MONTANA-DAKOTA UTILITIES CO.

Before the North Dakota Public Service Commission

Case No. PU-22-___

Direct Testimony of Ronald J. Amen

May 16, 2022

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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 North Dakota Public Service Commission ("Commission")?

A. Yes. I provided expert witness testimony on behalf of Montana-Dakota in Case No. PU-20-379.

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 K, Statement L, and the following exhibits:

- Exhibit No.____(RJA-1), Overall Bill Impact
- Exhibit No.____(RJA-2), Estimated Residential Bill Increases

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

[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).

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 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 North Dakota load data (2014-2021). Montana-Dakota meets all three FERC tests for using 12 CP for five out of the eight years. For 2015 and 2020 Montana-Dakota meets two of the three tests, and for 2016 Montana-Dakota meets one of the three tests. 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 system. Table 2 below shows the results of the Montana-Dakota's FERC 12-CP test.

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%
2021	17.6%	68.2%	83.8%
2020	18.2%	62.5%	84.1%
2019	12.9%	74.5%	89.5%
2018	16.2%	72.0%	86.8%
2017	15.0%	67.0%	85.9%
2016	19.2%	65.0%	84.0%
2015	16.7%	65.1%	83.8%
2014	12.0%	72.6%	83.5%

*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 cost is 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 North Dakota and its other jurisdictions.

Q. Does the one-mile minimum system approach a 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 three types of transformers (single-phase and three-phase pad mount transformers, and single-phase line transformers).[2] The weighted average of the three types yields the two classification components for the complete account.

[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.

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 – Primary	70.9%	29.1%
365	Overhead Conductors	92.4%	7.6%
367	Underground Conductors	85.9%	14.1%
364-367	Weighted Average	83.4%	16.60%
368	Line Transformers	64.1%	35.9%

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 – Generation 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 2019, 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 93% of jurisdictional load. The classes making up the remaining 7% 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 (2023), 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: 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 and benefits and post retirement 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 Total Customers.

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	2.498%	($19,599,153)
Small General	4.199%	($1,717,605)
Irrigation	(4.061%)	($125,973)
Large General Primary	5.533%	($1,274,750)
Large General Secondary	10.448%	$6,454,832
TOD Large General Primary	6.867%	($4,106)
TOD Large General Secondary	11.329%	$156,616
Space Heating	5.307%	($336,128)
Small Municipal	0.903%	($117,868)
Municipal Lighting Primary	14.815%	$16,238
Municipal Lighting Secondary	9.628%	$179,242
Municipal Pumping Primary	2.874%	($281,162)
Municipal Pumping Secondary	7.930%	$26,248
Outdoor Lighting	7.600%	$3,184
Interruptible Demand Response	11.627%	$279,336
Special Contracts	-	($1,198,470)
SYSTEM TOTAL	5.347%	($17,539,519)

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 K, Cost of Service by Component, consists of 17 pages and presents a summary of each rate class's projected 2023 Test Year rate base, the revenue requirements necessary to achieve the requested rate of return, and the rates of return under current rates.
- Statement K, Schedule K-1, consists of 102 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 K, Schedule K-2, Allocation Factor Report, consists of 27 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 K.

A. Statement K, provides a report entitled "Cost of Service by Component." This report shows the total dollars and unit cost required under each rate if the projected rate of return of 7.513 percent were to be earned for the demand – production and transmission, demand – distribution, energy, and customer cost components of each rate schedule. Statement K also shows the system total rate of return before increase as well as the individual rate schedule rates of return before increase.

Statement K, Schedule K-1, is a report of the projected 2023 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 Statement K, Schedule K-2.

The COSS is based on a projected 2023 average test period for North Dakota electric operations sponsored by Company witness Ms. Vesey.

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 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 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 peak 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

[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.

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. 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 revenue increase of $17,539,519 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 Statement L, Schedule L-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*, in Statement L, Schedule L-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 or 1.00). 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.

A third option was to limit the increase to customer classes above parity to receiving a revenue increase equal to 1/3 of the system average increase, or 4.634%, and cap the maximum increase to any class at 35%, with the balance of the increase going to the Residential class. Classes where an increase between 4.634% and 35% would bring them to parity were brought to parity. This option would mitigate the divergence from parity for those classes above parity, while making reasonable movement towards parity for the other classes[4] (see *Scenario B*, *Minimum Class Increase of 1/3 of System Average, Maximum of 35% Increase, Remainder to Residential*, in Statement L, Schedule L-1).

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 Schedules 10, 13, and 16), Small General Service (Rate Schedule 20 and 26), Irrigation Service (Rate Schedule 25), Large General Service (Rate Schedule 30), TOD Large General Service (Rate Schedule 31), Space Heating (Rate Schedule 32), Small Municipal Service (Rate Schedule 40), Municipal Lighting Service (Rate Schedule 41), Municipal Pumping Service (Rate Schedule 48), Outdoor Lighting Service (Rate Schedule 52), Interruptible Demand Response Service class (Rate Schedule 38) and Special Contact customers, as shown in Statement L.

In the case of the Residential Service class, the revenue adjustment ensures their proposed rates will move class revenues closer to the COSS for the class. The proposed revenue increase to the residential class will improve the class's revenue to cost ratio from 0.73 to 0.88.

[4] Special contact customers were limited to the same percentage increase as Rate 30, Large General Service, Primary.

The Small General Service (0.82), Large General Service Primary (0.88), and Space Heating (0.87) customers classes' revenue-to-cost ratios were below unity (1.00) at the Company's proposed ROR of 7.513%. The proposed revenue increases to these respective classes will result in a revenue-to-cost ratio for each of these classes at parity.

The maximum revenue increase of 35% is proposed for the Irrigation Service (0.34), Small Municipal Service (0.64), and Municipal Pumping Service Primary (0.73) customer classes. The Special Contract customers were limited to the same revenue increase as the Large General Service Primary class, or 13.239%.

The COSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return 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 revenue-to-cost ratios towards unity or 1.00), as shown in Statement L, Schedule L-1, under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service class 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 respective revenue adjustments of 1/3 of the system average increase to eligible customers, will mean these classes will be slightly higher than their current parity ratio levels relative to unity. The revenue increase for TOD Large General Service Primary was further adjusted to reflect the minimum adjustment of 1/3 of the system average increase because raising the class to parity was lower than this minimum threshold.

In summary, this preferred revenue allocation approach resulted in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00, while providing moderation of the revenue impact on this class by 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 class movement, and modest reduction in the existing class rate subsidies, is desirable.

Statement L, Allocation of Revenues, presents summaries by customer rate schedule of the proposed revenue increase. This Statement displays the revenues calculated under the present and proposed rates for each customer tariff rate schedule. The proposed revenue increase by rate schedule and corresponding percentage is also shown.

The allocation of the total revenue increase of $17,539,519 to the respective rate schedules is presented in Statement L, page 2. The target revenue increase as a percentage of total class revenues, excluding fuel costs, range from 15.9% to Residential, 17.4% to Small General, 4.8% to Large General, 6.9% to Municipal Lighting, 10.8% to Municipal Pumping, and 3.5% to Outdoor Lighting.

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 L:

- Residential Service (Rates 10, 13 & 16);
- Small General Service (Rates 20 & 26);
- Irrigation Service (Rate 25);
- Large General Service (Rates 32 & 38); and
- Municipal Service (Rate 40).

Q. Please describe the proposed changes to the Basic Service Charges for the respective tariff schedules.

A. As seen on page 4 of Statement L the Basic Service Charge under Residential Rate 10 is proposed at $0.67 per day which reflects an average monthly charge of $20.38, an increase of approximately $6.39 per month from the currently effective charge. This proposed charge reflects the $29.28 customer component identified in the embedded class cost of service as shown on Statement K, 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 800 Kwh on a monthly basis will see an increase in their electric service bill of $14.94 on a monthly basis as shown on Exhibit No. (RJA-2), page 1.

The following process was used to determine the rate components for each of the other 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 7 – 26 of Statement L. A summary of the proposed charges for each rate schedule is provided on Statement L pages 4 and 5.

Q. Was there an exception to the process that you just described for any Rate Schedule?

A. Yes. Rate 32 allows for heat pump use, which operate in the summer in cooling mode. Therefore, Montana-Dakota determined that the summer demand charge for Rate 32 should be equivalent to the Rate 30 demand charge. The proposed Rate 32 summer demand charge was matched to the Rate 30 demand charge and the secondary energy charge was increased by the percentage increase allocated to the Rate Class.

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 Schedule K-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. Yes. The monthly and annual bill impacts for a typical Residential customer using 800 Kwh per year is shown on page 1 of Exhibit No.___(RJA-2), Rate 10 Residential Bill Comparison for electric service. The average monthly increase for this residential customer under the Company's proposed rate design is $14.94 or 16.6%.

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

A. Yes. Total overall bill impact revenues and percentages, and base rate bill impact percentages by Rate Class, are presented on Exhibit No. ____(RJA-1).

Q. Does this conclude your direct testimony?

A. Yes.

ATRIUM ECONOMICS
CENTERED ON ENERGY

Ronald J. Amen

Managing Partner

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

University of Nebraska,
Bachelor of Science with Distinction, Business Administration, Finance and Economics

YEARS EXPERIENCE

42

PROFESSIONAL ASSOCIATIONS

American Gas Association
Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Policy, Strategy and Analysis

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canada Energy Regulator (CER), Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system. The case resulted in a settlement with all parties.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)
Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018, 2021)
Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC. Retained in 2021 to update quantitative analysis of the operation of the transportation balancing rules for reporting requirements of the BCUC in 2022.

McDowell Rackner & Gibson Law Firm (2015 – 2016)
Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)
Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)
Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)
Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)
Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)
Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)
Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Resource Planning, Strategy and Financial Analysis

Great Plains Natural Gas (2021)
Retained to review the gas supply procurement practices and objectives of Great Plains, the interstate pipeline, storage and supply contracts, and other information available to Great Plains leading up to and throughout the severe weather event that occurred from February 13-17, 2021, and the actions by Great Plains personnel in response to the weather event, as part of a state-wide investigation by the Minnesota Public Utilities Commission. Expert testimony filed on behalf of Great Plains.

Fortis BC Energy, Inc. (2011, 2021)
Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets. In 2021, retained to refresh all quantitative analysis of the operation of the GSMIP for reporting requirements of the BCUC in 2022.

Black Hills Colorado Electric Utility (2009)
Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)
Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)
Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2003)
Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

Cost Allocation, Pricing Issues and Rate Design

Until Electric System and Northern Utilities, Inc. (2021)
Mr. Amen provided allocated cost of service, marginal cost of service, class revenue apportionment, rate design, and expert witness support for the utility's separate electric and gas general rate cases before the New Hampshire Public Utilities Commission. Cases are currently pending before the NHPUC.

Manitoba Hydro – Centra Gas Manitoba (2021)
Retained to review and assist in the regulatory approval process of the Cost of Service Study for Centra Gas Manitoba's natural gas operations. Prepared a report assessing Centra's current COSS method in conformance with the regulatory requirements of the Manitoba Public Utilities Board.

Focusing on the trends of Canadian gas distribution utilities, the COSS method utilized in the current COSS was reviewed against the: (1) cost causative factors identified for each plant and expense element of Centra's total cost of service; and (2) the current range of regulatory practices observed in the North American gas utility market. The case is currently pending before the MPUB.

Montana-Dakota Utilities and Great Plains Natural Gas (2020 – 2021)

Mr. Amen provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utilities' general rate cases before the Montana Public Service Commission and North Dakota Public Service Commission. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the Straight Fixed-Variable Rate Design (SFV) in North Dakota with analysis showing low-income residential customers would experience lower annual bills under the SFV rate design than a volumetric weighted rate design. Provided a presentation at a public input hearing and oral testimony at Commission hearings in both jurisdictions. SFV rate design was approved by the North Dakota PSC.

Chesapeake Utilities Corporation (2020 – 2021)

Reviewed and evaluated Chesapeake's Swing Service Rider (SSR), which recovers intrastate pipeline capacity costs directly from all transportation customers, and the application of the current cost allocation methodology underlying the service for its Florida gas utilities, Central Florida Gas and Florida Public Utilities. Supported Chesapeake through three primary tasks; (1) Assessment of the factors influencing the current cost allocation method, its impact on various customer groups, and data collection, (2) Assessment of the appropriateness of alternative cost allocation methods and model the application to and impact on the SSR charges, and (3) Provided a report of the evaluation, modelling results and recommendations in a report and conducted a review session with Chesapeake management personnel.

Kansas City, KS Board of Public Utilities (2019 – 2020)

Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)
Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)
Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)
Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas , Inc. subsidiary.

Westar Energy (2018)
Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)
Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018)
Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which incorporated the Black & Veatch municipal COSA model for costing and ratemaking purposes. Future project work involves working on the re-design of the

general service and industrial rate schedules, economic development rate strategies, demand response rates, and other innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:
    - Application Fees
    - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs, and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discussed accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017, 2021)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in five general rate cases before the Indiana Utility Regulatory Commission. The 2021 rate case is currently pending before the IURC.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In the latest general rate case, Mr.

Amen is sponsoring expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement.

Utility System Operations and Organizational Development

Philadelphia Gas Works (2017, 2020)
Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)
Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)
Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)
Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent

regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)
Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)
Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- New Hampshire Public Utilities Commission
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

MONTANA-DAKOTA UTILITIES CO.
ELECTRIC UTILITY - NORTH DAKOTA

Overall Bill Impact
Case No. PU-22-_____

	Revenue at Current Rates				Generation Resource Recovery Rider (GRRR)							
Rate Class	Projected 2023 Revenue at Current Rates 1/	Rider Revenue 2/	Total Revenue	Rate Design Increase 3/	Proposed GRRR Revenue	GRRR at Current Rates	Net Increase in GRRR 4/	Proposed Increase	Total Proposed Revenue	Overall Bill Impact	Base Rate Bill Impact	GRRR Bill Impact
Residential Service	$69,769,528	$12,977,876	$82,747,404	$12,511,327	$3,221,567	$1,427,566	$1,794,001	$14,305,328	$97,052,732	17.3%	15.1%	2.2%
Small General Service	10,414,218	1,615,247	12,029,465	1,990,804	400,961	177,679	223,282	2,214,086	14,243,551	18.4%	16.5%	1.9%
General Service	88,497,679	17,403,425	105,901,104	6,011,117	4,014,827	1,763,008	2,251,819	8,262,936	114,164,040	7.8%	5.7%	2.1%
Municipal Lighting	980,235	183,996	1,164,231	78,471	17,434	11,153	6,281	84,752	1,248,983	7.3%	6.7%	0.5%
Municipal Pumping	2,878,349	613,256	3,491,605	379,396	168,837	67,663	101,174	480,570	3,972,175	13.8%	10.9%	2.9%
Outdoor Lighting Service	362,968	60,721	423,689	16,328	5,230	3,672	1,558	17,886	441,575	4.2%	3.9%	0.4%
Total North Dakota Electric	**$172,902,977**	**$32,854,521**	**$205,757,498**	**$20,987,443**	**$7,828,856**	**$3,450,741**	**$4,378,115**	**$25,365,558**	**$231,123,056**	**12.3%**	**10.2%**	**2.1%**

1/ Statement F, Schedule F-1, Page 1 includes Generation Resource Recovery Rider revenue.
2/ Transmission Cost Adjustment and Reneweable Resource Cost Adjustment revenue reflecting current rates.
3/ Includes the $3,450,741 currently being recovered through the Generation Resource Recovery Rider that will be collected through base rates.
4/ Reflects the net increase for the GRRR as $3,450,741 is already reflected in the current GRRR rates.

Montana-Dakota Utilities Co.
Electric Utility - North Dakota
Estimated Residential Bill Increases
2023

		Current Rates					Proposed Rates				
	Kwh	Base Rate	Energy	Riders	FPP Charge	**Total Current Bill**	Base Rate	Energy	Riders	FPP Charge	**Total Proposed Bill**
January	1,000	$14.26	$49.28	$18.87	$22.41	$104.82	$20.77	$57.62	$21.22	$22.41	$122.02
February	1,000	12.88	49.28	18.87	22.41	103.44	18.76	57.62	21.22	22.41	120.01
March	1,000	14.26	49.28	18.87	22.41	104.82	20.77	57.62	21.22	22.41	122.02
April	700	13.80	39.75	13.21	15.69	82.45	20.10	45.58	14.85	15.69	96.22
May	600	14.26	34.07	11.32	13.45	73.10	20.77	39.07	12.73	13.45	86.02
June	700	13.80	39.75	13.21	15.69	82.45	20.10	45.58	14.85	15.69	96.22
July	800	14.26	45.42	15.10	17.93	92.71	20.77	52.10	16.98	17.93	107.78
August	1,000	14.26	56.78	18.87	22.41	112.32	20.77	65.12	21.22	22.41	129.52
September	700	13.80	39.75	13.21	15.69	82.45	20.10	45.58	14.85	15.69	96.22
October	600	14.26	34.07	11.32	13.45	73.10	20.77	39.07	12.73	13.45	86.02
November	600	13.80	34.07	11.32	13.45	72.64	20.10	39.07	12.73	13.45	85.35
December	900	14.26	46.60	16.98	20.17	98.01	20.77	54.11	19.10	20.17	114.15
	9,600	$167.90	$518.10	$181.15	$215.16	**$1,082.31**	$244.55	598.14	$203.70	215.16	**$1,261.55**
	800										
Change by Component							$76.65	$80.04	$22.55	$0.00	**$179.24**
											16.6%
										Per Month	$14.94

	Current	Proposed
Basic Service Charge/ Day	$0.46	$0.67
Energy		
1st 750 winter & summer	$0.05678	$0.06512
Over 750 winter	0.02678	0.03512
TCA	0.00801	0.00801
ECRR	0.00000	0.00000
GRRR	0.00187	0.00422
Renewable Rider	0.00899	0.00899
Fuel	0.02241	0.02241
Total Riders (excl Fuel)	0.01887	0.02122