM SYSTEM METHOD TO CLASSIFY DISTRIBUTION COSTS IN THE CCOSS?

A. Yes. It is my understanding that OTP has used this method to classify distribution costs in each of its rate cases going back to at least 1982.

Q. IS IT YOUR UNDERSTANDING THAT ALL NORTH DAKOTA INVESTOR-OWNED UTILITIES CLASSIFY DISTRIBUTION COSTS IN THIS MANNER?

A. Yes. According to Staff testimony in Case No. PU-17-295, North Dakota electric and natural gas investor owned utilities have consistently used the minimum system approach to classify distribution costs.[28]

Q. ARE THERE OTHER METHODS FOR CLASSIFYING DISTRIBUTION COSTS?

A. Yes. The NARUC Electric Utility Cost Allocation Manual only recognizes two methods for classifying the electric distribution system: the minimum system method and the zero-intercept method.[29] Both separate the system into customer-related and demand-related costs.

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[27] Ice Direct Exhibit__GSI-1, Schedule 2, p. 17.

[28] Case No. PU-17-295, Direct Testimony of Sara Cardwell, p. 3-4 (Dec. 18, 2017).

[29] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, p. 90 (Jan. 1992) ("Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.").

Q. DOES DR. DISMUKES RECOMMEND THE USE OF EITHER OF THESE METHODS?

A. No. Despite characterizing the NARUC Electric Utility Cost Allocation Manual as being an "authoritative source,"[30] Dr. Dismukes recommends neither the minimum system method nor the zero-intercept method. Rather, Dr. Dismukes recommends that all distribution costs except for services be classified as demand-related; he recommends services be classified as customer-related.[31]

Q. IS DR. DISMUKES'S RECOMMENDATION CONSISTENT WITH THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL?

A. No. The NARUC Electric Utility Cost Allocation Manual clearly states "[t]o ensure that [distribution] costs are property allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both."[32] The NARUC Electric Utility Cost Allocation Manual goes on to say "Distribution plant Accounts 364 through 370 involve demand and customer costs."[33] In recommending that Accounts 364 through 367 be classified as entirely demand-related, Dr. Dismukes asks the Commission to deviate from the NARUC Electric Utility Cost Allocation Manual.

Q. HAS STAFF PREVIOUSLY RECOGNIZED THE IMPORTANCE OF CLASSIFYING DISTRIBUTION COSTS INTO CUSTOMER-RELATED AND DEMAND-RELATED COMPONENTS?

A. Yes. In Case No. PU-17-295, Staff provided the following testimony:

> The investor owned utilities serving customers in ND have consistently used the minimum system approach to allocate distribution costs to customers for both electric and natural gas service. The concept behind the minimum system approach is that there is a "minimum" size pipe or wire that the Company would install to serve customers regardless of usage. Therefore, this

[30] Dismukes Direct, p. 28.
[31] Dismukes Direct, p. 34.
[32] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, p. 89 (Jan. 1992).
[33] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, p. 90 (Jan. 1992).

> minimum size should be considered a customer cost meaning that customers should pay for some part of the system regardless of whether they are taking any gas or electricity from the system. Without this approach, customers who don't use the system consistently only pay based on usage and no recognition is given to the fact that the system has to be in place to serve the customer regardless of when they use it. Most utilities and commissions believe it is fair to recognize that the system exists, regardless of when and how much the customer chooses to use it and provide a signal of these fixed costs to customers. There are many examples of products that we purchase where we incur costs regardless of how much we use the product. Consider your car. You have to pay for insurance and a place to keep your car regardless of how much you use that car. The minimum system is based on the same concept. There should be some fixed cost assessed, regardless of how much you use the product.[34]

Q. WHAT DO YOU CONCLUDE REGARDING DR. DISMUKES RECOMMENDATION REGARDING CLASSIFICATION OF DISTRIBUTION COSTS?

A. Dr. Dismukes's recommendation is inconsistent with common regulatory practice in North Dakota and national practice, as reflected in the NARUC Electric Utility Cost Allocation Manual. The Commission should not follow his recommendation.

5. Minimum System Study [Staff-Dismukes]

Q. PLEASE DESCRIBE DR. DISMUKES'S ISSUES WITH OTP'S MINIMUM SYSTEM STUDY.

A. Dr. Dismukes identifies three issues with OTP's minimum system study: 1) adjustment for the load-carrying capabilities of the minimum system; 2) cost of the minimum system and 3) minimum sized equipment in the minimum system study.[35]

[34] Case No. PU-17-295, Direct Testimony of Sara Cardwell, p. 3-4 (Dec. 18, 2017).
[35] Dismukes Direct, p. 28-31.

Q. DID OTP ACCOUNT FOR THE LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM?

A. Yes, and Dr. Dismukes acknowledged this.[36]

Q. HOW DID OTP ACCOUNT FOR THE LOAD-CARRYING CAPABILITY OF THE MINIMUM SYSTEM?

A. As explained in ND-PSC-13.06 part a and ND-PSC-13.07 part a, included as Exhibit___(GSI-3), Schedule 2 and Schedule 3, OTP adjusted the D3 and D4 allocation factors downward to reflect the load carrying capability of the minimum system. Dr. Dismukes acknowledges that this adjustment is consistent with the NARUC Electric Utility Cost Allocation Manual.[37]

Q. HAS OTP MADE SIMILAR ADJUSTMENTS IN PRIOR CCOSSS?

A. Yes. We have made similar adjustments to reflect the load carrying capability of the minimum system in our CCOSSs filed with the Commission since at least 1982.

Q. WHAT WAS THE LOAD CARRYING CAPABILITY OF THE MINIMUM SYSTEM AT PRIMARY VOLTAGE IN THE MINIMUM SYSTEM STUDY?

A. The minimum system is assumed to have a load carrying capability of 1.5 kW per customer at the primary voltage.

Q. IS THIS CONSISTENT WITH THE ASSUMPTIONS OF OTHER UTILITIES?

A. Yes. NSP also assumes its minimum system had a load carrying capability of 1.5 kW per customer.[38]

[36] Dismukes Direct, p. 29.
[37] Dismukes Direct, p. 28-29.
[38] Minnesota PUC Docket No. E002-GR/15-826, Bloch Direct, p. 91-92.

Q. HOW DID OTP ESTABLISH THE MINIMUM SIZED EQUIPMENT IN THE MINIMUM SYSTEM STUDY?

A. OTP's distribution engineering department determined the minimum sized equipment for each FERC account in the minimum system analysis, choosing the smallest sized equipment for each account that could get service to a residential customer. The minimum sized equipment is chosen based on OTP's current material standards, which have been developed and designed to comply with the National Electric Safety Code (NESC) and North Dakota Century Code 69-09-02-35.

Q. IS THIS APPROACH CONSISTENT WITH THE NARUC ELECTRIC COST ALLOCATION MANUAL?

A. Yes. The NARUC Electric Cost Allocation Manual states: "the minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility."[39]

Q. WHAT IS THE MINIMUM SIZED EQUIPMENT IN THE MINIMUM SYSTEM STUDY?

A. The minimum system study is based on the following minimum sized equipment:

Overhead System

- Pole: Thirty-five-foot class five Southern Yellow Poles - 35C5
- Primary Conductor: 1/0 aluminum conductor steel reinforced – 1/0- ACSR, 10R
- Primary Insulation: 15 kilovolt rated pin type and suspension insulators for support
- Secondary and Service Conductor: #2 triplex, 600 volt conductor - 2TX
- Transformers: 10 kilo-volt ampere 10 kVA

Underground System

- Primary Conductor: 1/0 solid aluminum, 220 mil cross linked polyethylene insulated, copper concentric, jacketed 15 kV rated cable - 10J15

[39] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, p. 90 (Jan. 1992).

- Terminations: Either 15 kV polymer terminators or 15 kV, 200 amp, load-break elbows
- Transformers: 25 kVA pad-mounted transformers
- Secondary and Service Conductor: 1/0 triplex conductor.

Q. PLEASE DISCUSS HOW OTP DEVELOPED THE COSTS OF THE MINIMUM SIZED EQUIPMENT IN THE MINIMUM SYSTEM ANALYSIS.

A. OTP used its work order estimating system, which is the same system used for estimating costs for all OTP distribution construction projects. The work order estimating system uses current labor, material and other costs in producing project estimates.

The cost of the overhead and underground minimum system was estimated in two parts due to the configuration of the work order estimating system. The first step estimated the primary and secondary system and broke the costs down into the different FERC accounts. Following this, the services were estimated. Once the costs and accounts were determined, the combined system was assembled for use in the minimum system study.

The accounting area provided the historical asset attributes by year, costs and counts of installed equipment. The average age was determined based on the median year of OTP's installed equipment by FERC account. OTP used the Handy Whitman Index, which calculates the construction cost trends across different types of utilities, to trend the current costs to the average age year costs. This trending is an industry accepted practice for reproducing costs at a certain date. The trended values were then used to calculate the customer components and the demand components for both the primary and secondary systems.

Q. ARE THE HYPOTHETICAL WORK ORDERS BUILT FROM THE SAME DATA OTP USES TO PERFORM ACTUAL INSTALLATIONS ON THE SYSTEM?

A. Yes. The hypothetical work orders are built using the same systems we use to price out actual jobs. All of the information is pulled based on our current inventory stocks and prices.

Q. DOES THIS MEAN THE HYPOTHETICAL WORK ORDERS PROVIDE A REASONABLE ESTIMATE OF ACTUAL UNIT COSTS OF THE MINIMUM SIZED EQUIPMENT?

A. Yes. The minimum sized equipment is priced the same as other equipment installed on the system. Our method therefore results in a reasonable estimate of the actual unit costs of the minimum sized equipment.

Q. WHAT DO YOU CONCLUDE REGARDING OTP'S MINIMUM SYSTEM STUDY?

A. OTP's minimum system study was prepared consistent with prior studies performed in North Dakota and other states. It was prepared consistent with the NARUC Electric Cost Allocation Manual and is based on actual data used by OTP to operate its business. Dr. Dismukes's criticisms should be given no weight in this case.

6. Model Improvements [MLEC-Maini; MLEC-Schedin]

a) Single-Phase and 3-Phase Distribution [MLEC-Maini; MLEC-Schedin]

Q. DOES OTP TRACK THE EMBEDDED COST OF SINGLE-PHASE AND THREE-PHASE CIRCUITS IN THE PRIMARY DISTRIBUTION SYSTEM?

A. No. As explained in OTP's response to ND-MLEC-210,[40] OTP does not track the embedded costs of single-phase and three-phase distribution.

Q. PLEASE EXPLAIN WHY OTP DOES NOT SEPARATE EMBEDDED COSTS OF SINGLE-PHASE AND THREE-PHASE DISTRIBUTION.

A. As explained in OTP's response to ND-MLEC-131,[41] OTP does not have the system data available to determine the embedded amount of primary distribution system costs associated with single-phase and three-phase circuits.

[40] Included as Attachment 12 to Schedin Direct.
[41] Included as Attachment 8 to Maini Direct.

Q. DID MLEC REQUEST THAT OTP BE REQUIRED TO SEPARATE OUT THE SINGLE-PHASE AND THREE-PHASE RELATED CIRCUIT COSTS IN ITS NEXT RATE CASE?

A. Yes.[42]

Q. WHAT WOULD OTP NEED TO DO IN ORDER TO FULFILL MLEC'S REQUEST?

A. Based on discussions with our accounting department, it is my understanding that there are two general approaches to meeting MLEC's request. One option would be to perform a physical inventory of our entire system to categorize circuits as single-phase or three-phase. This would also involve changes to our accounting system. The overall cost of pursuing this approach could be between $500,000 - $1,000,000 (OTP Total).

Alternatively, we could examine data in our GIS system to see if that will allow us to identify the percentage of single-phase and three-phase circuits currently installed on our system. We would then apply those percentages to the accounting data to develop the costs of single-phase and three-phase circuits. This would cost significantly less than a full inventory, but would result in a split based on sampling, not physical inventory.

Q. HOW DOES OTP PROPOSE TO ADDRESS MLEC'S REQUEST IN ITS NEXT RATE CASE?

A. We propose to examine our GIS system to categorize circuits as single-phase or three-phase and then apply the percentages from that analysis to our cost data.

b) Intra-Class Embedded Costs [MLEC-Maini]

Q. HOW DOES OTP PROVIDE ITS EMBEDDED COST INFORMATION?

A. OTP provides its CCOSS broken out into 10 different customer classes. Each of these customer classes is made up of several rate groups (sub-class).

[42] Maini Direct, p. 21; Schedin Direct, p. 9.

Q. IS THIS MORE GRANULAR THAN DATA PROVIDED BY OTHER UTILITIES?

A. Yes. NSP, for example, aggregates its customers into four customer classes.[43] OTP's 10 customer-class CCOSS is comparable in detail to the CCOSS filed by Montana-Dakota Utilities (MDU).[44]

Q. DID MLEC REQUEST THAT OTP BE REQUIRED TO PROVIDE EMBEDDED COST INFORMATION BY SUB-CLASS IN ITS NEXT RATE CASE?

A. Yes.[45]

Q. IS OTP ABLE TO PROVIDE EMBEDDED COST INFORMATION BY SUB-CLASS?

A. No, it is not feasible at this time. OTP has 40 different rate groups that make up the 10 customer classes. Allocators would need to be developed for each of these rate groups to identify the embedded costs by sub-class. The CCOSS would also need to be reworked; both of these would require a substantial amount of time and effort.

c) FERC-Account Level of Detail [Staff-Dismukes]

Q. HOW DOES OTP FUNCTIONALIZE COSTS?

A. OTP functionalizes costs using FERC accounts. This process is shown in Volume 4A, Part A, Tab 3 (Functionalization). The functionalized costs are then fed into the CCOSS spreadsheet. Because the costs are already functionalized, several FERC accounts are aggregated into the different CCOSS output line items.

Q. IS IT COMMON PRACTICE TO AGGREGATE FUNCTIONALIZED COSTS INTO THE DIFFERENT CCOSS OUTPUT LINE ITEMS?

A. Yes. OTP uses the same CCOSS model across all of its jurisdictions. This approach has been a feature of OTP's CCOSS model since at least 1982. I also note that NSP and MDU aggregate functionalized costs into the different CCOSS output line items.[46]

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[43] Case No. PU-12-813, Peppin Direct, p. 5.
[44] Case No. PU-16-666, Chapman Direct, p. 8.
[45] Maini Direct, p. 25.
[46] Case No. PU-12-813, Direct Testimony of Michael A. Peppin, Schedule 4; Case No. PU-16-666, Statement M.

Q. DOES OTP'S CCOSS MODEL INDICATE WHICH FERC ACCOUNTS ARE INCLUDED IN THE DIFFERENT CCOSS LINE ITEMS?

A. Yes. While the printed version included in Volume 3, Tab E did not identify the FERC accounts aggregated into the different CCOSS line items, the live version of the CCOSS model provided to parties included the notations.[47]

Q. DID OTP PREPARE DISCOVERY RESPONSES THAT PROVIDED DETAILED CLASSIFICATION AND ALLOCATION INFORMATION BY FERC ACCOUNT?

A. Yes. OTP's Response to ND-PSC-13.04 provided detailed classification and allocation information by FERC account. This response is included as Exhibit__(GSI-3), Schedule 4.

Q. DID DR. DISMUKES UTILIZE THESE RESPONSES IN PREPARING HIS TESTIMONY?

A. Yes. Exhibit DED-3 identifies ND-PSC-13.04 as being a source for the results of his alternative CCOSS.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO CONTINUE PROVIDING CLASSIFICATION AND ALLOCATION INFORMATION BY FERC ACCOUNT THROUGH DATA REQUESTS?

A. Yes. Dis-aggregating the CCOSS line items is a manual, time-intensive process. While we will continue providing the information in response to data requests, requiring OTP to include FERC account-level detail in its CCOSS[48] will significantly complicate the initial filing process and would require a re-build of the entire CCOSS model at significant expense. We believe the existing approach of providing the information through data requests is working and should continue.

[47] Company's response to ND-PSC-04.23
[48] Dismukes Direct, p. 36.

Q. WHAT IS THE ESTIMATED COST IT WOULD TAKE FOR OTP TO PROVIDE INTRA-CLASS EMBEDDED COSTS AND FERC ACCOUNT LEVEL OF DETAIL INTO ITS COSS?

A. Given the substantial amount of time and effort it would take to perform these projects, OTP estimates it would cost at least $50,000 (OTP Total). The process OTP currently has in place for providing FERC account level of detail as well as the inclusion of the 10 customer classes is reasonable and appropriate and the parties' recommendations should be disregarded.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. OTP's proposed revenue allocation is the most reasonable approach in the record. Dr. Dismukes's recommended revenue allocation fails to follow his own stated methodology, while Ms. Maini's allocation, while cost-based, may not adequately reflect principles of gradualism and moderation.

OTP's CCOSS was prepared using the same basic principles and methodology as was used in OTP's last North Dakota rate case and previous North Dakota rate cases – at least as far back as 1982. Dr. Dismukes's observations regarding the CCOSS are not consistent with North Dakota or national practice. His recommendations should not be adopted.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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

ATTN: Matthew J. Olsen, Manager,
Regulatory Proceedings and Compliance
215 South Cascade Street
PO Box 496
Fergus Falls MN 56538-0496
molsen@otpco.com

Requested From: North Dakota Public Service Commission
Requested By: Matthew J. Olsen, Manager, Regulatory Proceedings and Compliance - 218-739-8657
Date of Request: 05/23/2018
Response Due Date: 06/07/2018

If you feel your responses are trade secret or privileged, please indicate this on your response.

OTP Information Request No.: ND-OTP-106

Please refer to the Direct Testimony and schedules of Dr. David E. Dismukes. Please prepare a version of DED-7 that assigns a 1.25 times the system average increase to the Residential class in addition to all other under-earning classes identified in DED-2, DED-3 and DED-7 under the alternative CCOSS. Please provide this version of DED-7 in live, Microsoft excel version of DED-7, with all formulas and links intact.

RESPONSE:

Dr. Dismukes has performed the requested analysis which is provided in the attached excel file Attachment ND-OTP-106 Alternative Revenue Distribution-1.25 Residential.xlsx. However, Dr. Dismukes does not recommend that the Residential class receive an increase equal to 1.25 times the system average increase as this will result in the Residential class earning a return above the Company's requested overall system return of 7.97 percent. Dr. Dismukes's recommended revenue distribution using the results of his Alternative CCOSS as filed in his Direct Testimony gradually moves each rate class closer to the requested overall system return and a relative rate of return ("RROR") of 1.00.

Response by Dr. David E. Dismukes
Title _____
Department _____
Telephone _____
Date of Response _____

Exhibit DED-7 : Alternative Revenue Distribution

	Total North Dakota Distribution	Residential	Farms	General Service	Large General Service
Cost of Service Study Results					
Operating Income	$ 18,454,393	$ 5,466,673	$ 125,356	$ 7,005,534	$ 7,021,249
Rate Base	$ 354,191,795	$ 111,241,451	$ 8,727,736	$ 86,382,257	$ 97,253,281
ROR	5.21%	4.91%	1.44%	8.11%	7.22%
Unitized ROR	1.00	0.94	0.28	1.56	1.39
Rate Schedule Specific Revenue Increase Allocation					
Revenue Requirement	$ 15,715,320				
Operating Income Deficiency	$ 9,774,693				
ROR	7.97%				
Proposed Revenue Allocation					
Operating Income at Fully Equalized (7.97%)	$ 28,229,086	$ 8,865,944	$ 695,601	$ 6,884,666	$ 7,751,087
Operating Income Increase at RROR	$ 9,774,693	$ 3,399,271	$ 570,245	$ (120,868)	$ 729,838
Revenue Conversion Factor	1.6078	1.6078	1.6078	1.6078	1.6078
Incremental Revenue Requirement at Proposed ROR	15,715,320	5,465,198	916,814	(194,326)	1,173,401
Percent Increase at Proposed ROR	10.62%	11.34%	35.09%	-0.50%	2.72%
Relative Revenue Increase	1.00	1.07	3.30	(0.05)	0.26
Step One Increase					
Maximum Increase at 1.25 times System Average Increase	13.27%	13.27%	13.27%	0.00%	0.00%
Step One Revenue Increase	8,745,103	6,399,143	346,795	-	-
Remaining Revenue Deficiency	6,970,217				
Step Two Increase					
Basis to Allocate Step Two Increase	82,111,325	-	-	38,950,615	43,160,710
Allocation of Shortfall to Remaining Customer Classes	6,970,217	-	-	3,306,416	3,663,800
Total Required Increase	15,715,320	6,399,143	346,795	3,306,416	3,663,800
Rate Schedule Specific Revenue Increase Allocation					
Annualized Current Base Rate Revenue[1]	$ 147,995,250	$ 48,209,916	$ 2,612,687	$ 38,950,615	$ 43,160,710
Revenue Change ($)	$ 15,715,320	$ 6,399,143	$ 346,795	$ 3,306,416	$ 3,663,800
Proposed Revenue	$ 163,710,570	$ 54,609,059	$ 2,959,482	$ 42,257,031	$ 46,824,510
Revenue Change based on Annualized Current Revenue (%)	10.62%	13.27%	13.27%	8.49%	8.49%
Rate Change as a Percentage of Overall Base Rate Revenue Change		1.25	1.25	0.80	0.80

Source: Alternative CCOSS; and Company's workpaper 43 Vol 2b Schedule 3 (E Schedules) NOT PUBLIC, Schedule E-2.

Witness: Dismukes
Case No. PU-17-398
Exhibit DED-7

	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptible	Controlled Service Deferred
Cost of Service Study Results						
Operating Income	$ (20,631)	$ 308,283	$ 84,350	$ (156,724)	$ (1,443,341)	$ 63,645
Rate Base	$ 380,503	$ 7,658,705	$ 3,072,368	$ 4,586,888	$ 30,904,119	$ 3,984,485
ROR	-5.42%	4.03%	2.75%	-3.42%	-4.67%	1.60%
Unitized ROR	-1.04	0.77	0.53	-0.66	-0.90	0.31
Rate Schedule Specific Revenue Increase Allocation						
Revenue Requirement						
Operating Income Deficiency						
ROR						
Proposed Revenue Allocation						
Operating Income at Fully Equalized (7.97%)	$ 30,326	$ 610,399	$ 244,868	$ 365,575	$ 2,463,058	$ 317,563
Operating Income Increase at RROR	$ 50,957	$ 302,116	$ 160,517	$ 522,299	$ 3,906,399	$ 253,919
Revenue Conversion Factor	1.6078	1.6078	1.6078	1.6078	1.6078	1.6078
Incremental Revenue Requirement at Proposed ROR	81,927	485,729	258,073	839,729	6,280,536	408,240
Percent Increase at Proposed ROR	138.67%	16.93%	21.43%	77.39%	75.00%	27.77%
Relative Revenue Increase	13.06	1.59	2.02	7.29	7.06	2.62
Step One Increase						
Maximum Increase at 1.25 times System Average Increase	13.27%	13.27%	13.27%	13.27%	13.27%	13.27%
Step One Revenue Increase	7,842	380,836	159,811	144,022	1,111,548	195,106
Remaining Revenue Deficiency						
Step Two Increase						
Basis to Allocate Step Two Increase	-	-	-	-	-	-
Allocation of Shortfall to Remaining Customer Classes	-	-	-	-	-	-
Total Required Increase	7,842	380,836	159,811	144,022	1,111,548	195,106
Rate Schedule Specific Revenue Increase Allocation						
Annualized Current Base Rate Revenue[1]	$ 59,081	$ 2,869,142	$ 1,203,986	$ 1,085,033	$ 8,374,186	$ 1,469,894
Revenue Change ($)	$ 7,842	$ 380,836	$ 159,811	$ 144,022	$ 1,111,548	$ 195,106
Proposed Revenue	$ 66,923	$ 3,249,978	$ 1,363,797	$ 1,229,055	$ 9,485,734	$ 1,665,000
Revenue Change based on Annualized Current Revenue (%)	13.27%	13.27%	13.27%	13.27%	13.27%	13.27%
Rate Change as a Percentage of Overall Base Rate Revenue Change	1.25	1.25	1.25	1.25	1.25	1.25

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/13/2018
Date Due: 04/27/2018
Date of Response: 05/07/2018
Responding Witness: Gina Ice, Rate Analyst

Data Request:

Please refer to the Company's Cost Allocation Manual provided as Schedule 2 to the Direct Testimony of Gina Ice where it states "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."

a. Please explain how the Company determined that 0.83 kW/customer was the appropriate adjustment to make the primary demand factor.

b. Please provide all workpapers and source documents which provide the calculation of the 0.83 kW/customer and the calculation of the D3 factor including this adjustment to the D3 factor in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 0

Response:

a. The customer component of primary distribution costs can supply approximately 1.5 kW of demand per location. Because the demand component of the minimum system constitutes only 55% of the total primary demand costs (the other 45% is directly assigned substation costs), the 1.5 kW must be reduced to 55% or 0.83 kW/customer. This 0.83 kW/customer must be subtracted when calculating the D3 allocation factor so that customers are not charged twice for this cost. This amount of kW per customer has been included and approved over the last several OTP rate cases in North Dakota, Minnesota, and South Dakota.

b. Attachment 1 of DR ND-PSC-04.25 includes the historical C, D, and E factor spreadsheet which includes D3.

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/13/2018
Date Due: 04/27/2018
Date of Response: 05/04/2018
Responding Witness: Gina Ice, Rate Analyst

Data Request:

Please refer to the Company's Cost Allocation Manual provided as Schedule 2 to the Direct Testimony of Gina Ice where it states "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."

a. Please explain how the Company determined that 3.0 kW/customer was the appropriate adjustment to make the secondary demand factor.

b. Please provide all workpapers and source documents which provide the calculation of the 3.0 kW/customer and the calculation of the D4 factor including this adjustment to the D4 factor in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 0

Response:

a. The customer component of secondary distribution costs can supply approximately 3.0 kW of demand per location and accounts for 100% of the total secondary demand costs. This 3.0 kW/customer must be subtracted when calculating the D4 allocation factor. The 3.0 kW/customer has been included and approved over the last several OTP rate cases in North Dakota, Minnesota and South Dakota.

b. Attachment 1 of DR ND-PSC-04.25 includes the historical C, D, and E factor spreadsheet which includes D4.

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

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/13/2018
Date Due: 04/27/2018
Date of Response: 04/27/2018
Responding Witness: Gina Ice, Rate Analyst

Data Request:

For the purpose of this request please refer to the Company's CCOSS provided in response to ND-PSC-04.23.

a. Please provide a breakout of the total costs and costs allocated to each North Dakota rate class for each FERC account rather than the aggregated amounts reflected in row 164 through row 206 for the Company's North Dakota portion of Production Plant, Transmission Plant, and Distribution Plant.

b. For each FERC account line item identified in (a) please provide the associated allocation factor used to allocate each of the plant costs at the FERC account level.

c. To the extent the Company cannot provide the level of detail requested in (a) please provide at a minimum a breakout of the total costs and costs allocated to each North Dakota rate case and the associated allocation factor for the following distribution plant accounts:

    i. 360 Land & Land Rights;

    ii. 361 Structures and Improvements (to the extent applicable);

    iii. 362 Station Equipment;

    iv. 364 Pole Towers and Fixtures broken down between primary and secondary demand levels as well as a break out, separately, the portion of this account allocated to area lighting and street lighting;

    v. 365 Overhead Conductors and Devices broken down between primary and secondary demand levels as well as a break out, separately, of the portion of this account allocated to area lighting and street lighting;

    vi. 366 Underground Conduit broken down between primary and secondary demand levels;

vii. 367 Underground Conductors and Devices broken down between primary and secondary demand levels as well as a break out, separately, of the portion of this account allocated to area lighting and street lighting;

viii. 368 Line Transformers;

ix. 369 Services;

x. 370.1 and 370.2 Meter Accounts.

d. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 1

Attachment 1 to DR ND-PSC-13.04.xlsx

Response:

Please refer to Attachment 1 to ND-PSC-13.04 for the breakdown of the gross Production Plant, Transmission Plant, and Distribution Plant amounts included in the Company's Cost of Service Study for total Company, ND jurisdictional share, and the jurisdictional amounts allocated per rate class. Also included is the allocation factor used for each FERC account.

	Gross Plant											
	OTP-Total ($)	OTP-ND ($)	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptible	Controlled Service Deferred
Production Plant - A/C 101 & 106 - Direct MN	**Direct - MN**											
310 - Land and land rights.	$10,140	$0										
311 - Structures and improvements.	$764,632	$0										
312 - Boiler plant equipment.	$2,062,883	$0										
314 - Turbogenerator units.	$401,400	$0										
315 - Accessory electric equipment.	$223,429	$0										
316 - Miscellaneous power plant equipment	$40,748	$0										
317 - Asset retirement costs for steam production plant.	$16,787	$0										
Production Plant - A/C 101 & 106 - Direct MN	**$3,520,019**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Production Plant - A/C 101 & 106 - Direct ND	**P10**		30.891%	1.917%	26.102%	34.511%	0.011%	1.091%	1.013%	0.452%	3.176%	0.835%
310 - Land and land rights.	$1,359	$1,359	420	26	355	469	0	15	14	6	43	11
311 - Structures and improvements.	$102,437	$102,437	31,644	1,964	26,738	35,352	11	1,118	1,038	463	3,254	856
312 - Boiler plant equipment.	$276,363	$276,363	85,372	5,298	72,137	95,375	29	3,016	2,801	1,249	8,779	2,308
314 - Turbogenerator units.	$53,775	$53,775	16,612	1,031	14,037	18,558	6	587	545	243	1,708	449
315 - Accessory electric equipment.	$29,933	$29,933	9,247	574	7,813	10,330	3	327	303	135	951	250
316 - Miscellaneous power plant equipment	$5,459	$5,459	1,686	105	1,425	1,884	1	60	55	25	173	46
317 - Asset retirement costs for steam production plant.	$2,249	$2,249	695	43	587	776	0	25	23	10	71	19
Production Plant - A/C 101 & 106 - Direct ND	**$471,575**	**$471,575**	**$145,675**	**$9,041**	**$123,091**	**$162,745**	**$50**	**$5,146**	**$4,779**	**$2,131**	**$14,979**	**$3,939**
Production Plant - A/C 101 & 106 - Direct SD	**Direct - SD**											
310 - Land and land rights.	$3,302	$0										
311 - Structures and improvements.	$248,954	$0										
312 - Boiler plant equipment.	$671,648	$0										
314 - Turbogenerator units.	$130,691	$0										
315 - Accessory electric equipment.	$72,746	$0										
316 - Miscellaneous power plant equipment	$13,267	$0										
317 - Asset retirement costs for steam production plant.	$5,466	$0										
Production Plant - A/C 101 & 106 - Direct SD	**$1,146,073**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Production Plant - Base Demand	**E1**		29.8351%	1.9478%	26.6635%	38.1004%	0.0000%	1.1814%	1.0888%	0.4232%	0.0000%	0.7598%
302 - Franchises and consents.	$0	$0	-	-	-	-	-	-	-	-	-	-
310 - Land and land rights.	$1,349,421	$481,181	143,561	9,373	128,299	183,332	-	5,685	5,239	2,036	-	3,656
311 - Structures and improvements.	$101,752,632	$36,283,267	10,825,150	706,742	9,674,383	13,824,085	-	428,644	395,036	153,545	-	275,682
312 - Boiler plant equipment.	$274,516,161	$97,887,817	29,204,930	1,906,704	26,100,302	37,295,691	-	1,156,430	1,065,759	414,245	-	743,756
314 - Turbogenerator units.	$53,415,949	$19,047,223	5,682,759	371,011	5,078,653	7,257,076	-	225,021	207,378	80,605	-	144,722
315 - Accessory electric equipment.	$29,732,614	$10,602,147	3,163,161	206,513	2,826,902	4,039,465	-	125,252	115,431	44,867	-	80,556
316 - Miscellaneous power plant equipment	$5,422,454	$1,933,555	576,878	37,663	515,553	736,693	-	22,843	21,052	8,182	-	14,691
317 - Asset retirement costs for steam production plant.	$2,233,978	$796,599	237,666	15,517	212,401	303,508	-	9,411	8,673	3,371	-	6,053
330 - Land and land rights.	$245,445	$87,522	26,112	1,705	23,336	33,346	-	1,034	953	370	-	665
331 - Structures and improvements.	$288,114	$102,737	30,652	2,001	27,393	39,143	-	1,214	1,119	435	-	781
332 - Reservoirs, dams, and waterways.	$3,503,665	$1,249,348	372,744	24,335	333,120	476,007	-	14,760	13,602	5,287	-	9,493
333 - Water wheels, turbines and generators.	$1,318,755	$470,246	140,298	9,160	125,384	179,166	-	5,555	5,120	1,990	-	3,573
334 - Accessory electric equipment.	$489,133	$174,417	52,037	3,397	46,506	66,453	-	2,061	1,899	738	-	1,325
335 - Miscellaneous power plant equipment.	$362,587	$129,293	38,575	2,518	34,474	49,261	-	1,527	1,408	547	-	982
340 - Land and land rights.	$104,778	$37,362	11,147	728	9,962	14,235	-	441	407	158	-	284
341 - Structures and improvements.	$4,089,289	$1,458,171	435,047	28,403	388,799	555,570	-	17,227	15,876	6,171	-	11,079
342 - Fuel holders, producers, and accessories.	$1,445,072	$515,288	153,737	10,037	137,394	196,327	-	6,088	5,610	2,181	-	3,915
343 - Prime movers.	$26,726,423	$9,530,190	2,843,342	185,633	2,541,081	3,631,045	-	112,588	103,760	40,330	-	72,411
345 - Accessory electric equipment.	$1,597,986	$569,815	170,005	11,099	151,932	217,102	-	6,732	6,204	2,411	-	4,329
346 - Miscellaneous power plant equipment.	$794,006	$283,129	84,472	5,515	75,492	107,873	-	3,345	3,083	1,198	-	2,151
Production Plant - Base Demand	**$509,388,464**	**$181,639,306**	**$54,192,273**	**$3,538,054**	**$48,431,367**	**$69,205,378**	**$0**	**$2,145,855**	**$1,977,608**	**$768,668**	**$0**	**$1,380,103**

	Gross Plant											
	OTP-Total ($)	OTP-ND ($)	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptible	Controlled Service Deferred
Production Plant - Peak Demand	**D1**		36.835%	2.139%	28.608%	27.766%	0.000%	0.960%	0.921%	0.076%	2.446%	0.249%
302 - Franchises and consents.	$0	$0	-	-								
310 - Land and land rights.	$301,651	$120,179	44,268	2,570	34,381	33,369	-	1,154	1,107	92	2,939	299
311 - Structures and improvements.	$22,745,878	$9,062,061	3,338,019	193,795	2,592,467	2,516,171	-	87,011	83,480	6,908	221,642	22,566
312 - Boiler plant equipment.	$61,365,597	$24,448,331	9,005,567	522,835	6,994,160	6,788,322	-	234,746	225,220	18,637	597,963	60,881
314 - Turbogenerator units.	$11,940,651	$4,757,209	1,752,323	101,734	1,360,939	1,320,886	-	45,677	43,824	3,626	116,353	11,846
315 - Accessory electric equipment.	$6,646,456	$2,647,978	975,385	56,628	757,532	735,237	-	25,425	24,393	2,019	64,765	6,594
316 - Miscellaneous power plant equipment	$1,212,140	$482,922	177,885	10,327	138,154	134,088	-	4,637	4,449	368	11,811	1,203
317 - Asset retirement costs for steam production plant.	$499,386	$198,957	73,286	4,255	56,918	55,243	-	1,910	1,833	152	4,866	495
330 - Land and land rights.	$54,867	$21,859	8,052	467	6,253	6,069	-	210	201	17	535	54
331 - Structures and improvements.	$64,405	$25,659	9,452	549	7,341	7,125	-	246	236	20	628	64
332 - Reservoirs, dams, and waterways.	$783,212	$312,035	114,939	6,673	89,267	86,640	-	2,996	2,874	238	7,632	777
333 - Water wheels, turbines and generators.	$294,796	$117,448	43,262	2,512	33,599	32,611	-	1,128	1,082	90	2,873	292
334 - Accessory electric equipment.	$109,341	$43,562	16,046	932	12,462	12,095	-	418	401	33	1,065	108
335 - Miscellaneous power plant equipment.	$81,053	$32,292	11,895	691	9,238	8,966	-	310	297	25	790	80
340 - Land and land rights.	$23,422	$9,332	3,437	200	2,670	2,591	-	90	86	7	228	23
341 - Structures and improvements.	$2,757,973	$1,098,789	404,740	23,498	314,341	305,090	-	10,550	10,122	838	26,874	2,736
342 - Fuel holders, producers, and accessories.	$323,033	$128,698	47,406	2,752	36,818	35,734	-	1,236	1,186	98	3,148	320
343 - Prime movers.	$5,974,449	$2,380,248	876,767	50,902	680,939	660,899	-	22,854	21,927	1,814	58,217	5,927
344 - Generators.	$55,676,947	$22,181,947	8,170,742	474,368	6,345,794	6,159,038	-	212,984	204,342	16,909	542,532	55,238
345 - Accessory electric equipment.	$4,683,779	$1,866,039	687,357	39,906	533,835	518,124	-	17,917	17,190	1,422	45,640	4,647
346 - Miscellaneous power plant equipment.	$216,143	$86,112	31,720	1,842	24,635	23,910	-	827	793	66	2,106	214
347 - Asset retirement costs for other production plant.	$51,785	$20,631	7,600	441	5,902	5,728	-	198	190	16	505	51
Production Plant - Peak Demand	**$175,806,963**	**$70,042,290**	**$25,800,146**	**$1,497,875**	**$20,037,644**	**$19,447,939**	**$0**	**$672,525**	**$645,235**	**$53,394**	**$1,713,112**	**$174,420**
Production Plant - Base Energy	**E2**		28.002%	1.646%	22.528%	32.191%	0.045%	0.998%	0.920%	0.858%	11.272%	1.541%
341 - Structures and improvements.	$6,162,443	$2,315,682	648,441	38,110	521,675	745,440	1,038	23,114	21,302	19,870	261,013	35,679
344 - Generators.	$186,081,397	$69,924,443	19,580,348	1,150,784	15,752,507	22,509,341	31,347	697,954	643,239	599,996	7,881,566	1,077,360
345 - Accessory electric equipment.	$14,460,077	$5,433,713	1,521,556	89,426	1,224,101	1,749,164	2,436	54,237	49,985	46,625	612,463	83,720
346 - Miscellaneous power plant equipment.	$129,176	$48,541	13,592	799	10,935	15,626	22	485	447	417	5,471	748
347 - Asset retirement costs for other production plant.	$173,073	$65,036	18,212	1,070	14,651	20,936	29	649	598	558	7,331	1,002
Production Plant - Base Energy	**$207,006,166**	**$77,787,414**	**$21,782,149**	**$1,280,189**	**$17,523,870**	**$25,040,506**	**$34,871**	**$776,439**	**$715,571**	**$667,466**	**$8,767,845**	**$1,198,509**
Production Plant - A/C 114 - Base Demand	**E1**		29.8351%	1.9478%	26.6635%	38.1004%	0.0000%	1.1814%	1.0888%	0.4232%	0.0000%	0.7598%
310 - Land and land rights.	$4,875	$1,738	519	34	464	662	-	21	19	7	-	13
311 - Structures and improvements.	$246,485	$87,893	26,223	1,712	23,435	33,487	-	1,038	957	372	-	668
312 - Boiler plant equipment.	$745,751	$265,922	79,338	5,180	70,904	101,318	-	3,142	2,895	1,125	-	2,020
314 - Turbogenerator units.	$187,091	$66,714	19,904	1,299	17,788	25,418	-	788	726	282	-	507
315 - Accessory electric equipment.	$91,833	$32,746	9,770	638	8,731	12,476	-	387	357	139	-	249
316 - Miscellaneous power plant equipment	$22,045	$7,861	2,345	153	2,096	2,995	-	93	86	33	-	60
Production Plant - A/C 114 - Base Demand	**$1,298,082**	**$462,874**	**$138,099**	**$9,016**	**$123,418**	**$176,357**	**$0**	**$5,468**	**$5,040**	**$1,959**	**$0**	**$3,517**
Production Plant - A/C 114 - Peak Demand	**D1**		36.835%	2.139%	28.608%	27.766%	0.000%	0.960%	0.921%	0.076%	2.446%	0.249%
310 - Land and land rights.	$1,090	$434	160	9	124	121	-	4	4	0	11	1
311 - Structures and improvements.	$55,100	$21,952	8,086	469	6,280	6,095	-	211	202	17	537	55
312 - Boiler plant equipment.	$166,706	$66,416	24,465	1,420	19,000	18,441	-	638	612	51	1,624	165
314 - Turbogenerator units.	$41,823	$16,662	6,138	356	4,767	4,626	-	160	153	13	408	41
315 - Accessory electric equipment.	$20,529	$8,179	3,013	175	2,340	2,271	-	79	75	6	200	20
316 - Miscellaneous power plant equipment	$4,928	$1,963	723	42	562	545	-	19	18	1	48	5
Production Plant - A/C 114 - Peak Demand	**$290,174**	**$115,607**	**$42,584**	**$2,472**	**$33,073**	**$32,099**	**$0**	**$1,110**	**$1,065**	**$88**	**$2,828**	**$288**

	Gross Plant											
	OTP-Total ($)	OTP-ND ($)	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptible	Controlled Service Deferred
Transmission Plant A/C 101 & 106	**D2**		36.835%	2.139%	28.608%	27.766%	0.000%	0.960%	0.921%	0.076%	2.446%	0.249%
350 - Asset retirement costs for steam production plant.	$548,815	$163,926	60,382	3,506	46,896	45,516	-	1,574	1,510	125	4,009	408
3501 - Transmission Easements	$16,897,667	$5,047,195	1,859,139	107,936	1,443,898	1,401,404	-	48,462	46,495	3,848	123,446	12,569
353 - Station equipment.	$123,560,361	$36,906,468	13,594,533	789,256	10,558,174	10,247,448	-	354,365	339,985	28,134	902,668	91,905
354 - Towers and fixtures.	$98,257,770	$29,348,791	10,810,656	627,633	8,396,079	8,148,984	-	281,798	270,363	22,373	717,820	73,085
355 - Poles and fixtures.	$142,620,862	$42,599,683	15,691,635	911,007	12,186,884	11,828,226	-	409,029	392,432	32,474	1,041,914	106,082
356 - Overhead conductors and devices.	$132,945,486	$39,709,726	14,627,116	849,204	11,360,128	11,025,801	-	381,281	365,809	30,271	971,231	98,886
358 - Underground conductors and devices.	$93,942	$28,060	10,336	600	8,027	7,791	-	269	258	21	686	70
Transmission Plant A/C 101 & 106	**$514,924,904**	**$153,803,849**	**56,653,798**	**$3,289,142**	**$44,000,086**	**$42,705,169**	**$0**	**$1,476,779**	**$1,416,853**	**$117,246**	**$3,761,773**	**$383,004**
Transmission Plant A/C 114	**D2**		36.835%	2.139%	28.608%	27.766%	0.000%	0.960%	0.921%	0.076%	2.446%	0.249%
353 - Station equipment.	$21,646	$8,572	3,157	183	2,452	2,380	-	82	79	7	210	21
355 - Poles and fixtures.	$23,654	$9,367	3,450	200	2,680	2,601	-	90	86	7	229	23
356 - Overhead conductors and devices.	$12,988	$5,143	1,894	110	1,471	1,428	-	49	47	4	126	13
Transmission Plant A/C 114	**$58,288**	**$23,081**	**$8,502**	**$494**	**$6,603**	**$6,409**	**$0**	**$222**	**$213**	**$18**	**$565**	**$57**
Distribution Plant - Primary Demand	**D3**		23.086%	4.289%	21.674%	24.684%	0.353%	1.463%	0.713%	2.022%	19.523%	2.193%
360 - Land and land rights.	$1,306,580	$599,335	138,360	25,705	129,897	147,942	2,115	8,767	4,274	12,121	117,008	13,145
362 - Station equipment.	$99,087,798	$45,452,078	10,492,875	1,949,425	9,851,103	11,219,587	160,415	664,866	324,097	919,232	8,873,630	996,848
364 - Poles, towers and fixtures.	$46,185,447	$21,185,500	4,890,795	908,639	4,591,661	5,229,520	74,770	309,898	151,064	428,460	4,136,055	464,637
365 - Overhead conductors and devices	$24,148,420	$11,077,003	2,557,190	475,089	2,400,786	2,734,295	39,094	162,033	78,985	224,024	2,162,568	242,939
367 - Underground conductors and devices	$15,568,337	$7,141,275	1,648,605	306,287	1,547,772	1,762,783	25,204	104,461	50,921	144,427	1,394,194	156,621
Distribution Plant - Primary Demand	**$186,296,582**	**$85,455,191**	**$19,727,825**	**$3,665,146**	**$18,521,218**	**$21,094,127**	**$301,599**	**$1,250,025**	**$609,340**	**$1,728,263**	**$16,683,456**	**$1,874,191**
Distribution Plant - Secondary Demand	**D4**		27.421%	5.063%	23.026%	14.057%	0.404%	1.014%	0.917%	4.057%	21.642%	2.399%
365 - Overhead conductors and devices	$13,703,488	$6,580,535	1,804,476	333,159	1,515,257	925,041	26,615	66,730	60,314	266,945	1,424,164	157,835
367 - Underground conductors and devices	$4,114,300	$1,975,723	541,771	100,027	454,937	277,732	7,991	20,035	18,109	80,147	427,587	47,388
368 - Line transformers.	$61,425,536	$29,497,082	8,088,519	1,493,377	6,792,099	4,146,471	119,300	299,117	270,357	1,196,574	6,383,777	707,492
369 - Services.	$8,794,392	$4,223,144	1,158,046	213,809	972,436	593,657	17,080	42,825	38,707	171,315	913,976	101,293
369.1 - Underground Services	$13,986,727	$6,716,549	1,841,773	340,045	1,546,576	944,160	27,165	68,110	61,561	272,462	1,453,600	161,097
Distribution Plant - Secondary Demand	**$102,024,443**	**$48,993,034**	**$13,434,585**	**$2,480,418**	**$11,281,303**	**$6,887,061**	**$198,150**	**$496,817**	**$449,048**	**$1,987,443**	**$10,603,103**	**$1,175,105**
Distribution Plant - Primary Customer	**C2**		76.83%	1.82%	19.76%	0.29%	0.13%	0.16%	0.92%	0.02%	0.07%	0.01%
364 - Poles, towers and fixtures.	$20,660,285	$9,249,791	7,106,188	167,886	1,827,731	26,974	12,381	14,740	85,196	1,474	6,191	1,032
365 - Overhead conductors and devices	$6,659,166	$2,981,367	2,290,447	54,113	589,109	8,694	3,991	4,751	27,460	475	1,995	333
367 - Underground conductors and devices	$50,790,714	$22,739,450	17,469,669	412,726	4,493,246	66,312	30,438	36,236	209,443	3,624	15,219	2,537
Distribution Plant - Primary Customer	**$78,110,165**	**$34,970,609**	**$26,866,304**	**$634,725**	**$6,910,086**	**$101,979**	**$46,810**	**$55,727**	**$322,099**	**$5,573**	**$23,405**	**$3,901**
Distribution Plant - Secondary Customer	**C3**		76.84%	1.82%	19.76%	0.28%	0.13%	0.16%	0.92%	0.02%	0.07%	0.01%
365 - Overhead conductors and devices	$3,116,910	$1,395,869	1,072,655	25,342	275,756	3,849	1,869	2,225	12,860	222	934	156
367 - Underground conductors and devices	$4,780,398	$2,140,841	1,645,129	38,867	422,927	5,903	2,866	3,412	19,723	341	1,433	239
368 - Line transformers.	$34,757,505	$15,565,713	11,961,468	282,593	3,075,033	42,922	20,841	24,811	143,406	2,481	10,420	1,737
369 - Services.	$4,269,965	$1,912,250	1,469,468	34,717	377,768	5,273	2,560	3,048	17,617	305	1,280	213
369.1 - Underground Services	$27,355,239	$12,250,701	9,414,048	222,410	2,420,147	33,781	16,402	19,527	112,865	1,953	8,201	1,367
Distribution Plant - Secondary Customer	**$74,280,017**	**$33,265,375**	**$25,562,769**	**$603,928**	**$6,571,632**	**$91,729**	**$44,539**	**$53,023**	**$306,471**	**$5,302**	**$22,270**	**$3,712**
Distribution Plant - Streetlighting	**C4**		0.000%	0.000%	0.000%	0.000%	0.000%	100.000%	0.000%	0.000%	0.000%	0.000%
364 - Poles, towers and fixtures.	$3,583,311	$1,561,650	-	-	-	-	-	1,561,650	-	-	-	-
365 - Overhead conductors and devices	$2,258,834	$984,427	-	-	-	-	-	984,427	-	-	-	-
367 - Underground conductors and devices	$2,530,864	$1,102,981	-	-	-	-	-	1,102,981	-	-	-	-
373 - Street lighting and signal systems.	$5,580,148	$2,431,896	-	-	-	-	-	2,431,896	-	-	-	-
Distribution Plant - Streetlighting	**$13,953,157**	**$6,080,955**	**$0**	**$0**	**$0**	**$0**	**$0**	**$6,080,955**	**$0**	**$0**	**$0**	**$0**

	Gross Plant											
	OTP-Total ($)	OTP-ND ($)	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Water Heating	Controlled Service Interruptible	Controlled Service Deferred
Distribution Plant - Area Lighting	**C5**		0.000%	0.000%	0.000%	0.000%	0.000%	100.000%	0.000%	0.000%	0.000%	0.000%
364 - Poles, towers and fixtures.	$1,752,408	$907,097	-	-	-	-	-	907,097	-	-	-	-
365 - Overhead conductors and devices	$1,104,677	$571,813	-	-	-	-	-	571,813	-	-	-	-
367 - Underground conductors and devices	$281,207	$145,561	-	-	-	-	-	145,561	-	-	-	-
371.2 - All other Private Lighting	$4,882,393	$2,527,268	-	-	-	-	-	2,527,268	-	-	-	-
Distribution Plant - Area Lighting	**$8,020,685**	**$4,151,739**	**$0**	**$0**	**$0**	**$0**	**$0**	**$4,151,739**	**$0**	**$0**	**$0**	**$0**
Distribution Plant - Meters	**C6**		29.655%	2.318%	35.702%	2.414%	0.178%	0.167%	1.054%	10.430%	15.607%	2.475%
370 - Meters.	$26,594,087	$11,882,166	3,523,613	275,411	4,242,213	286,799	21,125	19,890	125,290	1,239,322	1,854,392	294,112
Distribution Plant - Meters	**$26,594,087**	**$11,882,166**	**$3,523,613**	**$275,411**	**$4,242,213**	**$286,799**	**$21,125**	**$19,890**	**$125,290**	**$1,239,322**	**$1,854,392**	**$294,112**
Distribution Plant - Load Management	**C9**		21.775%	0.027%	0.113%	0.005%	0.129%	0.000%	0.000%	30.697%	43.115%	4.139%
370.1 - Load Management Switches	$8,713,737	$3,794,879	826,329	1,019	4,278	204	4,890	-	-	1,164,928	1,636,156	157,076
Distribution Plant - Load Management	**$8,713,737**	**$3,794,879**	**$826,329**	**$1,019**	**$4,278**	**$204**	**$4,890**	**$0**	**$0**	**$1,164,928**	**$1,636,156**	**$157,076**