Exh. RMM-1T
Docket UE-19____
Witness: Robert M. Meredith

BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-19____

PACIFICORP

DIRECT TESTIMONY OF ROBERT M. MEREDITH

December 2019

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp.

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 am testifying for PacifiCorp dba Pacific Power & Light Company (PacifiCorp or the Company).

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

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 15 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over nine years of experience preparing cost of service and pricing related analyses for all of the 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. Have you appeared as a witness in previous regulatory proceedings?

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

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Company’s functionalized class cost of service study, proposed revenue allocation of the requested revenue increase and proposed rates.

Q. What is the proposed change in rates requested by the Company in this case?

A. The Company is requesting a net $4.0 million decrease that consists of a base revenue requirement increase of $3.1 million offset by a $7.1 million decrease associated with the return of deferred federal tax reform benefits, referred to as the Federal Tax Act Adjustment (FTAA).

Q. Are there other rate changes occurring on January 1, 2021, that will impact what customers see on their bills?

A. Yes. In Order 01 in docket UE-171219, the Commission authorized the Company to pass through to customers the deferred tax reform benefits of the lower corporate tax rate, through the FTAA, effective January 1, 2019. This credit, which will back to $8.1 million to customers in 2020, will expire on January 1, 2021, which is, coincidentally, the requested effective date of this general rate case. Thus the net impact to customer rates on January 1, 2021, will be an increase of $4.1 million.

Q. What is the expected customer bill impact of the Company's request and the expiration of the FTAA on a typical residential customer?

A. A typical residential customer with monthly energy consumption of 1,200 kWh would see a monthly bill increase from the requested rate change of $3.33 or 3.19 percent.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- First, I present the results of the cost of service study, including a description of the procedures used in the preparation of the study.
- Second, I present the Company's proposed rate spread, which is the allocation of the rate increase to the customer rate schedules.

- Third, I introduce proposed revisions to the tariffs.
- Fourth, I present a new adjustment schedule and a change to the amount, which would be credited back to customers as a result of the Tax Cuts and Jobs Act (TCJA).
- Fifth, I present proposed minor revisions to the decoupling mechanism.
- Lastly, I explain the Company's calculation of normalized present revenues, which are used for the calculation of the revenue requirement.

Q. Please summarize the Company's rate spread and pricing proposals in this case.

A. PacifiCorp has not filed a full general rate case since 2014. Since that time, the electric industry has continued to evolve, driven by, among other things, increased customer engagement with their electricity usage, changes in technology, and changes in state policies such as the Clean Energy Transformation Act (CETA).[1] PacifiCorp's pricing proposals in this case take into consideration the changes that have occurred since the Company's 2014 general rate case, docket UE-140762 (2014 Rate Case), in many cases modernizing pricing proposals to provide customers more accurate price signals, offer customers more choices, and simplify and streamline pricing options for all customers.

The Company proposes a rate spread and rate design that is guided by the results of the cost of service study. For residential customers, the Company proposes to increase the residential basic charge from \$7.75 to \$9.50 per month. In addition, the Company proposes new time of use pricing pilots for residential, irrigation, and

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[1] Senate Bill 5116, 66th Leg., 2019 Reg. Sess. (Wa. 2019).

smaller general service customers. For large general service, the Company proposes modernizing the time of use periods and breaking the energy charge into prices for on- and off-peak consumption. Finally, for street and area lighting, the Company proposes simplifying Company-owned per lamp prices based on the results of its street light cost study. The Company's proposals make significant progress towards pricing for its customers that help to make energy more affordable, adapt to a more sustainable future and give customers choices. These are the key goals for the Company's rate design proposals, and I describe each proposal in light of these goals.

CLASS COST OF SERVICE STUDY

Q. What are the results from the class cost of service study?

A. Exhibit No. RMM-2 shows the results from the embedded class cost of service study. The study is based on the Company's annual results of operations for Washington presented in the direct testimony and exhibits of Ms. Shelley E. McCoy. Exhibit No. RMM-2 summarizes, both by customer group and function, the results of the study for the 12 months ended June 30, 2019. Page 1 shows the results at the Company's earned rate of return for that period. Page 2 shows the results using the target rate of return based on the requested $3.1 million revenue requirement increase.

Exhibit No. RMM-3 shows the cost of service results in more detail by class and function. Pages 1 and 2 summarize the total cost of service by class, pages 3 through 19 contain summaries by class for each major function, and pages 20 through 21 contain a summary by class and major function on a unit cost basis.

Exhibit No. RMM-4 shows the detailed results of the cost of service study using the most recently available methodologies considered by Staff of the

Washington Utilities and Transportation Commission (Commission) in the cost of service rulemaking proceeding in the Commission's generic investigation into electric cost of service studies, docket UE-170002 (COS Rulemaking).

Q. Is the cost of service study filed in this case consistent with the methodology used in the 2014 Rate Case?

A. No. The cost of service study filed in this case incorporates the proposed rules in the COS Rulemaking, which reflect significant changes to the cost of service approach used by PacifiCorp in the 2014 Rate Case. As a result, the methodology employed in the cost of service study filed in this case is substantially different than the study filed in the 2014 Rate Case. While the COS Rulemaking has not entirely concluded, Commission Staff's draft rules have been published and the Company has consequently endeavored to ensure that its cost of service study conforms to them. I support the draft rules in the COS Rulemaking and believe that following them is the most appropriate path forward for the Company's cost of service study in this rate case.

Q. In addition to the work that is nearing completion on the COS Rulemaking, are there other changes that influence cost allocations in the Company's class cost of service study?

A. Yes. As noted in the testimonies of Ms. McCoy and Mr. Michael G. Wilding, the methodology of allocating costs among the states reflects the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) as agreed to in the WIJAM memorandum of understanding. Significant changes include system allocation of non-emitting resources, excluding non-Washington qualifying facilities, and a transition to a system allocation for existing transmission. To be consistent with the WIJAM, the demand-related allocation of transmission in the class cost of service study is based on peaks coincident to the 12 monthly PacifiCorp system peaks instead of peaks coincident with the West Control Area Inter-Jurisdictional Allocation Methodology (WCA) peaks. For class cost of service allocations, the Company continues to use WCA peaks to allocate Generation function costs, since emitting resources are allocated by state using WCA peaks. One key difference, however, is that the times of the WCA peaks used for class cost of service allocations are based on those peak values net of renewables, which is a concept I will explain in more detail later in my testimony.

Q. In the 2014 Rate Case, did the Commission weigh-in on the classification and allocation methodologies used in the Company's cost of service study?

A. Yes. The Commission's final order in the 2014 Rate Case stated that, "However, the parties raise sufficient concerns to persuade us that the Company should return in its next case to using the Commission-approved Peak Credit method or provide a more detailed justification for using an alternative approach, or approaches including the use of Peak and Average method compared to the Peak Credit method, as well as consideration of the number of hours that should be used within these methods."[2] Since the 2014 Rate Case, stakeholders in Washington have worked collaboratively through the COS Rulemaking to develop an alternative approach, taking into consideration the feedback of a wide variety of different stakeholders. As a result, the Company is using the Renewable Future Peak Credit method in this case, which has

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[2] *WUTC v. Pac. Power & Light Co.,* Docket No. 140762, Order 8 at ¶161 (March 25, 2015).

some similarities with the Peak Credit method that has been used in the past, and is consistent with the direction of the COS Rulemaking.

Q. Please describe some of the more notable changes to the cost of service study for this case.

A. Changes to the methodology employed in the cost of service study include the following:

- Generation costs not related to net power costs are classified as demand- and energy-related based on the Renewable Future Peak Credit method.
- Generation net power costs are classified 100 percent as energy-related.
- Generation demand-related costs are allocated on the basis of class usage during the highest 12 monthly WCA coincident peaks net of renewables.
- Transmission costs are classified 100 percent as demand-related.
- Transmission costs are allocated to class loads during the 12 monthly PacifiCorp system coincident peaks.
- Distribution substations are allocated to class loads coincident with the Company's two Washington distribution peaks in summer and in winter.
- Distribution line transformers are allocated based on the current installation costs of each class' share of the transformers that serve them for all classes except the Street and Area Lighting class. Transformer costs are allocated to the Street and Area Lighting class on the basis of its share of non-coincident peak.

Description of Procedures

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

A. The study employs a three-step process generally referred to as functionalization, classification, and allocation. These three steps recognize the way a utility provides electric service and assigns cost responsibility to the customer groups for whom those costs are incurred. A detailed description of the Company's functionalization, classification, and allocation procedures and the supporting calculations for allocation factors are contained in pages 1 through 9 of Exhibit No. RMM-4.

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

A. Functionalization is the process of separating expenses and rate base items according to five utility functions—generation, transmission, distribution, customer, and common.

- The generation function consists of the costs associated with power generation, including wholesale purchases and sales.
- The transmission function includes the costs associated with the high voltage system used 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 customer function includes the costs of meter reading, billing, collections, and customer service.

- The common function includes administrative and general costs along with cash working capital.

Q. Describe how the classification process is used in the cost of service study.

A. Classification identifies the component of utility service being provided. The Company provides service that includes at least three different cost components: demand-related, energy-related, and customer-related. 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 kilowatt hours (kWh). Customer-related costs are driven by the number of customers served.

Q. Please describe how the Company determines cost responsibility among customer classes.

A. After 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's share of a particular cost driver, such as system peak demand, Washington distribution 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's share of the costs.

Q. How are generation costs classified between demand and energy?

A. The Company's generation-related resources must provide the capacity to meet peak load (demand) and the energy needs of its customers throughout the year. In this case, the Company uses the Renewable Future Peak Credit method discussed in the COS Rulemaking to determine the proportion of fixed generation costs that are demand-related. In this proceeding, the calculation results in 59 percent of generation costs classified as demand-related and the remaining 41 percent of costs classified as energy-related. The variable costs also known as net power costs within the generation function such as fuel, purchased power, and sales for resale are classified as energy-related.

Q. Please describe how the Renewable Future Peak Credit value was developed.

A. Exhibit No. RMM-5 shows the calculation of the Renewable Future Peak Credit value. The Renewable Future Peak Credit value was developed by calculating the costs of the lowest cost renewable energy generation source and storage resource considered in the Company's 2019 integrated resource plan (IRP). To determine the demand component of the Renewable Future Peak Credit method, the cost of a 1,200 MW, Washington-based pump storage system was used. While a compressed-air energy storage system does have a lower cost in the Company's IRP, these systems are used in concert with fossil fuel generators and were therefore not considered.[3] The cost to charge the system, including losses due to system efficiency, was used to determine the fixed cost per kW attributed to the demand cost of the credit.

The lowest cost generation option is a 3.6 MW wind turbine located in Wyoming. To determine the energy component, the fixed cost per kW of the Wyoming wind resource was first multiplied by the quotient of the WCA load factor and output capacity factor. This quotient is listed as the total kW capacity required,

[3] *Pacific Power & Light Company 2019 Integrated Resource Plan*, Docket No. UE-180259, Volume I at 149, (Oct. 18, 2019).

since this is the quantity of nameplate capacity that would be needed to produce the same energy as one kilowatt of WCA load on an annual basis. The portion of cost attributed to capacity contribution, which is based on the cost of storage, was subtracted from the total fixed costs to yield the total energy related cost. Dividing the total energy cost and demand cost by the sum of both costs gives the demand and energy components of the Renewable Futures Peak Credit to be used in the classification of fixed Generation function costs.

Q. How are generation costs allocated?

A. As described in the COS Rulemaking, the demand-related portion is allocated using class loads coincident with the Company's highest 12 monthly retail WCA peak loads net of renewable output. The energy-related portion is allocated using class annual megawatt hours (MWh) adjusted for losses.

Q. How is renewable output netted out of the 12 coincident peaks?

A. To properly reflect cost causation, it is important that class allocations reflect the total Company costs which are allocated to the state of Washington. In inter-jurisdictional allocations for this case, the Company has proposed that many fixed generation costs continue to be allocated using WCA loads. At the same time, the Company is proposing to allocate to Washington a share of all of PacifiCorp's non-emitting resources.[4] Accordingly, for class allocations, the Company proposes that the 12 monthly WCA peaks be netted by the WCA allocated proportion (allocation to Washington, Oregon, and California) of all of PacifiCorp's renewables to which the

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[4] *See* Exhibit No. MGW- 2. Consistent with the WIJAM, this share of all non-emitting resources excludes Qualifying Facilities not located in Washington.

Company is requesting recovery in this case. Netting by the WCA allocated proportion of all renewables ensures that their scale is appropriately commensurate with the WCA loads used to determine the hours for peak load allocation.

Q. How are transmission costs classified and allocated?

A. Consistent with the COS Rulemaking, transmission costs are classified as demand-related and are allocated using class loads coincident with the Company's 12 monthly PacifiCorp system peaks.

Q. How are distribution costs classified and allocated?

A. Distribution costs are classified as either demand-related or customer-related. In this study, meters, services, and transformers are considered customer-related, with all other costs considered demand-related. To follow the COS Rulemaking, distribution substations and primary lines are allocated on class loads coincident with the Company's highest Washington distribution system peak in the summer and winter seasons. Distribution line transformers are allocated based on the cost to install new transformers multiplied by the number of transformers serving each customer class. For the Street and Area Lighting class, line transformers are allocated on non-coincident peak, since assignment of transformers to this class is challenging with the datasets available to the Company. The costs of secondary lines are allocated using the same method as line transformers, but are only allocated to residential, small general service, and street and area lighting customers where line transformers are jointly used by more than one customer. Services costs are allocated to secondary voltage delivery customers only. The allocation factor is developed using the installed cost of new 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 activities such as meter reading, billing, and collections for different types of customers. Other customer service expenses are allocated based on the number of customers in each class.

Q. How does the Company allocate administrative and general expenses, general plant, and intangible plant?

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 customer function and have been allocated using customer factors. Coal mine plant is allocated consistent with generation resources.

Q. How are other revenues treated in the cost of service study?

A. Other electric revenues are treated as revenue credits. Revenue credits reduce the revenue requirement that is to be collected from retail customers.

Q. Does the cost of service study include results for partial requirements service on Schedule 47T (customers 1,000 kW and over)?

A. No. Customers on Schedule 47T are not included in the embedded cost of service study because large commercial or industrial partial requirements customers typically have very sporadic loads that vary from day to day and from year to year, producing volatile cost of service results depending on whether or not service has been required during actual peak hours. The Company's practice is to derive prices for this service from rates for full requirements service. Revenue from customers on Schedule 47T is allocated back to other classes as a revenue credit.

RATE SPREAD

Q. How is the Company proposing to allocate the revenue increase to customer classes?

A. Based on the direct testimony and exhibits of Ms. McCoy, the Company's requested base revenue requirement increase in this case is $3.1 million, or 0.9 percent. The Company proposes a rate spread that allocates the revenue requirement change to rate schedule classes guided by the results of the cost of service study. Specifically, the Company proposes to: (1) allocate an increase to the residential, Schedule 48T, and Schedule 48T-Dedicated Facilities classes that is one-half greater than the overall increase—or about 1.4 percent; (2) reduce overall revenue from the lighting schedules so that it recovers the level that the cost of service study indicates for the class; (3) the remaining increase is then spread equally to the rest of the rate schedules, which results in a 0.7 percent increase. Table 1 shows the Company's proposed rate spread compared to the cost of service study results.

Table 1. Proposed Rate Spread Relative to Cost of Service Results

A	B	C	D	E	F
Schedule		Cost of Service Study		Proposed Change	
No.	Description	% Change	% of COS	% Change	% of COS
16	Residential	6.7%	94.6%	1.4%	95.0%
24	Small General Service	-8.0%	109.7%	0.7%	109.5%
36	Large General Service <1,000 kW	-3.8%	104.9%	0.7%	104.7%
48T	Large General Service >1,000 kW	2.0%	98.9%	1.4%	99.4%
48T	Large General Service Dedicated Facilities	4.9%	96.2%	1.4%	96.7%
40	Agricultural Pumping Service	-6.0%	107.4%	0.7%	107.1%
15,51,53,54	Street Lighting	-32.1%	148.8%	-32.1%	100.0%
	Total Washington Jurisdiction	0.9%	100.0%	0.9%	100.0%

Column C shows the percentage increase required from the cost of service study. Column D shows each rate schedule's current revenues as a percentage of cost of service. Column E shows the Company's proposed rate spread for the requested increase. Column F shows each rate schedule's proposed revenues as a percentage of cost of service. Table 1 demonstrates that the proposed rate spread minimizes price impacts on customers while fairly reflecting cost of service and moving each class closer to its cost of service.

Q. Please explain Exhibit No. RMM-6.

A. Exhibit No. RMM-6, Table A (page 1), shows the effect of the proposed base rate increase as well as the proposed FTAA. In Table A, current rate schedule numbers, proposed rate schedule numbers, the number of customers during the test year, and the MWh of energy consumption during the test year are displayed in columns two through five. Normalized base revenues for the test period are displayed in column six. Proposed base revenues are displayed in column seven. Column eight shows the proposed base change in revenues for each schedule. Column nine shows the proposed percentage change. The overall proposed base rate increase of $3.1 million is shown at the bottom of column eight. Column 10 shows the proposed FTAA and column 11 shows the percentage change, which is a reduction in rates of $7.1 million. Columns 12 and 13 show the net proposed decrease of $4 million for both base revenues and the FTAA.

Table B (page 2), shows the effect of the proposed Schedule 94, System Transmission Adjustment, to phase in the incremental costs of a system allocation of all transmission costs agreed to in the WIJAM. These costs are described in the testimony of Ms. McCoy, and I explain the proposed Schedule 94 later in my testimony.

RATE DESIGN

Q. What underlying themes guide the rate design proposals that you are making in this rate case?

A. There are three major underlying themes to the rate design proposals that I make—making energy more affordable, adapting to a more sustainable future, and giving customers choices.

Q. How do your rate design proposals in this case make energy more affordable?

A. Making energy more affordable means designing rates in ways that make energy consumption less expensive for customers. My testimony proposes several ways to achieve this goal. Improving and expanding time varying rates gives customers more opportunities to save when they consume energy during times when energy is less expensive. More closely aligning the different elements of rate design with what the cost of service study indicates should be collected through each component generally will move costs from energy charges onto demand and customer charges. Unwinding rate structures with tiered energy charges will make the cost of energy more equitable across different customer usage levels and minimize the impacts of the Company's current tiered rates, which for the residential class can be particularly harmful to low-income customers.

Well-designed prices should send a clear price signal to customers about the incremental cost of additional energy consumption and thus promote energy efficiency. However, when rate structures unduly penalize incremental energy usage above its additional cost, it can result in unintended consequences. For example, inverted block tiered energy pricing discourages electric vehicle adoption and encourages the expansion of natural gas service.

Q. What does it mean for rate designs to adapt to a more sustainable future?

A. In the context of rate design, adapting to a more sustainable future means creating opportunities for the Company's rates to encourage customer behavior that mitigates impacts to the environment. Signaling customers to shift energy use to when renewables are more prevalent on the grid and removing disincentives to electrification are important ways that this can be accomplished.

Q. How do your rate design proposals give customers choices?

A. Giving customers choices means providing more than one option for how a customer will be charged for the services they receive from the utility. When customers have different options, this creates possibilities for bill savings, utility cost reductions, and the ability to use electricity in new and beneficial ways. For this rate case, the Company is proposing three new time of use pilot programs that would be available for participation by different segments of customers.

PROPOSED RATES

Q. How does the Company propose to design rates to implement the proposed revenue increase?

A. The Company's rate design proposals are guided by the cost of service study to reflect costs and to recover the proposed revenue requirement. Exhibit No. RMM-7 contains the proposed prices and the billing determinants used in calculating proposed prices.

Q. Has the Company included an exhibit that shows the estimated bill impacts from the proposed rates?

A. Yes. Exhibit No. RMM-8 contains monthly billing comparisons for customers with different consumption levels for each rate schedule. The bill comparisons presented include the impact of both the expiration of the current FTAA credit as well as the new level of credit proposed in the FTAA.

Residential Rate Design

Q. Please describe the Company's proposed rate design for the residential rate schedules.

A. The Company proposes increasing the basic charge to $9.50 per month. The remainder of the allocated increase will be recovered through the energy charges. The Company also proposes flattening the inverted tier block rate structure so that the first and second block energy prices make movement to be 50 percent closer together. In other words, the Company proposes modifying the relationship in price between both blocks such that the difference is halved.

Q. What costs should be reflected in the residential basic 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 Customer function and the portions of the Distribution function that are related to meters, services or service drops and line transformers. Exhibit No. RMM-9 shows a breakout per customer for each of the cost categories that I identify. Including these cost categories, an $11.35 basic charge can be justified. For this case, the Company proposes that the basic charge be increased to only $9.50 per month to minimize individual customer impacts and support the objective of gradualism. This change makes a conscious and incremental movement towards an appropriate basic charge for residential customers.

Q. Is recovering line transformers in the basic charge appropriate?

A. Yes. There are several reasons why the cost of line transformers should be recovered in the basic charge. First, the cost of line transformers is unaffected by changes in customer energy usage. Transformers are usually set at the time of construction and are designed to provide a sufficient level of capacity for the needs of a small group of customers that are located close-by. Transformers come in standard sizes and are not available in a continuous and granular range of capacities. For example, the smallest sized transformer is 10 KVA. The next largest size is 25 KVA or two and a half times larger. The next largest single phase transformer is 50 KVA or twice as large. When designing the electric infrastructure for a community of residential homes, appropriately sized transformers are selected to ensure that ample capacity is available to serve the different customers connected to them including some level of potential load growth. While a customer's conservation efforts may lessen the strain on upstream utility facilities and, in aggregate with many other customers, could defer the need to re-conductor a line, upgrade a substation or build new generating plants, those conservation efforts will not lower the Company's cost of line transformers.

Second, the cost of a transformer does not increase proportionately to overall customer size. A pole mounted 25 KVA transformer costs about $3,273 to install. A pole mounted 50 KVA transformer that has twice the capacity costs about $3,762 to install, an increase of only approximately 15 percent. Because of these economies of scale, a large factor in the overall cost of line transformers in the Company's system is the total number of transformers deployed. The cost to provide this equipment is consequently not driven entirely by size, but by the number of customers and their geographic dispersion.

For the residential class, size of customer may be particularly unimportant in driving the Company's cost of line transformers, because of how line extension allowances work. When service is provided to residential customers, the portion, if any, of the cost to connect to the Company's system for which they are responsible, otherwise known as the line extension allowance, is a fixed dollar amount. If the cost to connect a residential customer exceeds their line extension allowance,[5] they will pay for that additional cost. For a very large residential customer who requires a

[5] See Rule 14 of the Company's tariffs. The line extension allowance for residential customers is currently set at $3,150.

much larger than average transformer, that customer would likely not have had a sufficiently large line extension allowance and would have paid for the incremental cost of the larger transformer serving it upfront.

Finally, line transformers typically serve a small number of customers and are located geographically close to the customers they serve. On average, 3.9 residential customers are served by a transformer. Within PacifiCorp's less urban service area,[6] about 23 percent of line transformers serve a single residential customer. Line transformers should not be lumped together with generation, transmission and upstream distribution costs that are often included in the energy charge for residential customers. Generation, transmission and upstream distribution facilities are used by many customers, are often located far away from a customer's location and are consequently a more fungible resource that can more flexibly serve customers as they come and go and as loads rise and fall. Line transformers are more similar to meters and service drops, because they serve only one or a very small number of customers and are located close to customers. They are inflexible and cannot be easily redeployed to other customers as loads fluctuate.

Q. What is the effect of increasing the basic charge?

A. Given a fixed level of revenue to be collected from all residential customers, an increase in the basic charge will lower energy charges.

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[6] At about 51 customers per square mile, Pacific Power's Washington service area is more than three and a half times less dense than Puget Sound Energy's service area which has about 183 customers per square mile.

Q. How does the Company's basic charge compare to other utilities in the state?

A. Table 2 below shows how the Company's current basic charge compares with the other electric investor owned utilities (IOUs) in the state as well as nearby local publicly owned utilities.

Table 2. Residential Basic Charges from Other Utilities

Utility Name	Residential Basic Charge
Avista (Washington)	$9.00
Benton PUD	$19.16
Chelan County PUD	$7.70
Columbia REA	$47.00
Franklin PUD	$34.00
Grant County PUD	$16.73
Klickitat County PUD	$20.62
Puget Sound Energy	$7.49
Average Rate	$20.21

The Company's current basic charge is well below the $20.21 average of the other eight utilities examined in Table 2. Only two other utilities in this list have lower basic charges. Even with the Company's proposed $9.50 basic charge, only three other utilities would have lower basic charges.

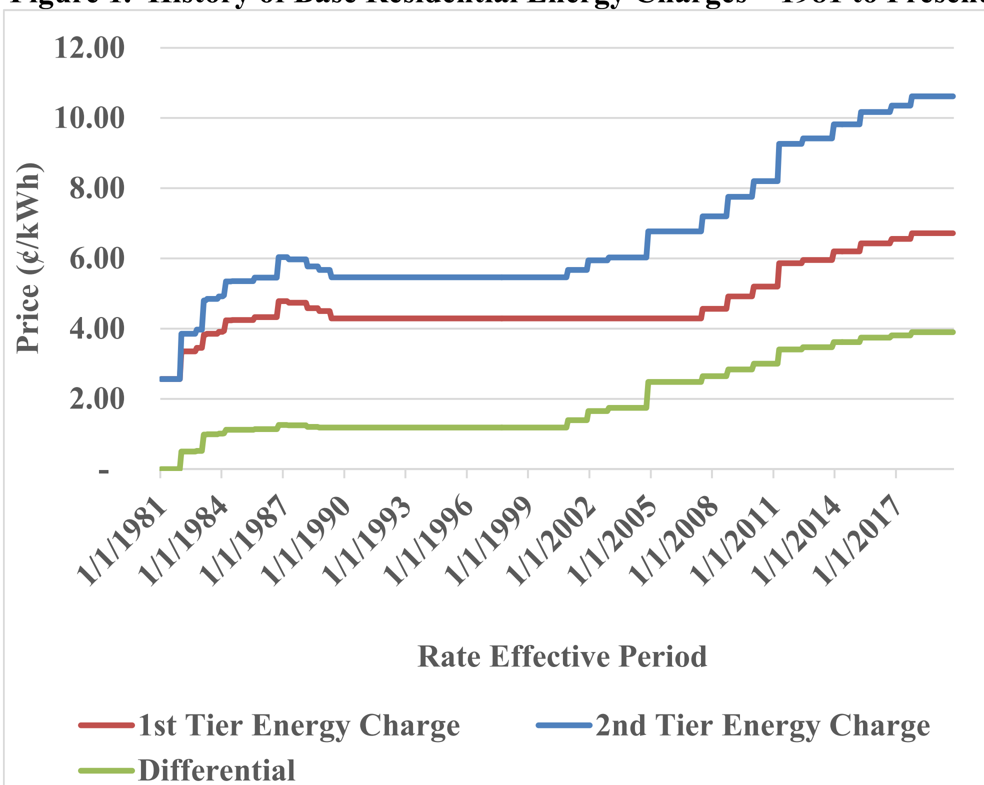
Q. How are residential energy charges currently structured?

A. Residential energy charges use what is called an inclining block or tiered rate structure where energy usage up to a specific threshold per month receives a lower price and successive energy consumption is priced at a higher rate. Presently, the first 600 kWh in a month are 6.717 cents per kilowatt hour and all additional kWh are 10.613 cents per kilowatt hour.

Q. Please provide a brief history of the Company's inclining block tiered energy charges.

A. Figure 1 below shows how the Company's base energy prices for residential customers have changed since the early 1980's when the current tiered rate structure was established.

Figure 1. History of Base Residential Energy Charges – 1981 to Present



Tiered rates were first incorporated into the Company's residential rates in December 1981 when the first tier was about 2.9 cents per kilowatt hour and the second tier was about 3.4 cents. Over time with different rate changes, the 0.5 cent differential between first and second tier energy has grown to the 3.9 cent differential that exists today. In 1982, the second tier price was 15 percent higher than the first tier price. Today the second tier is 58 percent more expensive than the first tier.

Q. Are residential customers of the other IOUs in Washington subject to inclining block energy charges?

A. Yes. Both Avista and Puget Sound Energy's residential customers are subject to inclining block energy charges. Avista's structure has three tiers and Puget Sound Energy's structure has two tiers. The percentage differentials between tiers, however, for the other two IOUs are much smaller than for the Company. Table 3 below shows the current base residential energy prices for all three utilities:

Table 3. Comparison of Tiered Residential Rates for IOUs in Washington[7]

Utility	1st block price (¢/kWh)	2nd block price (¢/kWh)	3rd block price (¢/kWh)	Difference between 1st and last block	% Difference
Pacific Power	6.717	10.613	N/A	3.896	58%
Avista	7.533	8.765	10.276	2.743	36%
Puget Sound Energy	8.7336	10.6297	N/A	1.8961	22%

The price for Avista's last tier is 36 percent higher than its first tier and the price for Puget Sound Energy's last tier is only 22 percent higher than its first tier. The Company's tiered structure is far more steeply inclined than its peers.

Q. What are the potential benefits of an inclining block structure?

A. The inclining block rate structure is often referred to as an effective tool for encouraging customers to save 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 and possibly third block with a higher rate makes incremental energy usage more expensive. For a customer with usage in the higher tiers, making energy efficient choices like installing a heat pump water heater will yield greater savings than would have been achieved under a flat energy charge rate design.

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[7] Prices for Avista and Puget Sound Energy were those that were available online on November 21, 2019, from their residential schedule's tariff.

Inclining blocks are also sometimes considered more progressive with low income users, who theoretically have lower usage, paying a lower average price.

Q. Is the inclining block structure still an appropriate rate design for residential customers?

A. No, not in light of changes in the electric industry and the likelihood of further evolution in the energy landscape of the future. While well intentioned, tiered rates produce more problems than they solve. Tiered rates are unfair, are not economically justified, and create perverse incentives. In addition, tiered rate structures can be a source of confusion for residential customers.

Q. How are tiered rates unfair?

A. Charging higher prices for greater usage in a given month arbitrarily creates winners and losers. Customers who heat their home with natural gas or a woodstove are winners and those who choose to heat their home with electricity or otherwise do not have access to natural gas are losers. A bustling, multi-generational household with a large number of people living under one roof is a loser and the person living alone in an apartment is a winner. A customer who chooses to buy an electric vehicle and charge it from home is a loser and another customer who keeps their internal combustion engine vehicle is a winner. Effectively, inclining block rates unfairly reward some customers and punish others, often for reasons outside the customer's control or in ways that incentivize behaviors that are at odds with changes in energy policy.

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

A. There is no reason why after using 600 kWh in a given month that the next kilowatt hour 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 kilowatt hours to the customer. The load factor or the effective utilization of kilowatt hour 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 kilowatt hour of electricity.

Q. How do tiered rates create perverse incentives?

A. Relative to a flat energy charge rate structure, inclining block prices encourage customers to switch fuels to natural gas. Cascade, the natural gas provider who is located in and around the Company's service area and is the most likely to serve the Company's customers, does not use an inclining block rate structure for its residential customers for volumetric gas consumption. In other words, the price for each therm that a Cascade customer purchases is flat and does not become more expensive with greater usage within a monthly billing period. As the result of its rate structure, Pacific Power has a competitive disadvantage to serving residential customers with electricity to heat their homes relative to natural gas.

Another unfavorable result of tiered rates is that they make residential transportation electrification less attractive. While a customer can at this time still experience "fuel" savings with charging their electric vehicle at the higher second tier price relative to purchasing gasoline, as more costs get pushed into the customer's incremental cost of energy on the second tier the economic rationale to choose an electric car is weakened.

Q. Do tiered rates help low income customers by making a modest level of usage tied to a customer's basic needs more affordable?

A. Not necessarily. It is true that overall average monthly usage tends to increase with income, but it is also true that the overwhelming majority of Pacific Power's lower income customers use more than 600 kWh a month on average. In 2017, the Company conducted an email survey of its customers and collected end use and demographic information from participants. Table 4 below highlights some of the Company's findings regarding energy usage and income:

Table 4. Usage Characteristics and Household Income from PacifiCorp's 2017 Residential Customer Survey

	Income Level		
Average Monthly Usage Level	**Below $35,000**	**$35,000 to $49,999[1]**	**$50,000 and greater**
0 - 600 kWh	15%	13%	7%
601 - 1,200 kWh	39%	36%	50%
1,201 kWh and over	46%	51%	43%

Average Monthly Usage (kWh)	1,221	1,292	1,423

	Income Level		
	Below $35,000	**$35,000 to $49,999[1]**	**$50,000 and greater**
Natural Gas Used as Main Fuel for Heating	19%	25%	38%
Sample Size	671	486	1,673

[1] Note - The median household income in Yakima, WA in 2017 was $47,402.
https://www.deptofnumbers.com/income/washington/yakima/

According to the Company's survey results, about 85 percent of customers with household incomes less than $35,000 per year have average monthly usage greater than 600 kWh a month. The survey results also show that lower income households are much less likely to use natural gas as their main fuel for heating.

Customers who heat their homes with electricity will have a much harder time staying warm and keeping kilowatt hour consumption in the winter below the 600 kilowatt hour monthly threshold than customers who use gas. Table 4 shows that only 19 percent of Pacific Power households making less than $35,000 per year use natural gas as their main fuel for heating. In contrast, customers making $50,000 and greater are about twice as likely to use gas with 38 percent reporting that they use natural gas as their main fuel to heat their homes. The tiered rate structure makes energy bills less affordable for many lower income customers, particularly when they use electricity to heat their home. The average monthly usage for survey respondents making less than $35,000 per year who do not use natural gas as their primary heating fuel during the peak heating season in the billing months of December, January, and February, was 2,202 kWh—well above the 600 kWh first tier threshold.

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

A. No. According to the Company's 2017 survey, only 46 percent of customers were aware of the tiered rate structure. Of those 46 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 residential energy charges?

A. The Company's proposal for residential energy charges in this case balances the need to effect change gradually while also striving to modernize the Company's rate design to be consistent with policy-driven changing demands on the electricity sector, including increased electrification through electric vehicle charging and a desire to decrease energy sector emissions. Thus, while the inclining block rate structure is problematic I propose reducing the differential between the price on the first tier and the second tier as a reasonable and gradual change that is in the interest of Pacific Power's customers.

Recognizing the long-standing nature of tiered rates and to mitigate any potential customer impacts, the Company recommends energy prices that reduce the differential between tiers by 50 percent. The Company therefore proposes a price of 7.796 cents for the first 600 kWh in a month and 9.744 cents per kilowatt hour for all additional kilowatt hours.

Q. How will the Company's proposed prices impact residential customers?

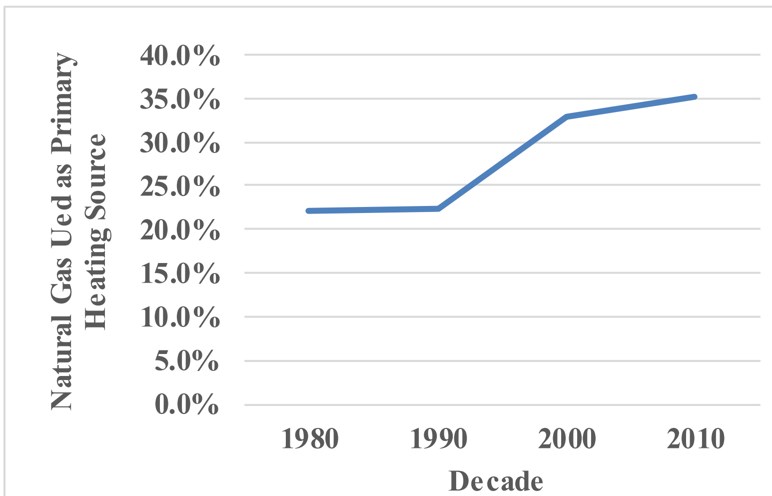
A. Page 1 of Exhibit No. RMM-8 shows how the Company's proposed residential price change would affect the monthly bill for different customer usage levels. Under the Company's proposed prices, no Schedule 16 customer would pay more than $8.38 per month more than under current rates. The Company's proposed increase to the basic charge and reduction in the differential between the two different energy price tiers has a combined effect of making incremental energy usage more affordable for the typical sized customer.

Q. Why are more affordable energy costs desirable?

A. The energy charge sends an important and powerful price signal to customers about the cost of their consumption. Motivated by bill savings, customers may modify their behavior, adopt conservation measures, and choose to live in more efficient homes. Along with demand-side management incentives and rebates, the price of energy that all customers face is an important tool for limiting overall customer usage.

Conservation, however, is not the only behavior that is motivated by the price signal that energy charges present. Customers can often save on their monthly energy costs by connecting to natural gas service and switching the fuel of end uses like space heating, water heating, and cooking from electricity to natural gas. All else equal, higher incremental energy charges provide a greater motivation for fuel switching. Over the past recent decades, the proportion of households that use natural gas as their primary heating source has steadily risen in Washington. Figure 2 below shows how the share of households that heat their home with natural gas has grown since 1980:

Figure 2 – Natural Gas Penetration in Washington State from U.S. Census Bureau Information



Source: United States Census Bureau website http://www.census.gov/hhes/www/housing/census/historic/fuels.html and https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?src=CF

The overall magnitude of energy charges are also a very important consideration for transportation electrification. In general, a customer's economic decision to adopt an electric vehicle will be influenced by the price of energy. Lower energy prices provide a greater incentive to switch from an internal combustion engine car to an electric vehicle.

When considering the Company's proposals to residential rate design, the Commission should carefully consider the ramifications of continuing the current pricing regime of a very low basic charge and steeply tiered energy charges that penalize consumption in excess of 600 kWh in a month and balance the interests of conservation with the need for a more modern rate design that accommodates current and future energy policy. At the Company's proposed energy charges of about 7.9 cents per kilowatt hour for the first tier and 9.9 cents for the second tier, that balance will be supported and customers will continue to have good reason to minimize their energy usage while also not dis-incentivizing transportation electrification or unfairly encouraging fuel switching to natural gas.

Q. What are the estimated bill impacts from the proposed rates?

A. Page 1 of Exhibit No. RMM-8 shows monthly billing comparisons for residential customers with different consumption levels.

Residential Time of Use Pilot

Q. Please describe the Company's proposed residential time of use pilot.

A. The Company proposes creating a new residential time of use rate pilot, Schedule 19. Under Schedule 19, residential customers would pay 11.942 cents per kilowatt hour during the on-peak period of 2pm to 10pm during the summer months of June through September and 6am to 8am and 4pm to 10pm in the winter months of October through May. During all other times considered off-peak, they would pay 6.654 cents per kilowatt hour. To recover the incremental cost of installing a new meter capable of recording time varying energy, participants would pay a $2.00 per month time of use metering fee. Schedule 19 would be available for up to 500 customers on a first-come, first-served basis.

Q. Why is the Company proposing a residential time of use pilot at this time?

A. Providing residential customers with a time of use rate option is consistent with the goals of making energy more affordable, adapting to a more sustainable future, and giving customers choices. Since the Company does not have automated meter infrastructure (AMI) at this time and it does not have experience offering a time of use option for residential customers in Washington, limiting participation to a modestly sized pilot allows the Company to gain time of use experience without significant risk or cost for its customers. Time varying rates can be an important way to manage load on the grid, shift load to times when renewables are more abundant, and responsibly encourage transportation electrification. This pilot would provide an opportunity for customers to lower their bills based on their own energy usage habits while providing the Company with useful data on customer behavior.

Q. How were the on- and off-peak time periods selected?

A. The Company selected its on-peak period based on the times during the year that wholesale market prices are likely to be at their highest during the rate effective period. The Company used the Mid-Columbia (Mid-C) prices from its Official Forward Price Curve for calendar year 2021. Mid-C is a liquid market for which the Company may, at different times, sell excess energy and purchase energy to serve its customers. Mid-C prices are therefore a reasonable approximation of the marginal differences in energy costs for the Company and generally for conditions in the Pacific Northwest.

Prices were examined during two seasons—summer, which includes June through September, which are the months when air conditioning load is more prevalent, and winter, which includes October through May. In both seasons, the Company took the average prices for each of the 24 hours in a day and ranked them. The highest eight hours in each season were selected as on-peak yielding the Company's proposed periods. Holidays and weekends were not considered as off-peak because their average prices were not substantially different than non-holidays or weekdays. Confidential Exhibit No. RMM-10C shows the ranking of prices by season and hour. Confidential Exhibit No. RMM-10C also shows a scalar of 1.7946 which is the relative difference in average price between the on- and off-peak periods.

Q. Please describe how the Company calculated rates for proposed Schedule 19.

A. Exhibit No. RMM-11 shows the calculation of proposed Schedule 19 prices. Energy prices were calculated by first determining the average proposed energy price for residential Schedule 16. The estimated units of on- and off-peak energy were taken from energy usage in both periods from the Company's load research study for the residential class. The average energy price was then adjusted so that the on- and off-peak prices would be revenue neutral and produce the same level of revenue as energy charges for the whole class, but still have a relative differential of the 1.7946 scalar calculated in Confidential Exhibit No. RMM-10C. The $2.00 per month time of use metering fee was determined by taking the Company's estimated $289 cost to install a meter capable of reading on- and off-peak energy, applying the Company's 8.86 percent distribution use of facilities factor and dividing by 12.

Q. Why does proposed Schedule 19 not have tiered energy charges?

A. As discussed earlier in my testimony, the tiered rate structure, while used as a tool to promote conservation, can create a number of unintended consequences. Combining tiered pricing with time of use rates may also be more confusing for customers and harder for them to understand. Including a component that makes energy more costly as a customer uses more during a monthly billing period may confuse customers and distract from the message to manage their loads to avoid the on-peak period. Including both a time of use element and an inverted tier block element within the proposed pilot may also make it harder for a customers to evaluate whether to enroll. Additionally, the Company has concerns that combining tiers with time varying rates may make it more challenging to study the pilot rate option.

The primary message given through a time of use rate is for participants to use energy at times when energy costs are lower. This gives customers a price signal that appropriately mirrors the actual costs incurred to serve customers. Energy costs are affected by the time of the day, but are not affected by how much usage a customer has in a particular month. As discussed earlier in my testimony, the 601^{st} kWh does not cost the Company more to serve. However, high usage during peak hours can impact the Company's costs, and eventually, the costs to customers.

Q. What is the guarantee payment and what is its purpose?

A. If over the course of the customer's first year on time of use rates, the customer's total energy costs are greater than 10 percent over what costs would have been for the same period under standard Schedule 16 residential rates, the Company will make a guarantee payment to refund the difference in excess of 10 percent. The purpose of the guarantee payment is to limit participant risk and provide some assurance and protection that participants will not face a severely adverse annual billing impact from their decision to participate. Offering this guarantee payment under which customers will face no greater than a 10 percent increase in their annual energy cost for the first year will help the Company sign up customers for the pilot while still providing an incentive to participating customers to change their behavior.

Low Income Customers

Q. Is the Company proposing changes to the current level of program spending for Schedule 17, the Low Income Bill Assistance Program (LIBA)?

A. No. The Company proposes continuing with the five-year plan that was approved in docket UE-170208. With the passage of the Clean Energy Transformation Act (CETA), the Commerce Department has initiated a rulemaking to consider implementation of the law's provision regarding low income bill assistance. Making changes to the overall program's magnitude in this rate case would be premature before more clarity is provided for how the Company should comply with CETA's low income provisions. The Company recommends that addressing program levels be addressed in a separate proceeding when more is definitively known.

Q. Does the Company propose any changes for Schedule 17?

A. Yes. Presently, the Schedule 17 LIBA customers receive assistance in the form of credits to the second tier energy price that differ based on the poverty level of participating customers. The Company proposes changing the credits into percentage discounts to the customer's total bill instead of as a credit to the second tier energy charge. Exhibit No. RMM-12 shows the calculation of the proposed percentage discounts, which are designed to provide the same level of assistance to each poverty level category as exists presently. Table 5 below shows present and proposed low income bill assistance credits:

Table 5 – Present and Proposed Low Income Bill Assistance Credits

Federal Poverty Level	Current Credit >600 kWh ($/kWh)	Proposed Credit %
0-75% FPL	-0.08904	**-59.5%**
76-100% FPL	-0.05989	**-38.8%**
101-150% FPL	-0.03744	**-24.9%**

Q. What are the benefits of providing low income program credits as a percentage of total bill instead of applying those credits to the second tier energy charge?

A. Providing the credits equally across all base revenue components, first tier energy, second tier energy, and basic charge preserves the price signals of standard residential rates, makes LIBA beneficial for smaller users, and is easier for customers to understand.

Providing the credit entirely onto the second tier energy charge has the potential to dampen the incentive for energy efficiency for participating customers. At the zero percent to 75 percent of poverty level category, the net second tier energy price after the LIBA credit is 1.709 cents per kilowatt hour. When a customer's incremental energy cost is at this level, the motivation to save energy is likely much less than it would be under standard rates. Using a percentage of overall bill also makes more sense for the Company's proposed Schedule 19 time of use pilot. The Company hopes that low income customers will participate in Schedule 19, which will allow qualifying customers an opportunity to further lower their bills by taking advantage of the time varying rates with LIBA credits applied.

The current form of LIBA credits also do not provide a benefit for low income customers with usage less than 600 kWh in a month. While only a small proportion of lower income customers use 600 kWh or less on average, it is important that the

Company's LIBA program is able to provide benefits on as broad of a basis as possible considering the expansions of low income assistance considered by CETA.

Finally, providing benefits that are a percentage of a customer's total bill is a simpler concept and easier for customers to understand than credits to the second tier energy charge. This proposal directly responds to feedback that the Company received through a series of discussions from community action agencies who work with customers to qualify for LIBA credits. Most customers know and understand how much their monthly electric bill is. Fewer customers understand what their energy charges are or how their tiered rates work. The Company's proposed change makes it easier for community action agencies to explain to qualifying customers the benefits of the LIBA program.

Q. How do the Company's proposed changes to the LIBA program align with the changes it is proposing for Schedule 16?

A. The changes requested for both Schedule 16 and 17 complement each other well. The proposed reduction to the tiered energy charge differential along with the proposed increase in the basic charge for Schedule 16 customers results in larger percentage increases for smaller users. The proposed changes to Schedule 17, however, make the LIBA credit for the first time a benefit for smaller users, effectively mitigating the bill impacts for smaller participating customers. Following the same themes as the Company's proposed Schedule 16 changes, the proposed changes to the LIBA program also embrace simpler, more transparent pricing where the cost of consuming energy is more consistent across different usage profiles.

Q. What are the estimated bill impacts from the proposed LIBA rates?

A. Pages 2 through 4 of Exhibit No. RMM-8 shows monthly billing comparisons for Schedule 17 customers with different consumption levels.

Schedule 24 – Small General Service

Q. Please provide an overview of the current pricing structure for Schedule 24?

A. Schedule 24 has a basic charge, three energy charges, and a demand charge that only applies to monthly usage in excess of 15 kilowatts. Schedule 24 has three declining block energy charges where the first 1,000 kWh is 10.878 cents, the next 8,000 kWh hours are 7.514 cents and all additional kilowatt hours are 6.472 cents. The much higher first tier is helpful at this time, because there is no demand charge for Schedule 24 customers who use less than 15 kilowatts of demand. This higher volumetric rate ensures an appropriate level of cost recovery from smaller Schedule 24 customers who do not have meters capable of recording a demand register.

Q. What changes are proposed for Small General Service Schedule 24?

A. For Small General Service Schedule 24, the Company proposes to apply the increase for this class by changing the underlying rate structure in two ways. First, the Company proposes that the different components of Schedule 24's rate design be moved 10 percent closer to the proportions of cost that the cost of service study suggests should be in those categories. Second, the Company proposes moving the second and third tier block 50 percent closer to each other in an effort to gradually eliminate declining block tiered energy charges.

When determining the cost categories that should be included in different rate components for Schedules 24, 36, 40, and 48T, each cost component was increased to include an allocation of the Common function. For Schedule 24, the categories related to the basic charge were considered to be the full costs as shown in the cost of service study of the Customer function and the portions of the Distribution function that are related to meters and services. Transformers were not included in the determination of what should be included in the basic charge, because the Schedule 24 rate design has a demand charge that kicks in after the first 15 kilowatts and a declining block energy charge where the first 1,000 kWh are significantly more expensive. These pricing components are intended to recover fixed costs like transformers. To determine proposed rates, the Company first applied the proposed rate increase of 0.7 percent for Schedule 24 to the cost of service results by component. The basic charge was increased by a level sufficient to bring the revenue it recovers 10 percent closer to the adjusted cost of service for Customer function and the portions of the Distribution function that are related to meters and services. All other costs are considered energy and demand charge related and were increased proportionately to make up the remaining revenue increase required.

Schedule 24 has three declining block energy charges. Like inclining block tiered rates to which residential customer are subject, declining block tiered rates create additional complexity and send confusing price signals. As discussed previously, the much higher first tier is useful, because many smaller Schedule 24 customers do not have meters capable of recording a demand register. If the Company deploys AMI in Washington, which would allow for measuring demand for all small non-residential customers, it will consider whether to propose changes to the higher rate for the first 1,000 kWh and to address the lack of a demand charge for the first 15 kilowatts. The Company does recommend that the difference between the second and third tier prices be eliminated sooner. For this case, the Company proposes that the prices of both move 50 percent closer together.

Q. What are the estimated bill impacts from the proposed rates?

A. Page 5 of Exhibit No. RMM-8 shows monthly billing comparisons for Schedule 24 customers with different consumption levels.

Schedule 36 – Large General Service Less than 1,000 kW

Q. What changes are proposed for General Service Schedule 36?

A. The Company's recommendations for Schedule 36 are similar to those for Schedule 24. The Company proposes that the different rate components for Schedule 36 make a ten percent movement towards alignment with what the cost of service study indicates should be recovered in different cost categories. The categories related to the basic charge were considered to be the full costs as shown in the cost of service study of the Customer function and the portions of the Distribution function that are related to meters and services. The categories related to the load size charge were considered to be the full costs as shown in the cost of service study of the portions of the Distribution function that are related to poles and conductor and transformers. The categories related to the demand charge were considered to be the full costs as shown in the cost of service study of the Distribution function that are related to substations and the Generation and Transmission function that are related to demand. All other costs are considered energy charge related. The Company also recommends that the first and second tier energy prices be moved 50 percent closer together.

Q. What are the estimated bill impacts from the proposed rates?

A. Page 6 of Exhibit No. RMM-8 shows monthly billing comparisons for Schedule 36 customers with different consumption levels.

Schedule 40 – Agricultural Pumping Service

Q. What changes are proposed for General Service Schedule 40?

A. The Company proposes that the different rate components for Schedule 40 make a ten percent movement towards alignment with what the cost of service study indicates should be recovered in different cost categories. The categories related to the annual load size charge were considered to be the full costs as shown in the cost of service study of the Customer function, the portions of the Distribution function that are related to meters, services, transformers, poles and conductor and substations and the Generation and Transmission function that are related to demand. All other costs are considered energy charge related.

Q. What are the estimated bill impacts from the proposed rates?

A. Page 7 of Exhibit No. RMM-8 shows monthly and annual load size charge billing comparisons for Schedule 40 customers with different consumption levels.

Q. What other change does the Company propose for Schedule 40?

A. The Company proposes including a time of use pilot option for Schedule 40 irrigators that would be available for the first 200 customers. Like proposed Schedule 19 for residential customers, the relative differential between on- and off-peak energy prices would be based on the differential in forecast 2021 MidC prices, but only considering those prices in the summer months of June through September when irrigators are more likely to use energy. Confidential Exhibit No. RMM-10C shows that using the summer on-peak period of 2pm to 10pm yields a scalar 1.8793 to be used in the calculation of on- and off-peak pricing. Like Schedule 19, the Company proposes charging a $2.00 time of use meter fee that would be based on the incremental cost of new metering which is estimated to be the same cost as for residential time of use customers. The calculation of proposed Schedule 40 time of use pilot prices are shown on Exhibit No. RMM-13.

Q. Why is the Company proposing a time of use pilot for agricultural pumping customers?

A. Wholesale market prices during the summer months can be quite high and irrigation is an end use load that, depending on the particular customer's operation, can have a high level of flexibility. In Utah, the Company has a permanent time of use option for its irrigation customers and it also has irrigation time of use pilots for its customers in Oregon and California. The Company's experience has been that irrigators can be very successful at shifting load away from peak times in response to savings opportunities. The Company would like to gain experience in Washington with a time varying rate option for its agricultural pumping customers.

Schedule 48T – Large General Service – 1,000 kW and Over

Q. What changes are proposed for General Service Schedule 48T?

A. The Company proposes that energy charges for Schedule 48 customers be broken out into time differentiated prices for on- and off-peak consumption. The Company proposes that the time of use periods be modified to reflect a more contemporaneous view of on-peak. Finally, the Company proposes that the different rate components for Schedule 48T make a ten percent movement towards alignment with what the cost of service study indicates should be recovered in different cost categories.

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 whose size is greater than one megawatt different prices for energy based on time period promotes economic efficiency by giving them the opportunity to save when they conserve during on-peak periods or shift energy from on-peak to off-peak. As the Company brings more renewables onto its system, encouraging greater flexibility in customer loads is more important than ever. Customers with larger loads represent the biggest opportunity per meter for this flexibility.

Q. What definition for on-peak does the Company propose for Schedule 48T?

A. The Company recommends that the current on-peak period of 6am to 10pm Monday through Friday be changed to 2pm to 10pm during the summer months of June through September and 6am to 8am and 2pm to 10pm in the winter months of October through May during all days.

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

A. The time periods the Company selected for on-peak are the same as those for the Company's proposed Schedule 19 residential time of use pilot with one notable difference. The Company proposes that the afternoon/evening period of 2pm to 10pm remain the same for both the summer and winter months. Keeping this period consistent throughout the year will make it easier for customers to understand and will also help maintain revenue stability while still providing significant opportunities for customer bill savings. The current on-peak period is 16 hours each day from Monday through Saturday. Under the Company's proposed on-peak period, winter months will have ten hours of on-peak and the summer months will have eight hours of on-peak every day of the week or six hours more off-peak in the winter and eight hours more off-peak in the summer for every day but Saturday and Sunday.

Q. How were the proposed prices for Schedule 48T set?

A. The Company proposes that the different rate components for Schedule 48T make a ten percent movement towards alignment with what the cost of service study indicates should be recovered in different cost categories. The categories related to the fixed component of the load size charge is considered to be the costs as shown in the cost of service study of the Customer function and the portions of the Distribution function that are related to meters and services. The categories related to the per kilowatt load size charge were considered to be the full costs as shown in the cost of service study of the portions of the Distribution function that are related to poles and conductor and transformers. The categories related to the demand charge were considered to be the full costs as shown in the cost of service study of the Distribution function that are related to substations and the Generation and Transmission function that are related to demand. All other costs are considered energy charge related.

For the time differentiated energy charges, the prices were set to recover in total the appropriate amount for energy that I described earlier, but with a 0.933 cents per kilowatt hour differential between the prices for the on- and off-peak. A 0.933 difference represents 50 percent of the 1.8658 cent differential between average 2021 Mid-C prices during the on- and off-peak periods. Making a 50 percent movement towards cost-based time differentiated pricing represents a reasonable and gradual shift away from the present flat energy charges that large customers pay.

Q. What are the estimated bill impacts from the proposed rates?

A. Page 8 through 10 of Exhibit No. RMM-8 shows monthly billing comparisons for Schedule 48T customers with different consumption levels.

Schedule 47T – Large Partial Requirements Service

Q. What does the Company propose for Schedule 47T?

A. As in previous rate cases, the Company proposes that the prices for Schedule 47T continue to be based on Schedule 48T's prices. The revised time of use periods and the time differentiation of energy prices would similarly apply to Schedule 47T.

Proposed Schedule 29 – Non-Residential Time of Use Pilot

Q. Please describe the Company's proposed Schedule 29 Non-Residential Time of Use Pilot.

A. The Company proposes a new optional time of use pilot program for non-residential customers whose loads are less than one megawatt and who would otherwise qualify for Schedule 24 or Schedule 36. Schedule 29 would be available for up to 100 customers and would both charge customers different prices for energy based on time of use and would recover demand-related costs through a different pricing structure.

Q. Please describe how energy prices would be time differentiated under proposed Schedule 29.

A. Schedule 29 would use the same on-peak period of 2pm to 10pm during all months and 6am to 8am during winter months that the Company proposes for Schedule 48T.

To keep the pricing structure as simple as possible, a sur-credit would apply to off-peak energy.

Q. Please describe how demand-related costs would be recovered on proposed Schedule 29.

A. Unlike conventional demand charges to which general service customers are subject, Schedule 29 customers would pay declining kilowatt-hour-per-kilowatt energy charges. The first 50 kWh for each kilowatt of demand will be charged a higher rate and all additional kilowatt-hours-per-kilowatt will be charged a lower rate. In effect this structure allows the Company to charge customers an average energy price that declines as load factor increases, much like demand charges do, but puts a cap on how high that average cost can be for low load factor customers.

Q. What are the benefits of this structure?

A. As the Company began investigating the roadblocks to transportation electrification, it realized that a significant impediment to the buildout of fast charging infrastructure was the very high cost of energy that stations with low utilization face because of the demand charge. In response to this roadblock, the Company implemented Schedule 45, an optional rate for publicly available DC fast charging stations that substitutes time of use energy charges for demand charges for a transitional period of time. While Schedule 45 provides a limited opportunity to give publicly available DC fast charging stations a reprieve from demand charges, the Company would like to explore a more broadly available time of use option that also minimizes the adverse bill impacts for very low load factor customers.

Other forms of transportation electrification could take advantage of proposed Schedule 29 such as bus charging or fleet charging where time of use rates could lower the incremental cost of off-peak charging and help the Company better manage around its peak periods. There may also be other beneficial applications for this rate option. For example, a fruit grower may want to install frost protection fans, but may only need to use those fans for a limited number of days in a year. Since this type of load's utilization is very low and demand charges would be very acutely felt, this fruit grower might instead turn to propane or diesel powered equipment. Limiting the impact of demand charges while sending time-based price signals under this option, helps to make energy more affordable and opens up new opportunities for the Company's customers.

Q. Why is it reasonable for very low load factor customers to pay less on this option?

A. Demand or capacity is an important and significant cost driver. When customers use power at the same time that generation, transmission, and upstream distribution are peaking this can drive the need for the Company to upgrade and expand its facilities over time. The demand charge, which measures the highest kilowatt reading in any 15 minute interval during the monthly billing period, is an effective way to recover these costs, producing stability over time and charging customers based on the overall size of their loads. However when the load factor, a measurement of a customer's energy utilization relative to peak demand, is very low it becomes less likely that the customer's peak demand will coincide with the same time that the Company system peaks. An examination of the profiles of all of the Schedule 36 customers on the

Company's load research sample shows this relationship. Figure 3 below shows how coincidence with the Company's 12 system peaks compares to load factor for its Schedule 36 load research participants:

Figure 3 – Schedule 36 Coincidence with Monthly System Peaks as Compared to Individual Customer Load Factor

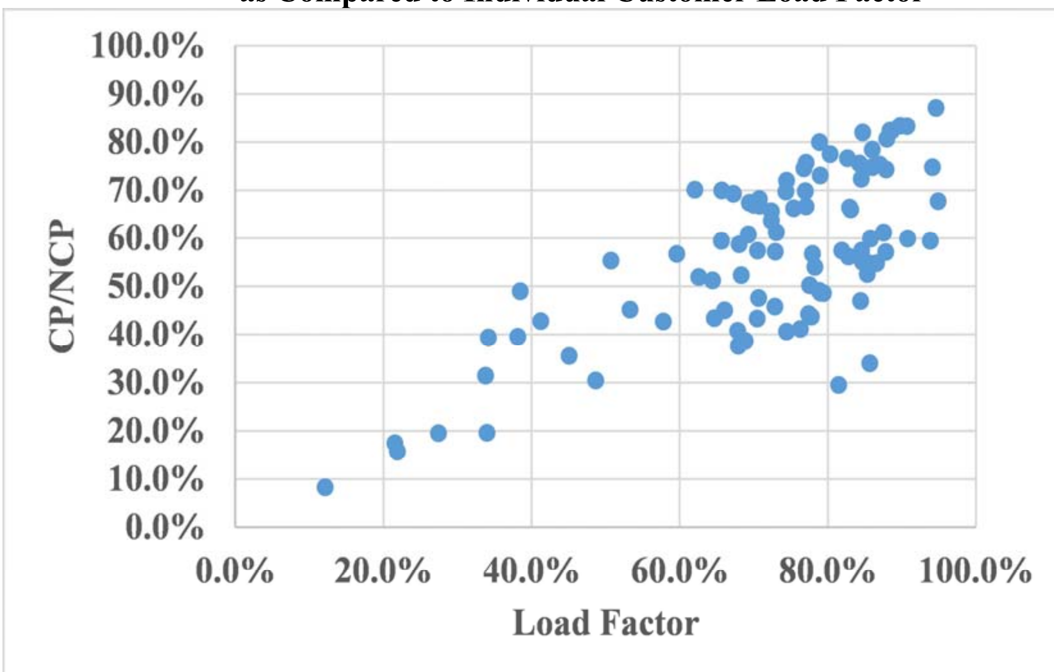


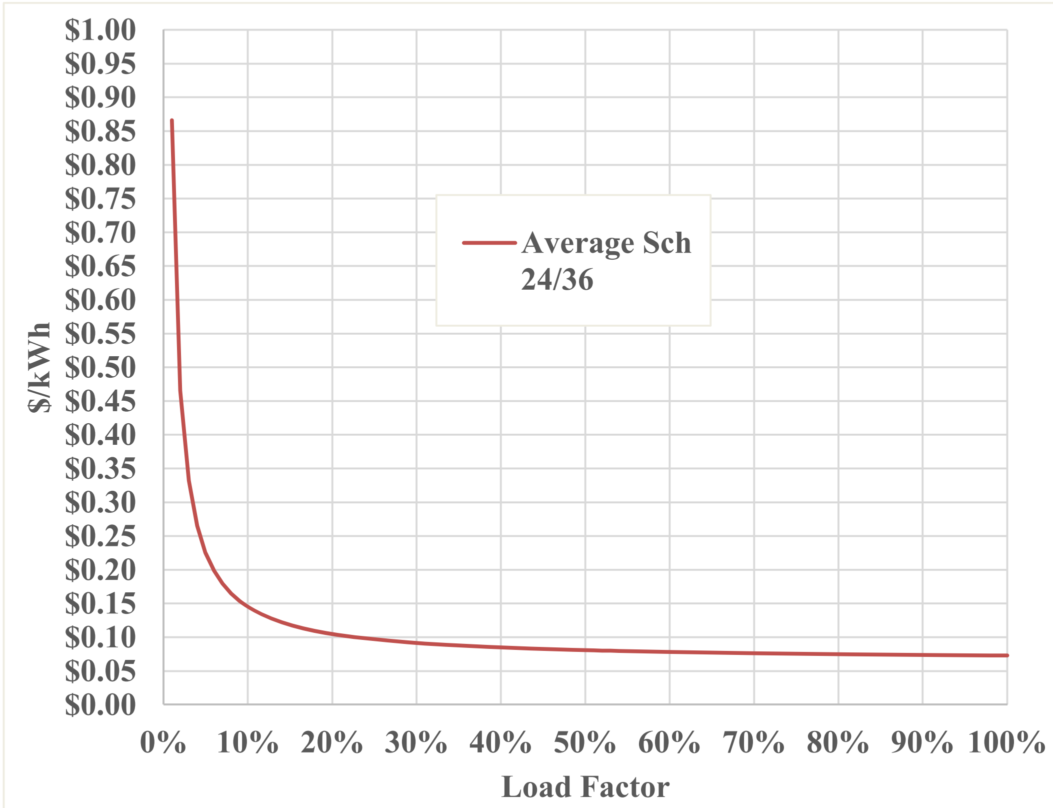
Figure 3 shows that as load factor decreases, the relationship between coincident peak (which is a key driver of costs) and non-coincident peak (which is how non-residential customers are billed for demand) gets weaker. Intuitively, this makes sense, because a 100 percent load factor customer would always hit the Company's peaks and conversely, using an extreme example, a customer who only used power for one hour in the year would be quite unlikely to use power during the Company's peak.

Customers on proposed Schedule 29 will be subject to time differentiated energy prices and will still pay a higher average price if their load factor is low, but will effectively have the combined effect of their average demand and energy charges capped. Limiting the very high average price paid by low load factor customers is in recognition that coincidence with peak declines with load factor.

Q. How were proposed Schedule 29 prices calculated?

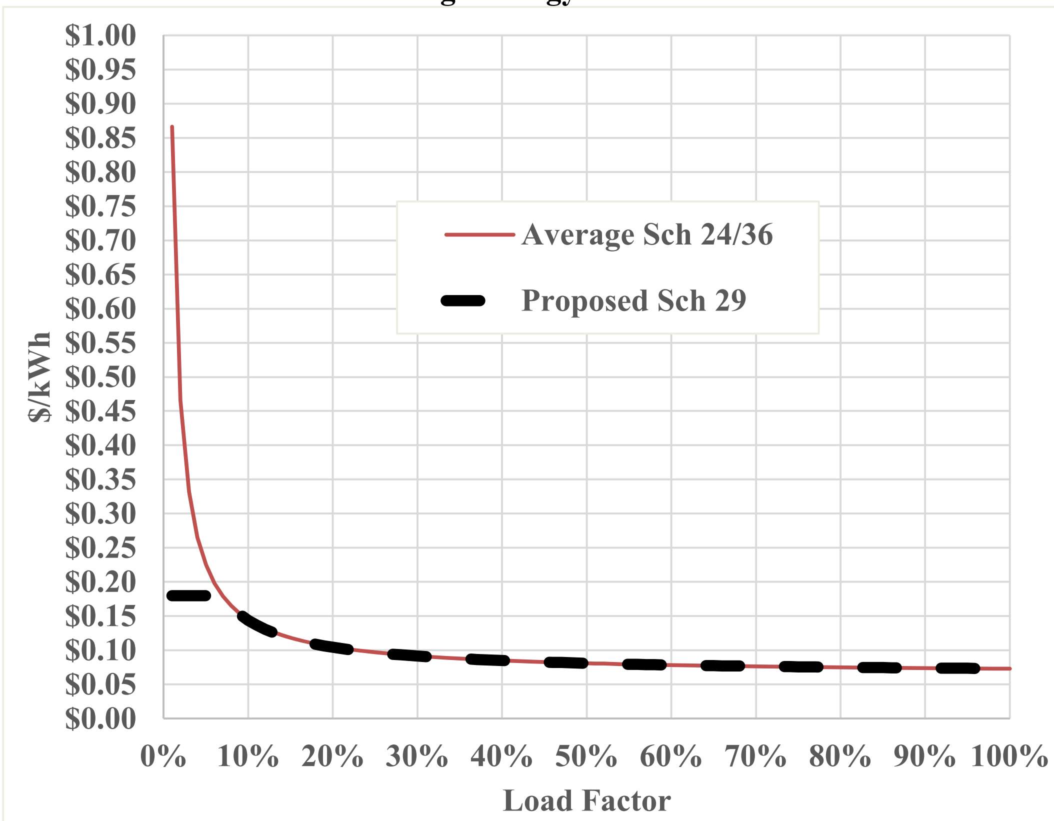
A. The prices proposed for Schedule 29 were based on an average of Schedule 36 and Schedule 24's proposed rates. The off-peak credit was set to the 1.866 cent differential between 2021 Mid-C prices during the on- and off-peak periods. 7.837 cents per kilowatt hour was then determined to be the average rate that would produce a value that in concert with the off-peak credit would be revenue neutral for both Schedule 24 and 36. The Company then calculated an average demand charge for Schedule 36 and Schedule 24 of $5.85 per kW demand. The Company then plotted the average energy cost of both the $5.85 per kW demand charge and the 6.488 cents per kilowatt hour average energy charge against load factor to better understand the relationship between average energy cost and load factor. Figure 4 shows this average demand and energy cost relative to load factor.

Figure 4. Average Demand and Energy Cost Relative to Load Factor for Combined Schedule 24/36 Prices



Through an iterative process of modifying two different kilowatt hour per kilowatt blocks, the Company developed a rate design that emulates the same average cost as shown on Figure 4. At 19.250 cents for the first 50 kWh per kilowatt and 7.837 for all additional kilowatt hours, virtually the same average cost can be achieved for all customers with load factors greater than about seven percent. For customers with lower load factors, their average demand and energy cost would be effectively capped at 19.250 cents per kilowatt hour. Figure 5 shows how the proposed prices accurately match the average demand and energy cost at different load factors.

Figure 5. Comparison of Proposed Schedule 29 Price to Average Energy and Demand Cost.



The Company proposes that the basic charge for Schedule 29 be set at $17.00 which is the weighted average price for the basic charges on Schedule 24 and 36. The calculation of proposed Schedule 29 prices is shown on Exhibit No. RMM-14.

Q. Please describe any other features that are included in proposed Schedule 29.

A. Like the proposed Schedule 19 and irrigation time of use pilots, the Company proposes that participants in Schedule 29 would pay a $2 per month time of use meter fee. The Company proposes that Schedule 29 participation be capped at 100 meters. After the Company has some experience and data on these customers, the Company can evaluate whether an expansion to the cap or any modifications to the tariff would be appropriate. Finally, the Company proposes that customers on Schedule 29 not be eligible also for net metering service on Schedule 135. Since customers receiving service under Schedule 29 would only pay volumetric energy charges, it would not be reasonable for them to be able to entirely offset their bill with on-site generation whose exported energy is compensated for through energy credits valued at full retail energy rates. Demand charges send an important price signal to help balance the economics of customer generation. An eligible customer can always be served under the Company's standard general service and participate in net metering.

Street Lighting Re-Design

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 15 – Outdoor Area Lighting – No New Service
- Schedule 51 – Street Lighting Service Company-Owned System
- Schedule 52 – Street Lighting Service Company-Owned System – No New Service
- Schedule 57 – Mercury Vapor Street Lighting Service – No New Service

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 $11.24 per month and a 5,600 lumen light emitting diode (LED) street light is $9.86. Schedule 52, which is closed to new service, charges a price per kilowatt hour plus a flat fee for the estimated operations and maintenance cost that is unique to different installations and has been in place for many years. Schedule 57 is for legacy mercury vapor lamps that the Company no longer offers. Schedule 57 charges different prices based on the type of pole, the vintage of installation and whether a lamp is served from overhead or underground facilities. For example, a 21,000 lumen mercury vapor, served from overhead facilities and installed on a wood pole after January 11, 1977, is $18.82 per month. In summary, pricing for Company-owned lights is complicated.

Q. What does the Company propose for the street and area lighting class?

A. The Company proposes re-designing the prices for rate schedules within the Street and Area Lighting class based on a lighting class cost study. For many years, the relationships of different prices within the schedules in this class have changed at a uniform rate. Considering the dominance of LED technology as the most efficient way to light a space, the time is ripe for a full examination and resetting of the different prices for lighting service. As part of the re-design of lighting prices, the Company recommends that prices for Company-owned street and area lights be simplified to be based on the level of lighting service that the Company is providing, rather than on technology (*i.e.*, bulb) type.

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 time is right to 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 (5,500-8,000 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)

In addition to these levels, the Company proposes retaining the customer-funded conversion option which appropriately rewards customers who fund the cost of conversion to LED by providing them a lower price. The Company also proposes including a decorative option for level 3 that compares to the existing decorative lamp option.

Q. Why does the Company propose to base Company-owned light prices on the level of service provided instead of the specific lamp technology used?

A. There are two reasons why the Company proposes this change. First, basing prices on service level better aligns the Company's incentives towards providing the service at the lowest possible cost. When the Company replaces an older light with LED, its revenue decreases to reflect the lower priced LED lamp. Even with this disincentive, the Company's policy is to replace legacy street lights with LED technology when they fail. LED is also now the Company's standard and it no longer deploys other less efficient lighting types for new installations. Basing the price for Company-owned lights on level of service will provide the Company with an even greater motivation to continue the transition of its fleet of lights to the most efficient technology available. For area lights, which have been closed to new service, this opens up additional opportunities to upgrade these lights to LED.

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 and also makes it easier for the Company and interested stakeholders to analyze the costs for rate setting purposes.

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) Generation/ 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 Street and Area Lighting class, 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. RMM-15 shows the calculations in the lighting class study, which were used to develop proposed prices. Page 1 of Exhibit No. RMM-15 shows the estimated cost to install street and area lights on existing distribution poles and calculates an estimated monthly revenue requirement based on an 8.89 percent annualization factor. The lowest cost installation on an existing distribution pole was assumed, except for decorative lights, 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 technology the Company will use going forward.

Page 2 of Exhibit No. RMM-15 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 3 of Exhibit No. RMM-15 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.

Page 4 of Exhibit No. RMM-15 shows the estimated cost of new service for the different aspects of price under each of the schedules included in the Street and Area Light class. For the Generation/Transmission/Distribution Cost category, the Company performed a 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 Street and Area Light class apart from the cost of the lamp installations themselves. These costs were then multiplied by the energy of the corresponding rate schedule and individual level of lighting service for Company-owned lights. For street and area lights the cost of the Customer function was allocated to each rate schedule based on customer count.

Schedule 54 – Recreational Field Lighting is a rate schedule for metered service that is included in the Street and Area Lighting class. The service provided to Schedule 54 customers is similar to the service the Company provides to Schedule 24 customers. The Company therefore included the average per customer cost of meters, services, and line transformers in the cost of service study from Schedule 24 in the Customer-Related cost category for Schedule 54.

The Company-Owned Light cost category was calculated by applying the monthly installation and maintenance costs to the lamp counts for each lighting service level.

The cost of new service was calculated for each rate schedule and in total for the Street and Area Lighting class. The cost of new service for the whole class is $1.852 million. This compares to the embedded cost of service of $1.198 million from the class cost of service study. Page 4 of Exhibit No. RMM-15 shows that an adjustment factor of 60.91 percent to be applied to Company-owned lamp prices is required to achieve the target proposed level of revenue.

Pages 5 and 6 of Exhibit No. RMM-15 show the present and suggested proposed prices for each lighting rate schedule. The energy price for customer-owned street lighting on Schedule 53 was set at 4.389 cents per kilowatt hour to recover the total cost for this schedule. For recreational field lighting on Schedule 54, the lighting cost study shows that a nearly three-fold increase to basic charges can be justified. To avoid rate shock, the Company proposes a 50 percent movement for the basic charges for single and three phase service from present rates to what the cost study indicates is needed to collect the Customer-Related cost category revenue requirement for this schedule. The remaining cost for Schedule 54 were assigned to the energy charge to produce a price of 4.697 cents per kilowatt-hour. Proposed rates for Schedule 54 are shown on Exhibit No. RMM-7. Company-owned lighting prices were based on the full cost of new service for each lighting service level multiplied by the 60.91 percent adjustment factor to get to the overall target revenue requirement for the entire Street and Area Lighting class. This approach to setting Company-owned 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 actual cost in the historic test period. Prices for lights served under the customer-funded conversion option do not include the cost of new installation.

With the Company's proposed level of service approach to pricing Company-owned lights, legacy Schedules 52 and 57 that are closed to new service would be canceled and customers on those schedules would go onto Schedule 51. Page 7 of Exhibit No. RMM-15 shows the list of consolidated prices for the Street and Area Lighting class for reference. With the Company's proposed pricing, the count of unique street and area lighting charges goes from 61 prices to 21 prices.

Area Lights

Q. In addition to re-designing the Company-owned lamp prices, what other change does the Company propose for Schedule 15 – Outdoor Area Lighting Service?

A. The Company proposes that Schedule 15 be open to new service again on existing distribution poles only.

Q. Why has the Company closed its area light tariffs to new service?

A. My understanding is that the Company closed area lights 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. Secondly, 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 15 be opened up for new service again?

A. With LED technology, maintenance of area lights is far less than for other legacy lighting technologies. Whereas 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' 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 area, 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.

Pricing Pilots

Q. For this rate case, you have proposed three different pricing pilots. What are your plans for evaluating their effectiveness?

A. The Company's goal with the three time of use pilots designed for residential, smaller non-residential, and irrigation customers is to gain some experience with time varying rate options in its Washington service area. The Company proposes that it would create and file a report with the Commission after its pilots have been in effect for three years. The report would provide recommended future actions for the pilots that may include terminating the pilot, expanding the pilot for further study or transitioning the pilot into a permanent rate option. Data that the Company plans to collect and share in its report include bill impacts, adoption rates, survey results from participating customers, estimated energy and capacity benefits and program costs. The Company anticipates that it will gain valuable insights from these pilots that will help inform future rate offerings.

Q. Why are you not recommending annual reports on these pilots?

A. There are several reasons why annual check-ins are too frequent. First, the data available may not be sufficiently different each year to yield useful insights. Second, preparing annual reports imposes an undue administrative burden on the Company often for very little benefit. In my experience, waiting longer for the Company to have a chance to gather more information and provide a more thoughtful analysis of its pilots is a better use of everyone's resources, especially at a time when Washington's energy policy is encouraging greater innovation. A good example of a reasonable reporting requirement is that which is required for the Company's decoupling mechanism where the Company will file a report after the end of the first three years.

Q. Why are you not recommending a definitive end date to the pilots?

A. At this time, the Company does not have plans to deploy AMI in Washington. If it does deploy AMI in the future, this would likely influence the timing of expansion of time varying rate pilots and/or transitioning those pilots to permanent rate options. Since potential future AMI deployment for the Company is unknown, I recommend that the timeframe over which the Company operates its pilots be flexible and not pre-determined at this time.

Decoupling

Q. What changes does the Company propose for its decoupling mechanism?

A. The Company has recently completed the third year of its five-year decoupling pilot. At this time, the Company is therefore not recommending major changes to the mechanism, but instead only three minor modifications. First, the Company proposes updating the Total Revenue, Net Power Cost Revenue, and Fixed Basic Charge Revenue to reflect the final revenue for this case. Second, the Company recommends a slight modification to the calculation of the Monthly Decoupling Deferral so that the Actual Decoupled Revenue used is based on actual revenue instead of multiplying actual kilowatt hour usage by an average monthly revenue value from the last rate case. Finally, for the decoupling mechanism the Company proposes including Schedule 19 in the residential class and including Schedule 29 in the Schedule 36 class.

Q. In the deferral calculation, how is Actual Decoupled Revenue presently calculated?

A. As described in Schedule 93, it is determined by multiplying the Decoupled Revenue per kWh Rate by the actual, non-weather adjusted kWh monthly usage. The Decoupled Revenue per kWh Rate is based on the final prices as applied to historic billing determinants approved in the last general rate case.

Q. Why is this an inaccurate measurement of actual revenue?

A. There are three main ways in which applying average prices that were established in a general rate case to actual energy usage results in an inaccurate measurement of actual revenue: 1) For non-residential rate schedules that have demand charges, the load factor in the deferral period could be different than what was experienced during the historic test period used in the rate case; 2) the mix of energy in different tiered pricing levels could be different than what was experienced during the historic test period used in the rate case; and 3) perhaps most significant considering some of the

Company's pricing proposals in this proceeding, revenue from customers who opt-in to a time-varying rate option could be different from the average set in a rate case.

Q. How does the Company propose modifying the mechanism's calculation to improve the accuracy of measuring actual revenue?

A. Instead of applying an average historic rate to actual energy to determine Actual Decoupled Revenue, the Company recommends determining Actual Decoupled Revenue from actual revenue. The present method is described in Schedule 93 as follows:

> <u>Step 8</u> – Determine the Decoupled Revenue per kWh Rate – Allowed Decoupled Revenue (Step 4) is divided by the annual kWh used to set rates.
>
> <u>Step 9</u> – Determine Actual Decoupled Revenue – Multiply the Decoupled Revenue per kWh Rate (Step 8) by the actual, non-weather adjusted kWh monthly usage.

The Company proposes that these steps in Schedule 93 be modified to read as follows:

> <u>Step 8</u> – Determine Actual Revenue – Determine Actual Base Revenue by taking total actual, non-weather adjusted monthly revenue less revenue from any non-base adjustment schedules.
>
> <u>Step 9</u> – Determine Actual Decoupled Revenue – Subtract Fixed Basic Charge Revenue and Net Power Cost Revenue from Actual Revenue.

Q. Please provide an illustrative example of how the mechanism would work using updated proposed rate schedule revenues.

A. Exhibit No. RMM-16 shows an illustrative example of how the Company's proposed modified decoupling mechanism calculation would operate with rate schedule revenues updated for the rate case.

System Transmission Adjustment

Q. What is the System Transmission Adjustment (STA)?

A. As described in the testimony of Mr. Wilding and calculated in the testimony of Ms. McCoy, the Company is requesting to include the costs of PacifiCorp's transmission system over a three-year period as part of this case. The cost of the first year's transition is included in the overall revenue requirement change that the Company is requesting. The second and third year transitions would each represent no greater than a $2.75 million increase and would be recovered through the STA.

Q. How does the Company propose to spread the STA to the different rate classes?

A. The Company proposes that the STA be allocated to each rate schedule based on their allocation of Transmission function costs from the Company' cost of service study. Since the Street and Area Lighting class contains multiple rate schedules, the allocation of the STA for this class is further spread to each rate schedule on the basis of energy.

Q. What is the Company's proposed rate design for the STA?

A. The Company proposes that each rate schedule's allocation be collected through a percentage surcharge to be applied to all base energy and demand charges. For Street and Area Lighting Schedules 15 and 51, the Company proposes a percentage surcharge to be applied to the per lamp rates. This rate design approach fairly distributes the cost to different customers. The price for partial requirements customers on Schedule 47 would be based on the price that Schedule 48T customers would pay. The rate spread and calculation of prices are shown on page 2 of Exhibit No. RMM-6. Prices for the STA will be shown on proposed Schedule 94 with rates that would be effective on January 1, 2022, and January 1, 2023.

Federal Tax Act Adjustment Price Change

Q. What change does the Company propose for Schedule 197 - Federal Tax Act Adjustment?

A. As discussed in the direct testimony of Ms. McCoy, prices for the FTAA will be revised to refund to customers $7.1 million annually to reflect a ten-year amortization of the excess deferred income taxes and the 2020 current tax benefit, effective January 1, 2021. Consistent with the previously-authorized allocation of the FTAA, the Company proposes spreading the credit to rate schedules on the basis of allocated rate base in the Company's class cost of service study. Prices for Schedule 47 are based on prices for Schedule 48T. The rate spread and calculation of prices are shown on Exhibit No. RMM-17.

Proposed Tariffs and New Adjustment Schedule

Q. Have you included the Company's proposed revised Washington electric tariff schedules in this filing?

A. Yes. Exhibit No. RMM-18 contains revised tariff sheets incorporating the changes proposed for approval in this proceeding. As part of these changes, the Company is requesting the cancellation of Schedule 52 and 57.

In addition to the rate schedules discussed in my testimony, Exhibit No. RMM-18 contains the following:

- The proposed revisions to Schedule 300 and various Rule tariff pages that are discussed in the direct testimony of Ms. Melissa S. Nottingham.
- Proposed Schedule 94 to implement the STA.

COST OF SERVICE, RATE SPREAD, AND RATE DESIGN COLLABORATIVE

Q. What direction on rate spread and rate design did the Commission provide in the Company's 2015 limited-issue rate case, Docket UE-152253 (2015 Rate Case)?

A. In its final order, the Commission stated that "The Company has agreed to participate in a collaborative on cost of service, rate spread, and rate design issues. If the parties reach consensus prior to the second year rates taking effect, the participants should file that agreement for the Commission's consideration. If the collaborative does not result in a consensus before the start of the second year rates, Pacific Power should apply the approved second year increase on an equal percentage basis across each schedule and address cost of service and rate design issues in its next general rate case."[8] The Commission also directed the Company to "to include an analysis of the potential impacts to low income customers of a third energy block rate design in the Cost of Service Study and Rate Design collaborative. In addition to Staff, the Company should invite Public Counsel, Boise, the Energy Project, and NWEC to participate."[9]

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[8] *WUTC v. Pac. Power & Light Co.*, Docket No. UE-152253, Order 12 at ¶15 (Sept 1, 2016).
[9] *Id.* at ¶255.

The Company complied with both of these requirements by participating in collaborative meetings with parties on April 12, 2017, and July 18. 2017. At the first meeting, parties did not reach a consensus on rate spread and therefore agreed to let the second-year rate increase go into effect on an equal percentage basis for each schedule. At the second collaborative session, the Company presented analysis that it had prepared that explored the potential impacts on low-income customers of a third energy block rate design. Exhibit No. RMM-19 is a copy of the presentation the Company gave to stakeholders that shared this analysis. From the Company's perspective, this analysis satisfies the Commission's requirement.

NORMALIZED REVENUES

Q. Please explain how the Company prepared normalized revenues for the test period in this case?

A. Normalized revenues are the 12-month revenues for the test period with certain adjustments applied to establish a 12-month base period on which to determine revenue requirement. Normalized revenues are developed using the actual billing units for the 12 months in the test period. Billing units include the number of customers, demand measurements (kW), both maximum and by time period such as on-peak, where applicable, energy measurements by block (kWh), and excess kilovolt-amperes reactive (kVar). The Company removes any out of period billing adjustments from historical billing units and revenues then applies temperature adjustments. Current rates are then applied to all billing units to calculate annualized revenues. Using a full 12-month period for billing units is necessary to capture seasonal variations in customers and usage and to be consistent with the cost of service study that allocates costs using the same 12-month period. This calculation is consistent with the Commission's long-established practice.

Q. Does this conclude your direct testimony?

A. Yes.