BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE	)	
APPLICATION OF ROCKY	)	**CASE NO. PAC-E-21-07**
MOUNTAIN POWER FOR	)	
AUTHORITY TO INCREASE ITS	)	**Direct Testimony of Robert M. Meredith**
RATES AND CHARGES IN IDAHO	)	
AND APPROVAL OF PROPOSED	)	
ELECTRIC SERVICE SCHEDULES	)	
AND REGULATIONS	)	

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-21-07

May 2021

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit No. 45—Billing Determinants

Exhibit No. 46—Cost of Service - Summary by Rate Schedule

Exhibit No. 47—Cost of Service - Summary by Function

Exhibit No. 48—Cost of Service Study

Exhibit No. 49—Proposed Price Change by Rate Schedule

Exhibit No. 50—Proposed Revised Tariffs

Exhibit No. 51—Proposed Revised Tariffs in Legislative Format

Exhibit No. 52—Basis for Residential Customer Service Charge

Exhibit No. 53—Average Weighted EIM Prices

Exhibit No. 54—Average 24 Hourly EIM Prices for Winter & Summer Seasons

Exhibit No. 55—Street Light - Estimated Annual Energy Consumption

Exhibit No. 56—Monthly Bill Comparisons

Q. Please state your name, business address and present position with PacifiCorp d/b/a Rocky Mountain Power ("the Company").

A. My name is Robert M. Meredith. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and Cost of Service.

I. QUALIFICATIONS

Q. Please describe your education and professional background.

A. I have a Bachelor of Science degree in Business Administration and a minor in Economics from Oregon State University. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 16 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 11 years of experience preparing cost of service and pricing related analyses for all six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In June 2019, I was promoted to my current position.

Q. What are your responsibilities?

A. I am responsible for regulated retail rates and cost of service analysis in the Company's six state service territory.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified for the Company in regulatory proceedings in Idaho, Utah, Oregon, Wyoming, Washington, and California.

Q. What is the purpose of your testimony?

A. I present the Company's embedded class cost of service ("COS") study based on the

12-month period ending December 31, 2020. I also present the Company's proposed rate spread and rate design changes for the affected rate schedules.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- First, I describe the present revenue used in this case which is based upon calendar year 2019 billing determinants and scaled to the level of energy sales and customer count that occurred during calendar year 2020.
- Second, I present the results of the COS study, including a description of changes in the COS since the last general rate case in Docket No. PAC-E-11-12 ("2011 Rate Case"), and procedures used in the preparation of the study.
- Third, I present the Company's proposed rate spread, which is the allocation of the rate increase to the major customer rate schedules.
- Fourth, I describe and present the Company's proposed rate changes for the major customer rate schedules.
- Lastly, I present the Company's street and area lighting cost study as well as its proposal to re-design pricing for Company-owned light service.

II. PRESENT REVENUE AND BILLING DETERMINANTS

Q. What is the historic test period used for this rate case?

A. The historic test period used in this rate case is the 12-month period ending December 31, 2020.

Q. Was 2020 a unique year for the composition of customer loads and usage characteristics?

A. Yes. As a result of the COVID-19 global pandemic, the mix of customer class loads and customer usage characteristics were altered during 2020. Stay-at-home orders resulted in a relative increase in residential customer load and a slump in load for commercial and industrial customers. Table 1 below shows the year-on-year change in load and average price for each major class for calendar year 2020:

Table 1. Change to Load and Average Price in 2020

	2019	2020	Year-over-Year Change
Residential Energy Sales (MWh)	729,881	742,806	1.8%
Commercial Energy Sales (MWh)	513,409	492,420	-4.1%
Industrial Energy Sales (MWh)	191,031	153,877	-19.4%
Special Contract Energy Sales (MWh)	1,474,154	1,488,237	1.0%
Irrigation Energy Sales (MWh)	616,729	646,312	4.8%
Total Energy Sales (MWh)	3,527,919	3,526,366	0.0%

	2019	2020	Year-over-Year Change
Residential Average Price ($/MWh)	$104.63	$105.53	0.9%
Commercial Average Price ($/MWh)	$82.97	$83.45	0.6%
Industrial Average Price ($/MWh)	$68.06	$69.47	2.1%
Special Contract Average Price ($/MWh)	$57.44	$58.22	1.3%
Irrigation Average Price ($/MWh)	$87.98	$88.99	1.1%
Total Average Price ($/MWh)	$76.93	$77.94	1.3%

Table 1 shows that while overall load was nearly flat, there were significant changes in energy usage for individual classes of customers. Table 1 also shows that despite having a stable level of total usage, the average price paid by all customers was about 1.3 percent higher.

Q. Why was the average price customers paid higher in 2020?

A. Overall price was higher in 2020 for two reasons. First, the mix of customer load by class in 2020 had more energy sales for the higher priced residential and irrigation classes and less energy sales for the lower priced industrial class. Second, the customer usage characteristics in 2020 resulted in a higher average price for each major class.

On residential Schedule 1, customers pay more per kilowatt-hour ("kWh") when their monthly usage exceeds a threshold and falls into the second block.[1] On residential time-of-day Schedule 36, customers pay more for kWh consumption during the 16 hour on-peak period.[2] During 2020, there was a greater proportion of second block and on-peak energy sales which increased the average price paid by residential customers.

Most non-residential commercial and industrial load is subject to demand charges, which are based upon the highest kilowatt ("kW") reading during any 15-minute interval during the month. Declining loads for commercial and industrial customers consequently resulted in a higher average price per kWh as load factor, or the effective utilization of maximum capacity, dropped with the more fixed component of kW charges being spread across fewer kWh. In summary, increased loads for residential customers raised the average price for residential customers while decreased loads for commercial and industrial customers also raised the average price for non-residential customers.

Q. Did the Company use the actual 2020 billing determinants to prepare present revenue and proposed prices in this rate case?

A. No. For the reasons given, the Company believes that 2020 was an abnormal year for both the mix of class load as well as the underlying billing determinants within each class. The Company does not believe that customer usage characteristics in 2020 will

[1] 700 kWh per month in summer and 1,000 kWh per month in winter.
[2] 8 A.M. to 11 P.M., Monday through Friday, except holidays in summer and 7 A.M. to 10 P.M., Monday through Friday, except holidays in winter.

reflect conditions going forward.

Q. What set of billing determinants did the Company use to prepare present revenue and proposed prices in this rate case?

A. The Company used calendar year 2019 billing determinants, which were adjusted to the same overall level of energy sales and customer count as occurred in 2020. From 2019 to 2020, the Company's normalized energy sales decreased by 0.04 percent and its customer count increased by 2.17 percent. To put the 2019 billing determinants on a comparable basis with the 2020 historical test period, the Company therefore decreased all usage-related billing determinants by 0.04 percent and increased all customer-related billing determinants by 2.17 percent. The Company believes that this is appropriate since 2019 is a more typical year for customer usage patterns that will be more likely to represent the rate effective period. Exhibit No. 45 shows the billing determinants used in preparing the pricing proposals in this case. It shows billing quantities and prices at present rates and proposed rates.

Q. How was this treatment of adjusted normalized 2019 actuals applied to assumptions in the cost of service study?

A. In the class cost of service study, class energy usage and demand measurements derived from load research from 2019 information were adjusted down by the same 0.04 percent applied to billing determinants. Similarly, customer counts by class used in the cost of service study were increased by 2.17 percent. The inputs for cost of service were therefore put on a comparable basis with present revenues and billing determinants for each class.

III. CLASS COST OF SERVICE STUDY

Q. Please identify Exhibit No. 46, Cost of Service – Summary by Rate Schedule, and explain what it shows.

A. Exhibit No. 46, Cost of Service – Summary by Rate Schedule, shows the summary of the results from the cost of service ("COS") study for Idaho. It is based on the Company's actual December 2020 results of operations for the state of Idaho presented in the testimony of Company witness Mr. Steven R. McDougal. Page 1 presents a summary of the Company's actual earned rate of return by rate schedule based on current rate levels. Page 2 shows the results using the target rate of return based on the requested $19.0 million revenue increase.

Q. Please describe Exhibit No. 47, Cost of Service – Summary by Function.

A. Exhibit No. 47, Cost of Service – Summary by Function, shows the cost of service results by rate schedule and by function. Page 1 contains the total cost of service summary by rate schedule and pages 2 through 6 contain a summary by rate schedule for each function.

A. Cost of Service Study Changes

Q. Are the methodologies used in this COS study the same as those used in the cost study filed with the Commission in the 2011 Rate Case?

A. Yes. The class COS study is generally consistent with the methodologies used in the 2011 Rate Case, with the exception of two changes that the Company is proposing to the way it allocates distribution costs.

Q. What two changes does the Company propose for the allocation of distribution cost?

A. First, the Company proposes that the weighting of monthly distribution coincident peaks be based upon the capacity instead of the count of substations that peak in each month. This more accurately reflects cost causation, because the cost of a substation will be largely driven by its capacity and a simple count does not take into consideration the size of different substations as they peak throughout the year.

Second, the Company proposes allocating distribution line transformer costs on each class' share of the current installation costs of the transformers that serve them, with the exception of the lighting classes. For lighting classes, the Company proposes allocating distribution line transformers on the basis of their share of non-coincident peak ("NCP").

Q. In the 2011 Rate Case, how were distribution line transformers allocated?

A. Distribution line transformers were allocated on the maximum secondary voltage NCP for the class weighted by a coincidence factor for classes that typically share transformers. The coincidence factor recognized that transformers could be designed at capacities less than the sum of the estimated non-coincident peaks for all customers sharing that transformer, because of the diversity in the timing of their loads.

Q. How does the Company propose allocating distribution line transformers?

A. Instead of allocating on weighted maximum NCP for the class, the Company proposes allocating distribution line transformer cost on the current installed cost of the actual transformers serving each class.

Q. How did the Company determine the current installed cost of the actual transformers serving each class?

A. First, the Company determined which transformers serve each customer based upon information in its geographical information system. For transformers that are shared by more than one customer, a fraction of the transformer was allocated to that customer by taking the class average NCP for the customer and dividing by the sum of the class average NCPs for all customers sharing the transformer. For example, suppose a residential customer shares a transformer with a Schedule 23 customer. The average maximum NCP for a residential Schedule 1 customer is 5.9 kW and 7.8 kW for a Schedule 23 customer. Under this example, 43 percent[3] of the transformer would be assigned to the residential customer and the remaining 57 percent would be assigned to the Schedule 23 customer.

Next, the Company determined the current installed cost for each type of transformer based upon phase, capacity in kilovolt amperes, and whether the transformer is pole mount (overhead service) or pad mount (underground service). The Company then calculated an average transformer cost for each class by multiplying the cost of each type of transformer by the number of transformers serving each class and dividing by the number of customers in the class for the data examined.

Finally, the average installed cost for each class was input into the cost of service study and multiplied by secondary voltage customer count to produce the proposed distribution line transformer allocator.

[3] 5.9 kW / (5.9 kW + 7.8 kW).

Q. Please describe why this method of allocating distribution line transformers is more accurate.

A. This method is more accurate because it utilizes the actual current installed cost of the transformers that are serving customers and thus is a more realistic representation of the costs customers impose on the system for this aspect of their service. This method is also very similar to the way the Company allocates the costs of meters and services, which are allocated on the average current installed cost of meters and service drops multiplied by the count of customers for each class.

Q. Does the Company propose using this method to allocate transformer costs to all classes?

A. No. The Company does not have good data regarding the transformers that serve customers on the lighting classes. For the lighting classes (Schedules 7, 7A, 11 and 12), the Company proposes to allocate transformer costs on maximum NCP.

Q. Are there any new adjustments to revenue requirement that require special handling in the class cost of service study?

A. Yes. As described in Mr. McDougal's testimony, a situs reduction in renewable energy credit ("REC") sales was made to the state of Idaho to reflect an agreement the Company entered into with its largest Idaho customer. Under the terms of this agreement, Special Contract Customer 1 will forego its allocated share of REC sales and the Company will retire those RECs on behalf of the customer to help it meet its corporate sustainability goals. This situs adjustment in revenue requirement to the state of Idaho is therefore reflected in the class cost of service study as a direct assignment to Special Contract Customer 1. The reduction in REC sales revenue increases Special

Contract Customer 1's revenue requirement, which reflects this customer's choice and holds other customers harmless.

B. Description of Cost of Service Procedures

Q. Please explain how the cost of service study was developed.

A. The cost of service study utilizes the Idaho results of operations produced by Mr. McDougal. The study employs a three-step process generally referred to as functionalization, classification, and allocation. These three steps recognize the way a utility provides electrical service and assigns cost responsibility to the groups of customers for whom those costs were incurred.

Q. Please describe functionalization and how it is employed in the cost of service study.

A. Functionalization is the process of separating expenses and rate base items according to utility function. The production function consists of the costs associated with power generation, including coal mining and wholesale sales and purchases. The transmission function includes the costs associated with the high voltage system utilized for the bulk transmission of power from the generation source and interconnected utilities to the load centers. The distribution function includes the costs associated with all the facilities that are necessary to connect individual customers to the transmission system. This includes distribution substations, poles and wires, line transformers, service drops, and meters. The retail service function includes the costs of meter reading, billing, collections, and customer service. The miscellaneous function includes costs associated with demand side management, franchise taxes, regulatory expenses, and other miscellaneous expenses.

Q. Describe classification and explain how the Company uses it in the cost of service study.

A. Classification identifies the component of utility service being provided. The Company provides, and customers purchase, service that includes at least three different components: demand-related, energy-related, and customer-related components. Demand-related costs are incurred by the Company to meet the maximum demand imposed on generating units, transmission lines, and distribution facilities. Energy-related costs vary with the output of a kWh of electricity. Customer-related costs are driven by the number of customers served.

Q. How does the Company determine cost responsibility between customer groups?

A. After the costs have been functionalized and classified, the next step is to allocate them among the customer classes. This is achieved by the use of allocation factors that specify each class' share of a particular cost driver such as system peak demand, energy consumed, or number of customers. The appropriate allocation factor is then applied to the respective cost element to determine each class' share of cost. A detailed description of the Company's functionalization, classification and allocation procedures and the supporting calculations for the allocation factors are contained in Exhibit No. 48, Cost of Service – Study. Also, included in the Exhibit No. 48 is the functionalized results of operations and class cost of service detail.

Q. How are generation and transmission costs apportioned among customer classes?

A. Production and transmission plant and non-fuel related expenses are classified as 75 percent demand-related and 25 percent energy-related. The demand-related portion is allocated using the class' 12 monthly peaks coincident with the Company's system firm peak. The energy portion is allocated using class megawatt hours adjusted for losses to generation level.

Q. Please describe how distribution costs are determined.

A. Distribution substations and primary lines are allocated using the weighted monthly coincident distribution peaks. Secondary lines are allocated on NCP-only to classes whose average number of customers per transformer is greater than one. Distribution line transformers and services costs are allocated to secondary voltage delivery customers only using the installed cost of new transformers and services for different types of customers. Meter costs are allocated to all customers. The meter allocation factor is developed using the installed costs of new metering equipment for different types of customers.

Q. Please explain how customer accounting and customer service expenses are allocated.

A. Customer accounting expenses are allocated to classes using weighted customer factors. The weightings reflect the resources required to perform such activities as meter reading, billing, and collections for different types of customers. Customer service expenses are allocated on the number of customers in each class.

Q. How are administrative & general expenses, general plant and intangible plant allocated by the Company?

A. Most general plant, intangible plant, and administrative and general expenses are functionalized and allocated to classes based on generation, transmission, and distribution plant. Costs identified as supporting customer systems are considered part of the retail services function and are allocated using customer factors. Coal mine plants are allocated on the energy factor.

Q. How are costs and revenues associated with wholesale contracts and other electric revenues treated in the cost of service study?

A. The revenues from wholesale transactions are treated as revenue credits and are allocated to customer classes using appropriate allocation factors. Other electric revenues are also treated as revenue credits. Revenue credits reduce the revenue requirement that is to be collected from retail customers. The cost of purchased power contracts are allocated to customer classes using the appropriate allocation factors increasing the Company's revenue requirement.

IV. PROPOSED RATE SPREAD

Q. Please describe Rocky Mountain Power's proposed rate spread in this case.

A. The Company proposes to allocate the price change to customers in line with the class cost of service results filed in this case. In developing the rate spread, the Company proposes to follow the results of the cost of service study with one exception. The Company proposes that the rate increase be limited so that all major rate schedule classes receive proposed increases at or below 10 percent. This will assure that movement toward full cost of service responsibility is maintained for all rate schedule classes.

Q. Please describe the Company's proposal for the allocation of the revenue requirement.

A. The overall proposed revenue requirement increase is 7.0 percent. The Company proposes the following allocation of the base price increase for the major rate schedules:

Customer Class	Proposed Rate Change
Residential – Schedule 1	9.2%
Residential – Schedule 36	10.0%
General Service	
Schedule 23/23A	5.1%
Schedule 6/6A	9.4%
Schedule 9	8.1%
Irrigation – Schedule 10	6.7%
Special Contracts	
Schedule 400	4.9%
Lighting Schedules	-38.6%

Q. Please describe Exhibit No. 49.

A. Exhibit No. 49 shows the estimated effect of the proposed price change by rate schedule for the adjusted normalized test period. The table displays the present schedule number, the average number of customers during the adjusted test year, and the megawatt hours of energy use in Columns (2) through (4). Revenues by tariff schedule are divided into two columns – one for present revenues and one for proposed revenues. Column (5) shows annualized revenues under present base rates. Column (6) shows annualized revenues under proposed base rates. Column (7) shows Schedule 197 – Federal Tax Act Adjustment ("FTAA") at zero as a placeholder. Columns (9) and (10) show the dollar and percentage changes in rates.

Q. Please describe Exhibit Nos. 50 and 51.

A. Exhibit No. 50 contains the Company's proposed revised tariffs in this case. Exhibit No. 51 contains the revised tariff sheets in legislative format.

A. Federal Tax Act Adjustment

Q. What does the Company propose regarding the disposition of the remaining benefits associated with the Tax Cut and Jobs Act?

A. As discussed in the testimony of Company witness Ms. Joelle R. Steward, the Company proposes holding off on refunding the remaining deferred tax benefits and setting the price on Schedule 197 – Federal Tax Act Adjustment to zero at this time, since near-term federal tax policy is uncertain.

V. RATE CHANGES FOR THE MAJOR CUSTOMER RATE SCHEDULES

Q. How are the major rate schedules presented in the remainder of your testimony?

A. In the next two sections, I present the major customer rate schedule changes. First, I describe the changes to the residential schedules, followed by the changes to general service and irrigation rate schedules. Second, I explain changes to special contracts and the Company's proposal to move the Schedule 401 customer to Schedule 9. Third, I explain changes to Schedule 400 and Schedule 19. Fourth, I describe the Company's proposed lighting price re-design and supporting lighting cost study. Finally, I introduce Exhibit No. 56 and the monthly billing comparisons.

A. Residential Rate Design

Q. How does the Company propose to implement the price change for Schedule 1 residential customers?

A. The Company proposes to increase the customer service charge from $5 to $8 for Schedule 1. The Company also proposes flattening the differential in the tiered block energy charges by 50 percent and moving the difference between summer and winter energy prices towards levels that reflect seasonal differences in cost with an update to the seasons so that May is included in the lower cost winter season.

Q. What costs should be reflected in the residential customer service charge?

A. The residential basic charge should include the fixed costs associated with customer service, billing, and the local infrastructure that is located geographically close to the customer and is dedicated to serving one or a small number of customers. Specifically, it is appropriate for the residential basic charge to recover the full costs as shown in the cost of service study of the Retail and Miscellaneous functions and the portions of the Distribution function that are related to meters, services or service drops and line transformers. Exhibit No. 52 shows a breakout per customer for each of the cost categories that I identify for the residential Schedule 1 class. Including these cost categories, a $17.29 customer service charge can be justified. For this case, the Company proposes that the customer service charge be increased to $8 per month to make movement towards cost while minimizing bill impacts.

Q. Why is the Company proposing an increase in its customer service charge for Schedule 1 customers?

A. At $5, the Company's present customer service charge falls short of cost. Setting the customer service charge at a level that better recovers the fixed costs of customer service, billing, and local infrastructure is important because this helps the Company keep energy more affordable for its customers. Given a fixed level of revenue to be collected from all residential customers, an increase in the basic charge will lower energy charges.

Q. How does the Company's current and proposed customer service charge compare to other electric utilities in Idaho?

A. The Company's current and proposed customer service charge compare favorably to the basic charges of other major Idaho utilities. The Company examined the residential rates of 6 other electric utilities in Idaho. Table 2 below shows those basic charges as well as an average for all 6 utilities.

Table 2. Comparison of PacifiCorp's Current and Proposed Basic Charge to Other Idaho Electric Utilities

Utility	Residential Basic Charge
Current Rocky Mountain Power	$5.00
Proposed Rocky Mountain Power	$8.00
Idaho Power	$5.00
Avista	$6.00
City of Idaho Falls	$18.00
Kootenai Electric Coop Inc	$32.50
Northern Lights, Inc	$30.00
Clearwater Power Company	$33.75
Average	$20.88

Note - Prices were those available from each utility's website as of March 23, 2021

The average basic charge of the six utilities examined is $20.88, which is higher than the Company's proposed customer service charge of $8.

Q. Please explain how the Company's current tiered energy charges work.

A. Residential Schedule 1 customers are subject to seasonal inclining block tiered rates where the price of energy is more expensive when a customer uses more than a given threshold during a monthly billing period. Additionally, energy charges vary in their price depending upon the season with higher energy pricing in the summer season of

May through October and lower pricing in the winter season of November through April. During each monthly billing cycle in the winter season, a residential customer's first 1,000 kWh of energy consumption is 8.5806 cents per kWh, and all additional kWh are priced at 11.4943 cents. In the summer season, the first 700 kWh of consumption is 11.1316 cents and all additional kWh is priced at 14.9382 cents. Table 3 below shows the Company's current residential Schedule 1 energy charge prices:

Table 3. Current Residential Energy Charge Pricing

	Price
May through October	
1st 700 kWh	11.1316 ¢/kWh
All additional kWh	14.9382 ¢/kWh
November through April	
1st 1,000 kWh	8.5806 ¢/kWh
All additional kWh	11.4943 ¢/kWh

Q. Historically, why have tiered energy charges been implemented?

A. The inclining block rate structure has been used as a tool for encouraging customers to use less energy. The theory is that the first block covers some basic level of usage at a lower rate to help keep the overall bill affordable for customers and a second or third block with a higher rate makes incremental energy usage more expensive to encourage energy efficiency. For a customer with usage in the higher tier, making an energy efficient choice like installing light emitting diode ("LED") light bulbs would yield greater savings than under a flat energy charge rate design.

Q. Why is the Company proposing to cut the difference between first and second tier energy charges by half?

A. While well intentioned, tiered rates produce more problems than they solve because they are not economically justified and unduly penalize customers. In this case, the

Company proposes a flattening of the tiered energy charge rate structure. While the Company believes that eliminating tiers is in the best interest of customers in the longer term, it is only requesting a 50 percent reduction in the differential at this time to mitigate bill impacts for smaller users.

Q. Please explain why tiered rates are not economically justified.

A. There is no reason why after using 700 kWh or 1,000 kWh in a given month that the next kWh consumed by a customer should cost more. The timing of energy consumption, both seasonally and during different hours, can affect the utility's cost of providing service to the customer. The load factor or the effective utilization of kWh consumption relative to peak kilowatt demand can also change the average cost of providing energy. However, there is nothing special about additional overall usage in a monthly billing period that makes it more expensive for the utility to produce that next kWh of electricity.

Q. Please explain why tiered rates unduly penalize customers.

A. Charging higher prices for greater usage in a given month causes larger users to subsidize smaller users. Under a tiered rate structure, customers who heat their home with natural gas benefit and those who use electric heat are punished. A large household with a lot of people living under one roof will be more likely to have usage in the higher second block rate and the person living alone will likely not. Someone who has a demanding career and seldom comes home may also have less energy consumption, while a retiree who is home all day may find it more challenging to reduce electric usage. Effectively, inclining block rates unfairly reward some customers and punish others, often for reasons outside the customer's control.

Q. Is the tiered rate structure universally understood by customers?

A. No. In 2019, the Company conducted an email survey of its customers and collected end use and demographic information from participants. According to the Company's 2019 survey, only 37 percent of customers were aware of the tiered rate structure. Of those 37 percent who were aware of the structure, 38 percent said that it did not impact their electricity usage decisions.

Q. What prices does the Company propose for Schedule 1 residential energy charges?

A. The Company's proposal for residential energy charges in this case balances the need to effect change gradually while also making movement towards a more equitable and economically principled rate structure. While the inclining block rate structure is problematic, the Company proposes flattening tiered rates by half as a reasonable and gradual first step.

The Company also proposes that the difference in energy charges for both tiers would more closely reflect seasonal cost differences and that the summer season would be limited to June through October and May would move to the lower cost winter season. The Company therefore proposes a price of 9.7463 cents for the first 1,000 kWh and 11.3324 cents for all additional kWh during the winter season of November through May, and 11.6955 cents for the first 700 kWh and 13.5988 cents for all additional kWh during the summer season of June through October.

Q. Upon what basis did the Company determine a cost difference between the summer and winter seasons?

A. To determine a cost basis for charging different prices based upon the two seasons, the

Company took 15-minute PacifiCorp east balancing authority area ("PACE") Energy Imbalance Market ("EIM") load aggregation point ("LAP") prices for the 36 month period ending December 2020 and weighted it by PacifiCorp's hourly loads for each month. Exhibit No. 53 shows the average weighted EIM prices for each of the 12 months of the year. For the summer season, which includes June through October, the weighted average price is $29.73 per megawatt-hour ("MWh"), which is about 1.11 times the weighted average price of $26.86 per MWh calculated for the winter season, which includes November through May. Currently, the Schedule 1 summer energy prices are about 30 percent higher than winter energy prices. To better reflect the seasonal difference in cost while moderating potential impacts to individual customers, the Company set average summer energy prices for the first and second tier at levels that are 1.2 times the corresponding average for winter energy prices. For other rate schedules, the Company proposes relying upon the same 1.11 relative difference in the seasonal value of energy as a guide for rate design.

Q. Why is the Company moving May from the summer season to the winter season?

A. Exhibit No. 53 shows that the weighted average EIM price is the lowest in the month of May. As a result, the Company proposes moving May to the lower cost winter season for residential as well as all other rate schedules. Making this change better aligns with cost and will help customers focus their energy efficiency efforts to the higher cost summer months.

Q. How does the Company propose to implement the price change for Schedule 36 – Optional Time of Day Residential Service?

A. The Company proposes to increase the current customer service charge of $14 per month to $15, which is still below the $20.18 that can be justified by cost on Exhibit No. 52 and increase energy charges proportionately. The Company is not requesting any changes to the seasonal definitions for Schedule 36, because doing so would require re-programming meters. After the Company has data from advanced metering infrastructure in Idaho, the Company anticipates requesting improvements to the seasons and time of use periods for Schedule 36 in a future rate case.

B. General Service and Irrigation Rate Design

Q. Please summarize the Company's proposed rate design changes for general service customers.

A. For general service customers, the Company proposes moving May from the summer season prices to the winter season prices and setting seasonally differentiated rates at levels where summer prices are 1.11 times winter prices. The Company proposes to implement time of use pricing for Schedule 9 and eliminate the 15,000 kW load size cap from Schedule 9 and 31. The Company also proposes eliminating Schedule 19 and 401.

Q. What changes does the Company propose for customers on Schedule 6 and 6A?

A. The Company proposes to apply the proposed revenue requirement change by applying the average percentage price change to the customer service charge, power charges, and energy charges. Power charges were designed so that summer prices were set at a level 1.11 times winter prices.

Q. What changes does the Company propose for customers on Schedule 10?

A. The Company proposes to apply the revenue requirement change by applying the average percentage price change to the customer service charge, power charge, and energy charges.

Q. What changes does the Company propose for customers on Schedule 23 and 23A?

A. The Company proposes to apply the proposed revenue requirement change by increasing the customer service charge from $16 to $18 to make movement towards the level of $22.21 that can be justified from cost of service as shown on Exhibit No. 52. The remaining increase was applied to energy charges and the summer energy price was set at a level 1.11 times the winter energy price.

Q. What changes does the Company propose for customers on Schedule 35 and 35A?

A. The Company proposes to apply the proposed revenue requirement change uniformly to all prices.

Q. What does the Company propose for Schedule 9?

A. The Company proposes that energy charges for Schedule 9 customers be broken out into time differentiated prices for on- and off-peak consumption. Power charges were designed so that summer prices were set at a level 1.11 times winter prices.

Q. Why does the Company propose differentiating energy charges by time period?

A. The cost to produce and procure energy varies depending on the time at which customers consume it. Charging large customers different prices for energy based on time period promotes economic efficiency by giving them the opportunity to shift when they use energy from on-peak to off-peak. Customers with larger loads represent the greatest opportunity per meter for loads to be shifted into lower cost periods.

Q. What definition for on-peak does the Company propose for Schedule 9?

A. The Company proposes to use the on-peak periods of 6 a.m. to 9 a.m. and 6 p.m. to 11 p.m. in the winter months of November through May, and 3 p.m. to 11 p.m. in the summer months of June through October.

Q. Why did the Company select these periods for on-peak?

A. Similarly to how it developed a seasonal price differential, the Company developed its proposal for time of use periods for Schedule 9 based upon prices for the 15-minute PACE EIM LAP for the 36-month period ending December 2020. Exhibit No. 54 shows the average 24 hourly EIM prices for the winter and summer seasons. The Company proposes to use the top eight hours in both seasons as the on-peak period for Schedule 9. Exhibit No. 54 also shows the average prices for the on- and off-peak periods. The difference in value between the on- and off-peak periods is 1.272 cents per kWh. To moderate rate impacts to customers, the Company proposes that half of this difference or 0.636 cents per kWh would be used as the difference in energy charge prices between the on- and off-peak periods.

C. Special Contract Requirements and Schedule 401

Q. Is there a limitation on the size of customer that may take service under Schedule 9?

A. Yes. Presently, the Company's tariff Schedule 9 is restricted to customers with load sizes less than or equal to 15,000 kW. Customers with load sizes that are greater than 15,000 kW must negotiate with the Company for conditions of service under special contract arrangements.

Q. Why does Schedule 9 have this prohibition?

A. It is not entirely clear to the Company why Schedule 9 is limited to customers with load sizes of 15,000 kW or less. This limitation has been a part of the Company's Schedule 9 tariff since the 1970's.

Q. What does the Company propose with respect to this limitation?

A. The Company proposes eliminating the 15,000 kW load size limit for Schedule 9 and 31. The Company does not presently have a reason for this restriction and lifting it will make the Company's pricing more transparent for prospective customers who may consider siting new loads greater than 15,000 kW in the Company's service area. This change will also make the Company's Idaho Schedule 9 tariff better align with the Company's tariffs for transmission voltage service in its other Rocky Mountain Power jurisdictions of Utah and Wyoming where such a limitation does not exist.

Q. What does the Company propose for Schedule 401?

A. The Company proposes to discontinue Schedule 401 and move the one customer on it to Schedule 9.

Q. What is the bill impact for the Schedule 401 customer on proposed Schedule 9 rates?

A. The bill impact for Schedule 401 under Schedule 9 rates is a 5.7 percent increase.

Q. Has the Company communicated to this customer that it would be proposing to move it onto Schedule 9 as part of its rate case?

A. Yes.

Q. Why does the Company propose making this change?

A. There are no special circumstances for why the customer on Schedule 401 is different from other customers on Schedule 9, except that it has a load size greater than 15,000 kW. Schedule 401 was required for this customer because of the requirement on Schedule 9 that customers with loads greater than 15,000 kW be subject to special contract arrangements. As explained earlier in my testimony, the Company proposes eliminating this provision from Schedule 9.

D. Schedule 400

Q. Please describe the Company's proposed rate design changes for Schedule 400.

A. For Schedule 400, the Company proposes a uniform percentage increase to all billing elements.

E. Schedule 19 – Commercial and Industrial Space Heating

Q. What does the Company propose for Schedule 19?

A. The Company proposes to discontinue Schedule 19 and move the current customers served under Schedule 19 to Schedule 23.

Q. Why does the Company propose making this change?

A. Schedule 19's rates are structured in a very similar way to those on Schedule 23 with a customer service charge plus seasonally differentiated energy charges. Schedule 19 offers a much lower energy price in the winter season. Since the Company is proposing to set the difference between summer and winter energy charges at the same level as their difference in value for Schedule 23, the Company does not believe that there is a compelling reason to retain the closed Schedule 19 legacy option.

Q. What would be the bill impact to Schedule 19 customers of moving them onto proposed Schedule 23 rates?

A. The Company estimates that bills would rise on average by 13 percent for Schedule 19 customers when they are moved onto Schedule 23.

VI. LIGHTING PRICE RE-DESIGN

Q. What does the Company propose for lighting customers?

A. For Company-owned street and area lights, prices have been re-designed to be based on the level of lighting service that the Company is providing, rather than on technology (i.e., bulb) type.

Q. Please provide a brief overview of the Company's current pricing structure for Company-owned lighting?

A. The Company currently offers service to Company-owned lights under the following schedules:

- Schedule 7 - Security Area Lighting
- Schedule 11 - Street Lighting Service Company-Owned System

Street lights are provided for governmental entities to illuminate public streets, highways, and thoroughfares. Area lights, which are currently closed to new service, are provided to residential and non-residential customers to light spaces outside such as driveways or alleys. Prices for Company-owned street and area lights are based on the particular technology and type of lamp that the Company is providing. For example, a 7,000 lumen mercury vapor area light is $27.22 per month and a 4,000 lumen LED street light is $15.34. Additional charges are also imposed if a security area light has a steel pole, which varies based upon the length, vintage, and gauge. For example, an 11 gauge steel pole installed before June 1, 1973 increases the cost by $1.00 per pole per month. A three gauge, 35 foot direct, direct buried pole installed after June 1, 1973 increases the cost by $4.65 per pole per month. In summary, pricing for Company-owned lights is complicated.

Q. What does it mean to base prices for Company-owned street and area lighting on level of service?

A. Presently, prices for Company-owned street and area lights are based on the particular technology and type of lamp that the Company is providing. The Company believes that at this time it should move away from this model for pricing lights that the Company owns and maintains. Ultimately, what the Company provides street and area lighting customers is a level of light to a specific area. The Company therefore proposes that Company-owned street and area light prices be based on the level of lighting service that the Company provides irrespective of technology or lamp type. The level of lighting service would be based on ranges of LED equivalent lumens. Under this new paradigm, an LED, a mercury vapor, and a high pressure sodium vapor lamp that provide the same level of light would have the same price. For area lights, the Company proposes the following levels:

- Level 1 (0-5,500 LED Equivalent Lumens)
- Level 2 (5,501-12,000 LED Equivalent Lumens)
- Level 3 (12,001 and Greater LED Equivalent Lumens)

For street lights, the Company proposes the following levels:

- Level 1 (0-3,500 LED Equivalent Lumens)
- Level 2 (3,501-5,500 LED Equivalent Lumens)
- Level 3 (5,501-8,000 LED Equivalent Lumens)
- Level 4 (8,001-12,000 LED Equivalent Lumens)
- Level 5 (12,001-15,500 LED Equivalent Lumens)
- Level 6 (15,501 and Greater LED Equivalent Lumens)

Q. Why is the Company proposing this change to the way it prices Company-owned street and area lights?

A. First, basing prices on service level better aligns the Company's incentives towards providing the provision of lighting at the lowest possible cost. LED has emerged as the dominant lighting technology and is the most efficient way to light a space, but the present structure of its rates dis-incentivizes the Company from converting lights to LED. If the Company replaces an older light with LED, its revenue decreases to reflect the lower-priced LED lamp. Basing the price for Company-owned lights on level of service will provide the Company with an incentive to transition its fleet of lights to the most efficient technology available.

Second, the Company's present prices for Company-owned lighting service are hard to understand. Simplifying them to specific ranges of light levels makes it easier for customers to understand.

Q. What is the Company's lighting class cost study?

A. The lighting cost study is a more detailed analysis of the different prices included in the rate schedules that form the street and area lighting class. This study specifically examines three cost categories: (1) Production/Transmission/Distribution Costs; (2) Customer-Related Costs; and (3) Company-Owned Light Cost. Informed by the cost analysis and based on the Company's proposed rate spread for the lighting classes, the study produces proposed prices including those for Company-owned lights that are based on level of service.

Q. How were prices calculated on the lighting class cost study?

A. Exhibit No. 55 shows the calculations in the lighting class study, which were used to develop proposed prices. Page 1 of Exhibit No. 55 shows the estimated annual and monthly maintenance of Company-owned street and area lights. Maintenance activities include replacing poles, mast arms, photocells, and luminaires. Estimated materials and labor are shown for each maintenance activity. Page 1 also shows the estimated cost to install street and area lights on existing distribution poles and calculates an estimated monthly revenue requirement based on an 8.81 percent annualization factor. The lowest cost installation on an existing distribution pole was assumed, because it is likely that an installation on another more costly pole would be paid for by the customer as part of the line extension policy. The Company's most recent cost estimates for LED lamps were used to reflect that this is the lowest cost technology that the Company plans to use going forward. Page 2 of Exhibit No. 55 shows the estimated annual energy consumption for the different proposed street and area lighting levels of service based on the most current LED lamps which the Company plans to use for new lamps going forward. Page 2 also shows how these estimated annual energy consumption amounts, along with counts of lamps and customers, are applied to functionalized unit costs to determine the pricing for each of the proposed service levels. For the Production/Transmission/Distribution functions, the Company performed an embedded cost of service study that stripped out the cost of owning and maintaining lights. This study produces the average cost of delivering energy to the lighting classes apart from the cost of the lamp installations themselves. For the Customer and Miscellaneous functions, costs were allocated to each rate schedule based on customer count. The Company-Owned Lighting function was calculated by applying the monthly installation and maintenance costs for each lighting service level.

Page 3 of Exhibit No. 55 show the present and suggested proposed prices for each level of lighting service. The bottom of page 4 shows that an adjustment factor of 44.18 percent applied to Company-Owned Lighting prices is required to achieve the overall target revenue requirement for both of the Street and Area Lighting classes specified in the Cost of Service Study. This approach to setting prices ensures that the relative differences across prices for different levels of service reflect the cost of owning and maintaining current LED technology, but collect the embedded revenue requirement related to cost in the test period.

Page 4 of Exhibit No. 55 shows the list of consolidated prices for the lighting classes for reference. With this new pricing, the count of unique Company-owned street and area lighting charges goes from 40 prices to 12 prices.

A. Area Lights

Q. In addition to re-designing the Company-owned lamp prices, what other change does the Company propose for Schedule 7 - Security Area Lighting?

A. The Company proposes that Schedule 7 be open to new service again on existing distribution poles only.

Q. Why did the Company close its area light schedule to new service?

A. My understanding is that area lights were closed for new service for two reasons. First, the Company was concerned about the costs associated with maintaining lights at homes and businesses throughout its service area. Second, the Company reasoned that a customer could always install an area light on its own side of the meter.

Q. Why is the Company requesting that Schedule 7 be opened up for new service again?

A. With LED technology, maintenance of area lights is far less than for other legacy lighting technologies. While a high pressure sodium vapor lamp needs to have its bulb changed out every six years on average, an LED area light head is designed to last for 25 years. With the falling cost of LED lights, the Company can provide an efficient, low-cost solution for its customers' outdoor lighting needs.

While customers can install area lights on their side of the meter, this is not always a good option for them. Sometimes the area that a customer wants to illuminate is much closer to distribution lines than to the customer's meter. In these circumstances, particularly in the Company's more rural service areas, running wire underground to a light a long distance away is not always cost effective or practical. Offering to own and maintain area lights can be a valuable service for customers.

Q. Why is the Company restricting new lamps to being on existing distribution poles only?

A. Installing new poles on customers' premises to provide area lighting service can increase maintenance costs for the Company and can also create access issues for service personnel who need to visit a lamp. Restricting new service to existing distribution poles mitigates these concerns.

Q. Does the Company propose any other changes to its lighting schedule tariffs?

A. Yes. Presently, Schedule 7 contains a price for customer-owned and customer-maintained 150 watt sodium vapor flood lights. To keep all customer-owned lights together, the Company proposes moving this price to Schedule 12 and renaming

Schedule 12 to "Street and Security Area Lighting Service – Customer-Owned System".

Monthly Billing Comparisons

Q. Please explain Exhibit No. 56.

A. Exhibit No. 56 details the customer impacts of the Company's proposed pricing changes. For each rate schedule, it shows the dollar and percentage change in monthly bills for various load and usage levels.

Q. Does this conclude your direct testimony?

A. Yes.