STATE OF NORTH DAKOTA

BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF OTTER TAIL POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC UTILITY SERVICE IN NORTH DAKOTA /	Case No. PU-23-342

AMENDED DIRECT TESTIMONY OF KARL R. PAVLOVIC (amendments highlighted)

Submitted on Behalf of the Advocacy Staff of the North Dakota Public Service Commission

June 6, 2024

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Prefiled Amended Direct Testimony of Karl R. Pavlovic and Exhibits
Public Service Commission Advocacy Staff
Mitch Armstrong, SAAG, Advocacy Counsel

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Karl Richard Pavlovic. My business address is 22 Brookes Avenue, Gaithersburg, MD 20877. I am a Senior Consultant with and the Managing Director of PCMG and Associates LLC.

Q. PLEASE DESCRIBE PCMG.

A. PCMG and Associates LLC (PCMG) is an association of experts in economics, accounting, finance, and utility regulation and policy, with over 75 years collective experience providing assistance to counsel and expert testimony regarding the regulation of electric, gas, water, and wastewater utilities. PCMG began operation on January 1, 2015. Most recently PCMG has provided assistance to counsel and/or testimony in regulatory proceedings before Federal Energy Regulatory Commission, the Pennsylvania Public Service Commission, the Arkansas Public service Commission, California Public Utilities Commission, the Massachusetts Department of Public Utilities, the New Jersey Board of Public Utilities, and the Hawaii Public Utilities Commission.

.Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A to my testimony summarizes my qualifications and experience.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment A contains a complete list of my engagements as an expert in matters before state and federal regulatory agencies. I have submitted testimony to the Federal

Communications Commission, the Federal Energy Regulatory Commission, the Alaska Public Utilities Commission, the Alberta Utilities Commission, the Corporation Commission of the State of Kansas, the Delaware Public Service Commission, the Hawaii Public Utilities Commission, the Pennsylvania Public Service Commission, the Illinois Commerce Commission, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the North Dakota Public Service Commission, the Maine Public Utilities Commission, the California Public Utilities Commission, and the Public Service Commission of the District of Columbia.

Q. IN WHICH PROCEEDINGS HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. I appeared on behalf of the North Dakota Public Service Commission Advocacy Staff in Case No. PU-12-813 Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, in Case No. PU-17-295 Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Natural Gas Service, in Case PU-20-441 Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, and in Case No. PU-21-381 Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in North Dakota.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS?

A. I received undergraduate and graduate degrees in Philosophy from Yale College and Purdue University. By education and professional experience I have expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. I have knowledge and experience in the areas of commercial and industrial operations in the energy, transportation, and telecommunications industries and am familiar with a wide range of experimental and investigative methods in science and engineering.

Q. PLEASE SUMMARIZE YOUR ELECTRIC AND GAS REGULATORY EXPERIENCE.

For most of my career I have performed analyses and submitted testimony regarding electric and gas utility least-cost planning, reliability, cost of service, rate design, and weather-emergency response. Specifically regarding electric utilities, I have testified on: (a) integrated resource planning, (b) class cost of service and rate design, and (c) various infrastructure operating expense and investment recovery mechanisms.

I. PURPOSE AND ORGANIZATION

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Commission's Advocacy Staff to address Otter Tail Power's (OTP) assertions and proposals in this proceeding regarding its (1) North Dakota jurisdictional cost of service study, (2) North Dakota class cost of service study, (3) North Dakota class revenue responsibility distribution, and (4) North Dakota rate design.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have included the following three exhibits:

Exhibit KRP-1:	OTP JCOSS and CCOSS without Minimum-Size Classification
Exhibit KRP-2:	OTP CCOSS and Revenue Allocation Rates of Return
Exhibit No. KRP-3:	Advocacy Staff Class Revenue Allocation

II. SUMMARY OF TESTIMONY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. As detailed below, OTP's North Dakota minimum size system jurisdictional and class cost of services studies, proposed class revenue allocations and proposed tariff rates are inconsistent with the principal of cost causation. Therefore, I recommend that OTP's jurisdictional and class cost of services studies without minimum size system be used as the basis for both class revenue allocation and tariff rate design. Also, OTP's proposed Section 5.02 formula rate and Sales Adjustment Rider lack supporting evidence and analysis, and would reduce regulatory efficiency. I recommend the Commission reject both the Section 5.02 formula rate and the Sales Adjustment Rider,

III. DISCUSSION

Q. WHAT IS THE RELATIONSHIP BETWEEN COST ALLOCATION AND RATE DESIGN/

A. In regulatory theory and practice the relationship between cost allocation and rate design and the utility's recovery of its approved revenue requirement is conceptually simple. If a utility's costs of providing service are not accurately allocated to its rate classes and rate class costs are not accurately reflected in the rate classes' tariff billing charges, then the utility will either over or under recover its costs of service or revenue requirement. The less accurately the costs are reflected in the rate classes' tariff billing charges, the greater the utility's under or over recovery of its costs will be. Regarding electric utilities, the primary drivers of costs are (1) the number of customers served by the utility's production and delivery system, (2) customer demand on the system, and (3) the volume of electric energy delivered to customers.

In this proceeding the revenue requirement, class costs and tariff rates at issue concern Otter Tail's electric production, transmission and delivery systems serving North Dakota customers. Consequently, the fundamental issue is whether Otter Tail's proposed customer class cost allocations and tariff rates (1) accurately reflect the customer costs, demand costs, and commodity costs of its customers and (2) thus minimize the likelihood of either under or over recovery of Otter Tail's North Dakota electric revenue requirement.

A. OTP'S NORTH DAKOTA JURISDICTIONAL COST OF SERVICE STUDY

Q. HAVE YOU EXAMINED OTP'S NORTH DAKOTA JURISDICTIONAL COST OF SERVICE STUDY.

A. Yes. The testimony[1] and exhibits of Christy L. Petersen present (1) the process[2] and (2) the top line results[3] of the embedded jurisdictional cost of service study (JCOSS) for the forecast year 2024. The JCOSS follows the standard approach of functionalizing, classifying, and then as appropriate directly assigning or allocating the costs to Otter Tail's North Dakota jurisdiction.[4] The JCOSS itself is part of a single confidential excel file[5] that also contains the CCOSS and uses the same account functionalizations, classifications, and

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[1] Direct Testimony of Christy L. Petersen (Petersen Direct), page 3 line 16 to page 5 line 21; see also Direct Testimony of Amber M. Stalboerger (Stalboerger Direct), page 2 line 4 to page 7 line 14 and Direct Testimony of Christopher E. Byrnes (Byrnes Direct), page 2 line 21 to page 9 line 9.
[2] Exh. CLP-1, Sch. 2.
[3] Exh. CLP-1, Sch. 3.
[4] Petersen Direct, page 4 line 19 to page 5 line 21.
[5] Attachment 1 to DR ND-PSC-302_NOTPUBLIC.xlsx.

allocators for both cost studies. The JCOSS allocates and directly assigns OTP's functionalized accounts to its Minnesota, South Dakota and North Dakota jurisdictions.[6]

Q. HAVE YOU FOUND ANY ERRORS IN OTP'S TEST YEAR 2024 JCOSS?

A. Yes. The JCOSS uses the minimum size system method to classify and allocate distribution primary and secondary plant and associated O&M expense accounts. As I demonstrate below regarding the CCOSS, 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.

B. OTP'S NORTH DAKOTA CLASS COST OF SERVICE STUDY

Q. HAVE YOU EXAMINED OTP 'S NORTH DAKOTA CLASS COST OF SERVICE STUDY?

A. Yes. The testimony[7] and exhibits of Amber M. Stalboerger present (1) the class cost allocation manual[8] and (2) the top line results of the embedded class cost of service study (CCOSS).[9] The CCOSS also follows the standard approach of functionalizing, classifying, and then as appropriate directly assigning or allocating the JCOSS North Dakota costs to Otter Tail's North Dakota customer classes.[10] The CCOSS uses allocators based on energy, demand and customer service characteristics.[11] As I noted above, the CCOSS uses the minimum-size System method to classify the distribution primary and secondary plant and O&M expense as consisting of both a customer-related component and a demand-related

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[6] Attachment 1 to DR ND-PSC-302_NOTPUBLIC.xlsx, excel columns B - K.
[7] Direct Testimony of Amber M. Stalboerger (Stalboerger Direct), page 2 line 4 to page 10 line 4.
[8] Exh. AMS-1, Schs. 2-3.
[9] Exh. AMS-1, Sch. 6.
[10] Attachment 1 to DR ND-PSC-302_NOTPUBLIC.xlsx, excel columns M - Z.
[11] Stalboerger Direct, page 7 line 15 to page 10 line 4 and Exhibit AMS-1, Schedule 2, pages 2-14.

component.[12] The customer component is allocated to classes on the number of customers in the classes; the demand component is allocated to classes on coincident and non-coincident demand factors.

Q. WHAT FACILITIES ARE CONTAINED IN OTP'S DISTRIBUTION PRIMARY AND SECONDARY PLANT ACCOUNTS?

A. OTP's primary and secondary plant accounts contain costs associated with the overhead and underground wires, supporting structures, line transformers and service lines that connect the distribution system to meters and other installations at customer premises. Typically electric utilities classify service lines as wholly customer-related, but OTP applies the minimum size system method to classify services as well. This is unusual, but not unheard of.

Q. WHAT IS THE MINIMUM-SIZE SYSTEM METHOD OF CLASSIFICATION AND ALLOCATION?

A. It is one of two methods for classification of distribution costs that are described in the NARUC Electric Utility Cost Allocation Manual: (1) the minimum-size method,[13] which OTP uses and (2) the minimum-intercept method.[14] The objective of the minimum-size method is to classify distribution plant and associated operating costs to determine the cost driver of each rate base item and operating cost — namely demand or customers — and allocate the plant and operating costs purportedly consistent with the principle of cost causation. OTP applies the minimum-size method to plant accounts 364, 365, 366, 367, 368 and 369 and O&M accounts 580-581, 583-584, 588, 590, 593-595, and 598.

[12] Exhibit CLP-1 Schedule 2, page 5 and Exhibit AMS-1, Schedule 2, pages 15 – 19 (Appendix A-1).
[13] National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (NARUC Manual) 1992, pages 90-92.
[14] NARUC Manual, pages 92-94.

The minimum-size system method assumes that a minimum-size distribution system can be built to serve the minimum loading requirements of the system's customers.[15] This assumption is addressed below. The NARUC Manual describes how to calculate the minimum size and cost of a given distribution system.[16] The calculated minimum size system costs for each distribution plant type are classified as customer-related and allocated to classes based on the number of customers. The remaining cost of each plant type is classified as demand-related and allocated based on demand.

Q. HAVE YOU IDENTIFIED ANY COST CLASSIFICATION ERRORS IN THE CCOSS?

A. Yes. In the classification step, as I noted above, OTP uses the minimum-size system method to classify the primary and secondary portions of distribution plant and associated O&M accounts[17] as both demand-related and customer-related. Classifying any portion of these distribution accounts as customer-related contravenes the principle of cost causation, which is the guiding principle of all regulated utility cost of service studies.[18]

Q. WHAT SUPPORT DOES OTP OFFER FOR ITS USE OF THE MINIMUM-SIZE METHOD OF CLASSIFICATION?

A. Neither witness Petersen nor witness Stalboerger even mention in testimony the minimum size system method. The only substantive references to OTP's minimum-size system occur in the flow chart depictions of OTP's JCOSS and CCOSS costing process in Exhibit CLP-1, Schedule 2[19] and in Exhibit AMS-1, Schedule 2.[20] None of these references provide support

[15] NARUC Manual, page 90.
[16] NARUC Manual, pages 91-92.
[17] Exhibit AMS-1, Schedule 2, pages 15 – 19 (Appendix A-1).
[18] NARUC Manual, pages 12-13.
[19] Exhibit CLP-1, Schedule 2 pages 2-4, 6, 8, 11 and 14.
[20] Exhibit AMS-1, Schedule 2, pages 3, 5, 13 and 15-19.

or evidence for the assumption that the minimum-size system is a cost causative basis for classification of distribution primary and secondary plant costs and associated O&M expenses.

Q. ARE YOU RECOMMENDING REVISIONS TO OTP'S MINIMUM SIZE SYSTEM METHOD USED IN THE CCOSS?

A. No. As I explain below. I am recommending that OTP's minimum size classification of a portion of its distribution costs as customer-related be rejected, because OTP has not provided any quantitative evidence that customers are in fact the cause or driver of any portion of its distribution costs.

Q. IS THE MINIMUM SIZE METHOD COMMONLY USED BY ELECTRIC UTILITIES?

A. At the time that the NARUC Manual was written, the minimum-size method was commonly used by electric utilities in North America, hence its inclusion in the NARUC Manual, which has not been revised since 1992. Today, however, it is less used by major electric utilities. For example, none of the Exelon electric operations use the minimum-size method.

Q. IS THE COMMON USE OF THE MINIMUM-SIZE METHOD OF CLASSIFICATION RELEVANT TO DETERMINING THE PROPER CLASSIFICATION OF DISTRIBUTION SYSTEM COSTS FOR OTP IN THIS PROCEEDING?

A. No. Selection of the appropriate classification method(s) for a utility's electric distribution system for costing purposes depends on the specific design and operating characteristics of the distribution system consistent with the principle of cost causation, not on whether other utilities in other jurisdiction use a specific classification method nor on whether the utility has used a specific classification method in prior proceedings. Regulatory costing is a forward-looking exercise. The only relevant question is whether the classification method reflects the cost causation inherent in the design and operation of OTP's distribution system. Again, as I demonstrate below, the minimum-size method of classification does not reflect the design and operation of OTP's distribution system.

Q. WHAT DISTRIBUTION COSTS ARE CAUSED BY CUSTOMERS?

A. Principles of Public Utility Rates (Bonbright), the canonical regulatory rate making text, defines electric distribution customer costs as "those operating and capital costs found to vary with the number of customers."[21] Bonbright points out that the distribution system costs that satisfy this definition are "the minimum service, metering, accounting, etc. costs of connecting another customer or the savings in costs of not connecting the customer," viz., the costs of the customer equipment recorded in plant accounts 369-371 Thus, this is not an arbitrary or theory-driven definition, but rather a definition based on a practical and empirically verifiable cause – namely, the act of adding a customer to or dropping a customer from the distribution system.

Q. DOES BONBRIGHT ADDRESS THE NARUC MANUAL'S MINIMUM-SIZE AND MINIMUM-INTERCEPT CLASSIFICATION OF DISTRIBUTION COSTS?

A. Yes. Bonbright describes both methods as assuming "hypothetical" and "phantom" distribution systems that rest on the erroneous assumption that "since [the minimum system costs] vary directly with the area of the distribution system (or else with the lengths of the lines, depending on the type of distribution system), they therefore vary directly with the number of customers," which "makes no allowance for the density factor (customers per

[21] Principles of Public Utility Rates 1988 (Bonbright), page 490; NARUC Electric Manual, page 90.

linear mile or square mile)."[22] In simpler terms, the costs of distribution primary and secondary accounts for a given system will be the same if the system serves X number of customers or 2X number of customers. Electric utilities design the components of their distribution system that are upstream of the equipment required to connect a customer to the system to meet the aggregate peak demand of the customers on the system. Otherwise, the utility would not be able to deliver firm service to customers at system peak demand. Regarding the minimum-intercept system, Bonbright adds that a systematic regression analysis found no statistical association between distribution costs and number of customers.[23] I note that I have never seen an analysis of empirical utility data that demonstrates either that distribution system costs vary with the number of customers on a distribution system or that there is a statistically significant correlation between distribution system costs and the number of customers.

Q. DOES OTP DESIGN AND OPERATE ITS DISTRIBUTION SYSTEM TO MEET PEAK LOAD?

A. Yes. Every regulated utility that offers firm electric service to its customers does and must design and operate the components of its distribution system that are upstream of the customer equipment to meet the peak load. Otherwise, the utility would not be able to provide firm service at peak load.

Q. HOW DOES THE NARUC MANUAL DEFINE DISTRIBUTION CUSTOMER COSTS?

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[22] Bonbright, page 491.
[23] Bonbright, page 491.

A. Consistent with Bonbright. the NARUC Manual defines "the customer component of distribution facilities [as] that portion of costs which varies with the number of customers." The NARUC Manual then immediately follows, however, with a *non-sequitur*, viz., the unsupported assertion that "[t]hus, the number of poles, conductors, transformers, services and meters are directly related to the number of customers on the utility's system" (emphasis added).[24] Note that this is exactly the same assumption debunked by Bonbright above. The number of customers directly causes the amount and costs of the customer equipment, not the amount and cost of the distribution system's primary and secondary accounts (overhead and underground wires, supporting structures and line transformers). In this regard, the NARUC Manual is simply wrong. The amounts and costs of the facilities recorded in distribution overhead and underground lines are not "directly related to the number of customers." They are rather directly related to the load or demand of customers.

Q. DOES THE NARUC MANUAL PROVIDE ANY EXPLANATION OR DEMONSTRATION THAT A PORTION OF DISTRIBUTION COSTS VARIES WITH OR IS CAUSED BY THE NUMBER OF CUSTOMERS?

A. No. As I explained above, the NARUC Manual simply assumes without explanation or demonstration that the minimum-size method and the minimum-intercept method identify and quantify a portion of distribution costs that varies with or is caused by the number of customers.

Q. HAS OTP PROVIDED ANY EMPIRICAL QUANTITATIVE EVIDENCE THAT ANY PORTION OF ITS DISTRIBUTION SYSTEM COSTS VARY WITH THE NUMBER OF CUSTOMERS?

[24] NARUC Electric Manual, page 90.

A. No.

Q. WHAT DO YOU CONCLUDE REGARDING OTP'S USE OF THE MINIMUM-SIZE SYSTEM METHOD TO CLASSIFY A PORTION OF ITS DISTRIBUTION COSTS AS CUSTOMER-RELATED AND ALLOCATE THOSE COSTS TO CUSTOMER CLASSES BASED ON THE NUMBER OF CUSTOMERS?

A. As explained above, there is no basis in theory, system design and operation practice, or empirical quantitative data to support OTP's use of the minimum size system method to classify as customer-related any portion of its distribution primary and secondary costs. OTP's distribution costs do not vary with the number of customers – additions and deletions of customers do not cause those costs to increase or decrease. Thus, I conclude that the Company's distribution primary and secondary costs are properly classified as 100 percent demand-related and properly allocated to classes using OTP's demand allocation factors.

Q. WHAT IS THE IMPACT ON OTP'S RATE CLASSES OF ELIMINATING THE MINIMUM-SIZE CLASSIFICATION OF OTP'S DISTRIBUTION PRIMARY AND SECONDARY COSTS IN ITS CCOSS?

A. As a general matter, minimum-size classification of distribution costs increases the costs allocated to rate classes with large numbers of customers and decreases costs allocated to rate classes with small numbers of customers. Because the number of customers in a rate class is not a cause or driver of distribution costs, minimum-size classification <u>over allocates</u> costs to rate classes with large numbers of customers and <u>under allocates</u> costs to rate classes with small numbers of customers The effect of this misallocation of costs can be seen by comparing the class rates of return and relative rates of return calculated by OTP's CCOSS to those calculated by eliminating minimum-size classification from OTP's CCOSS. Table

1 below compares the class rates of return and relative rates of return under OTP's CCOSS with and without minimum-size classification. As can be seen, the CCOSS without minimum-size classification, which allocates distribution costs on demand, results in higher rates of return and relative rates of return for the Residential, Other Public Authorities and Controlled Service Off-Peak rate classes and lower rates of return for the Farm, General Service, Large General Service, Irrigation, Outdoor Lighting, Controlled Service Deferred Load, and Controlled Service Interruptible rate classes.

Table 1 - Comparison of Relative Rate of Return by Rate Class Under Current Rates – CCOSS w/ and w/o Minimum-Size Classification				
	OTP CCOSS w/ Minimum-Size		**OTP CCOSS w/o Minimum-Size[25]**	
Customer Classes	**Rate of Return on Rate Base[26]**	**Relative Rate of Return on Rate Base**	**Rate of Return on Rate Base**	**Relative Rate of Return on Rate Base**
Residential	1.03%	0.32	2.99%	0.95
Farm	2.97%	0.93	2.09%	0.67
General Service	3.50%	1.09	3.30%	1.05
Large General Service	4.81%	1.50	4.13%	1.32
Irrigation	-1.89%	-0.59	-4.59%	-1.42
Outdoor Lighting	10.78%	3.36	10.02%	3.20
Other Public Authorities	-1.28%	-.040	-1.20%	-0.39
Controlled Service Deferred Load	-1.84%	-0.57	-4.62%	-1.48
Controlled Services Interruptible	4.08%	1.27	0.16%%	0.05
Controlled Service Off Peak	23.33%	7.28	23.37%	7.47
Total Company	3.21%	1.00	3.13%	1.00

[25] Exhibit KRP-1

[26] Attachment 1 to DR ND-PSC-301_NOTPUBLIC.xlsx, "CCOSS FINAL" tab, excel row 15.

Q. WHAT IS THE PURPOSE OF THE RELATIVE RATE OF RETURN METRIC?

A. Relative rate of return is the most metric by which fair cost apportionment is usually measured and evaluated. OTP's CCOSS calculates the overall rate of return for OTP's electric system and the rates of return for each class, but does not calculate relative rates of return. I have calculated class relative rates of return by dividing the class rates of return by the overall rate of return. A class relative rate of return of 1.00 indicates that the class is earning the overall rate of return. A class relative rate of return less than 1.00 indicates that the class is underearning or under recovering its cost of service, i.e., the revenue generated by rates is not covering the full cost of service to the class. A class relative rate of return greater than 1.00 indicates that the class is overearning or over recovering its cost of service, i.e., the revenue generated by rates is more than covering the full cost of service to the class. Relative rates of return are used as a guide for allocating the revenue increase to classes so as to move each class closer to full recovery.

Q. HAVE YOU IDENTIFIED ANY ERRORS IN THE COST ALLOCATORS IN OTP'S CCOSS?

A. No.

Q. WHAT DO YOU CONCLUDE AND RECOMMEND REGARDING OTP'S CCOSS?

A. I conclude that OTP's CCOSS produces results inconsistent with the principle of cost causation, because contrary to the minimum-size method's assumption, the number of customers is neither a cause nor a driver of distribution costs. I also conclude that OTP's CCOSS without minimum-size classification produces results consistent with the principle of cost causation, because demand is both the cause and the driver of OTP's electric system costs. I recommend that the Commission adopt the CCOSS without minimum-size classification as a guide for determining OTP's class revenue allocation and tariff rates.

C. OTP'S NORTH DAKOTA CLASS REVENUE RESPONSIBILITY DISTRIBUTION

Q. HAVE YOU EXAMINED OTP'S NORTH DAKOTA CLASS REVENUE RESPONSIBILITY DISTRIBUTION?

A. Yes. The testimony[27] and exhibits of Amber M. Stalboerger present OTP's class revenue responsibility distribution.[28] Witness Stalboerger states that the proposed class revenue responsibilities are based on the CCOSS results but adjusted to meet the objectives of maintaining reasonable rate continuity and mitigating disproportionate or abrupt rate impacts.[29] Table 2 shows OTP's proposed revenue allocation and net bill impacts.

Table 2 - OTP Proposed Revenue Allocation and Net Bill Impact[30]

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

[27] Stalboerger Direct, page 18 line10 to page 24 line 10.
[28] Exh, AMS-1, Sch. 7 and Tables 5-9.
[29] Stalboerger Direct, page 21 line 1 to page 22 line 12.
[30] Stalboerger Direct, page 20, Table 6.

Q. HOW DO OTP'S PROPOSED CLASS REVENUE REQUIREMENTS IMPACT CLASS RATES OF RETURN?

A. Table 3 compares the OTP's proposed rates of return and relative rates of return to the CCOSS calculated rates of return and relative rates of return.

Table 3 - Comparison of CCOSS Relative Rate of Return by Rate Class versus OTP Proposed Revenue Requirements

	OTP CCOSS w/ Minimum-Size		**OTP Proposed Class Revenue Requirements**	
Customer Classes	**Rate of Return on Rate Base**[31]	**Relative Rate of Return on Rate Base**	**Rate of Return on Rate Base**[32]	**Relative Rate of Return on Rate Base**
Residential	1.03%	0.32	4.05%	0.70
Farm	2.97%	0.93	5.94%	1.02
General Service	3.50%	1.09	6.67%	1.14
Large General Service	4.81%	1.50	7.61%	1.31
Irrigation	-1.89%	-0.59	0.17%	0.03
Outdoor Lighting	10.78%	3.36	7.08%	1.22
Other Public Authorities	-1.28%	-.040	1.79%	0.31
Controlled Service Deferred Load	-1.84%	-0.57	-1.73%	-0.30
Controlled Services Interruptible	4.08%	1.27	4.28%	0.73
Controlled Service Off Peak	23.33%	7.28	23.98%	4.11
Total Company	3.21%	1.00	5.83%	1.00

Measured by the change in relative rate of return, OTP's revenue allocation moves most of the customer classes towards parity, but there are anomalies regarding the General Service and Controlled Services Interruptible classes. General Service sees a marginal movement away from parity (1.09 to 1.14). Controlled Services Interruptible moves from significantly

[31] Attachment 1 to DR ND-PSC-301_NOTPUBLIC.xlsx, "CCOSS FINAL" tab, excel row 15.
[32] Exhibit KRP-2.

above parity to significantly below parity (1.27 to 0.73), reversing over recovery of cost to under recovery of cost.

Q. DO YOU AGREE WITH OTP'S PROPOSED CLASS REVENUE REQUIREMENT?

A. No, for two reasons. First, it is based on OTP's minimum-size CCOSS which, as I explained above, is not consistent with or reflective of actual cost causation. Second, it does not reflect the overall revenue requirement and rate of return presented in Advocacy Staff witness Mugrace's testimony.[33]

Q. HAVE YOU CALCULATED CLASS REVENUE REQUIREMENTS BASED ON WITNESS MUGRACE'S OVERALL REVENUE REQUIREMENT AND OTP'S CCOSS WITHOUT MINIMUM-SIZE SYSTEM CLASSIFICATION?

A. Yes. Tables 4 and 5 show, respectively, the rates of return and relative rates of return results of those calculations and the net class bill impacts that result.

[33] Direct Testimony of Dante Mugrace, Schedule DM-4

Table 4 - Comparison of Relative Rate of Return by Rate Class – CCOSS w/o Minimum-Size Classification and PSC Proposed Class Revenue Requirements

	OTP CCOSS w/o Minimum-Size[34]		PSC CCOSS Proposed Class Revenue Requirements[35]	
Customer Classes	**Rate of Return on Rate Base**	**Relative Rate of Return on Rate Base**	**Rate of Return on Rate Base**	**Relative Rate of Return on Rate Base**
Residential	2.99%	0.95	7.27%	0.97
Farm	2.09%	0.67	6.01%	0.80
General Service	3.30%	1.05	7.59%	1.02
Large General Service	4.13%	1.32	8.76%	1.17
Irrigation	-4.59%	-1.42	2.36%	0.32
Outdoor Lighting	10.02%	3.20	9.71%	1.30
Other Public Authorities	-1.20%	-0.39	5.07%	0.68
Controlled Service Deferred Load	-4.62%	-1.48	1.58%	0.21
Controlled Services Interruptible	0.16%%	0.05	4.21%	0.56
Controlled Service Off Peak	23.37%	7.47	10.76%	1.44
Total Company	3.13%	1.00	7.48%	1.00

Measured by the change in relative rate of return, all of the customer classes move significantly toward parity, i.e., significantly reducing the over and under recovery in each case. None of the customer classes flip from over recovery to under recovery of costs or from under recovery to over recovery of costs.

As can be seen in Table 5, compared to OTP's revenue allocation (Table 2 above), none of the customer classes have net bill impacts that are excessive.

[34] Exhibit KRP-1

[35] Exhibit KRP-3 AMENDED.

Table 5 - PSC Proposed Revenue Allocation and Net Bill Impact[36]

Line No.	Class	Total Present Revenues	Total Proposed Revenues	Net Bill Increase	Net Bill Impact
1	Residential	$58,596,832	$56,166,647	-$2,430,185	-4.15%
2	Farms	3,035,105	2,930,102	-105,003	-3.46%
3	General Service	44,329,329	43,926,806	-402,523	-0.91%
4	Large General Service	79,991,537	85,584,811	5,593,274	6.99%
5	Irrigation	105,695	96,646	-9,049	-8.56%
6	Lighting	3,705,988	3,922,624	216,636	5.85%
7	OPA	1,551,133	1,471,405	-79,728	-5.14%
8	Controlled Service Deferred Load	2,666,277	2,435,150	-231,127	-8.67%
9	Controlled Service Interruptible	11,230,365	11,497,523	267,159	2.38%
10	Controlled Service Off-Peak	776,948	769,975	-6,973	-0.90%
11	Total	$205,989,209	$208,801,690	$2,812,481	1.37%

Q. WHAT DO YOU CONCLUDE AND RECOMMEND REGARDING OTP'S REVENUE ALLOCATION?

A. I conclude that OTP's proposed class revenue allocation should be rejected because (1) it is based on a CCOSS that is inconsistent with the principle of cost causation and (2) even on that basis it does not produce consistent movement towards parity in cost recovery. I recommend that the Commission accept Advocacy Staff's class revenue allocation because it based on a CCOSS that is consistent with the principle of cost causation and (2) produces consistent movement towards parity in cost recovery.

[36] Exhibit KRP-3 AMENDED.

D. OTP'S NORTH DAKOTA RATE DESIGN

Q. HAVE YOU EXAMINED OTP'S NORTH DAKOTA RATE DESIGN?

A. Yes. The testimony and exhibits of David G. Prazak present (1) the rate design objectives of the proposed rate design and rates,[37] (2) the roles that the embedded CCOSS and the marginal cost study results play in the proposed rate design and rates,[38] (3) the marginal cost study,[39] and (4) OTP's rate proposals.[40]

Q. IN SUMMARY WHAT IS OTP'S RATE DESIGN PROCESS?

A. OTP begins with the embedded cost class revenue requirements developed by witness Stalboerger.[41] In the case of customer classes that have two or more rate classes, the allocation of the customer class revenue requirement to the rate classes is effected by either (1) applying the marginal cost study results or (2) applying the customer class revenue increase to each of the rate classes.[42] Next the individual rates were restructured in a variety ways to reduce complexity while maintaining flexibility, balance revenue requirement needs and customer needs, and meet changing customer expectations.[43] Finally, for each rate class the customer charge was set approximately at marginal cost, a facilities charge was added, and energy and demand charges were derived from the forecast billing determinants and residual revenue requirement.[44]

Q. HAVE YOU FOUND ANY ERRORS IN OTP'S RATE DESIGN?

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[37] Direct Testimony of David G. Prazak (Prazak Direct), page 2 line 16 to page 3 line 11.
[38] Prazak Direct, page 3 line 12 to page 4 line 28 and page 6 line 21 to page 9 line 19.
[39] Prazak Direct, page 4 line 29 to page 6 line 27and Exh. DGP-1, Schs. 2-3
[40] Prazak Direct, page 9 line 20 to page 55 line 18, Tables 3-24 and Exh. DGP-1, Sch. 4 and Attachment 1 to DR ND-PSC-601_NOTPUBLIC.xlsx.
[41] Prazak Direct, page 3 line 25 to page 4 line 12.
[42] Prazak Direct, page 6 line 21 to page 9 line 13 and Table 2.
[43] Prazak Direct, page 9 line 20 to page 11 line 34.
[44] Prazak Direct, page 12 line 1 to page 51 line 7, Tables 3-24, Figures 1-15 and Attachment 1 to DR ND-PSC-601_NOTPUBLIC.xlsx.

A. I have found no errors in the process itself.

Q. WHAT DO YOU CONCLUDE AND RECOMMEND REGARDING OTP'S REVENUE ALLOCATION?

A. I recommend, however, that OTP's North Dakota rates be based, not on witness Stalboerger's embedded cost class revenue requirements, but rather the embedded cost revenue requirements I recommend above.

E. <u>OTP'S OTHER RATE DESIGN PROPOSALS</u>

Q. ARE THERE OTHER RATE PROPOSALS THAT OTP MAKES?

A. Yes. OTP proposes (1) a Section 5.02 rate formula to recover costs associated with equipment installations under schedules 11.02 Irrigation and 14.02 Bulk Interruptible Service[45] and (2) a Sales Adjustment Rider that would capture the effect of sales changes on base rate jurisdictional allocations and revenues.[46]

Q. WHAT IS YOUR ASSESSMENT OF THE SECTION 5.02 RATE FORMULA?

A. OTP's current practice is to request changes in this rate in a rate case. OTP proposes to change the Section 5.02 rate to a formula rate that would be billed monthly and updated annually using FERC Form 1 inputs to take account of "changing economic conditions." OTP does not provide in testimony, exhibits or the Section 5.02 tariff (1) the actual formula to be used to update the rate, (2) any substantive evidence regarding the need for such an annual adjustment and (3) any substantive evidence of the probable impact on customers.

[45] Prazak Direct, page 53 line 2 to page 54 line 13.
[46] Stalboerger Direct, page 10 line 5 to page 12 line 5 and Exhibit AMS-1 Sch. 4; see also Direct Testimony of Bruce G, Gerhardson, page 21 line 1 to page 25 line 20.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROPOSED SECTION 5.02 FORMULA RATE?

A. As a matter of regulatory policy, formula rate cost recovery mechanisms in the interim years between rate cases work against the rate of return regulatory model. Formula rate mechanisms reduce the utility's incentive to devise and implement cost reductions in the face of the "changing economic conditions" referenced by witness Prazak. Instead, the utility simply passes through to customers any increase in costs due to changing economic conditions. Moreover, formula cost recovery mechanisms reduce rather than increase regulatory efficiency by requiring additional Commission processing and oversight of utility filings and rate changes. For all these reasons I recommend that the Commission reject OTP's Section 5.02 formula rate.

Q. WHAT IS YOUR ASSESSMENT OF THE SALES ADJUSTMENT RIDER?

A. The Sales Adjustment Rider is in essence a decoupling mechanism to true-up changes in actual versus forecast revenues on an annual basis by providing to customers rider charges (if actual revenues are less than forecast) or credits (if actual revenues are greater than forecast). As with the Section 5.02 rate formula, OTP does not provide in testimony, exhibits or the Section 5.02 tariff (1) the actual formula to be used to update the rate, (2) any substantive evidence regarding the need for such an annual adjustment and (3) any substantive evidence of the probable impact on customers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROPOSED SALES ADJUSTMENT RIDER?

A. As a matter of regulatory policy, decoupling mechanisms in the interim years between rate cases are problematic. A determination of the justness and reasonableness of decoupling mechanisms depends very much on the details of the true-up calculation and the rider calculation of the charges or credits applied to individual rate classes. As I noted above, none of these details have been provided by OTP. Moreover, decoupling mechanisms reduce rather than increase regulatory efficiency by requiring additional Commission processing and oversight of utility filings and rate changes. For all these reasons I recommend that the Commission reject OTP's Sales Adjustment Rider.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to submit supplementary testimony on further information received.

North Dakota Proposed 2024 Test Year

This spreadsheet model requires hard coding of % increase for all classes except general service which is driven by the overalll revenue increase required.

Hard Coded Number
Formula Number

			North Dakota	Residential	Farms	General Service	Total Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
Rate Base			666,288,748	178,993,644	11,549,742	149,790,467	235,875,871	794,619	13,753,018	6,089,886	21,810,134	46,635,092	996,275
			100.00%	26.86%	1.73%	22.48%	35.40%	0.12%	2.06%	0.91%	3.27%	7.00%	0.15%
Total Available for Return			20,845,603	5,345,215	241,280	4,937,686	9,750,095	(36,504)	1,378,033	(73,379)	(1,006,539)	76,856	232,860
			100.00%	25.64%	1.16%	23.69%	46.77%	-0.18%	6.61%	-0.35%	-4.83%	0.37%	1.12%
Rate of Return Earned			3.13%	2.99%	2.09%	3.30%	4.13%	-4.59%	10.02%	-1.20%	-4.62%	0.16%	23.37%
Relative Rate of Return				0.9545	0.6677	1.0536	1.3212	-1.4684	3.2027	-0.3851	-1.4751	0.0527	7.4708
Rate of Return Requested			7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%
Operating Income Required			52,303,667	14,051,001	906,655	11,758,552	18,516,256	62,378	1,079,612	478,056	1,712,096	3,660,855	78,208
Total Available for Return			20,845,603	5,345,215	241,280	4,937,686	9,750,095	(36,504)	1,378,033	(73,379)	(1,006,539)	76,856	232,860
Operating Income Deficiency			31,458,064	8,705,787	665,375	6,820,865	8,766,161	98,882	(298,421)	551,436	2,718,635	3,583,999	(154,653)
Incremental Taxes	GRCF =	1.3228371	10,155,829	2,810,551	214,808	2,202,028	2,830,042	31,923	(96,341)	178,024	877,676	1,157,048	(49,928)
Revenue Increase Required		Gross	41,613,893	11,516,337	880,182	9,022,893	11,596,203	130,805	(394,762)	729,459	3,596,311	4,741,046	(204,580)
CCOSS Percent Increase		Gross	22.78%	22.61%	33.36%	23.44%	15.99%	142.36%	-12.52%	53.71%	151.14%	45.63%	-28.40%
Current Revenue Responsibility													
Present Retail Revenue without Rider Roll-In			182,686,888	50,929,292	2,638,536	38,489,021	72,538,663	91,886	3,151,974	1,358,100	2,379,440	10,389,651	720,325
Revenue Increase Required			41,613,894	11,516,337	880,182	9,022,893	11,596,203	130,805	(394,762)	729,459	3,596,311	4,741,046	(204,580)
CCOSS - Revenue Responsibility			224,300,782	62,445,629	3,518,718	47,511,915	84,134,865	222,690	2,757,212	2,087,559	5,975,751	15,130,697	515,744
% of Present Revenue (no riders)				27.88%	1.44%	21.07%	39.71%	0.05%	1.73%	0.74%	1.30%	5.69%	0.39%
CCOSS - Percent Responsibility				27.84%	1.57%	21.18%	37.51%	0.10%	1.23%	0.93%	2.66%	6.75%	0.23%

North Dakota Proposed 2024 Test Year			This spreadsheet model requires hard coding of % increase for all classes except general service which is driven by the overalll revenue increase required.										
Hard Coded Number													
Formula Number							*Total*						
			North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
Rate Base			661,733,555	205,126,967	10,826,081	147,590,894	226,405,626	578,900	13,293,092	6,108,235	15,571,307	35,235,809	996,643
Total Available for Return			21,208,695	2,105,053	321,162	5,158,815	10,895,058	(10,923)	1,432,702	(78,072)	(286,637)	1,438,974	232,561
Rate of Return Earned			3.21%	1.03%	2.97%	3.50%	4.81%	-1.89%	10.78%	-1.28%	-1.84%	4.08%	23.33%
Relative Rate of Return				0.3202	0.9256	1.0906	1.5015	-0.5887	3.3628	-0.3988	-0.5743	1.2742	7.2806
Rate of Return Requested			7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%	7.85%
Operating Income Required			51,946,084	16,102,467	849,847	11,585,885	17,772,842	45,444	1,043,508	479,496	1,222,348	2,766,011	78,236
Total Available for Return			21,208,695	2,105,053	321,162	5,158,815	10,895,058	(10,923)	1,432,702	(78,072)	(286,637)	1,438,974	232,561
Operating Income Deficiency			30,737,389	13,997,414	528,685	6,427,071	6,877,784	56,366	(389,194)	557,568	1,508,984	1,327,037	(154,324)
Incremental Taxes	GRCF =	1.3228371	9,923,169	4,518,884	170,679	2,074,897	2,220,403	18,197	(125,646)	180,004	487,156	428,417	(49,822)
Revenue Increase Required		Gross	40,660,558	18,516,298	699,364	8,501,967	9,098,187	74,564	(514,841)	737,572	1,996,140	1,755,453	(204,146)
CCOSS Percent Increase		Gross	22.26%	36.36%	26.51%	22.09%	12.54%	81.15%	-16.33%	54.31%	83.89%	16.90%	-28.34%
Current Revenue Responsibility													
Present Retail Revenue without Rider Roll-In			182,686,888	50,929,292	2,638,536	38,489,021	72,538,663	91,886	3,151,974	1,358,100	2,379,440	10,389,651	720,325
Revenue Increase Required			40,660,559	18,516,298	699,364	8,501,967	9,098,187	74,564	(514,841)	737,572	1,996,140	1,755,453	(204,146)
CCOSS - Revenue Responsibility			223,347,447	69,445,591	3,337,900	46,990,988	81,636,850	166,449	2,637,134	2,095,672	4,375,580	12,145,104	516,179
% of Present Revenue (no riders)				27.88%	1.44%	21.07%	39.71%	0.05%	1.73%	0.74%	1.30%	5.69%	0.39%
CCOSS - Percent Responsibility				31.09%	1.49%	21.04%	36.55%	0.07%	1.18%	0.94%	1.96%	5.44%	0.23%
Proposed Revenue Responsibility													
Present Retail Revenue without Rider Roll-In			182,686,888	50,929,292	2,638,536	38,489,021	72,538,663	91,886	3,151,974	1,358,100	2,379,440	10,389,651	720,325
Revenue Increase Required			40,660,559	13,878,232	719,001	10,530,559	13,788,230	25,728	63,039	380,268	303,379	909,094	63,028
Total Revenue Proposed			**223,347,447**	**64,807,525**	**3,357,537**	**49,019,580**	**86,326,893**	**117,614**	**3,215,014**	**1,738,368**	**2,682,818**	**11,298,745**	**783,353**
Percentage Increase Proposed		**Gross**	**22.26%**	27.25%	27.25%	**27.36%**	**19.01%**	28.00%	2.00%	28.00%	12.75%	8.75%	8.75%
% of Proposed Revenue				29.02%	1.50%	21.95%	38.65%	0.05%	1.44%	0.78%	1.20%	5.06%	0.35%
CCOSS - Percent Responsibility				31.09%	1.49%	21.04%	36.55%	0.07%	1.18%	0.94%	1.96%	5.44%	0.23%
Proposed Above/Below COSS Responsibility				-2.08%	0.01%	0.91%	2.10%	-0.02%	0.26%	-0.16%	-0.76%	-0.38%	0.12%
				-7.16%	0.58%	4.14%	5.43%	-41.52%	17.97%	-20.55%	-63.10%	-7.49%	34.11%
Present Revenues Without a Case													
Present Retail Revenue without Rider Roll-In			182,686,888	50,929,292	2,638,536	38,489,021	72,538,663	91,886	3,151,974	1,358,100	2,379,440	10,389,651	720,325
Present Rider Roll-In			23,302,321	7,667,540	396,569	5,840,308	7,452,874	13,810	554,013	193,033	286,838	840,714	56,623
Total Present Revenues Without a Case			205,989,209	58,596,832	3,035,105	44,329,329	79,991,537	105,695	3,705,988	1,551,133	2,666,277	11,230,365	776,948
			17,358,238										
% of Present Revenue (with riders)				28.45%	1.47%	21.52%	38.83%	0.05%	1.80%	0.75%	1.29%	5.45%	0.38%
CCOSS - Percent Responsibility				31.09%	1.49%	21.04%	36.55%	0.07%	1.18%	0.94%	1.96%	5.44%	0.23%
Present Above/Below Responsibility				-2.65%	-0.02%	0.48%	2.28%	-0.02%	0.62%	-0.19%	-0.66%	0.01%	0.15%
				-18.51%	-9.98%	-6.00%	-2.06%	-57.48%	28.84%	-35.11%	-64.11%	-8.15%	33.56%
Total Revenue Increase Required			17,358,238	10,848,758	302,795	2,661,659	1,645,313	60,754	(1,068,854)	544,539	1,709,303	914,739	(260,769)
Less: Incremental Change RRA Rider Revenue			(694,393)	(296,207)	(14,864)	(210,019)	(169,298)	(453)	(1,027)	(6,869)	(975)	4,972	346
Less: Incremental Change TCR Rider Revenue			6,424	67,585	4,091	54,035	25,341	189	(22,621)	2,529	(15,617)	(102,062)	(7,045)
Less: Incremental Change AMDT Rider Revenue			34,505	11,516	499	10,070	608	59	3,541	340	3,120	4,543	210
Less: Incremental Change CWIP Removal from Rider Revenue			(555,034)	(211,610)	(10,646)	(155,375)	(156,550)	(355)	(7,407)	(5,003)	(4,307)	(3,593)	(187)
Less: Incremental Change GAAP Provision			824,787	(165,999)	(11,910)	(151,084)	1,257,196	622	(18,876)	(2,497)	24,658	(70,809)	(36,512)
New Base Revenues			17,741,949	11,443,473	335,627	3,114,033	688,016	60,693	(1,022,464)	556,039	1,702,424	1,081,689	(217,581)
Net Revenue Increase Requested			17,358,238	6,210,692	322,432	4,690,251	6,335,357	11,918	(490,974)	187,235	16,541	68,381	6,405
Rate of Return													
Percentage Increase - New Revenue		Net	8.43%	10.60%	10.62%	10.58%	7.92%	11.28%	-13.25%	12.07%	0.62%	0.61%	0.82%
Revenue Apportionments				1.2578	1.2607	1.2556	0.9399	1.3381	(1.5721)	1.4324	0.0736	0.0723	0.0978
Present Average Rate		8.43%	$ 0.08047	$ 0.12217	$ 0.10455	$ 0.11560	$ 0.05738	$ 0.07861	$ 0.28592	$ 0.08644	$ 0.08821	$ 0.05685	$ 0.05698
Proposed Average Rate		$/kWh	$ 0.08725	$ 0.13512	$ 0.11566	$ 0.12784	$ 0.06192	$ 0.08747	$ 0.24804	$ 0.09687	$ 0.08876	$ 0.05720	$ 0.05745
Increase/(Decrease)			$ 0.00678	$ 0.01295	$ 0.01111	$ 0.01223	$ 0.00454	$ 0.00886	$ (0.03788)	$ 0.01043	$ 0.00055	$ 0.00035	$ 0.00047
Test Year kWh sales			2,559,917,871	479,617,595	29,028,983	383,458,014	1,394,170,020	1,344,574	12,961,488	17,945,320	30,225,685	197,531,759	13,634,433
Rider Revenues Rolling In													
Renewable Resource Recovery	RRCR	E2-E8760	15,539,967	5,020,393	251,924	3,765,812	5,243,594	7,451	370,680	112,954	177,506	551,238	38,415
Transmission Cost Recovery	TCRR	D2	3,547,829	1,278,967	77,410	1,022,544	985,090	3,585	34,065	47,854	12,310	80,450	5,553
Generation Cost Recovery Rider	GCR	D1	3,595,685	1,161,634	58,291	871,345	1,213,279	1,724	85,769	26,136	41,072	127,547	8,889
Advanced Meter & Distribution Technology	AMDT		618,840	206,546	8,944	180,607	10,911	1,050	63,498	6,090	55,950	81,479	3,766
Rider Revenues Rolling In			23,302,321	7,667,540	396,569	5,840,308	7,452,874	13,810	554,013	193,033	286,838	840,714	56,623
Return Allocation			38,566,933	8,315,745	643,595	9,849,065	17,230,415	996	941,728	109,163	(270,096)	1,507,355	238,966
Rate of Return			5.83%	4.05%	5.94%	6.67%	7.61%	0.17%	7.08%	1.79%	-1.73%	4.28%	23.98%
Relative Rate of Return				**0.70**	**1.02**	**1.14**	**1.31**	**0.03**	**1.22**	**0.31**	**-0.30**	**0.73**	**4.11**

PU-23-342
Exhibit KRP-3
Amended

ND PSC Class Revenue Distribution			North Dakota	Residential	Farms	General Service	*Total* Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service Deferred	Controlled Service Interruptible	Controlled Service Off-Peak
Rate Base	DM-1	660,656,681	660,656,681	177,480,630	11,452,113	148,524,304	233,882,037	787,902	13,636,765	6,038,409	21,625,775	46,240,891	987,854
Total Available for Return	DM-1	28,837,854	28,837,854	7,394,582	333,787	6,830,807	13,488,303	-50,500	1,906,373	-101,513	-1,392,449	106,323	322,140
Rate of Return Earned			4.37%	4.17%	2.91%	4.60%	5.77%	-6.41%	13.98%	-1.68%	-6.44%	0.23%	32.61%
Relative Rate of Return			*1.000*	*0.954*	*0.67*	*1.05*	*1.32*	*-1.47*	*3.20*	*-0.39*	*-1.48*	*0.05*	*7.47*
Rate of Return Requested	DM-1	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%
Operating Income Required			49,417,120	13,275,551	856,618	11,109,618	17,494,376	58,935	1,020,030	451,673	1,617,608	3,458,819	73,891
Revenue Increase Required		0	20,579,266	5,880,969	522,831	4,278,811	4,006,073	109,435	-886,343	553,186	3,010,057	3,352,496	-248,248
adjustment 1			2,922,939	588,097	99,338	727,398		60,189	-886,343	276,593	1,505,028	838,124	-285,485
Adjt %				0.10	0.19	0.17		0.55	1.00	0.50	0.50	0.25	1.15
adjustment 2		17,656,327		4,922,216	255,009	3,719,888	7,010,719	8,881	304,632	131,258	229,968	1,004,139	69,618
adjustment 3													
Sum of Adjustments				5,510,313	354,347	4,447,286	7,010,719	69,071	-581,710	407,851	1,734,997	1,842,263	-215,866
adjusted revenue required			49,417,123	12,904,894	688,135	11,278,093	20,499,022	18,570	1,324,663	306,338	342,548	1,948,586	106,273
Rate of Return			7.48%	7.27%	6.01%	7.59%	8.76%	2.36%	9.71%	5.07%	1.58%	4.21%	10.76%
Relative Rate of Return			*1.000*	*0.972*	*0.803*	*1.015*	*1.172*	*0.315*	*1.299*	*0.678*	*0.212*	*0.563*	*1.438*
Rider Revenue-~~Rolling~~In			23,302,321	7,667,540	396,569	5,840,308	7,452,874	13,810	554,013	193,033	286,838	840,714	56,623
Present Revenue without Rider Roll-In			182,686,888	50,929,292	2,638,536	38,489,021	72,538,663	91,886	3,151,974	1,358,100	2,379,440	10,389,651	720,325
				27.88%	1.44%	21.07%	39.71%	0.05%	1.73%	0.74%	1.30%	5.69%	0.39%
Total Proposed Revenues			**208,801,690**	**56,166,647**	**2,930,102**	**43,926,806**	**85,584,811**	**96,646**	**3,922,624**	**1,471,405**	**2,435,150**	**11,497,523**	**769,975**
Total Present Revenues			205,989,209	58,596,832	3,035,105	44,329,329	79,991,537	105,695	3,705,988	1,551,133	2,666,277	11,230,365	776,948
Net Revenue Increase			**2,812,481**	**-2,430,185**	**-105,003**	**-402,523**	**5,593,274**	**-9,049**	**216,636**	**-79,728**	**-231,127**	**267,159**	**-6,973**
Net Bill Impact			**1.37%**	**-4.15%**	**-3.46%**	**-0.91%**	**6.99%**	**-8.56%**	**5.85%**	**-5.14%**	**-8.67%**	**2.38%**	**-0.90%**