MONTANA-DAKOTA UTILITIES CO.

Before the South Dakota Public Utilities Commission

Docket No. EL23 - ___

Direct Testimony

of

Ronald J. Amen

August 15, 2023

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Montana-Dakota Utilities Co. ("Montana-Dakota" or the "Company").

Q. By whom are you employed and in what capacity?

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. Please describe Atrium's business activities.

A. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, distributed generation, and affiliate transactions. We have extensive experience in rate case management; revenue requirement development; allocated embedded and marginal cost of service studies; rate design and rate alignment; and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission (FERC). The Atrium Team has extensive background and experience both in management positions inside electric and gas utilities and as advisors to our clients.

Q. What has been the nature of your work in the energy utility consulting field?

A. I have over 40 years of experience in the utility industry, the last 25 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before numerous utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A.

Q. Have you previously testified before the South Dakota Public Utilities Commission ("Commission")?

A. No.

Q. Please summarize your testimony.

A. In my testimony I present Montana-Dakota's Cost of Service Study ("COSS") and discuss its results. I also present the rate design proposals filed by Montana-Dakota in this proceeding. My testimony consists of this introduction and summary section and the following additional sections:

- Principles of Cost Allocation
- The Cost of Service Process

- Selection of Class Cost of Service for Montana-Dakota
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Montana-Dakota's Rate Design Proposals
- Customer Bill Impacts

Q. Please provide a list of the exhibits and schedules supporting your testimony.

A. I am sponsoring Statement N, Statement O, and the following exhibits:

- Exhibit No.____(RJA-1), Proposed Revenue Allocation
- Exhibit No.____(RJA-2), Rate Schedule Bill Impacts

II. COST OF SERVICE STUDIES

Q. What are the purposes of cost of service studies?

A. The primary purpose of a cost of service study is to allocate a utility's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. In other words, a cost of service study is an analysis of costs that assigns to each class of customers its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

The cost of service study provides a reasonable starting point for policy makers to decide the portion of common costs borne by each class of service. In addition, it must be remembered that other constraints impact policy decisions, such as the concept of just and reasonable rates and non-discriminatory rates. The cost analyst must rely on who causes costs and how those costs are recovered within a class of customers as the basis for determining rates that result from the cost of service study.

The cost of service study is useful in identifying cost causation that is a critical element of the allocation of costs between classes and customers within the class, and for adjusting rates to reduce or eliminate cross subsidies that result in rates that are not just and reasonable. A fully unbundled cost of service study provides critical information for the design of just and reasonable rates.

III. PRINCIPLES OF COST CAUSATION

Q. Please discuss the principle of cost causation.

A. Cost studies are a basic tool of ratemaking. Just and reasonable rates must avoid undue discrimination and must reflect the principle of “user pays,” also known as “cost causation,” which is another way of saying those who cause the costs should pay the costs. The development of unbundled costs permits regulatory review of the costs that are the same on average for customers in the class. The term “on average” is used because no two customers are exactly alike. Therefore, costs are determined, and cost-based rates are set, for “typical” customers grouped by similar demand and usage patterns.

If those costs are not recovered in the customer charge or basic service fee as they should be, the customers with more than average energy consumption subsidize the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

In order for rates to be efficient the concept of customers being charged for the distinct services they use is important since different customers use different services. Further, the costs of those services may be different because of the different load characteristics of customers in a class. Both cost allocation and rate design play a role in efficient rates.

A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system.

Q. Why is the principle of cost causation important?

A. Cost causation is the key element to selecting an allocation method. This has been the standard by which an allocation method is evaluated, and it continues to be the gold standard for assessing cost allocation. The principle of cost causation is also relevant for analysis within classes of customers where each customer must have rates that, on average, match the cost of service for that customer.

Q. What are the measures of demand that may be used in cost allocation?

A. The demands used to develop allocation factors essentially fall into three fundamental categories as follows:

1. Coincident Peak ("CP") Methods
2. Non-Coincident Peak ("NCP") Methods
3. Average and Excess Demand ("AED") Methods.

Q. Please briefly summarize the basic assumptions underlying each potential allocator.

A. The following table summarizes the basic provisions of each category of allocation methods:

<u>Table 1</u>

<u>Cost Allocation Methods Summary</u>

Allocation Method	Assumption about Cost	Allocation Factor
CP	Peak loads drive costs	Class coincident demand
AED	Peak loads and energy usage drive costs	NCP and load factor
NCP	Class or customer peaks drive costs	Class or customer NCP

Q. What methodology was used in the preparation of the Montana-Dakota cost of service study?

A. A combination of a) the 12-CP demand method for production and transmission costs, and b) the class NCP demands at the generation and distribution levels were used in developing the Montana-Dakota COSS.

Q. Is there a test or analysis used in the utility industry to determine the appropriateness of the allocation method for production and transmission assets?

A. Yes. The Federal Energy Regulatory Commission ("FERC"), the body that regulates the wholesale rates of electricity in interstate commerce, has primarily affirmed the use of a 12 CP allocation method because it "believe[s] the majority of utilities plan their system to meet their twelve monthly peaks."[1] FERC will allow utilities to propose an alternative to 12 CP, but the utility must demonstrate that such alternative is consistent with the utility's system planning and would not

[1] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 F.R. 21540-01 at 21599, Order No. 888 (1996).

result in an over-collection of the utility's revenue requirement. In evaluating such determinations, FERC uses the three peak ratios test established in *Golden Spread Electric Coop., Inc.*, 123 FERC ¶ 61,047 at 61,249 (2008):

Test No. 1 – On and Off-Peak Test: This test first compares the average of the coincident peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincident peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

Test No. 2 – Low-to-Annual Peak Test: Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.

Test No. 3 – Average to Annual Peak Test: Compares the average of the twelve monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.

I applied FERC's three peak ratios test to Montana-Dakota's System load data (2014-2022). Montana-Dakota meets all three FERC tests for using 12 CP for five out of the nine years. For 2015, 2016, 2020, and 2022 Montana-Dakota meets two of the three tests, narrowly missing the Test No. 2 – Low-to-Annual Peak Test in those years. Therefore, based on the FERC three peak ratio test, it is appropriate to use the 12 CP allocation method for production and transmission demand-related costs on Montana-Dakota's system. Table 2 below shows the results of the Montana-Dakota's FERC 12-CP tests.

Table 2

FERC 12-CP Tests*

Use 12 CP if:	Peak - Off-Peak % Difference <=19.0%	Low/Annual Peak Ratio >=66.0%	Avg/Annual Peak Ratio >=81.0%
2022	17.1%	62.9%	86.3%
2021	19.0%	69.2%	83.0%
2020	18.1%	63.8%	83.6%
2019	12.3%	74.1%	89.1%
2018	15.4%	72.0%	87.8%
2017	15.7%	68.6%	86.1%
2016	18.0%	65.3%	82.5%
2015	17.2%	65.1%	83.6%
2014	10.9%	73.5%	86.9%

*Per 123 FERC ¶ 61,047 at 61,249

IV. THE COST OF SERVICE STUDY PROCESS

Q. What are the basic steps in developing a cost of service study?

A. Cost of service studies use a three-step process as follows:

1. Functionalization
2. Classification
3. Allocation

Q. Please explain the functionalization process.

A. A systematic process for identifying functions is used based on the traditional categories of production, transmission, distribution, and customer. To the extent permitted by the accounting data, this functionalization may include subcategories such as primary distribution and secondary distribution and directly assigned dollars based on unique facilities that need to be assigned rather than allocated. The process of functionalization has become a more robust and simplified process with the use of accounting data as reported under a uniform system of accounts ("USOA"). That is not to say that all of the issues have been resolved. Certain accounts such as intangible plant still require some analysis to functionalize individual cost elements in the account for some utilities. The typical functions used in a cost study are as follows:

- Production/Supply
- Transmission
- Distribution
- General, Common, and Intangible

Each of these functions is described below.

The Production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The Transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the distribution grid and to move power from generation to load.

The Distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly, plant and expenses caused by individual customers.

The General, Common, and Intangible function includes office buildings and equipment, vehicles, materials and supplies, the Customer Care and Billing (CC&B) system, and other engineering and communications software systems.

Q. Please describe the cost classification step.

A. Cost classification is driven by as detailed an analysis as the accounting data permits. Costs are classified as demand, energy, and customer. Only costs that vary with energy are classified as energy. The costs classified as demand are those costs that are a function of some measure of demand. Customer costs are those costs that vary with the number of customers. For some of the costs associated with the distribution system, costs must be split between the portion that is demand related and the portion that is customer related. That split is based on the principles of cost causation, as discussed above. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built, and operated.

Q. Please elaborate on the nature of the cost classification categories.

A. *Demand* costs are capacity related costs associated with plant that is designed, installed, and operated to meet maximum electric usage requirements such as larger transformers or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expense.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer costs are largely a function of the number and density of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Q. Can costs be classified into more than one category?

A. Yes. For example, as mentioned earlier, some distribution costs may have both a demand and a customer cost component.

Q. Please describe the allocation process.

A. Allocation is based on the factors that cause costs to be incurred. Cost studies use two types of allocation factors: external factors and internal factors. External allocation factors are based on direct knowledge from data in the utility's accounting and other records such as the load research data. Energy allocation factors are based on the class energy consumption and adjusted for losses to equate to total energy production. Another example of an external allocation factor is allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers, and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles and conductors are allocated using the minimum system to classify the costs between demand and customer related costs and then are allocated on external allocation factors. Demand allocation factors are based on load research data that is used to calculate the demand for the sampled rate classes and is adjusted to equal system peaks. Internal allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors.

Q. How do the principles and processes you have explained pertain to fixed costs and variable costs?

A. In the utility ratemaking context, fixed costs include all costs that do not vary with the amount of energy consumed by customers and constitute the vast majority of the cost to provide service.

Variable costs include only those costs that vary with the amount of energy consumed by the customers. In other words, variable costs relate directly to how much power is actually consumed; these costs include fuel, the energy component of purchased power costs, reagents used in generation for the operation of emission control systems, and any O&M costs directly related to energy production.

All other costs incurred by the utility are fixed costs because the utility must incur them in order to be capable of providing service whether or not customers actually consume any energy.

V. SELECTION OF CLASS COST OF SERVICE FOR MONTANA-DAKOTA

A. Characteristics of Distribution Plant

Q. Please discuss the nature and characteristics of distribution plant.

A. The Montana-Dakota system distribution plant consists of different facilities that have different cost causation factors. The reason for this conclusion is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility costs are directly the result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer, but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest size of transformer costs much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity. For transformers larger than the minimum size, the remainder of transformer cost is related to demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer.

Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of the distribution system at all. Where customers own their own substation and connect directly to the transmission system, the customer causes no distribution costs for the utility. These customers are typically served either through special contracts or under a transmission service rate schedule. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities to serve a load based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. When customers who have common load characteristics, “homogeneous” load characteristics, they may warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics of this type of customer.

For distribution costs found in Account Nos. 364 (Poles, Towers & Fixtures), 365 (Overhead Conductor), 367 (Underground Conductor), 368 (Line Transformers), 369 (Services), 370 (Meters), and 373 (Street Lighting), either all or a portion of the costs are customer related because they are caused by customers. There is no basis for arguing that Account Nos. 369 – 373 are not customer related. For Account No. 369 – Services, each customer has a service designed to meet that customer’s own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services are dedicated to a customer and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge, the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system without and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 – 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The concept of a minimum system assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

B. Minimum Distribution System

Q. Is the method used by the Company to determine a customer cost component of a distribution system a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-size unit of plant investment. The zero-intercept method determines the costs associated with zero loads by valuing the costs of all assets in an account and conducting regression analysis of cost on current-carrying capacity or demand rating to establish the cost of a zero-load system. The most commonly installed, minimum-sized unit of plant method classifies the costs of a hypothetical minimum-size version of the utility's distribution system capable of connecting to all customers as customer-related, then classifies all remaining costs as demand-related. Each of the accounts (e.g., Account Nos. 364 – 367) are examined to identify the smallest, most commonly used type of pole, conductor, etc. The unit cost of this minimum-size plant is then multiplied by the total number of units of that plant type. A comparison with the value of all the assets in the account yields the minimum-sized result. Both methods are acceptable to the industry. One of the more commonly accepted literary references relied upon when preparing embedded cost of service studies is the Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC").

Q. Of the two methods, which has Montana-Dakota used to determine its minimum distribution system?

A. Montana-Dakota uses the minimum-size method for Account Nos. 364 – 367 and the zero-intercept method to classify transformers (Account 368). The Company's method for Account Nos. 364 – 367 uses a modeling approach that creates representative one-mile minimum and normal underground and overhead systems, and then calculates the current replacement cost of each. The one-mile minimum underground and overhead systems are regarded as customer-driven systems, while the difference in cost between a normal and a minimum system is deemed demand-driven. This approach has been used by Montana-Dakota in prior COSS studies in South Dakota and its other jurisdictions.

Q. Does the one-mile minimum system approach provide a reasonable representation of customer-driven distribution system costs?

A. Yes. The one-mile-of-circuit approach attempts to construct a realistic representation of a Montana-Dakota circuit under two scenarios and applies the standard minimum system logic that uses the smallest feasible equipment size to serve that circuit as an acceptable way to identify customer-driven cost. Montana-Dakota's approach of creating a hypothetical one-mile circuit is a realistic proxy for circuits in Montana-Dakota's service territory.

Q. How does Montana-Dakota apply the one-mile minimum system methodology in its COSS study?

A. Montana-Dakota combines its customer and demand portions of Account Nos. 364-367 based on weighted asset values for each account to derive single percentages for the combined accounts.

Q. How does Montana-Dakota separate the two classification components for Account No. 368, line transformers?

A. Montana-Dakota uses the zero-intercept approach for each of two types of transformers (single-phase pad mount transformers, and single-phase line transformers).[2] The results of the zero-intercept regression analysis were used to determine the customer component of transformers. Specifically, the zero

[2] In each case, the analysis makes use of the transformers that are both currently in use and likely to be reordered as replacements for aging line transformers to determine the zero-intercept value and then uses the entire asset base to calculate shares. This technical detail is adopted to avoid the need to develop replacement prices for transformer sizes that are not going to be reordered at the time that existing transformers of those sizes are to be replaced.

intercept cost was multiplied by the number of single phase transformers at or below 50 kVA. The ratio of that amount to the total replacement cost of all transformers was 44.8%, which was used for establishing the customer component of transformer plant.

Q. Why does Montana-Dakota use the zero-intercept method for Account No. 368, but the minimum-size method for the other accounts described above?

A. Line transformers are not readily included in the methodology based on the representative one mile of circuit. Line transformers offer, by their standard equipment types, a more readily developed zero-intercept analysis.

The results of Montana-Dakota's analyses appear in the **Table 3** below. The values for the weighted average of FERC accounts 364-367 and FERC account 368 are inputs to the COS model. Note that, as with other utilities, FERC account 366, underground conduit, is assumed to have the same classification properties as underground conductors.

Table 3

Minimum Size/Minimum Intercept Results

FERC A/C	Account Name	Customer	Demand
364	Poles	61.3%	38.7%
365	Overhead Conductors	66.9%	33.1%
367	Underground Conductors	57.0%	43.0%
364-367	Weighted Average	59.3%	40.7%
368	Line Transformers	44.8%	55.2%

C. Allocation of Customer Costs

Q. Please discuss the allocation of customer related costs.

A. There are costs other than distribution plant that are customer related and should be included in the customer cost allocation. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer costs. In addition, where all of a plant account is allocated as customer related, all of the associated O&M costs should also be allocated to customer costs. Second, customer service-related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities and other types of facilities such as the meter shop, stores, tools, and equipment. Fourth, a portion of administrative and general expenses should be allocated to customer costs as well. The allocation of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items related directly to employee costs.

D. Distribution Plant

Q. What method does Montana-Dakota employ to allocate demand-related distribution costs?

A. Montana-Dakota allocates demand-related distribution costs primarily by reference to class shares of noncoincident peak (“NCP”) demand. Load research reveals each class’s single maximum level of consumption over the course of a year. The “One NCP” allocator is simply each class’s share of the sum of these values. (The “One” signifies a single annual maximum value.) Investment in distribution costs occurs in response to the increase in peak demands of customers on individual feeder lines, such peak demands not necessarily corresponding in timing to system peak demands. Accordingly, measuring each customer class's peak and then estimating the class's share in the sum of the peaks across all classes, is a reasonable way to judge responsibility for demand-related cost causation applying to distribution investment.

The Montana-Dakota COSS model uses two NCP allocators, one applicable at the generation level and another at the secondary service level. The "NCP – Supply Level" allocator is based on the peak demands of all customers and allocates demand related costs associated with land, station equipment, poles, conductors, and conduit. The "NCP – Secondary Level" allocator is based on the peak demands of secondary distribution customers and allocates demand-related line transformer costs.

Q. What is the underlying evidentiary basis for Montana-Dakota's One NCP allocators?

A. Montana-Dakota has developed load research data for its customer classes. For each class, Montana-Dakota developed sample usage, coincident peak, and class non-coincident peak data for calendar 2021, then scaled the values based on billed kWh. This results in demand values that preserve observed load factors of the load research sample. Load research results are available to Montana-Dakota for about 99% of jurisdictional load. The classes making up the remaining 1% of load were each matched to a class for which interval data are available. Demand values were calculated that produce load factors identical to the class with which each class lacking interval data was matched. For the test year

(2022), Montana-Dakota produced kWh forecasts and demand values that yielded load factors identical to those of the historical data.

Q. In your opinion is Montana-Dakota's load research process reasonable?

A. Yes. This application of load research data to generate demand-related allocators is standard practice; it is consistent with other utilities' practices.

Q. How does Montana-Dakota allocate customer-related distribution costs?

A. Montana-Dakota uses allocators based on customer numbers, weighted by costs for certain cost categories, for various types of assets and expenses. The Company develops several customer-related allocation factors: total customer numbers; customer less outdoor lighting; customer meters, weighted by an index of meter costs; customer service drops, weighted by service cost; customer transformers, weighted by transformer cost; and customer accounts, weighted by the cost of customer support. The Company's forecasts of test year customer numbers and meter numbers underpin these allocation factors.

E. Other Allocation Factors

Q. Please describe other types of allocation factors within the COSS.

A. There are numerous other allocation factors in the COSS. Fuel and purchased power expenses are allocated on energy at generation as are certain fuel related O&M costs. Purchased power capacity also has a demand component, which is allocated on 12-CP. O&M costs for the various plant functions are allocated as the associated plant is allocated. There are a number of internal allocation factors that distribute costs according to the factor or factors causing those costs. Thus, rate base items like provision for pension, benefits, and post-retirement costs, are allocated on O&M excluding fuel and purchased power. General, Common, and intangible plant investments are allocated on Production, Transmission and Distribution plant. General, Common-Intangible-CC&B and PCAD are allocated on customers excluding outdoor lighting.

F. Summary of the Allocated Cost of Service Study

Q. Please summarize the results of the recommended cost of service study.

A. The following Table 4 provides a high-level summary of the results of the COSS. Table 4 shows the rate of return for each rate class based on current rates as well as the system overall return and the revenue deficiency or excess for each rate class at the uniform system rate of return.

Table 4

Rate of Return and Revenue Excess/(Deficiency) by Rate Class

Rate Class	Rate of Return By Class	Revenue Excess or (Deficiency)
Residential	4.64%	($1,355,021)
Small General Primary	(5.50%)	($774)
Small General Primary	5.21%	($481,870)
Irrigation	(1.79%)	($14,977)
TOD Small General	6.52%	($769)
Large General Secondary	5.76%	($376,452)
Space Heating	(0.89%)	($358,618)
Municipal Pumping	5.37%	($18,541)
Outdoor Lighting	0.11%	($54,357)
Street Lighting Company Owned	13.51%	$77,951
Street Lighting Municipal Owned	4.12%	($10,006)
SYSTEM TOTAL	4.84%	($2,593,434)

Q. Do these results provide guidance for the allocation of revenue requirements in this case?

A. Yes. Cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Cost of service is not, however, the only consideration in determining the portion of the revenue deficiency allocated to each rate class. Other considerations include principles such as gradualism, competitive considerations, standalone costs and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Q. Has Montana-Dakota taken the above factors into account in recommending the level of rate increase for rate classes?

A. Yes. The process for determining the revenue increase for each class is addressed in Section VII of this testimony.

Q. Please describe the COSS schedules attached to this testimony.

A. There are three schedules attached to this testimony that provide further details of the COSS that include the following information: They are:

- Statement N, Schedule N-1 Cost of Service by Component, consists of 13 pages and presents a summary of each rate class's 2022 Test Year rate base, the revenue requirements necessary to achieve the requested rate of return, and the rates of return under current rates.
- Statement N, Schedule N-2, consists of 132 pages and presents the Rate Base, Revenue, and Expenses by Class at Current Rates. This schedule provides the detail by cost and revenue component resulting in the projected rate base and class rates of return at current rates.
- Statement N, Schedule N-3, Allocation Factor Report, consists of 18 pages and shows the development of the factors used to allocate costs to the rate classes.

Q. Please explain the COSS information contained in Statement N.

A. Statement N, Schedule N-1, pages 1 – 13, provides a report titled Cost of Service by Component. This report shows the total dollars and unit cost required under each rate if the pro forma rate of return of 7.600 percent were to be earned for the demand – production and transmission, demand – distribution, energy, and customer cost components of each rate schedule along with a summary of the results by the major rate classifications, Residential, Small General, Large General, Municipal Pumping, and Lighting. The pro forma system rate of return of 4.842%, before allocation of the requested increase, is also shown on Schedule N-1, as well as the individual rate schedule rates of return before increase.

A summary of the results by the major rate classifications, Residential, Small General Service, Large General Service, Municipal Pumping, and Lighting is provided in Statement N, Schedule N-1, pages 12 – 13.

Statement N, Schedule N-2, pages 1 – 132, titled Embedded Class Cost of Service Study, provides the complete rate base and income statement as allocated to each rate schedule. The description of each allocator and the allocation factors for each class and cost component are provided in the Allocation Factor Report, Statement N, Schedule N-3, pages 1-18.

The COSS is based on the South Dakota results of electric operations recorded for the 12 months ended December 31, 2022, as adjusted to reflect pro forma adjustments sponsored by Company witness Ms. Vesey.

Q. Please summarize the results of the COSS.

A. As shown in Statement N, Schedule N-1, the overall rate of return for South Dakota natural gas service is 4.842% at present rates, based on the results of electric operations for the twelve months ended December 31, 2022, adjusted for known and measurable changes. The returns by customer class at current rates are shown below:

- Residential Service 4.641%
- Small General Service (1.926%)
- Large General Service 4.888%

- Municipal Pumping 5.365%
- Lighting 8.182%

VI. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design utilized in development of the Company's rate design proposals.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service,

(2) Efficiency,

(3) Value of Service,

(4) Stability/Gradualism,

(5) Non-Discrimination,

(6) Administrative Simplicity, and

(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3]

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an

[3] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

engineering dimension. Economically efficient pricing promotes good decision-making by electric power producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the electric utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that was previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. As noted above, there are tensions between cost and value of service principles. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction
- Consumer Rationing
- Fairness to Ratepayers

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

VII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Montana-Dakota's proposed base rate revenue increase of $2,593,434 to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for Montana-Dakota's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Montana-Dakota's interclass revenue proposal?

A. Yes. Using Montana-Dakota's proposed revenue increase, and the results of its COSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Montana-Dakota personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under Montana-Dakota's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost ratio for each class was equal to 1.00 (Unity), as shown in Exhibit No____(RJA-1), under *Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option I considered was assigning the increase in revenues to Montana-Dakota's customer classes based on an equal percentage basis of its current non-fuel revenues (see *Scenario A, Equal Percentage Increase (System average)*, in Exhibit No.___ (RJA-1)). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Montana-Dakota's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards Unity). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Montana-Dakota's class revenue proposal.

Q. What was the result of this process?

A. After further discussions with Montana-Dakota, I concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Montana-Dakota's customer classes: Residential Service (Rate Schedule 10), Small General Service (Rate Schedule 20 and 26), Irrigation Service (Rate Schedule 25), Large General Service (Rate Schedule 30), Space Heating Service (Rate Schedule 32), Municipal Pumping Service (Rate Schedule 48), Outdoor Lighting Service (Rate Schedule 24), Street Lighting Company Owned (Rate Schedule 41), Street Lighting Municipal Owned (Rate Schedule 41), as shown in Exhibit No.___ (RJA-1), *Scenario B: Maximum Increase of 2 Times System, Removal of Discount for Rate 41*.

In the case of the Residential Service class, the revenue adjustment ensures their proposed rates will maintain class revenues at the class's cost of service level for the class; that is, the proposed revenue increase to the residential class will maintain the class's parity ratio at 1.00 or Unity.

The Small General Service Primary (0.61), Irrigation Service (0.56), Space Heating (0.61), and Outdoor Lighting (0.38) customer classes' parity ratios were well below Unity (1.00) at the Company's proposed ROR of 7.600%. Therefore, the maximum revenue increase of 38.17% is proposed for these respective classes, which resulted in modest movement toward Unity.

The COSS results for the remaining customer classes, except Company Owned and Municipal Owned Lighting, indicate their respective class rates of return are above the system average rate of return ("ROR") at both the Company's current and proposed ROR levels. While this would suggest the need for revenue <u>decreases</u> in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting parity ratios towards Unity), as shown in Exhibit No.___ (RJA-1), under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service class and the classes that are receiving revenue increases of twice the system average increase has led me to conclude, in consultation with the Company, to refrain from revenue reductions for the remaining customer classes, or alternatively, exempting these classes from revenue increases. Instead, the proposed balanced revenue adjustments will bring these classes' parity ratios levels to 1.03 relative to Unity.

The Company Owned Lighting class's negative parity ratio shown in the Exhibit is a function of rent revenue associated with this class exceeding the related cost of service, the net of which gives the appearance of negative costs. The Company Owned and Municipal Owned Lighting classes each received a proposed revenue increase of 11.12%, approximately 60% of the system average increase.

In summary, this preferred revenue allocation approach maintained the Residential class's revenue at Unity or 1.00, while providing moderation of the revenue impact on the classes well below parity and requiring some level of revenue increase responsibility from all customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of apportionment of the overall system revenue increase, and modest reduction in the existing class rate subsidies, is desirable.

Q. Please discuss the information provided in Statement O.

A. Statement O, titled Revenue Under Current Rates and Proposed Rates Pro Forma, page 1 of 2, presents summaries by customer class of the proposed revenue increase, inclusive of the changes to the Company's Infrastructure and Transmission Riders and the Fuel and Purchased Power rate (which is proposed to include the Production Tax Credits offset as explained further by Ms. Vesey and Ms. Bosch). This Statement displays the revenues calculated under the present and proposed rates, including the proposed Infrastructure and Transmission riders, for each customer class. The proposed revenue increase components by rate class and corresponding percentages are also shown.

The allocation of the total target revenue increase of $2,593,434 to the respective rate schedules is presented on page 2 of 17, of Statement O, Schedule O-1, titled Allocation of Revenues – Rate Design Results. The pro forma 2023 billing determinants and the embedded cost of service by rate class prior to the proposed revenue increase are presented on page 1 of 17 of the Schedule. The target revenue increase as a percentage of total class revenues, including the Infrastructure costs, range from 19.3% to Residential; 18.8% to Small General; 18.9% to Large General; 12.2% to Street Lighting; 18.2% to Municipal Lighting (Rate Schedule 48), and 35.4% to Outdoor Lighting (Rate Schedule 24), as shown on Schedule O-1, page 2 of 17. A Summary of Proposed Charges by rates schedule is shown on page 3 of 17. The remaining fourteen pages of Schedule O-1, titled Derivation of Rate and Reconciliation, provide the derivation of the proposed rates for each Rate Schedule.

VIII. MONTANA-DAKOTA'S RATE DESIGN PROPOSALS

Q. Please summarize Montana-Dakota's proposed rate design changes.

A. I will present the specific rate design changes and supporting rationale for Montana-Dakota's proposals. Montana-Dakota has proposed to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service for customers served under the following Rate Schedules, as shown on Schedule O-1:

- Residential Service (Rates 10 & 16);
- Small General Primary & Secondary Service (Rates 20);
- Irrigation Service (Rate 25);
- Time-of Day ("TOD") Primary & Secondary Service (Rate 26);
- Large General Primary & Secondary Service (Rate 30);
- Space Heating Primary & Secondary Service (Rate 32);
- TOD Primary & Secondary Service (Rate 33);
- Public Lighting, Company & Municipally Owned (Rate 41);
- Municipal Pumping Service (Rate 48); and
- Outdoor Lighting Service (Rate 24)

The proposed rate design changes to the Company's Residential Electric Dual Fuel Space Heating Service Rate 53 are discussed in the direct testimony of Ms. Bosch.

Q. Please describe the process to determine the proposed changes to the Basic Service Charges and the other rate components for the respective tariff schedules.

The following process was used to determine the rate components for each of the rate schedules:

1. The first step was to establish the Basic Service Charge by considering the customer costs identified in the COSS and the Demand Charge based on the demand costs identified in the COSS, for those rate schedules where demand metering is warranted.
2. The second step was to deduct the revenues to be recovered under the Basic Service Charge, Demand Charge, seasonal or service level differential and Base Fuel and Purchased Power components for each rate schedule.
3. The Energy Charge component was then determined by dividing the revenues remaining to be collected by the proforma sales under the applicable rate schedule.

The calculations just described are provided for each rate schedule on pages 4 – 17 of Schedule O-1. A Summary of the Proposed Charges for each rate schedule is provided on Schedule O-1, page 3.

Q. Please further discuss your proposal to increase the Basic Service Charge component of the previously identified rate schedules.

A. The Basic Service Charge component of each rate schedule has been set at or near the cost per customer component identified in the embedded class cost of service study. As shown on Statement N, Schedule N-1, the customer component reflects those costs that vary by the number of customers served in each rate class. This includes the investment in meters and services that directly serve each individual customer, and a portion of the investment in poles, overhead and underground conductors, and line transformers. Through the COSS, these facilities have been determined to be associated with the minimum investment necessary to provide service to a customer regardless of the energy or peak load requirements of that customer.

The Basic Service Charge can be characterized as a connection charge for access to service. It is imperative that appropriate fixed costs be collected through the Basic Service Charge in order to minimize intra-class subsidies and provide customers with the appropriate economic price signals. Increasing the Basic Service Charge to the amount identified as necessary to recover customer-related fixed costs does not provide a disincentive to use energy wisely. Customers' conservation efforts are rewarded through lower bills because of lower energy consumption. Other benefits of better aligning cost recovery with cost causation include:

- Mitigating the impact of significantly colder or warmer than normal weather on customers' bills;
- Mitigating the impact abnormal weather has on the Company's ability to recover fixed cost;
- Residential customers' bills will be more stable as approximately 19.4 percent of the total bill will be fixed each month and not dependent on changes in weather; and
- Provides a better match of revenues to the investment made to serve each customer.

If fixed costs are not recovered from fixed charges, average or higher than average use customers subsidize low use customers, regardless of the reason a customer uses less energy than average.

IX. CUSTOMER BILL IMPACTS

Q. Has Montana-Dakota prepared a bill comparison for its Residential Service customers?

A. As seen on page 4 of Statement O, Schedule O-1, the Basic Service Charge under Residential Rate 10 is proposed at $0.494 per day which reflects an average monthly charge of $15.03, an increase of approximately $7.52 per month from the currently effective charge. This proposed charge reflects the $20.70 customer component identified in the embedded class cost of service as shown on Statement N, Schedule N-1, page 1. The Basic Service Charge is collected on a daily basis in order to avoid prorating the monthly charge when customers are in service less than 30 days, on average, or when a billing period extends beyond a 30 day average. A typical residential customer, using approximately 900 kWh on a monthly basis will see an increase in their electric service bill of approximately $20 on a monthly basis as shown on Exhibit No. ___ (RJA-2), page 1 of 13.

Q. Has Montana-Dakota prepared overall bill impacts by Rate Class?

A. Yes. Total overall annual bill impacts in dollars and percentages are presented for each Rate Schedule in Exhibit No.___ (RJA-2), pages 2 – 13, titled Bill Comparison Annual Effects. The stratified bill comparisons are presented over ranges of annual billed dollars, including the number of customers in each strata and the average monthly kWh usage.

Q. Does this conclude your direct testimony?

A. Yes.