WUTC DOCKET: UE-190529, et al
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EXH. BDJ-1T
DOCKETS UE-___/UG-___
2019 PSE GENERAL RATE CASE
WITNESS: BIRUD D. JHAVERI

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-19____** **Docket UG-19____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

BIRUD D. JHAVERI

ON BEHALF OF PUGET SOUND ENERGY

JUNE 20, 2019

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF BIRUD D. JHAVERI

CONTENTS

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF BIRUD D. JHAVERI

LIST OF EXHIBITS

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF BIRUD D. JHAVERI

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Birud D. Jhaveri. I am employed as Manager of Pricing and Cost of Service with Puget Sound Energy ("PSE"). My business address is 355 110th Ave NE, Bellevue, Washington 98004.

Q. Have you prepared an exhibit describing your education, relevant employment experience and other professional qualifications?

A. Yes. Please see the First Exhibit to the Prefiled Direct Testimony of Birud D. Jhaveri, Exh. BDJ-2, for an exhibit describing my education, relevant employment experience and other professional qualifications.

Q. What is the purpose of your testimony?

A. My testimony presents PSE's pro forma revenue from electric operations and PSE's electric cost of service study.

Q. Please summarize your testimony.

A. My testimony summarizes the electric cost of service results based on the Revenue Change before Attrition and Riders of $104.5 million as presented in the Second Exhibit to the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-3.

II. COST OF SERVICE OVERVIEW

Q. Please summarize the purpose of a cost of service study.

A. A cost of service study identifies the costs that are incurred to serve a particular customer class. Identifying the cost responsibility of each class requires an analysis of PSE's costs and then an allocation of those costs to each customer class. This allocation is done by first directly assigning to a customer class any costs determined to be caused by that class alone. Joint costs that are shared by multiple customer classes are then allocated to various classes on a pro rata basis, based on factors appropriate to the costs being allocated.

The ultimate objective of the cost allocation process is to create a just, fair, reasonable and sufficient allocation of costs to different customer classes. This cost of service information is then used to allocate the revenue requirement determined in a rate case to the different customer classes.

In order to provide the benefits of cost analysis to individual customers in addition to customer classes, the cost of service study also serves as a guide for the rate design process. For example, the basic charge has historically been based, in part, upon customer-related costs determined in the cost study. Similarly, demand charges have historically been guided by demand-related costs determined in the cost study.

Q. How are cost of service study results generally used for ratemaking purposes?

A. Historically, the Commission has treated cost of service studies as a guidepost for the allocation of the revenue requirement and has eschewed a mechanical application of these studies, particularly given the widely varying perspectives among rate case participants as to the "true" cost of providing service to any given class of customers. Therefore, while such studies may be representative of the overall level of costs that should be recovered from any particular class, the Commission routinely exercises its broad discretion in how strictly to apply the results of such analyses.

Q. Please summarize the process for preparing the electric cost of service study.

A. The electric cost of service study starts with the electric revenue requirement that is set forth in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, and associated exhibits, which represents PSE's costs to provide service to its electric customers. The first step of this study is to separate these costs into the major electric utility functions: generation, transmission, and distribution. This process is referred to as the functionalization of costs. The second step is to further divide the costs associated with each of the major functions into customer, demand and energy components (which are explained below). This process is referred to as the classification of costs. The third step is to allocate each of the cost components to the individual customer classes.

Q. Please describe the first step in a cost of service study, functionalization.

A. Functionalization separates plant and expenses into categories based on the major functions of the utility. For PSE's electric service, these functions include generation, transmission, and distribution.

Q. Please describe the second step in a cost of service study, classification.

A. Classification further separates costs into categories based on the utility operation for which the plant is constructed and expenses are incurred. PSE's utility systems are designed to perform the following three primary tasks: (1) stand ready to provide services to *customers* served by the system; (2) serve peak *demands* of all customers, and (3) supply or deliver the *energy* sold to or transported for its customers. There are costs associated with each of these services, and the cost of service study categorizes them according to customer, demand, or commodity.

Given these three primary functions of PSE's utility systems, classification answers the question: "Why was the cost incurred – to serve the customer, to meet peak demand, or to provide the energy?" Another way to ask this is, "Does the cost vary with the number of customers, the peak demand for which the system was designed, or the amount of energy sold or transported over the system?"

Q. Please describe customer-related costs.

A. Customer-related costs are those costs that would be needed to serve customers regardless of their level of energy usage. These costs include, at a minimum, the costs of the service line and meter, meter reading and billing, and maintaining the

customer accounting system. Customer costs vary with the number of customers on the utility system, regardless of how much energy those customers consume.

Q. Please describe demand-related costs.

A. Demand, or capacity, costs are those costs associated with designing, installing, and operating the system to meet peak demands. The system must be sized to meet peak requirements, even though average loads are below peak levels; otherwise the system would not have adequate capacity to serve customers' demand during the times of greatest energy consumption. Demand costs vary with the size of the peak demand for which the system was designed. Demand costs are incurred whether all the capacity is used or not.

Q. Please describe energy costs.

A. Energy costs vary with the amount of energy supplied or delivered over PSE's system. This includes both the energy sold to customers and the energy transported for customers who purchase their energy supply from providers other than PSE. Over a one-year period, the average daily energy delivered through PSE's utility systems is considerably less than that delivered on a peak day. Generally speaking, energy-related costs are more associated with the supply of energy rather than its delivery.

Q. Is it always clear whether costs are demand, energy or customer related?

A. No. One of the challenges of classifying costs between demand, energy, and customer categories is that some utility equipment is commonly considered to

serve multiple functions. For example, electric generation equipment is widely recognized as jointly providing capacity (demand) and energy. While there are several generally accepted methods for apportioning these joint costs between demand and energy, even these methods are the subject of considerable debate.

Q. Please describe the third step in a cost of service study, allocation.

A. Allocation is the final step in the assignment of costs to customer classes. Unless a cost is unique to a specific customer class and can be directly assigned to that class, it is allocated based on an allocation factor that is related to that type of cost. In general, (1) customer-related costs are allocated based on the number of customers; (2) demand-related costs are allocated based on peak demand, and (3) energy-related costs are allocated to customer classes based on energy sales. There are many variations of these allocation factors based on the specific costs and plant items being allocated, and some costs may be allocated based on a combination of allocation factors.

III. ELECTRIC COST OF SERVICE

A. Previous Cost of Service Studies

Q. Please identify all electric cost of service studies conducted by PSE in the last five years.

A. Prior to the electric cost of service study conducted in this case, PSE conducted a fully allocated embedded cost of service study to support its 2017 general rate case ("GRC").

Q. Please describe the methodology used in the 2017 study.

A. The 2017 electric cost of service study used the same basic methodology for functionalization, classification and allocation of costs as is presented in the study supporting this 2019 proceeding.

B. Overview of PSE's Electric Cost of Service Study

Q. What are the results of PSE's electric cost of service study?

A. The parity percentages by customer class that result from the electric cost of service study are shown in Table 1 below. Parity reflects the relative relationship between normalized revenue currently recovered in rates to the revenue required based upon the cost of service analysis. A parity percentage over 100 percent indicates that the customer class is currently paying more than its allocated costs (once all classes are adjusted for system over or under recovery).

Table 1. Results of PSE's Electric Cost of Service Study

Customer Class	Rate Schedule	Parity Percentage
Residential	7	97 %
General Service, < 51 kW	24	105 %
General Service, 51 – 350 kW	25	106 %
General Service, >350 kW	26	106 %
Primary Service	31/35/43	101 %
Special Contract	SC	99 %
High Voltage	46/49	106 %
Lighting Service	51 - 59	93 %
Choice/Retail Wheeling	448/449	88 %
Firm Resale/Special Contract	5	50 %
System Total / Average		100 %

Q. Was the model used to develop the cost of service study the same model used in PSE's most recent general rate case?

A. Yes, the model used for this study is the same model used in PSE's 2017 GRC. This model was originally developed for PSE by Navigant Consulting, Inc. for PSE's 2006 GRC.

C. Classification of Production Costs

Q. Please describe how production costs were classified into energy and demand components in PSE's electric cost of service study.

A. PSE utilized the "peak credit" methodology to divide production costs into demand and energy components. The peak credit method classifies PSE's electric production costs, regardless of the type of generating resource, as either energy-related or demand-related, based on the ratio of the cost of a proxy peaking generating resource to the cost of a proxy baseload generating resource. The numerator and denominator of the ratio are expressed in $/kW-year.

Q. Was the peak credit analysis for this rate case performed in accordance with the Rate Design Settlement approved by the Commission in Docket UE-141368?

A. No. While the Rate Design Settlement approved by the Commission in Docket UE-141368 committed PSE to adjust the demand/energy cost allocation to fixed percentages, it was only required for PSE's 2017 GRC. The Settling Parties were

not bound by any cost of service or allocation agreements in any proceedings following the issuance of the final order in PSE's 2017 GRC.

Q. Has the Commission endorsed any other classification methodology to be used for this rate case?

A. No. However, the Commission filed a Preproposal Statement of Inquiry to address cost of service studies for investor owned utilities.[1] The Commission is seeking feedback on draft rules and is seeking clarification on several issues related to classification and allocation methods.

Q. Does PSE propose departing from the peak credit methodology at this time?

A. No. At this time, PSE proposes only to refresh the inputs and assumptions used to conduct this analysis. However, given the apparent support of other parties to explore alternatives to the peak credit methodology, PSE is amenable to continuing dialogue with parties to explore preferable approaches to allocating PSE's production and transmission costs in the future.

Q. Does the peak credit analysis contain the most currently available data?

A. Yes. The peak credit analysis used to support this rate case reflects the most currently available information. The analysis has been updated to use the 2017 Integrated Resource Plan ("IRP") as filed with the Commission, updated emissions costs, and the rate of return proposed in this proceeding.

[1] Dockets UE-170002 and UG-170003 (consolidated).

Q. Why does the peak credit analysis not apply data from the 2019 IRP?

A. PSE has commenced the process to develop its 2019 IRP, but final results will not be available until the first quarter of 2020. Therefore, the 2017 IRP provides the most recent available data for the peak credit calculation to support this rate case.

Q. Please explain the proposed update to the peak credit analysis related to emissions costs.

A. For the updated peak credit analysis, PSE proposes to employ carbon costs based on the recently enacted Washington state legislation, Senate Bill 5116, which mandates electric utilities to use the social cost of carbon, as defined in the U.S. Environmental Protection Agency's ("EPA") Technical Support Document under Executive Order 12866, in developing its IRP and clean energy action plan.

Q. What is the rationale for using the social cost of carbon in the peak credit analysis?

A. In previous rate cases there was uncertainty surrounding the ultimate way in which greenhouse gases would be regulated in Washington; however, parties recognized that some form of regulation would apply in the future. Emission prices reflected in previous peak credit analyses were based on estimated costs reflecting impacts from several key pieces of potential carbon regulation. Now that Washington has passed Senate Bill 5116, which specifically requires electric utilities to utilize the social cost of greenhouse gas emissions as prescribed in the

legislation, it would be inappropriate to continue to use the projected carbon prices from the 2017 IRP.

Additionally, the peak credit method relies on forward-looking assumptions used by PSE in planning its power supply portfolio. The social cost of carbon has now become a significant and permanent factor in the costs of these portfolios. Including the legislatively mandated emission costs in the peak credit method allows the analysis to be consistent with how PSE is required to determine resource planning and acquisition decisions, cost effectiveness of its conservation programs and calculation of avoided costs.

Q. Have any other changes been applied to the peak credit analysis?

A. Yes. Since Senate Bill 5116 mandates the production of 100 percent clean electricity by 2045, the useful life of gas plants as proxies for the peak credit calculation has been shortened to end in 2044.

Q. What is the result of PSE's peak credit calculation?

A. Applying assumptions consistent with the most currently available data, the percent of production cost classified as demand is 11 percent, with 89 percent classified as energy. The derivation of these percentages is provided in the Second Exhibit to the Prefiled Direct Testimony of Birud D. Jhaveri, Exh. BDJ-3C.

Q. Does the use of the legislatively mandated social cost of carbon have a material impact on peak credit results?

A. Yes. Emissions costs have a significant effect on the peak credit results in this case. Removing the prescribed social cost of carbon costs from PSE's proposed peak credit method would increase the percentage of demand-related electric production costs from 11 percent to 19 percent. Pages four through six of the Second Exhibit to the Prefiled Direct Testimony of Birud D. Jhaveri, Exh. BDJ-3C, provide calculations that remove emissions costs from PSE's proposed peak credit model.

Q. Does limiting the useful life of gas plants as proxies for the peak credit calculation to year 2045 have a material impact on the peak credit results?

A. No. Limiting the useful life of gas plants as proxies for the peak credit calculation to year 2045 has de minimis impact on peak credit results.

D. Classification of Transmission Costs

Q. How are transmission costs classified in PSE's electric cost of service study?

A. PSE uses the peak credit method, described above, to classify transmission costs. The peak credit percentages are applied to transmission costs under the theory that transmission lines are constructed to deliver the energy and capacity provided by generating plant, and in the same proportion as it is being provided.

Using the peak credit method, 11 percent of transmission costs are classified as demand and 89 percent are classified as energy. PSE also separately identifies

transmission related to generation-integration and other transmission before allocating costs to customer classes.

Q. Why does PSE distinguish between generation-integration transmission and other transmission?

A. Generation-integration transmission brings PSE's remote generation to PSE's integrated transmission system. One must segregate the costs of generation-integration transmission from other transmission because customers in the Choice/Retail Wheeling class, as well as the Special Contract class, do not use PSE's remote generation resources. Thus, it is appropriate to exclude these customers from the allocation of costs for transmission lines used for integration of remote resources. However, these classes continue to receive an allocation of PSE's other transmission costs.

E. Classification of Distribution Costs

Q. How are distribution costs classified in PSE's electric cost of service study?

A. With two exceptions, all electric distribution costs are classified as demand-related. The two exceptions are the costs of meters and service lines. These are classified as customer-related, as discussed below in Sections G(2) and G(3).

F. Allocation of Production and Transmission Demand Costs

Q. How are production and transmission demand costs allocated in PSE's electric cost of service study?

A. In accordance with a settlement approved by the Commission in Docket UE-141368, PSE's demand-related production and transmission costs were allocated in this case on the basis of each class's contribution to coincident system peaks ("CP") in the months of January, February, November and December 2018. This is referred to as the "4-CP" allocation factor. PSE utilized the same methodology as used in its last general rate case.

Q. Did the Commission endorse the use of this allocation methodology for this rate case?

A. No. The Commission only approved this allocation methodology for PSE's 2017 GRC, with the expectation that this subject would be explored more thoroughly in the future.

Q. Has the Commission endorsed any other allocation methodology to be used for this rate case?

A. No. However, the Commission filed a Preproposal Statement of Inquiry to address cost of service studies for investor owned utilities.[2] The Commission is seeking feedback on draft rules and is seeking clarification on several issues related to classification and allocation methods.

[2] Dockets UE-170002 and UG-170003 (consolidated).

Q. Why is the "4-CP allocation factor" a reasonable approach to use for allocating production and transmission demand costs?

A. First, a 4-CP allocation factor has ample precedents within the industry, including at the Federal Energy Regulatory Commission ("FERC"). In fact, a FERC administrative law judge ruled in the late 1990s that, while not perfect, a 4-CP allocation factor appeared reasonable for PSE's system at that time.[3] More recently, PSE evaluated the applicability of the 4-CP allocation factor to its system using the tests relied upon by FERC to evaluate the appropriateness of various CP allocation factors.[4] Applying these tests to PSE's more recent loads, the results continue to support the conclusion that a 4-CP allocation factor is reasonable for PSE's system.

Second, while not as theoretically pure as allocating on the basis of the contribution to PSE's single annual peak load, use of a 4-CP allocator mitigates some of the volatility in results that may be experienced if an annual peak allocator were used instead.[5]

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[3] FERC Docket Nos. OA96-161-000 *et al., Initial Decision Resolving Open Access Rate Questions*, 88 FERC P 63001 (F.E.R.C.), 1999 WL 500637 (July 15, 1999).

[4] These are discussed on pages 63-65 of *A Guide to FERC Utility Ratemaking* by Michael E. Small.

[5] In the past, PSE has considered using a 2-CP allocator, which instead would focus only on the months of December and January. While a stronger case could be made for the use of the 2-CP allocator from a cost causation perspective, as with the 1-CP allocator, it would also potentially lead to more volatility in results. Use of the 4-CP allocator is more consistent with the Commission's preference for gradualism when making methodological changes that impact customer rates.

Finally, the use of an allocator based on PSE's top 75 hours of load, as utilized in PSE's 2011 GRC, appears to run counter to cost causation principles. Demand-related costs should be allocated using measures of peak demand, rather than energy use. While it could be argued that an allocation factor based on the top 75 hours of load is indicative of peak loads, the use of so many hours tends to blur the lines between demand and energy.

G. Allocation of Distribution Costs

1. Distribution Substations and Feeder Costs

Q. How does PSE allocate distribution substations and feeder costs in its cost of service study?

A. Consistent with PSE's past general rate cases, PSE assigns the cost of distribution underground circuits, overhead circuits, and substations based upon allocation factors constructed from each class's contribution to feeder and substation peak loads and the length of the distribution circuit. These allocation factors are constructed from monthly energy and load factors for the twelve-month period ending December 2018.

Q. Would you please describe specifically how substation costs are allocated?

A. For each month, each customer class's contribution to the peaks of individual distribution substations, as a percent of those peaks, is calculated using the average hourly consumption of each class's load on the substation, divided by the non-coincident peak ("NCP") load factor of that class in that month. Each class's

contribution to the peak load on each individual substation is then averaged across the months of the year. This average monthly contribution to each substation's peak load is then multiplied by the booked cost of the individual substation in 2018 dollars to derive the allocated cost of each substation. These allocated substation costs are then summed by customer class and compared with PSE's total substation investment in 2018 dollars to develop the substation cost allocations for FERC Accounts 360-362.

Q. How does PSE allocate distribution line costs?

A. PSE uses customer information system ("CIS") and geographic information system ("GIS") to associate each customer with a feeder. Monthly NCP load factors are then used for each customer class to determine each class's contribution to each feeder's monthly NCP as a percent of each month's peak on the feeder. Each class's contribution to monthly peak load on the feeder is multiplied by the number of overhead and underground miles on the feeder. These load-weighted line miles are then added across all the feeders to develop the total load-weighted overhead and underground distribution line miles allocated to each class. Allocation factors for overhead and underground lines are then developed by dividing the total load-weighted line miles attributable to each class by the total load-weighted line miles for all classes. The overhead allocators are applied to FERC Accounts 364 and 365, and the underground allocators are applied to FERC Accounts 366 and 367.

2. Distribution Line Transformer Costs

Q. How does PSE classify line transformer costs in its cost of service analysis in this case?

A. In this case, line transformer costs are classified as being demand-related.

Q. Is the classification of line transformer costs as demand-related consistent with prior Commission guidance?

A. Yes. The Commission has previously treated line transformer costs as demand-related costs. In the 2017 GRC, the Commission rejected proposals that would have treated these costs as customer-related costs. The Commission stated:

> We are not persuaded on the basis of the current record that transformer costs should be recovered in basic charges, or through a minimum bill. We have never approved such a proposal and continue to believe these costs are not customer-related costs as that term is generally understood. Transformer Costs should be recovered as distribution charges subject to PSE's electric decoupling mechanism, which adequately protects the Company's recovery of its fixed costs…[6]

Q. Please describe how the line transformer cost allocation factor is developed.

A. PSE uses its CIS and GIS to associate each line transformer with the customers using the transformer. This results in allocating approximately 330,550 transformers to PSE's different customer classes by type and size. The majority of line transformers are used by a single class and thus are directly assigned. The remaining transformers are allocated to each class based upon the class's relative contribution to the transformer's load. The transformers are priced at current

[6] Dockets UE-170033 and 170034 (consolidated) Order 08 at paragraph 357

costs, including installation, to determine each class's contribution to embedded line transformer costs (FERC Account 368). The embedded line transformer costs in the FERC account reflect PSE's line extension policy and are reduced for customer contributions.

3. Service Line and Meter Costs

Q. How are service line and meter costs allocated in PSE's cost study?

A. Service line costs are allocated based on the number of customers taking service at secondary voltage. Costs of all underground service lines are assigned to the residential class because non-residential secondary voltage customers own their underground services. Costs of overhead service lines are allocated based on the number of secondary voltage overhead service customers in each class. Meter costs are allocated based on the current cost of electric meters assigned to customers in each class relative to the current cost of all electric meters.

H. Administrative and General Costs and Other Cost Allocation Factors

Q. How does PSE allocate administrative and general costs in its electric cost of service study?

A. Most administrative and general costs are assigned based on production, transmission, distribution, and customer costs. Property insurance allocations are based on allocated plant, and pensions and employee insurance follow the allocation of salary and wages.

Q. What other cost allocations does PSE use in its electric cost of service study?

A. PSE reviews historical experience with late payments and assigns the costs to each class. Other miscellaneous revenues associated with non-sufficient fund checks and reconnects are allocated to each class based upon a historical analysis of revenues received from these sources.

Q. Has PSE provided a summary of its electric cost of service study in this proceeding?

A. Yes. PSE's proposed electric cost of service study is summarized in the Third Exhibit to the Prefiled Direct Testimony of Birud D. Jhaveri, Exh. BDJ-4.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.