EXH. CTM-1T
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: CHRISTOPHER T. MICKELSON

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-240004 Docket UG-240005

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

CHRISTOPHER T. MICKELSON

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

PUGET SOUND ENERGY

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I. INTRODUCTION

Q. Please state your name, position, and business address with Puget Sound Energy.

A. My name is Christopher T. Mickelson, the Manager of Cost of Service and Pricing for Puget Sound Energy ("PSE" or the "Company"). My business address is 355 110th Avenue NE, Bellevue, Washington 98004.

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

A. Yes. Exh. CTM-2 provides a comprehensive overview of my education, relevant employment experience, and professional qualifications.

Q. What are your duties as Manager of Cost of Service and Pricing for PSE?

A. I am responsible for overseeing electric and gas cost of service studies, rate spread, rate design, and load research at PSE.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. Can you provide an overview of the topics covered in your testimony?

A. Certainly. My testimony encompasses several critical areas related to PSE's electric operations and pricing, including:

- restated and normalized test year electric revenue;
- projected rate year electric revenue for the multiyear rate plan ("MYRP");
- electric cost of service study, compliant with WAC 480-85, and a rule exemption request for FERC Account 565;
- proposed revenue allocation for electric service;
- proposed rate design for electric service;
- overall rate impacts for the projected rate years;
- updated allowed revenue for electric decoupling mechanisms; and
- a summary of tariff sheets potentially filed in the compliance process.

Q. Could you provide a brief summary of your testimony?

A. Absolutely. I have summarized my testimony as follows:

Normalized Test Year Electric Revenue

The total normalized test year electric revenue at current base rates is estimated to be $2.376 billion based on 23.292 billion kWh in electric sales, as presented in Exh. CTM-4.

Projected Rate Year Electric Revenues

The total projected rate year electric revenue at forecasted base rates is estimated to be $2.703 billion in 2025 based on 23.558 billion kWh in electric sales, and $2.985 billion in 2026 based on 23.776 billion kWh in electric sales, as developed in Exh. CTM-6.

Electric Cost of Service Study

The electric cost of service study complies with WAC 480-85, and PSE seeks a rule exemption for the treatment of FERC Account 565 – Transmission of Electricity by Others.

For the lighting cost of service study, PSE is proposing to update overall lighting rates to better reflect cost causation and consolidating lighting schedules into wattage ranges to enhance tariff efficiency and future proofing the lighting tariff as lighting equipment and bulb types evolve. The methodology employed in PSE's proposal is consistent with how other rate schedules are designed under a "postage stamp" approach; otherwise, the methodology employed in PSE's proposal is consistent with that approved in the 2022 general rate case. The analysis includes identifying the revenue required from the lighting customer class, classifying lighting costs based on relevant cost drivers, identifying the revenue contribution, allocating the classified costs, and developing lighting and pole rates from the allocated costs established in the electric cost of service study.

Electric Revenue Allocation

Based on the proposed cost of service study, most rate classes are near a revenue to cost ratio of 1.00, also known as a "parity ratio." An exception is Schedule 35, Irrigation and Pumping Service, which is below the parity ratio and warrants an increase to base rates of one and half times the proposed average increase to base rates, and Schedule 46 and Schedule 49, High Voltage Service, which are above the parity ratio to warrant a smaller than average increase to rates.

Electric Rate Design

PSE's electric rate design proposal is a strategic approach aimed at realigning pricing components for existing customer classes over multiyear periods. The proposal includes a potential up to 30 percent increase in monthly customer charges and demand charges, keeping these charges within the respective cost of service study results. Simultaneously, the energy charge components will experience flat rate increases for each tier within the classes. Notably, specific classes such as Choice and Retail Wheeling, Special Contract, and Lighting Schedules 50-59 have unique considerations where charges align with cost-based levels.

PSE is proposing to create three new tracker schedules: (1) Schedule 141WFP, Wildfire Prevention Tracker; (2) Schedule 141DCARB, Decarbonization Rate Adjustment; and (3) Schedule 141CGR, Clean Generation Resources Rate Adjustment. In addition, PSE is proposing to eliminate or zero out and embed into base rates the following rider and tracker schedules: (1) Schedule 95, Power Cost Adjustment Clause; (2) Schedule 137, Renewable Energy Credit; (3) Schedule 141PFG, Intervenor Funding; (4) Schedule 141CEI, Clean Energy Implementation; (5) Schedule 141N, Rates Not Subject To Refund Rate Adjustment; and (6) Schedule 141R, Rates Subject To Refund Rate Adjustment.

Overall Electric Rate Impacts

PSE requests a multiyear rate plan with electric revenue increases of approximately \$192.2 million in 2025, or 6.74 percent, and \$259.9 million in 2026, or 8.48 percent, as developed in Exh. CTM-8. Table 1 reflects the net overall impact on PSE's electric customer classes associated with the proposed update to base rates and multiyear rate plan trackers.

Table 1 – Electric Overall Impact

Customer Class	Rate Schedule	No. of Customers	2025 Overall Impact	2026 Overall Impact
Residential Service	7/307/ 317/ 327	1,071,481	6.92%	8.79%
General Service, <51 kW	8/24/324	125,774	7.83%	8.49%
General Service, 51-350 kW	7A/11 /25/29	8,784	5.61%	8.92%
General Service, >350 kW	12/26	854	5.47%	8.18%
Primary Service, General	10/31	501	5.81%	8.22%
Primary Service, Irrigation	35	2	13.30%	10.27%
Primary Service, Schools	43	143	7.28%	8.51%
High Voltage Service	46/49	23	5.34%	8.36%
Lighting Service	50-59	9,096	-0.02%	8.87%
Retail Wheeling	449/459	15	4.67%	0.00%
Special Contract	SC	89	72.66%	4.79%
Firm Resale	5	8	146.93%	0.00%
Total Sales		1,216,770	6.74%	8.48%

Compliance Filing

The rates in a number of PSE's adjusting price schedules will need to be reset simultaneously with the proposed changes to base rates in this general rate case. The compliance filing will include updates to all PSE base electric rate schedules and adjusting price schedules. The adjusting price schedules to be updated and included in the compliance filing are:[1]

- Electric Schedule 95, Power Cost Adjustment Clause;

[1] As discussed later in this testimony, not all required tariff sheets have been filed as part of this case because they have either annual filing requirements or some other circumstance that applies; those tariff sheets will be updated during or shortly after the conclusion of this case.

- Electric Schedule 137, Renewable Energy Credit;
- Electric Schedule 307, Residential Service Time-of-Use;
- Electric Schedule 317, Residential Service Time-of-Use with Peak Time Rebate;
- Electric Schedule 327, Residential Service Time-of-Use with Super Off-Peak;
- Electric Schedule 324, General Service Time-of-Use with Peak Time Rebate;
- Electric Schedule 85, Line Extensions and Service Lines;
- Electric Schedule 87, Income Tax Rider;
- Electric and Natural Gas Schedules 141PFG, Intervenor Funding;
- Electric and Natural Gas Schedules 141N, Rates Not Subject to Refund;
- Electric and Natural Gas Schedules 141R, Rates Subject to Refund;
- Electric and Natural Gas Schedules 142, Revenue Decoupling Adjustment Mechanism; and
- Natural Gas Schedule 141D, Distribution Pipeline Provisional Recovery Adjustment.

This summary provides a comprehensive view of the key components and proposals in my testimony.

Q. Do you sponsor any exhibits in support of your testimony?

A. Yes. I sponsor the following exhibits:

- Exh. CTM-2, Professional Qualifications;
- Exh. CTM-3, Billing Determinants;
- Exh. CTM-4, Normalized Test Year Revenue from Electric Operations;
- Exh. CTM-5, Electric Cost of Service Study;
- Exh. CTM-6, Electric Rate Year Revenue Allocation and Rate Design;
- Exh. CTM-7, Lighting Cost of Service and Rate Design;

- Exh. CTM-8, Electric Revenue Impacts;
- Exh. CTM-9, Electric Decoupling Allowed Revenue Calculation;
- Exh. CTM-10, Electric Fixed Power Cost Decoupling Allowed Revenue Calculation;
- Exh. CTM-11, Electric and Gas Low-Income Program Funding Increase; and
- Exh. CTM-12, Electric and Gas Tariff Schedules.

III. NORMALIZED TEST YEAR REVENUE FROM ELECTRIC OPERATIONS

Q. What does normalized test year revenue mean in the context of a utility rate case?

A. Normalized test year revenue is an estimate of test year revenue that considers normalized and proforma test year billing determinants. It makes the revenue calculation reflect only the rate schedules considered in the ongoing case, incorporates any rate changes since the test year, and aligns with the normalized test year revenue requirement and loads. This approach factors in billing determinants shown in Exh. CTM-3, such as energy sales, billed demand, and the number of bills, to produce an estimate of revenue from proposed rates.

Q. Can you provide more details on how PSE developed its normalized test year revenue from electric operations?

A. Certainly. Detailed information on this is available in Exh. CTM-4. This exhibit outlines the normalization adjustments made to test year energy sales, including adjustments for billed and unbilled electricity sales, migration between rate schedules, and temperature adjustments to account for non-normal temperatures during the test year.

Q. Please explain page one of Exh. CTM-4, normalized test year delivered sales.

A. Exh. CTM-4 (Proforma kWh & Rev) involves essential normalizing adjustments to test year energy sales. This includes adjustments for billed electricity sales, unbilled electricity sales to address billing cycle misalignments, schedule migration to estimate customer and sales movements between rate schedules, and a temperature adjustment accounting for non-normal temperatures during the test year. The adjustments are reflected in:

- *Column (d)*: Billed electricity sales for the test year, twelve-months ending June 2023.
- *Column (e)*: Adjustment for unbilled electricity sales, considering the billing cycle misalignments.
- *Column (f)*: Schedule migration adjustment for estimated customers and sales movement between rate schedules.
- *Column (g)*: Temperature adjustment for electricity sales to account for non-normal temperatures during the test year. This adjustment is described in the Prefiled Direct Testimony of Josh Jacobs, Exh. JJJ-1T.

The result, presented in column (c), is the normalized test year electricity sales used to calculate revenue shown in column (h) of Exh. CTM-4.

Q. Can you elaborate on the normalized test year revenue summary on page two of Exh. CTM-4?

A. Certainly. Exhibit CTM-4 (Revenue Requirement Summary) provides a detailed breakdown of the differences between test year revenue in PSE's income statement and normalized test year revenue calculated based on billing determinants and current rates. It highlights various adjustments, including removal of revenue from municipal taxes and specific adjusting price schedules (rows 5-31), other adjustments for rate changes to annualize base related revenues (rows 33-35), temperature normalization adjustments (row 37), schedule migration adjustments reflecting customer movements (row 40), and other restating adjustments such as unbilled revenue (rows 38-39, 41), and proforma revenue adjustments (rows 47-48).

Q. Will there be changes to the rates in the adjusting electric price schedules because of this filing?

A. Yes. As part of this filing, rates in certain adjusting electricity price schedules will be reset alongside the approval of new base rates. Schedule 95 rates for power cost recovery, Schedule 137 rates for renewable energy credits, Schedule 141PFG rates for intervenor funding, Schedule 141CEI rates for clean energy implementation, and Schedules 141N and 141R related to base rates in Docket UE-220066 will be reset to zero or eliminated. Additionally, rates and allowed revenue per customer within electric and natural gas Schedules 142, Revenue Decoupling Adjustment Mechanism, will be reset to align with the newly approved base rates.

Q. What are the resulting figures for normalized test year electricity sales and revenue?

A. The total normalized electricity sales for the test year is 23.292 billion kWh, presented in column (c) of page one of Exh. CTM-4 (Proforma kWh & Rev). The total normalized test year revenue is $2.095 billion, presented in column (h). These figures are a reflection of the adjustments made to promote accuracy based on billing determinants and rates.

IV. PROJECTED RATE YEAR REVENUES FROM ELECTRIC OPERATIONS

Q. What does the term “projected rate year revenues” mean in the context of utility pricing and operations?

A. Projected rate year revenues are estimates of the revenue expected for each rate year. These estimates are based on forecasted billing determinants, such as, energy sales, billed demand, and customer count. The calculations utilize the base rates in effect at the time of filing for a rate change. The information provided in Exh. CTM-6 (Rate Spread), columns (e) thru (h) presents the forecast load and estimated revenue at current rates for the projected rate year periods. The derivation of projected rate year revenue is explained in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T.

Q. How did PSE project base rate revenues for the rate year periods?

A. PSE projected base rate revenues for each of the multiyear rate periods (2025 and 2026) by applying the current rates to the forecasted billing determinants. The billing determinants are crucial factors used not only in developing rate year revenues but also in estimating revenue from proposed rates.

Q. What load and customer forecast did PSE use for projecting its revenues?

A. PSE utilized its Forecast 2023 ("F2023") for load and customer count that was approved by its Energy Management Committee in May 2023. It is important to note that a single modification was made to the forecast specifically for developing the rate year revenue or revenue from proposed rates that adjusted for customer migration between Schedule 449 to Schedule 31. The forecast provides a baseline for predicting future electricity sales and revenues.

Q. Can you provide the resulting figures for PSE's projected electricity sales and revenues for the multiyear rate periods?

A. Certainly. The total projected electricity sales for the first rate year are 23.558 billion kWh, as shown in column (e) of Exh. CTM-6 (Rate Spread). The total projected revenue for the first-rate year is $2.703 billion, as presented in column (p). For the second rate year, the total projected electricity sales are 23.776 billion kWh, column (g), and the total projected revenue is $2.985 billion, column (v).

Q. How does the change in forecasted load impact the proposed revenue requirement?

A. The alteration in forecasted load influences the proposed revenue requirement. This makes the revenue forecast accurate and responsive to changes in energy consumption patterns, thereby informing decisions on rate structures.

Q. Could you elaborate on how the load forecast results changes the required revenue?

A. Certainly. The revenue required shapes the rate structure to generate accurate forecasted revenues. Utilizing the revised loads from the F2023 forecast, resulted in a $61.5 million reduction in required revenue due to increased energy demands compared to the Company's 2022 general rate case; see Exh. CTM-4 (Load Analysis) for support. This approach prioritizes adapting to the dynamic nature of energy demands.

V. ELECTRIC COST OF SERVICE STUDY

Q. What does a cost of service study measure and what is its purpose?

A. A cost of service study measures whether the revenue provided by the customers recovers the cost to serve those customers, by apportioning the revenue, expenses, and plant balances, or rate base, associated with providing service to distinct customer groups.

First, this takes the Company's costs and rate base and sorts them into the basic functions of doing business, such as production, transmission, distribution, and customer. Then, the expenses and rate base are further classified as customer-related, energy-related, or demand-related. Customer-related costs are those that vary as customers are added or subtracted to the system. Energy-related costs vary by total consumption. Demand-related costs vary by the size of the peak demand to meet the demands of customers on each rate schedule and system build requirements. Lastly, the classified-related costs are assigned or allocated to each customer class. Each customer grouping is based on, among other things, customers with similar load characteristics and facilities requirements, resulting in an evaluation of the cost of the service provided to each group.

The parity ratios by customer group indicate whether the revenue provided by the customers in each group recovers the cost to serve those customers. If an increase in overall revenues is necessary to provide the utility with a fair return on rate base, then each schedule may require a different percentage increase to achieve an equal rate of return across all schedules. "Parity" is accomplished if all schedules provide the same rate of return on the rate base allocated to them.

Q. What is the basis for the electric cost of service study provided in this case?

A. The electric cost of service study, as presented in Exh. CTM-5, is based on the pro forma results of operations for the 12-months ending December 2023, outlined in the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, and Exh. SEF-4E.

Q. Can you explain the content of Exh. CTM-5, the electric cost of service study?

A. Certainly. Exh. CTM-5 provides the results of the cost of service study through an electric template that adheres to WAC 480-85-040(1). It consists of five workbook tabs presented as separate sections. Section A cross-references PSE's revenue requirement development, as presented in Exh. SEF-4E, at the FERC account level to facilitate assignment of costs to customer rate classes in the study. Section B details the FERC account level cost of service results for all customer rate classes. Section C illustrates the allocation factors used to assign each type of cost to the customer rate classes. Section D summarizes revenue requirement adjustments, akin to Exh. SEF-4E. Finally, Section E offers a high-level summary of the cost of service results, indicating parity ratios at present rates and revenue-to-cost ratios at proposed rates.

A. Requirements

Q. Are cost of service studies mandatory in general rate case filings?

A. Yes. Per WAC 480-07-510(6), amended by General Order R-599 on July 7, 2020, an initial general rate case filing must include a cost of service study in compliance with WAC 480-85.

Q. What are the Commission's requirements under WAC 480-85 for cost of service studies?

A. The Commission sets forth minimum filing requirements in WAC 480-85-040 that mandate cost of service results be filed using the Commission's electric and gas cost of service templates. Guidelines for supporting testimony, exhibits, work papers, and electronic models are specified. The Commission also outlines sources for the cost of service study inputs, under WAC 480-85-050, and mandates the use of an embedded cost method with instructions on functionalized, classified, and allocated costs per WAC 480-85-060. Guidelines for seeking exemptions from the rules are provided under WAC 480-85-070.

Q. Has PSE complied with these rules in its electric cost of service study?

A. Yes. PSE has complied with the cost of service rules set by WAC 480-85. However, the Company seeks an exemption from the rules concerning the treatment of "FERC Account 565 – Transmission of Electricity by Others," with additional detail provided later in the testimony.

Q. Does the electric cost of service study employ the same methodology as PSE's last electric case in Docket UE-220066?

A. Yes. The electric cost of service study utilizes the same methodology as the previous rate case. However, PSE highlights the request for an exemption from the rules and methodology, as these were not officially recognized within the Commission's Orders under Docket UE-220066.

B. Rule Exemption Request

Q. What exemption is the Company seeking as it pertains to WAC 480-85?

A. PSE is seeking an exemption from the WAC rules concerning the treatment of "FERC Account 565 – Transmission of Electricity by Others." FERC Account 565 is part of power costs included in PSE's power cost adjustment mechanism.

Q. How are transmission costs treated under WAC 480-85?

A. All transmission costs are considered demand-related and allocated to customer rate classes using the average of 12 system coincident peaks.

Q. Is this methodology different from PSE's prior electric cost of service studies?

A. Yes. In prior cases, before the creation of WAC 480-85, the transmission costs were an extension of production costs and were subject to the peak credit methodology. The Company utilized a peak credit method that was applied to all generation costs including variable power costs. The new methodology removes power costs, thereby increasing the proportion considered demand-related costs. Additionally, the demand allocation factor is based on the average of 12 system coincident peaks ("12CP"), unlike the previous method based on the average of four-winter month system coincident peaks.

Q. How are fixed generation costs treated in this study?

A. Consistent with WAC 480-85-060, fixed generation costs are classified as energy- or demand-related based on a renewable future peak credit ratio. Variable power costs are considered 100 percent energy related. The demand-related portions of generation costs are allocated based on the average of 12CP, determined from power supply native load excluding renewable generation. The energy-related portions of generation costs are allocated based on annual energy usage at the point of generation.

The renewable future peak credit method compares the cost of battery storage (demand) to wind turbine (energy) derived from the Company's 2023 Integrated Resource Plan ("IRP") at 2023 cost assumptions. This analysis resulted in 70 percent demand and 30 percent energy peak credit allocation. This proportion is exclusive of all energy-related variable power costs. Further detail surrounding this method and its assumptions are described later within my testimony. The renewable future peak credit calculation incorporated into this proposed cost of service study is methodologically the same as used in the Company's 2022 general rate case, updated to reflect current cost estimates including the applicable tax credits made available from the passage of the Inflation Reduction Act.[2]

Q. Does the proposed change have a material impact on the cost of service study results?

A. No. The replacement of the previous peak credit method with the renewable future peak credit method, along with allocating all variable power costs to energy and all transmission costs, except FERC Account 565, to demand, results in a minimal net effect. The impact of the change to parity ratios is insufficient to alter the results of the rate spread.

Q. What is included in PSE's power costs?

A. Power costs include the costs of fuel to run generating units, purchased power, costs of third-party transmission capacity, and various other costs directly associated with the purchase of electricity.

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[2] On August 16, 2022, President Biden signed the Inflation Reduction Act, PL 117-169, 136 Stat 1818, into law.

Q. Is it appropriate to classify FERC Account 565 as energy, similar to variable power costs, instead of classifying the costs as demand, similar to other transmission costs?

A. Yes. FERC Account 565 costs are incurred for wheeling energy over other utility transmission systems on behalf of PSE customers. These costs are not typically viewed as demand-related costs and have historically been charged to customers as variable power costs on a dollars per MWh basis.

C. Methodology

Q. How are generation costs treated in this study?

A. Generation costs are classified as energy- or demand-related based on a renewable future peak credit ratio. Demand-related portions are allocated to customer rate classes using the average of 12CP, and energy-related portions are allocated based on annual energy usage at the point of generation.

Q. Can you elaborate on the 'renewable peak energy credit' method used by PSE to classify fixed generation costs?

A. Certainly. The renewable peak energy credit method employed by the Company is fundamentally based on estimating the cost of designing a hybrid renewable and storage resource with planning attributes, Effective Load Carrying Capacity ("ELCC"), comparable to representative Combined Cycle Gas Turbine ("CCGT") generation on the PSE system. Costs for the hybrid resource are estimated in alignment with the Company's 2023 IRP. These costs are then fragmented into demand- and energy-related components. Storage costs are assumed as demand-related, considering storage's inability to produce energy independently. Wind costs are primarily energy-related, with a small portion related to demand due to the wind resource contributing to ELCC. The resulting demand-to-energy cost ratio is utilized to classify fixed generation costs before allocation to customer classes.

Q. Can you explain how the energy-related costs were derived in more detail?

A. Yes. To analyze the energy characteristics of the hybrid resource, the study compared the energy output delivered to PSE's system by existing CCGTs with the expected energy output from potential wind resources. The study then estimated a levelized fixed cost for wind resource additions, net of available tax credits. This cost was scaled based on the ratio of the desired energy output from existing CCGTs to the expected output of potential wind resource additions.

Q. Could you provide more insight into how the demand-related costs were derived?

A. Absolutely. The analysis of demand characteristics involved reviewing the ELCC provided by existing CCGTs and comparing it to the expected ELCC of storage and wind resources that could be added to PSE's system. The study used the average ELCC calculated in PSE's 2023 IRP for four-hour energy storage systems over the next 3,000 megawatts and a similar approach for the assumed wind ELCC. Subsequently, the study estimated a levelized fixed cost for four-hour storage resource additions, net of available tax credits, scaling this cost based on the ratio of CCGT firm capacity contribution to four-hour storage ELCC, adjusted for the wind ELCC.

Q. What was the result of this analysis?

A. The results of the analysis led to a modification of the 2022 general rate case classification. The shift moved from an 80 percent demand-related and 20 percent energy-related fixed generation costs to a revised ratio of 70 percent demand-related and 30 percent energy-related. This adjustment primarily reflects the increased availability of Inflation Reduction Act tax credits, which were not previously considered in the 2022 general rate case classification.

Q. How are transmission costs treated in this study?

A. All transmission costs, except FERC Account 565, are considered demand-related and allocated to customer rate classes using the average of 12CP.

Q. How are distribution costs treated in this study?

A. Distribution costs for direct assignment remain unchanged for substations, poles, conduit, and wires, directly assigned to high voltage general service and special contract customer classes based on the load ratio share of substations they are fed from. For distribution substations not directly assigned, costs are allocated using the average of the relative share of the summer and winter distribution system coincident peaks.

The methodology differs from prior studies, before the creation of WAC 480-85, which used monthly load contributions based on each customer class's percentage contribution to the peaks of individual distribution substations, 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 was then averaged across the months of the year. This average monthly contribution to each substation's peak load was then multiplied by the booked cost of the individual substation in current dollars to derive the allocated cost of each substation. These allocated substation costs were then summed by customer class and compared with PSE's total substation investment in current dollars to develop the substation cost allocations for FERC Accounts 360-362.

Q. Please identify any changes to the methodology associated with distribution poles, conduit, and wire costs.

A. Distribution poles, conduit, and wires are allocated to customer groups using the average of 12 monthly distribution system NCP for primary system and secondary system customers.

This differs from prior studies, before the creation of WAC 480-85, that used load-weighted line miles calculated monthly for each customer class based on feeder associates. PSE used monthly NCP load factors to determine each class's percentage peak load contribution for each feeder. Each class's contribution to monthly peak load on the feeder was multiplied by the number of overhead and underground miles on the feeder. These load-weighted line miles were then summed across all feeders to develop the total load-weighted overhead and underground distribution line miles allocated to each class. Allocation factors for overhead and underground lines were 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 were then applied to FERC Accounts 364 and 365, and the underground allocators were applied to FERC Accounts 366 and 367.

Q. How are customer-related costs treated in this study?

A. Line transformer costs are allocated to customers who receive power at secondary voltage by the relative ratio of transformers at current installation, consistent with prior studies. Service line and meter costs are allocated by customer count multiplied by installed cost of new service lines and meters, respectively. Customer service and billing operating expenses are allocated by customer counts weighted by meter counts and direct assignment of costs. In previous studies, service line costs were allocated by average secondary customer counts without weighting.

Q. How are administration and general operating expenses and general plant costs treated in this study?

A. Property insurance and taxes are functionalized and allocated based on plant in service. Pensions and employee insurance expenses are allocated based on salary and wages. FERC fees are identified and allocated based on energy consumption. Revenue-based fees, uncollectible accounts expenses, and excise taxes are allocated by the relative share of total revenue. Other administrative and general costs directly associated with production, transmission, distribution, or customer relations are assigned to relevant functions based on Company departments and are directly assigned to those functions and then allocated to customer class by the relevant plant or number of customers associated with the function. The remaining expenses are allocated based on internal allocation factors generated by the cost of service model.

Q. Has the Company submitted a cost of service study that complies with WAC 480-85?

A. Yes. The Company has submitted two cost of service studies, one compliant with WAC 480-85 and another based on the proposal to classify FERC Account 565 as energy and allocate those costs to variable power costs. Both studies' results are presented in Exhibit CTM-5. PSE's proposed cost of service study results informed the calculation for the Company's proposal for rate spread and rate design.

D. Rate Class Results

Q. What is the typical output of a cost of service study?

A. The typical outputs are parity ratios for each customer class.

Q. What is a parity ratio?

A. A parity ratio indicates how close a rate schedule is to covering its cost to service. A parity ratio of 1.00 means revenues cover 100 percent of costs, while 0.70 indicates coverage of only 70 percent, and 1.30 indicates coverage of 130 percent.

Q. What are the results of the Company's electric cost of service study presented in this case?

A. Section E of Exh. CTM-5 provides a high-level summary of the rate class results. Table 2 below displays the rate of return, relative return ratio, and the revenue-to-cost parity ratio at present rates for each rate schedule. These results inform the calculation for the Company's rate spread and rate design proposal.

Table 2 – Electric Cost of Service Base Case Results

Customer Class	Customer Schedule	Rate of Return	Return Ratio	Parity at Current Rates
Residential Service	7	1.60%	0.87	0.99
General Service, <51 kW	8/24	3.28%	1.78	1.05
General Service, 51-350 kW	7A/11 25/29	1.56%	0.84	1.00
General Service, >350 kW	12/26	0.60%	0.32	0.98
Primary Service, General	10/31	1.44%	0.78	1.00
Primary Service, Irrigation	35	-8.81%	-4.77	0.49
Primary Service, Schools	43	1.08%	0.58	0.99
High Voltage Service	46/49	4.74%	2.57	1.11
Lighting Service	50-59	3.24%	1.75	1.02
Retail Wheeling	449/459	14.95%	8.09	1.71
Special Contract	SC	-2.63%	-1.42	0.44
Firm Resale	5	-6.74%	-3.65	0.94
Total System		1.85%	1.00	1.00

VI. ELECTRIC REVENUE ALLOCATION

Q. Please explain the general concept of revenue allocation.

A. Revenue allocation, also known as "rate spread," is the process of determining the portion of total revenues to be collected from each rate schedule.

Q. How are parity ratios used from the cost of service study to allocate revenues?

A. Parity ratios play a crucial role in the allocation process. While they are used to move rate schedules closer to parity, it is not the sole factor. Other considerations include fairness, equity perceptions, economic conditions in the service territory, and rate stability.[3]

Q. Is it practical to achieve a parity ratio of 1.00 for every rate schedule?

A. While arithmetically possible, achieving a perfect 1.00 parity ratio for every rate schedule is challenging in practice. Disputes over assumptions and study results, coupled with the need for informed judgement, make it complex. Typically, a range of 95 percent to 105 percent parity justifies an equal percentage system increase.

Q. Would you please summarize PSE's proposed electric revenue allocation?

A. PSE's proposed electric revenue allocation aims for gradual movement towards full parity, 100 percent or shown as 1.00. Key aspects include applying an adjusted average rate increase to retail classes within five percent of full parity,

[3] *WUTC v. Puget Sound Energy*, Dockets UE-111048 and UG-111049, Order 08 ¶ 350 (May 7, 2012).

with four exceptions: (1) applying a rate increase that is 110 percent of the adjusted average to the class more than five percent below full parity; (2) applying a rate increase that is 90 percent of the adjusted average to the class more than five percent above full parity; (3) applying a rate increase that is 150 percent of the adjusted average to the class more than 20 percent below full parity; and (4) transportation customers and firm wholesale customers are excluded from parity analysis as their rate increase or decrease driven by cost of service study results.

As in PSE's last rate case, special contract and choice/retail wheeling rates are based on cost of service resulting in a calculated rate spread, rather than a rate spread based on a class-specific cost of service and revenue allocation analysis. The firm resale and special contract classes are allocated an amount to reach full parity to avoid cross-jurisdictional subsidy. The adjusted average electric rate increase considers variations for certain classes, to achieve fairness in the overall rate adjustment. Table 3 below and worksheet '(Rate Spread)' in Exh. CTM-6 provide a summary, and a detailed worksheet is available in Exh. CTM-6 for comprehensive insight into PSE's revenue allocation proposal.

Table 3 – Proposed Electric Revenue Allocation

Customer Class	Customer Schedule	Parity Ratio	Percent of Uniform Change
Residential Service	7	0.99	100%
General Service, <51 kW	8/24	1.05	100%
General Service, 51-350 kW	7A/11/25/29	0.99	100%
General Service, >350 kW	12/26	0.99	100%
Primary Service, General	10/31	1.00	100%
Primary Service, Irrigation	35	0.52	150%

Customer Class	Customer Schedule	Parity Ratio	Percent of Uniform Change
Primary Service, Schools	43	0.99	100%
High Voltage Service	46/49	1.08	90%
Lighting Service	50-59	1.03	100%
Retail Wheeling	449/459	1.44	-
Special Contract	SC	0.76	-
Firm Resale	5	1.36	-
Total System		1.00	

Q. Where are the imbalances shown in the results of the cost of service study?

A. Imbalances are reflected in Primary Irrigation, Schedule 35, covering 52 percent of its cost of service. High Voltage, Schedules 46 and 49, cover 108 percent of their cost of service, respectively. Other rate schedules fall within an acceptable range of covering their specific costs.

Q. Is there anything distinctive or unusual about PSE's proposed electric revenue allocation?

A. Yes. PSE introduces a distinctive element in its electric revenue allocation. The determination of the MYRP's total revenue requirement involves subtracting its allocated share of approximately $16.9 million, distributed nearly uniformly across the multiple rate-years before proceeding with the distribution across classes. This $16.9 million is intricately linked to targeted electrification initiatives, aligning with PSE's recent 2022 general rate case settlement. The distribution of costs follows a specific criterion—they will be assigned to each electric rate schedule based on the schedule's proportionate share of the total funding allocated for the Targeted Electrification Pilot program; it is crucial to note that customers on Schedules 449 are exempt from bearing these costs.[4]

Q. How was the revenue requirement for targeted electrification allocated?

A. The allocation of costs for targeted electrification followed a meticulous process where each electric rate schedule shouldered expenses based on its proportional share of the total program funding, with an exception for Schedule 449 customers. The outcome of this allocation resulted in 97.97 percent directed towards the residential class and the remaining 2.03 percent spread equally across the non-residential classes, excluding Schedule 449. It is essential to highlight that this allocation aligns precisely with the specifications outlined in the settlement agreement. For an in-depth discussion of PSE's targeted electrification pilot, please refer to the Prefiled Direct Testimony of John Mannetti, Exh. JM-1T.

VII. ELECTRIC RATE DESIGN

Q. What is PSE's electric rate design proposal?

A. PSE's electric rate design proposal is a strategic approach aimed at realigning pricing components for existing customer classes over the MYRP periods. The proposal includes a potential up to 30 percent increase in monthly customer charges and demand charges, keeping these charges within the respective cost of service study results. Simultaneously, the energy charge components will experience flat rate increases for each tier within the classes. Notably, specific

[4] *WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067 & UG-210918, Order 24/10 App. A, ¶ 67.g (Dec. 22, 2022).

classes have unique considerations where charges align with cost-based levels, such as:

- *Choice and Retail Wheeling*: customer charge set to cost-based levels.
- *Special Contract*: customer charge set to cost-based levels, and distribution rates charged per contract.
- *Lighting Schedules 50-59*: individual charges calculated based on a lighting cost study. These cost-based rates were scaled to generate the revenue proposed for this group of customers.

Q. Are there any structural changes to PSE's pricing proposal?

A. With the exception of lighting, there are no structural changes to PSE's pricing proposal.

Q. Why is PSE proposing such changes to its rate design?

A. PSE's pricing changes are driven by a forward-looking perspective considering industry trends and legislative mandates, particularly the Clean Energy Transformation Act ("CETA") enacted by the Washington State Legislature in 2019.[5] With a vision of the rapid electrification of various sectors, including transportation, PSE aims to provide precise pricing signals to incentivize the right investments on both sides of the meter. This entails aligning pricing components such as customer charges, demand charges, and energy charges with the outcomes of electric cost of service studies. The objective is to reduce cross-subsidization, address inequities, and establish accurate pricing signals for efficient grid utilization.

[5] Ch. 19.405 RCW.

A. Pricing Components

Q. Please explain the general concept of electric rate design.

A. Electric rate design is a systematic process that involves allocating the total revenue requirement for each electric rate schedule to specific charges within that schedule. These charges typically include the customer charge per month, the demand charge per kilowatt ("kW"), and the energy charge per kilowatt-hour ("kWh"). The goal is to create a structure that reflects the actual costs of providing service, promotes revenue stability for the utility, and offers fairness and predictability to customers.

Q. What are the guidelines used by PSE in designing customer rate development?

A. PSE adheres to a set of comprehensive guidelines in rate development. These include: (1) recover the Company's total revenue requirement; (2) provide revenue stability and predictability to the utility; (3) offer rate stability and predictability to the customer; (4) reflect the actual cost of providing service; (5) embed fairness in rate structures; (6) transmit accurate price signals to customers; and (7) maintain simplicity and ease of understanding. These guidelines align with established principles in utility rate development, as articulated in "Principles of Public Utility Rates" by James C. Bonbright, et al. (2nd ed. 1988).

1. Customer Charges

Q. Is PSE's proposed monthly customer charge cost-based?

A. Yes. PSE's proposed monthly customer charge, also known as the "basic charge," is cost-based. This charge covers customer-related costs such as the cost of meters, service drops, meter reading, meter maintenance, and billing.[6] The allocation of these costs to the basic charge is justified by the fact that they vary with the number of customers rather than usage. Importantly, PSE's proposal prevents the customer charge from exceeding the respective cost of service study results for each customer class.

Q. Why is PSE proposing to increase the basic charge?

A. The increase in the basic charge serves a dual purpose. First, it causes customers to pay an amount that reflects the fixed costs incurred by the Company to serve them, irrespective of their consumption level. This is crucial for reducing cross-subsidization, where customers with above-average consumption end up subsidizing those with below-average usage. Second, the increase delivers accurate price signals to both high- and low-usage customers, promoting energy efficiency and providing guidance on optimal grid utilization.

[6] In essence, customer-related costs reflect the minimum amount of equipment and service needed for customers to access the electric grid.

Q. How does increasing monthly customer charges contribute to addressing financial burden and improving utility cash flow?

A. Elevating monthly customer charges strategically addresses multiple objectives that benefit both the utility and its customers. By mitigating cross-subsidization, the approach makes customers contribute proportionally to the fixed costs of providing services, thereby minimizing disparities in the financial burden among different customer segments. In addition, higher customer charges minimize the influence that extreme weather conditions have on customers' bills, promoting greater predictability and stability in their utility costs to help with financial budgeting. As utilities face significant fixed costs for infrastructure, maintenance, and service provision, higher monthly customer charges contribute to the recovery of these fixed costs, creating a more stable and predictable revenue stream. This predictability enhances utility cash flow, and supports strategic planning, infrastructure investments, and operational stability.

2. Demand Charges

Q. What is a demand charge and how does it work?

A. A demand charge is a pricing mechanism calculated based on the highest average electricity usage within a defined period, typically 15 minutes, during a billing cycle. This charge is designed to contribute toward the cost of electrical infrastructure required to meet peak demand and enable sufficient generation, transmission, and distribution capacity. Demand could vary considerably across utilities, locations, building size, and electric vehicle charging which is rapidly expanding.

Unlike energy consumption charges, which are based on the total amount of energy used during the billing cycle measured in kWh, demand charges focus on the highest rate of electricity used in kW. The greater the requirement for electricity at any time during the billing cycle, the higher the customer's demand. This high, short-term power use requires larger transformers, power lines, substations, and generating capacity to meet these infrequent peak needs.

Illustrating demand, consider two customers consuming the same amount of electricity but impacting the electric system differently. For instance, a 100-watt light bulb used by customer number one for 10 hours results in one kWh consumption and a 0.1 kW demand. In contrast, customer number two, leaving ten 100-watt bulbs on for one hour, still consumes one kWh but places a one kW demand due to simultaneous usage. Though both used the same kWh, customer number two created a higher demand, necessitating the generation plant to produce more power quickly to meet the demand and stressing transmission and distribution components.

An analogy comparing electricity to a car further illustrates the distinction between energy and demand charges. Much like a car's speedometer measures its maximum speed (akin to demand measuring peak energy use), the odometer gauges distance traveled (similar to energy measuring total consumption). Just as a car's engine is built for maximum speed regardless of distance traveled, electrical systems must handle peak demands efficiently. Two cars covering the same 100-mile road – one at ten miles per hour for ten hours and the other at 100 miles per hour for one hour – underscore the need for a more capable and expensive engine to sustain higher speeds.

Q. Why would increasing demand rates be beneficial?

A. Increasing electric demand rates offers several benefits in the context of Washington's progress toward full electrification by 2045. First, higher demand rates serve as an incentive for consumers to use electricity more efficiently, discouraging load stacking, especially during peak demand periods. Second, electrifying various sectors requires additional infrastructure investments or more efficient utilization of existing assets, especially at the localized substation, feeder, and transformer level. Higher demand rates support these initiatives by optimizing grid load, preventing strain on the system during high-demand hours, and freeing up capacity. Third, increased demand rates incentivize the adoption of energy storage solutions, such as batteries, allowing consumers to store excess energy during low-use times for use during periods of higher demand. This reduces immediate demand on the substation during peak usage periods and aligns consumption with renewable energy generation, contributing to better grid stability. Moreover, aligning consumption with renewable energy generation is facilitated by demand rates, encouraging consumers to use electricity when renewable energy sources are abundant; this not only minimizes the environmental impact but also optimizes the use of renewable energy. Last, higher demand charges adhere to the cost causation principle, ensuring fair cost allocation, with those having higher peak demand contributing proportionally to overall system costs, which can help reduce interclass inequities.

Q. How do utility electric demand rates provide the right price signals to shift localized and system loads?

A. Utility electric demand rates play a pivotal role in providing accurate price signals to consumers, encouraging load shifting at both localized and system-wide levels. These rates can vary based on seasons or the time of day, reflecting the changing costs of electricity production and distribution. By introducing demand charges for residential and non-demand general service customers or increasing demand rates to reflect proper pricing levels, utilities can signal to consumers when electricity is more cost-effective, and promote more efficient use of the grid. Demand rates help incentivize consumers to shift their electricity usage, distributing the load more evenly, and minimizing strain on the system during peak demand periods. It also provides an economic incentive for consumers to adopt energy storage solutions on their side of the meter.

Q. How does increasing demand rates not interfere with incentivizing electric vehicle adoption?

A. PSE is actively engaged with customers interested in adopting fleet electric vehicles ("EV") as part of their transportation electrification ("TE") initiatives. Although increasing demand rates is under consideration, PSE acknowledges the importance of incentivizing EV adoption. Separate proposals for EV charging rates or programs, and offering favorable pricing during low-demand periods, are being developed. This strategic approach makes TE and the charging of EVs cost-effective during times of lower demand, supporting the integration of EVs into the grid without imposing stress during peak demand periods.

PSE will bring a proposal outside of this rate case to implement as part of a stage one technical feasibility study, to help inform a larger deployment in stage two to a larger set of customers.

Q. You mention introducing demand charges for residential and non-demand general service customers. Can you elaborate?

A. While not part of PSE's proposal in this rate case, PSE might consider introducing demand charges for residential and non-demand general service customers in the future. This consideration is driven by changing dynamics, including the evolving demand profiles of households, increased adoption of energy-intensive devices, and the growing infrastructure requirements associated with EV charging at home.

Traditionally, demand charges were not applied to normal residential service due to the assumption that most homes exhibit a consistent demand profile. However, this assumption is evolving as modern homes incorporate more energy-intensive devices, and the electrification pathway progresses. As mentioned earlier, PSE recognizes the need to leverage various tools to strategically manage this transition while maintaining grid reliability and providing appropriate price signals for efficient grid use.

The potential introduction of demand charges for residential customers is rooted in the necessity to accurately capture the costs associated with varying demand levels, especially considering the rise in EV adoption and the subsequent increase in localized demand. By incorporating demand charges, PSE aims to provide fair and equitable cost allocation, avoid cross-subsidization, and provide price signals that align with the evolving energy landscape.

3. Energy Charges

Q. What is an energy charge and what does it measure?

A. Energy charges are volumetric charges that account for the volume of electricity consumed in kWh during the entire billing cycle. Essentially, energy charges measure the total amount of electricity used, akin to the odometer in a vehicle tracking the total distance traveled.

Q. Please describe and explain the Company's proposal for flat rate increase for volumetric rates and tiers.

A. PSE's proposal includes a flat rate increase in cents per kWh for each tier within the customer classes. This approach promotes consistency and maintains the current spread between the rates. The flat rate increase is a straightforward and uniform adjustment applied across all tiers, providing a clear structure for energy charges. This proposal aligns with the objective of accurately reflecting the costs associated with providing electricity and contributes to the overall revenue requirement for the utility.

Q. Why is it essential to demonstrate accurate utility price signals?

A. Accurate utility price signals are vital for the efficient functioning of the electrical grid, serving multiple critical purposes. These signals act as powerful drivers of energy efficiency, prompting consumers to align their electricity usage with system needs. This promotes a more rational consumption pattern. During periods of peak demand, these signals play a pivotal role in load balancing by discouraging unnecessary consumption, thereby preventing undue strain on the grid. The result is a more stable and reliable grid, capable of withstanding challenging conditions, including extreme events. Additionally, responsive consumer behavior, guided by accurate pricing signals, contributes to the overall resilience of the grid. Beyond reliability, these signals support sustainability objectives, fostering responsible energy consumption practices among consumers. In essence, accurate utility price signals are the cornerstone for achieving an electrical grid that is not only efficient and balanced but also resilient and aligned with sustainability goals.

In summary, PSE's electric rate design proposal is a comprehensive strategy that considers the evolving energy landscape, legislative mandates, and the need for equitable and efficient grid utilization. The proposed changes to customer charges, demand charges, and energy charges aim to strike a balance between recovering fixed costs, incentivizing efficient energy use, and preparing the grid for the challenges and opportunities of electrification in the coming decades.

B. Customer Class Pricing Proposals

Q. Please provide an overview of PSE's proposal.

A. As mentioned through this testimony, PSE's electric rate design proposal is a strategic approach aimed at realigning pricing components for existing customer classes over multiple rate years. The proposal incorporates a potential maximum increase of up to 30 percent in both monthly customer charges and demand charges, while ensuring these adjustments are at or below their respective cost-of-service study unit costs. Concurrently, the energy charge component will see a flat rate increase for each tier within the customer class. Notably, specific classes such as Choice and Retail Wheeling, Special Contract, and Lighting Schedules 50-59 have unique considerations where charges align with cost-based levels.

1. Residential Service

Q. What is PSE's rate design proposal for residential customers?

A. PSE's rate design proposal for Residential Service, Schedule 7, involves adjustments to the basic charge rate and two-tier energy rates. The first tier, set at 600 kWh per month, is followed by a tail tier for all monthly usage exceeding 600 kWh. For the first rate year, PSE proposes a 30 percent increase in the monthly customer charge for residential customers, Schedule 7, from $7.49 to $9.74 for single-phase, and from $17.99 to $23.39 for three-phase. The remaining increase is assigned to the energy charge components by a flat rate of 0.027079 cents per kWh. In the second rate year, PSE proposes a 30 percent increase in the monthly customer charge from $9.74 to $12.66 for single-phase, and from $23.39 to

$30.40 for three-phase. Similar to the first year, the energy charge components receive a flat rate increase of 0.009159 cents per kWh.

Q. Will increasing the basic charge send the wrong price signal to customers?

A. No. The increase sends the correct price signal by recovering fixed costs incurred by the Company to serve the customer, such as the service drop and the meter. It also addresses the growing variation between customer charge-related costs and the basic charge set a decade ago.[7]

Q. Is PSE's level of customer charge appropriate?

A. Yes. PSE's proposed customer charge aligns with the balance point identified by the Commission in 2007:

> an increase in the customer charge…will result in the Company recovering about one-fourth of its fixed costs allocated to residential customers via a fixed charge on each customer's bill. This is about eight to ten percent of an average customer's total bill, considering both fixed and variable costs. This seems to us the right balance point for the recovery of fixed costs via the customer charge.[8]

The increase, representing 13.21 percent of fixed customer costs allocated to residential customers,[9] equals 6.92 percent and 9.64 percent of an average customer's total bill in the first and second-rate year, respectively, meeting the Commission-approved limits.

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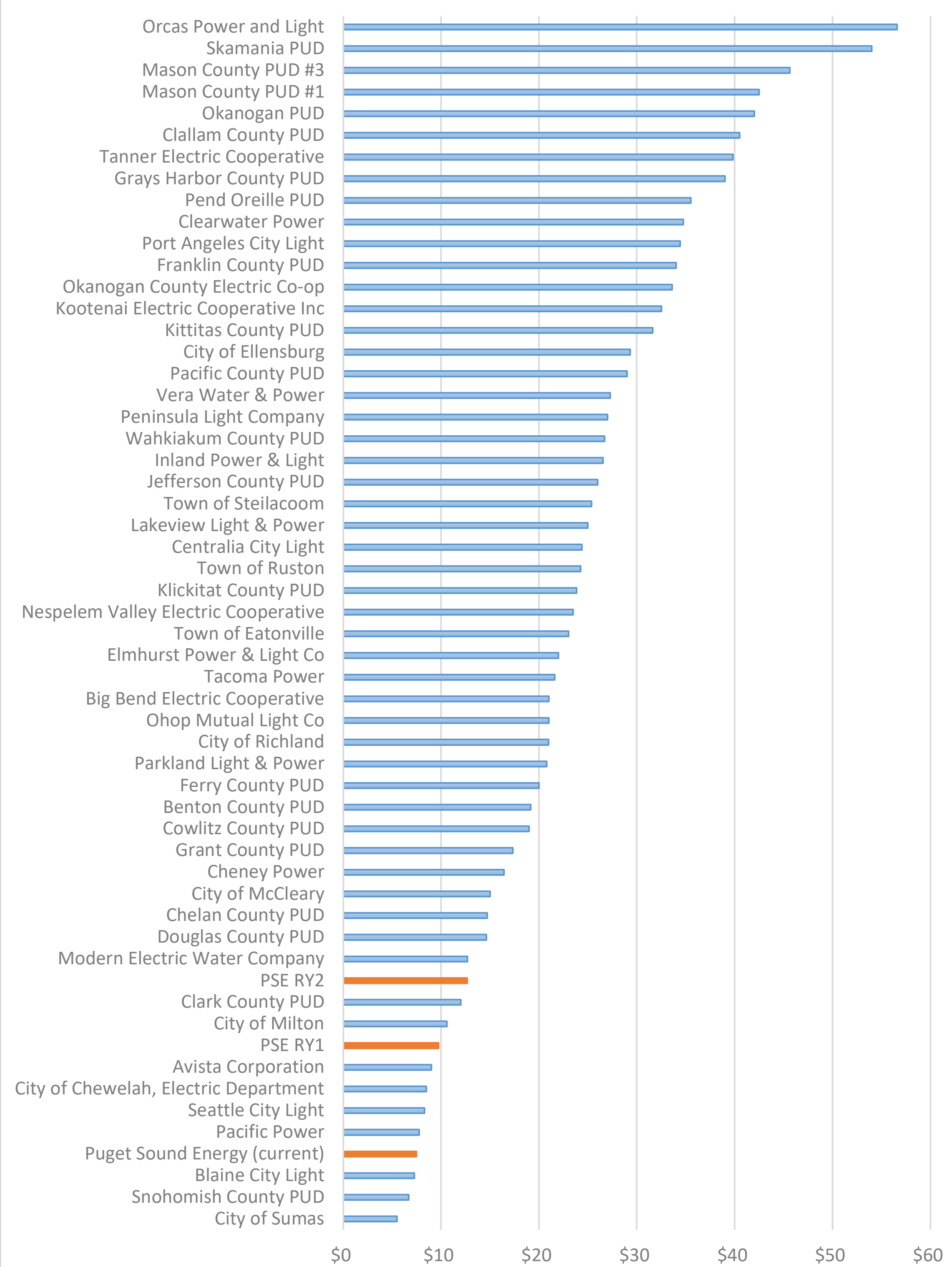
[7] *WUTC v. Puget Sound Energy*, Dockets UE-111048 and UG-111049, Order 08 (May 7, 2012).
[8] *WUTC v. Puget Sound Energy*, Dockets UE-060266 and UG-060267, Order 08 ¶ 139 (Jan. 5, 2007).
[9] Percentage is based on total customer and distribution customer costs.

Q. How does PSE's level of customer charge compare to other electrical utility providers in the state of Washington?

A. See Table 4, below, for a comparison of PSE's current and proposed customer charges for the MYRP to other electrical utility providers in the state of Washington. The specific values and comparisons are provided in the table for a comprehensive assessment, which illustrates that PSE's current customer charge is already the fourth lowest in the state. Despite proposing an increase for the first and second rate years, PSE's customer charge will remain near the bottom 20 percent of the state at today's charges. This indicates that even with the proposed adjustments, PSE's customer charge remains competitive and comparatively low within the state's utility landscape.

Table 4 – Residential Basic Charges by Electrical Utility Providers in Washington



Q. Why is a higher basic charge, reflecting fixed costs, crucial for addressing interclass cross-subsidization in rate designs?

A. A higher basic charge reflecting fixed costs is essential because it provides proportional contributions to the fixed infrastructure related to connecting to the grid, promoting equitable cost distribution among customer classes. This prevents situations where one group subsidizes another, averting an imbalanced distribution of fixed costs onto higher-use customers through volumetric energy charges. Notably, limited income customers, often with lower adoption rates of net energy metering technologies and higher-than-average usage, as shown in Table 5, below, face heightened bill impacts due to the burden of cost shifting. Implementing a higher basic charge aligned with actual fixed costs is vital to rectify this disparity, shielding low-income customers from undue financial burdens. This approach, aligned with sound rate design principles, fosters transparency and fairness in cost allocation.

Q. Will PSE's proposal to increase the basic charge harm known low-income customers?

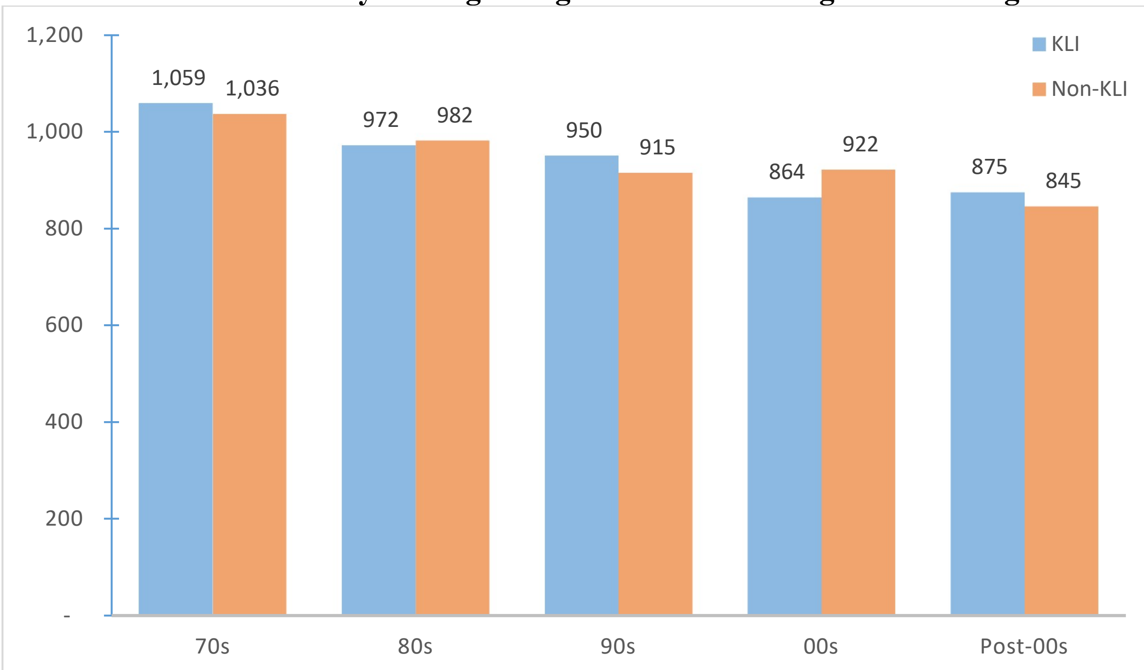
A. No. While all customers will experience an increase, the goal is to minimize the impact on average and high-use known low-income ("KLI") customers, establishing a modest increase before factoring in additional assistance. Various factors influencing high-energy burden, such as higher fuel costs or energy-inefficient homes in older properties, are considered.[10] Studies show that property age significantly affects energy inefficiency, contributing to above-average energy usage.[11] Adjusting the cost structure by allocating more fixed costs to the basic charge serves to mitigate interclass cross-subsidization, particularly from those with highly efficient, low-use homes or solar installations. This shift also aims to minimize the impacts on limited-income customers with higher energy consumption. PSE's data, illustrated in Table 5, shows higher monthly average usage in older properties. These older properties, often lacking insulation, contribute to above-average energy usage which PSE's own data shows residential customers segmented by housing vintage.

Additionally, limited-income customers have access to PSE's bill discount rate program ("BDR"), fostering a more significant reduction in financial burden and enhancing equity. Conversely, for customers with vintage homes who do not qualify for BDR, our approach is designed to alleviate the impact on them as well.

[10] *See* Dep't of Energy, Office of State and Community Energy Programs, Low-Income Community Energy Solutions, https://www.energy.gov/scep/slsc/low-income-community-energy-solutions#:~:text=According%20to%20DOE's%20Low%2DIncome,be%20as%20high%20as%2030%25 (last visited Feb. 7, 2024).

[11] Marry Blake, Creating the Right Retail Rate Environment for Energy Conservation and Energy Efficiency, *Management Quarterly*, at 6 (Dec. 22, 2009); *see also* Office for National Statistics, Age of the property is the biggest single factor in energy efficiency of homes (Jan. 6, 2022) https://www.ons.gov.uk/peoplepopulationandcommunity/housing/articles/ageofthepropertyisthebiggestsinglefactorinenergyefficiencyofhomes/2021-11-01 (last visited Feb. 7, 2024).

Table 5 – Monthly Average Usage based on Housing Stock Vintage



Q. Is there anything else influencing older homes compared to newer homes?

A. Yes. The influence on older homes stems from a transformative shift in energy consumption patterns over the past decades, catalyzed by key regulatory policies. The Public Utility Regulatory Policy Act of 1978 marked a turning point, shaping energy use practices through stringent building codes and conservation initiatives. Despite positive changes, older homes, unable to undergo deep energy efficiency retrofits, remain inefficient and bear associated costs. While building codes and conservation efforts have transformed practices and contributed to a cultural shift towards sustainability, challenges persist in retrofitting older homes, emphasizing the need for a nuanced approach to address their unique energy consumption dynamics.

Q. Is the increase to the basic charge in addition to changes in energy rates?

A. Yes. The increase in the basic charge is accompanied by changes in energy rates. While the energy charge increases, it is less than it would be without the basic charge increase. The Company's revenue requirement drives the overall rate increase, and without elevating the basic charge, a greater share of the revenue requirement would be achieved through larger increases to volumetric charges. For customers with usage levels consistent with low-income, rates are between 0.3 percent and 0.9 percent lower with the basic charge increase in the first year, shown in Table 6.

Table 6 – Residential Crossover

Usage in kWh	Total Bill per Rate Design Option		
	Current Basic Rate = $7.49	Proposed Basic Rate = $9.74	% Difference
1,000	$134.45	$134.02	-0.3%
1,100	$148.31	$147.61	-0.5%
1,200	$162.17	$161.21	-0.6%
1,300	$176.03	$174.80	-0.7%
1,400	$189.89	$188.39	-0.8%
1,500	$203.75	$201.99	-0.9%

Q. Do time-varying rate schedules undergo similar changes as the rest of residential service?

A. Yes. For time-varying rate ("TVR") schedules,[12] PSE has maintained revenue neutrality by implementing a class percentage increase to energy components aligned with the current off-peak to on-peak ratios. Simultaneously, the customer

[12] Electric Schedule 307, Residential Service Time-of-Use; Electric Schedule 317, Residential Service Time-of-Use with Peak Time Rebate; Electric Schedule 327, Residential Service Time-of-Use with Super Off-Peak; and Electric Schedule 324, General Service Time-of-Use with Peak Time Rebate.

charge is tethered to Schedule 7, Residential Service. This strategic approach aims to preserve revenue neutrality, so that the on-to-off-peak ratios remain consistent. This effort assists PSE in developing and evaluating an effective TVR structure that can successfully shift power usage away from peak demand times, with the ultimate goals of maintaining grid reliability, conserving energy, and potentially achieving cost savings. The TVR two-year pilot programs commenced in the fall of 2023, with the final report and review scheduled for 2026.

2. General Services

Q. Please summarize the proposed rate design for the General Service rate class.

A. The General Service class, Schedule 24, has a monthly basic charge and a single-tier energy rate that varies by season. This rate schedule does not have a demand charge. For the first rate year, PSE's proposal is to increase the customer charge by 30 percent to $13.27 for single-phase, to $33.74 for three-phase, and the remaining increase is assigned to the energy charge component by a flat rate of 0.024459 cents per kWh.

For the second rate year, PSE's proposal is to increase the customer charge by 30 percent to $17.25 for single-phase, to $43.86 for three-phase, and the remaining increase to the energy charge component by a flat rate of 0.008613 cents per kWh.

Q. Please summarize the proposed rate design for Small Demand General Service.

A. The Small Demand General Service class, Schedule 25, currently has a basic charge rate, two-tier seasonal energy rates and a two-tier seasonal demand rate. The first 50 kW tier of billing demand has no demand charge and demand related costs are recovered in the first tier of the energy rate. For the first rate year, PSE's proposal is to increase the customer charge by 30 percent to $70.14, increase the seasonal demand charges by 30 percent to $13.16 (winter) and $8.78 (summer), and the remaining increase is assigned to the energy charge components by a flat rate of 0.020089 cents per kWh.

For the second rate year, PSE's proposal is to increase the customer charge by 30 percent to $91.18, increase the seasonal demand charges by 30 percent to $17.10 (winter) and $11.41 (summer), and the remaining increase is assigned to the energy charge components by a flat rate of 0.005087 cents per kWh.

Q. Please summarize the proposed rate design for large general service customers.

A. These customers are served under two principal schedules: Large Demand General Service, Schedule 26, and Primary General Service, Schedule 31. Both schedules have basic charges, a single-tier energy charge and seasonally-differentiated demand charges. The demand and energy rates of the two schedules are linked such that the lower rates for Schedule 31 reflect the lower voltage transformation costs and associated lower energy losses.

Q. Why does PSE link the demand rates of the two schedules?

A. Since the loads and load factors for these schedules are comparable, PSE's intent is to provide a cost-based differential between the two rate schedules that create an end-point where customer motivation to take primary service will be based upon customer needs. In other words, PSE's proposal is an effort to incentivize customers to take service at either primary or secondary voltage based on their actual service needs rather than a desire to qualify for the schedule with the lower rate.

Q. Please describe the proposed Schedule 26 and Schedule 31 rate designs.

A. For the first rate year, PSE's proposal for Schedule 26 is to increase the customer charge by 30 percent to $141.80, increase the seasonal demand charges by 30 percent to $15.90 (winter) and $10.60 (summer), and the remaining increase is assigned to the energy charge component by a flat rate of 0.014864 cents per kWh.

For the second rate year, PSE's proposal for Schedule 26 is to increase the customer charge by 30 percent to $184.35, increase the seasonal demand charges by 30 percent to $20.67 (winter) and $13.77 (summer), and the remaining decrease is assigned to the energy charge component by a flat rate of 0.000149 cents per kWh.

For the first rate year, PSE's proposal for Schedule 31 is to increase the customer charge by 30 percent to $465.54, increase the seasonal demand charges by 30 percent to $15.52 (winter) and $10.35 (summer), and the remaining increase is assigned to the energy charge component by a flat rate of 0.014407 cents per kWh.

For the second rate year, PSE's proposal for Schedule 31 is to increase the customer charge by 30 percent to $605.21, increase the seasonal demand charges by 30 percent to $20.18 (winter) and $13.45 (summer), and the remaining increase is assigned to the energy charge component by a flat rate of 0.000311 cents per kWh.

For the Conjunctive Demand Service option, the demand pricing percentage splits will be adjusted to reflect coincidental peak for all metered locations rather than the arithmetic sum of the demand charges, in dollars, resulting from each service location's NCP demand, as per the Commission's Order 08 in Docket UE-190529.

Q. Please describe the proposed Schedule 35 and Schedule 43 rate designs.

A. For the first rate year, PSE's proposal for Schedule 35 (Primary Service, Irrigation, and Schedule 43 (Primary Service, Schools) is to increase the customer charge by 30 percent to $465.54, increase the seasonal demand charges by 30 percent to $6.40 (winter) and $4.26 (summer) for Schedule 35 and $6.51 (all) for Schedule 43, and the remaining increase is assigned to the energy charge component by a flat rate of 0.027618 cents per kWh and 0.014905 cents per kWh, respectively.

For the second rate year, PSE's proposal for Schedule 35 and Schedule 43 is to increase the customer charge by 30 percent to $605.21, increase the seasonal demand charges by 30 percent to $8.31 (winter) and $5.54 (summer) for Schedule 35 and $8.47 (all) for Schedule 43, and the remaining increase is assigned to the energy charge component by a flat rate of 0.007840 cents per kWh for Schedule 35, and a decrease is assigned to the energy charge component by a flat rate of 0.000789 cents per kWh for Schedule 43.

3. High Voltage Services

Q. Please summarize the high voltage service rate designs.

A. These customers are served under two schedules: High Voltage Interruptible Service, Schedule 46, and High Voltage General Service, Schedule 49. Both schedules have demand charges and a single-tier energy charge. The energy rates for these schedules are tied together, and only the demand charge differs to reflect the lower cost of providing interruptible service. For the first rate year, PSE's proposal for Schedule 46 and Schedule 49 is to increase the demand charge by 30 percent to $3.95 and $7.35, respectively, and the remaining increase is assigned to the energy charge component by a flat rate of 0.011558 cents per kWh and 0.011572 cents per kWh, respectively.

For the second rate year, PSE's proposal for Schedule 46 and Schedule 49 is to increase the demand charge by 30 percent to $5.14 and $9.55, respectively, and the remaining increase is assigned to the energy charge component by a flat rate of 0.001592 cents per kWh and 0.001671 cents per kWh, respectively.

4. Retail Wheeling

Q. Please summarize the retail wheeling rate design.

A. PSE proposes to set the only charge, a basic charge, for Power Supplier Choice and Retail Wheeling Service, Schedules 448, 449, 458 and 459, at its cost of service. This is an increase of $2,202.45 per month.

5. Special Contract

Q. Please summarize the special contract rate design.

A. There are two charges that PSE proposes to set for the special contract – the customer charge and distribution service charges for specific campuses served under the special contract. The customer charge is proposed to be set at its cost of service, which is $471.56 per month or an increase of $164.56. The distribution rate for each of the four campuses is designed to recover customer-specific distribution costs on a levelized basis. PSE reviewed the distribution service charge for each campus and adjusted the distribution transformer, circuit, feeder, and substation costs based on plant additions and retirements that have occurred since PSE's last 2022 general rate case proceeding. These updates will be made in the special contract contemporaneously with rate changes resulting from this proceeding.

6. Lighting Service

Q. Is PSE proposing any changes to its electric lighting tariffs in this case?

A. Yes. PSE is proposing to update overall lighting rates to better reflect cost causation and consolidate lighting schedules into wattage ranges to enhance tariff efficiency and future proof the lighting tariff as lighting equipment and bulb types keep changing.

Q. Please provide an overview of how this lighting analysis was performed.

A. The methodology employed in PSE's proposal is consistent with how other rate schedules are designed under a "postage stamp" approach. Unfortunately, the lighting schedule has become very complex and granular, unlike any other rate schedule. Otherwise, the overall methodology is consistent with how other rate schedules have costs allocated to them. The process used was the following:

1. Identify the revenue required from the lighting customer class based on electric rate spread and rate design, as identified in Exhibit CTM-6.
2. Classify lighting costs based on relevant cost drivers in the following categories: Capital, Distribution O&M, Administrative and General, Demand-Related and Energy-Related costs, through the electric cost of service study in the Exhibit CTM-5.
3. Allocate the classified costs across the lighting schedule wattage range based on weighted average energy based on bulb wattage and bulb count for each of the wattage range.
4. Develop pole rates separately from the allocated costs.

Through this process, the lighting revenue requirement is allocated to the lighting class based on the characteristics of the current lighting inventory within the wattage ranges under which the customer takes service. This provides continuity in rates across all lighting schedules and sets rates proportional to the estimated cost of service, as reflected in Exh. CTM-7.

Q. Why does consolidating lighting schedules to represent wattage ranges improve tariff efficiency and future proofing compared to the historical approach of recognizing different bulb types and equipment?

A. Consolidating lighting schedules into wattage ranges enhances tariff efficiency and future proofing due to several reasons. Recognizing various bulb types and equipment leads to a complex tariff structure, creating confusion for consumers. Consolidating schedules based on wattage simplifies the structure, making it clear and easily understandable for both consumers and utility administrators. In addition, recognizing specific bulb types may become outdated as technology evolves, requiring frequent adjustments. Focusing on wattage accommodates technological advancements, allowing seamless inclusion of new, energy-efficient lighting options without constant tariff revisions.

Managing multiple schedules for different bulb types increases administrative workload, possibly leading to higher operational costs, and complexity that is not recognized within any other rate schedule. A postage stamp type approach, consolidating based on wattage, significantly reduces administrative burden, streamlines processes, minimizes operational complexities, and results in the lighting class being consolidated back into the electric cost of service study in the next general rate case; instead of having its own separate cost of service study. In addition, recognizing specific bulb types may limit flexibility and hinder the ability to adapt to future energy trends. Focusing on wattage provides flexibility to accommodate emerging technologies and changing consumer preferences, so the tariff remains relevant over time.

Q. How does a postage stamp type approach reduce the administrative burden and complexity of pass-through charges compared to the historical method of recognizing different types of bulbs and equipment?

A. Adopting a postage stamp type approach, by consolidating based on wattage ranges, offers significant advantages in terms of administrative efficiency in updating pass-through schedules for each bulb type and simplicity of presentation of charges both on the pass-through schedule and on the customer's bill. Consolidating schedules simplifies the management of pass-through charges, creating a unified system for tracking and processing. Managing various charges for different bulb types and equipment complicates administrative tasks, leading to errors, and inefficiencies.

Updating pass-through charges becomes straightforward, as it allows uniform implementation of changes across wattage ranges. Managing changes for specific bulb types involves intricate adjustments, increasing the likelihood of errors, and delays in implementing updates.

Q. What is PSE's proposal for implementing the consolidated lighting approach?

A. PSE plans to fully implement the consolidated lighting approach in January 2026, as part of the second-rate year increase. During the first-rate year increase, the current lighting structure will be in place to allow time for IT and billing system configurations.

Q. What costs are proposed to the lighting cost of service model?

A. The lighting cost of service model costs are from the test year of the twelve-month period ending June 30, 2023, with proforma and restating adjustments through December 31, 2023, as identified in the electric cost of service study in Exh. CTM-5. As mentioned, PSE proposes for the first year to have separate lighting lamp rates allocated to each of the lamp sizes that recover revenue from each schedule, while the second year will have the consolidated lighting wattage, as presented in Exhibit CTM-7. The proposed rates for each tracker schedule are set for the multiyear rate plan period, changing annually.

Q. Has PSE prepared the impacts associated with the proposed rates for lighting?

A. Yes. Rate impacts for lighting are presented in Table 7 below. The proposed rate revenue change for lighting schedules represents the total revenue impact for the base portion as well as revenue change due to tracker or rider schedules discussed later within my testimony. Table 7 demonstrates overall impacts are 0.02 percent lower than current light base rate revenue in the year 2025, and 8.87 percent higher in year 2026. More detail is provided in Exh. CTM-8.

Table 7 – Estimated Lighting Impacts of Proposed Changes

	2025		2026	
Customer Class	Revenue Change	Overall Impact	Revenue Change	Overall Impact
Lighting	-$3,523	-0.02%	$2,051,067	8.87%

C. Tracker Schedules

Q. Is PSE proposing any changes to tracker schedules?

A. Yes. PSE is proposing to create three new tracker schedules: (1) Schedule 141WFP, Wildfire Prevention Tracker; (2) Schedule 141DCARB, Decarbonization Rate Adjustment; and (3) Schedule 141CGR, Clean Generation Resources Rate Adjustment. In addition, PSE is proposing to eliminate or zero out and embedded into base rates several existing rider and tracker schedules: (1) Schedule 95, Power Cost Adjustment Clause; (2) Schedule 137, Renewable Energy Credit; (3) Schedule 141PFG, Intervenor Funding; (4) Schedule 141CEI, Clean Energy Implementation; (5) Schedule 141N, Rates Not Subject To Refund Rate Adjustment; and (6) Schedule 141R, Rates Subject To Refund Rate Adjustment.

1. Wildfire Prevention Tracker

Q. Please describe the Wildfire Prevention Tracker.

A. PSE proposes creating Schedule 141WFP, focusing on recovering costs associated with the Company's Wildfire Mitigation and Response Plan. This includes expenses such as wildfire liability insurance premiums, amortization of previous deferrals from Docket UE-231048, O&M expense, and depreciation and return on rate base projects or services related to wildfire prevention.

Q. Why would creating a wildfire schedule be beneficial, as opposed to having these costs embedded within base rates?

A. Creating a dedicated wildfire schedule offers several advantages for PSE and its customers, especially in terms of addressing wildfire-related concerns and costs. When wildfire-related costs are embedded within base rates, it can be challenging for stakeholders, including consumers, to discern the specific financial implications associated with wildfire prevention and management. Establishing a separate schedule provides transparency by clearly delineating the costs attributed to wildfire prevention, tracking, and mitigation. This transparency allows for better understanding and scrutiny of expenses related to wildfire efforts.

When wildfire costs are part of base rates, it might be challenging to allocate resources specifically for wildfire prevention and management, as these expenses may compete with other operational needs. Having a dedicated schedule allows the Company to allocate resources with precision, so that funds are specifically earmarked for wildfire-related initiatives. This focused approach enhances the Company's ability to address and mitigate wildfire risks effectively.

Costs embedded in base rates may lack explicit accountability and tracking mechanisms, making it difficult to assess the efficiency and effectiveness of wildfire-related expenditures. A dedicated schedule facilitates detailed tracking of costs associated with wildfire prevention and management. This transparency enhances accountability, enabling the company to evaluate the impact of its efforts over time and make informed adjustments as needed.

Wildfire risks can evolve, and new challenges may emerge. Embedding costs in base rates may limit the Company's ability to adapt quickly to changing wildfire prevention dynamics. A separate schedule allows for agility in responding to evolving wildfire risks. The Company can make adjustments to the wildfire schedule more readily, ensuring that resources are aligned with the most current and pressing threats.

Including wildfire-related costs within base rates may lead to challenges in effectively conveying the significance of these expenses to consumers and other stakeholders. A dedicated schedule facilitates clear and targeted communication. The Company can engage with stakeholders to explain the specific initiatives, investments, and measures undertaken to prevent and manage wildfires, fostering a better understanding of the associated costs.

In conclusion, creating a wildfire schedule offers a strategic and transparent approach to address the challenges posed by wildfires. It enables focused resource allocation, accountability, adaptability to changing risks, and effective communication with stakeholders, ultimately enhancing the Company's ability to increase, track, and prevent wildfires.

Q. Has PSE prepared the rate spread for Schedule 141WFP tracker?

A. Yes. The rate spread for the Schedule 141WFP tracker can be found in Exh CTM-6. PSE used the same cost of service methodology under WAC 480-85 to allocate the revenue requirements for wildfire prevention developed by Susan E. Free in Exh. SEF-22. That way, whether these costs would be reflected in base rates or as a separate tracker, in theory, the customer would encounter the same rates and bills related to these costs.

Q. How are the Schedule 141WFP charges designed for customers?

A. PSE proposes removing wildfire costs from base rates and recovering them through a separate tracking and true-up mechanism in Schedule 141WFP. The tracker is applicable to all electric customers classes.

As mentioned earlier, PSE used the same cost of service methodology under WAC 480-85 to allocate the revenue requirement based on the underlying FERC accounts where the expenses are reflected. The Schedule 141WFP tariff reflects the proposed charges for 2025 only, as the tracker will be updated annually. Nonetheless, PSE calculated the rates for 2025 and estimated rates for 2026 in Exhibit CTM-6 in an effort to provide transparency on the future charges related to Schedule 141WFP; actual charges are likely to vary from the estimate. PSE developed the energy charges on a dollar per kWh basis and demand charges on a dollar per kW basis using 2025 and 2026 forecasted load for all customer rate schedules. For a comprehensive understanding of PSE's wildfire prevention plan, please see the Prefiled Director Testimony of Ryan Murphy, Exh. RM-1T.

2. <u>Decarbonization Rate Adjustment</u>

Q. Please describe the Decarbonization Rate Adjustment.

A. PSE proposes to create Schedule 141DCARB, to focus on recovering costs associated with the Company's targeted electrification strategy and decarbonization pilots. This includes projects and services related to low-income heat pump direct installs, gas constrained areas, income-qualified fuel-switching rebates, small business direct installs, multi-family rebates, and the commercial and industrial custom grant pilot, as well as O&M expenses and capital expenses that enable decarbonization implementation.

Q. Why would creating a decarbonization schedule be beneficial, as opposed to having these costs embedded within base rates?

A. Establishing a dedicated decarbonization schedule offers several strategic advantages for PSE and its customers, particularly in addressing the challenges associated with targeted electrification, carbon emissions reduction, and transitioning from gas to non-emitting and renewable energy sources.

When decarbonization efforts are part of base rates, it may be challenging to allocate resources specifically for targeted electrification and the transition to non-emitting and renewable energy sources, as these costs may compete with other operational needs. In addition, a dedicated schedule allows the Company to allocate resources strategically, ensuring that funds are explicitly earmarked for initiatives, such as targeted electrification and carbon reduction. This targeted approach enhances the company's ability to meet decarbonization goals efficiently.

Costs embedded in base rates may lack transparency, making it difficult for stakeholders to discern the specific financial implications associated with decarbonization efforts. Creating a separate schedule provides transparency by clearly attributing costs to targeted electrification, carbon reduction initiatives, and fuel switching. This transparency facilitates better understanding and scrutiny of the expenses related to the company's commitment to decarbonization.

Decarbonization efforts embedded in base rates may lack explicit accountability and measurement mechanisms, hindering the assessment of the effectiveness of these initiatives. A dedicated schedule enables detailed tracking of costs associated with targeted electrification, emissions reduction, and fuel switching. This transparency enhances accountability, allowing the company to assess the impact of its decarbonization efforts over time and make informed adjustments.

Including decarbonization efforts within base rates may lead to challenges in effectively conveying the significance of these initiatives to consumers and stakeholders in terms of environmental impact. A dedicated schedule facilitates clear communication of the company's commitment to decarbonization, targeted electrification, and emissions reduction. Stakeholders can better understand the specific measures being undertaken to reduce the company's carbon footprint.

Creating a decarbonization schedule provides a focused and transparent approach to address the challenges associated with targeted electrification, carbon emissions reduction, and the transition to non-emitting and renewable energy sources. It allows for strategic resource allocation, transparent cost attribution, accountability, and effective communication with stakeholders, ultimately enhancing the Company's ability to achieve its decarbonization goals.

Q. Has PSE prepared the rate spread for the Schedule 141DCARB tracker?

A. Yes. The rate spread for the Schedule 141DCARB tracker can be found in Exh. CTM-6. PSE used the cost of service methodology under WAC 480-85 to functionalized and classify the revenue requirement developed by Susan E. Free in Exh. SEF-23.

Q. How is the Schedule 141DCARB charge designed for customers?

A. The Schedule 141DCARB trackers is applicable to all electric and natural gas customers classes. First, PSE allocated the costs between electric and natural gas using the Company's 4-factor methodology that is commonly used to allocate general and common expenses and plant. Next, PSE used the same cost of service methodology under WAC 480-85 to functionalize and classify the revenue requirement based on the underlying FERC account 908, where these expenses are reflected. PSE allocated based on 50 percent customer counts and 50 percent margin revenue from the test year to apportion the revenue requirement to all customer classes. Lastly, the Schedule 141DCARB tariff reflects the proposed charge to remain flat during the two-year program period of 2025 and 2026, which will be tracked and trued up at the end of the second program year. PSE calculated the rates for 2025 and 2026 in Exhibit CTM-6 in an effort to provide transparency on the future charges related to Schedule 141DCARB. For electric, PSE developed the energy charges on a dollar per kWh basis and demand charges on a dollar per kW basis using 2025 and 2026 forecasted billing determinates for all customer rate schedules. For natural gas, PSE developed the delivery charges on a dollar per therm basis using 2025 and 2026 forecasted billing determinates for all customer rate schedules. For a comprehensive understanding of PSE's decarbonization plan, refer to the Prefiled Direct Testimony of John Mannetti, Exh. JM-1T.

3. <u>Clean Generation Resource Rate Adjustment</u>

Q. Please describe the Clean Generation Resource Rate Adjustment.

A. PSE proposes to create Schedule 141CGR, to focus on recovering costs associated with the Company's clean generation resources to meet the requirements of CETA. Cost recovery will include (i) financing costs incurred during construction, (ii) construction work in progress ("CWIP") in rate base before the resources are in service, (iii) amounts already accrued as allowance for funds used during construction, and (iv) return on CWIP.

Q. Has PSE prepared the rate spread for the Schedule 141CGR tracker?

A. Yes. The rate spread for the Schedule 141CGR tracker can be found in Exh CTM-6. PSE used the cost of service methodology under WAC 480-85 to allocate the revenue requirement developed by Susan Free in Exh. SEF-23.

Q. How is the Schedule 141CGR charge designed for customers?

A. The Schedule 141CGR tracker is applicable to all electric customer classes. Like the other newly created trackers, PSE used the same cost of service methodology under WAC 480-85 to allocate the revenue requirement based on the underlying FERC accounts, where the expenses are reflected. The Schedule 141CGR tariff reflects the proposed charges for 2025 only, as the tracker will be updated annually. Nonetheless, PSE calculated the rates for 2025 and estimated rates for 2026 in Exhibit CTM-6 in an effort to provide transparency on the future charges related to Schedule 141CGR; actual charges are likely to vary from the estimate. PSE developed the energy charges on a dollar per kWh basis and demand charges on a dollar per kW using 2025 and 2026 forecasted load for all customer rate schedules. For a comprehensive understanding of PSE's clean generation resource, refer to Josh Jacobs's testimony in Exh. JJJ-1T.

4. <u>Power Cost Adjustment</u>

Q. What is the first proposal for eliminating or zeroing out a pass-through schedule?

A. PSE proposes resetting Schedule 95 to zero; these rates and corresponding costs will be embedded and reflect as part of the power cost baseline going forward.

5. <u>Renewable Energy Credit</u>

Q. What is the second proposal for eliminating or zeroing out a pass-through schedule?

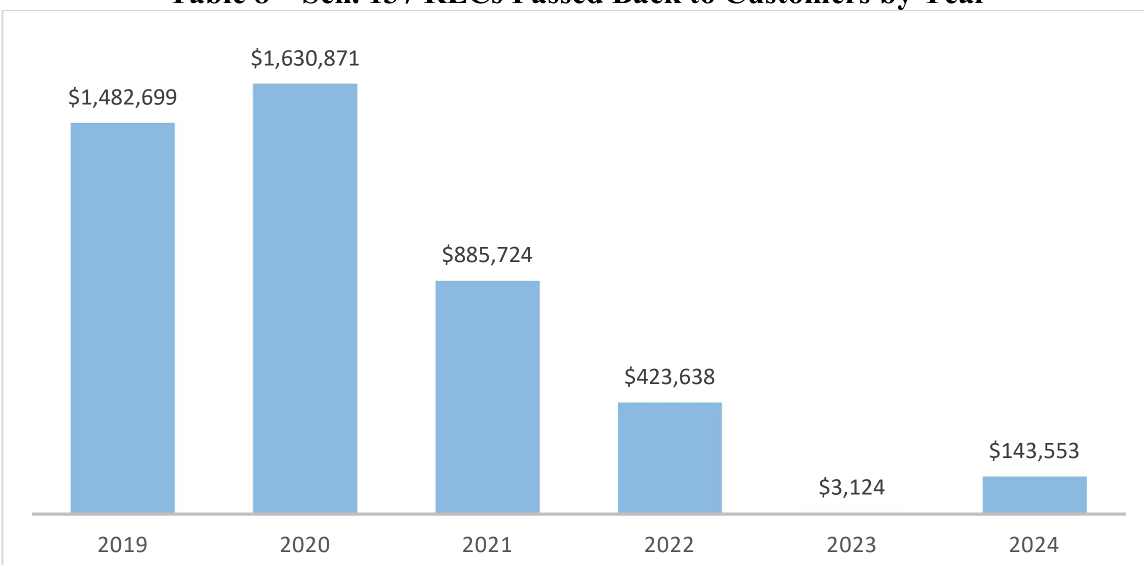
A. PSE proposes eliminating Schedule 137;[13] these rates and corresponding costs will be embedded and reflected as part of the power cost baseline going forward.

[13] Any true up related to 2024 will be incorporated into the 2025 power cost. Furthermore, if this proposal were not accepted, PSE would promptly file its annual adjustment shortly after the conclusion of this rate proceeding that follows the guidelines outlined in Docket UE-111048, Order 08, Appendix C.

Q. Why is Schedule 137 being eliminated?

A. The revenues and expenses associated with Schedule 137 and its underlying renewable energy certificates ("RECs")[14] have become too small to have their own standalone tracker. Since 2020, these RECs have drastically diminished in value, as reflected in Table 8 below. As such, in the last few Schedule 137 filings, some of our customer classes were not able to produce a rate since it was out to the seventh and eighth decimal place; PSE reflects rates to the fifth or sixth decimal place.

Table 8 – Sch. 137 RECs Passed Back to Customers by Year



It is hard to pin point what exactly influences the REC market, but CETA's requirement that Washington's electricity supply be free of greenhouse gas emissions by 2045 likely contributed because selling unbundled RECs would

[14] Retail renewable energy certificates are sold, delivered, or purchased separately from electricity (commonly referred to as "unbundled"). They represent proof of renewable electricity delivered to the grid and represent the environmental effect or energy attributes of that renewable electricity.

make them ineligible for CETA interim targets. Even the U.S. Environmental Protection Agency discusses that state policies can affect the dynamics of compliance-eligible REC prices, and prices had been on a steady decline.[15]

6. Intervenor Funding

Q. What is the third proposal for eliminating or zeroing out a pass-through schedule?

A. PSE proposes eliminating Schedule 141PFG, Intervenor Funding; these costs will be embedded into base rates going forward.

Q. Why is Schedule 141PFG being eliminated?

A. Similar to the previous tracker, the revenues and expenses associated with Schedule 141PFG have become too small to have their own standalone tracker and to reset the rates annually. The Company will monitor payments and consistently disburse funds to intervenors in accordance with Commission directives.

Q. How will the intervenor funding be allocated to customers?

A. The Company proposes to allocate the total intervenor funding level available and disbursed based on historical payment disbursement that follows the Commissions' Orders and directives.[16] Historically, the breakdown of intervenor

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[15] *See* Environmental Protection Agency, *Green Power Pricing* (https://www.epa.gov/green-power-markets/green-power-pricing).

[16] *See WUTC v. Puget Sound Energy*, Docket U-210595, Order 02 (Feb. 9, 2023); *see also WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, and UG-210918, Order 27/13 (March 2, 2023); *see also WUTC v. Puget Sound Energy*, Docket UE-210795, Order 10 (Sept. 18, 2023).

disbursement reveals a distribution of 68.8 percent to electric service and 31.2 percent to natural gas service. For the electric service portion, 20.9 percent goes to residential, 21.8 percent to industrial, and 57.3 percent to all customer classes. For the natural gas service portion, 20.2 percent goes to residential, 9.1 percent to industrial, and 70.7 percent to all customer classes.

This will remove the impact of any carrying costs on customers and eliminate an annual tariff revision filing, while still providing the overall benefits the Commission sought.

7. <u>Clean Energy Implementation</u>

Q. What is the fourth proposal for eliminating or zeroing out a pass-through schedule?

A. As per PSE's 2022 general rate case settlement, PSE proposes resetting Schedule 141CEI to zero and include the costs associated with its 2025 clean energy implementation plan as part of base rates in PSE's next multiyear rate plan general rate case.[17]

8. <u>Refund Rate Adjustments</u>

Q. What is the last proposal for eliminating or zeroing out a pass-through schedules?

A. For Schedule 141N (Rates Not Subject to Refund Rate Adjustment) and Schedule 141R (Rates Subject to Refund Rate Adjustment), PSE proposes to have these

[17] *WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, and UG-210918, Order 24/10 (Dec. 22, 2022).

incremental base rates related to Docket UE-220066 be reset to zero or eliminated, as they will be rolled into their respective rate schedules. Moreover, Schedule 141R will undergo rebranding to exclusively represent the refund rate component, particularly in connection with MYRP assets that are not implemented within the in-service date timeframe, if applicable, pursuant to the Commission's final review of assets allowed.

D. Low-Income Support

Q. Is PSE proposing to increase funding for low-income programs?

A. Yes. PSE remains committed to enhancing funding for low-income bill assistance, aligning with past general rate cases. The doubling of the proposed residential percentage increases in this case translate to a rise in residential bill assistance,[18] totaling $5.63 million ($3.90 million for electric and $1.73 million for gas) in 2025 and an additional $5.63 million ($5.44 million for electric and $0.19 million for gas) in 2026, as illustrated in Exh. CTM-11. This enhanced funding equates to a 34.1 percent increase in funding above current Schedule 129 levels. Furthermore, PSE maintains a dedicated BDR for eligible low-income customers, so they benefit from reduced rates compared to other residential customers, thereby keeping their energy burden at or below the six percent threshold. Additionally, PSE extends support to residential customers meeting low-income criteria through various programs outside of the BDR and the Home Energy Lifeline Program. For a comprehensive understanding of PSE's commitment to

[18] *See* RCW 80.28.425(2).

low-income energy assistance, refer to the Prefiled Direct Testimony of Carol Wallace, Exh. CLW-1T.

E. Summary of Rate Design Proposal

Q. Has PSE prepared an exhibit consistent with its base rate design proposals in this case?

A. Yes. Please see Exh. CTM-6 for the derivation of PSE's proposed base rates in this case. As discussed above, for each rate year period, PSE proposes all existing classes to experience an increase in monthly customer charges by up to 30 percent, and for all applicable classes to experience an increase in demand charges by up to 30 percent, to include more costs that are fixed. The remaining classes' revenue increases are set as flat rate increases for volumetric charges to each tier with some exceptions for Choice and Retail Wheeling customers, Special Contract customers, and Lighting Schedules.

Q. Has PSE prepared new base electric tariff schedules based upon the electric cost of service study results and consistent with its rate design proposals in this case?

A. Yes. Please see Exh. CTM-12 for the proposed electric tariff schedules.

F. Summary of Rate Impacts

Q. What are the impacts of PSE's proposed electric rates in this case?

A. Several electric tracker or rider schedules will be reset concurrent with the effective date of new base electric rates resulting from this rate case. Specifically, the impacts of the base electric rate changes must be added to the impacts of electric rate changes associated with the concurrent changes to Schedule 95, Power Cost Adjustment Clause; Schedule 137, Renewable Energy Credit; Schedule 141PFG, Intervenor Funding; Schedule 141CEI, Clean Energy Implementation; Schedule 141N, Rates Not Subject To Refund Rate Adjustment; and Schedule 141R, Rates Subject To Refund Rate Adjustment. The bill impacts also incorporate the new proposed Schedule 141WFP, Wildfire Prevention Tracker; Schedule 141DCARB, Decarbonization Rate Adjustment; and Schedule 141CGR, Clean Generation Resources Rate Adjustment. The combined impact of these changes, based on rates currently in effect using forecasted billing determinants for each of the rate years, is presented in the Exhibit CTM-8. See Table 9 below for rate schedule revenue requirements change and overall impacts by rate schedule.

Table 9 – Estimated Class Impacts of Proposed Changes

		2025		2026	
Customer Class	Rate Schedule	Revenue Change	Overall Impact	Revenue Change	Overall Impact
Residential Service	7	$108,884,874	6.92%	$149,355,197	8.79%
General Service, <51 kW	8/24	$29,004,038	7.83%	$34,040,192	8.49%
General Service, 51-350 kW	7A/ 11/ 25/ 29	$21,892,106	5.61%	33,278,230	8.92%
General Service, >350 kW	12/26	$13,007,617	5.47%	$20,821,962	8.18%
Primary Service, General	10/31	$9,406,795	5.81%	$13,996,740	8.22%
Primary Service, Irrigation	35	$55,670	13.30%	$48,536	10.27%

Primary Service, Schools	43	$1,039,823	7.28%	$1,299,120	8.51%
High Voltage Service	46/49	$2,997,672	5.34%	4,490,630	8.36%
Lighting Service	50-59	-$3,523	-0.02%	$2,051,067	8.87%
Retail Wheeling	449/459	$775,772	4.67%	$0	0.00%
Special Contract	SC	$4,440,892	72.66%	$520,251	4.79%
Firm Resale	5	$716,302	146.93%	$0	0.00%
Total Sales		**$192,218,039**	**6.74%**	**$259,901,924**	**8.48%**

Q. What is the impact on the typical electric residential customer monthly bill?

A. Exh. CTM-8 presents residential bill impacts for a typical residential customer. The impact on the monthly bill of PSE's typical residential customer using 800 kWh is an increase of $7.84, or 7.19 percent over current levels in 2025 and an additional increase of $11.20, or 9.58 percent over 2025 levels in 2026. For additional insights into the impacts on both residential and non-residential classes at various consumption levels, please refer to Exh. CTM-8.

VIII. COMPLIANCE FILING

Q. Please summarize all of the rates that PSE intends to update in its compliance filing for this case.

A. The compliance filing will include updates to all PSE base electric rate schedules and select adjusting price schedules. The adjusting price schedules to be updated and included in the compliance filing are:

- Electric Schedule 95, Power Cost Adjustment Clause;
- Electric Schedule 137, Renewable Energy Credit;
- Electric Schedule 141CEI, Clean Energy Implementation;

- Electric and Natural Gas Schedules 141PFG, Intervenor Funding;
- Electric and Natural Gas Schedules 141N, Rates Not Subject to Refund;
- Electric and Natural Gas Schedules 141R, Rates Subject to Refund;
- Electric and Natural Gas Schedules 142, Revenue Decoupling Adjustment Mechanism; and
- Natural Gas Schedule 141D, Distribution Pipeline Provisional Recovery Adjustment.

Q. Have the proposed tariff sheets for these adjusting price schedules been included in this filing?

A. No. Schedule 141D is suspended per Docket UG-230393 and may require an update. Moreover, the schedules listed below have not been submitted as part of this case due to their annual filing requirements for rates before the conclusion of this general rate case. These schedules include Electric Schedule 137, Renewable Energy Credit; Electric and Natural Gas Schedules 141N, Rates Not Subject to Refund; Electric and Natural Gas Schedules 141R, Rates Subject to Refund; Electric and Natural Gas Schedules 142, Revenue Decoupling Adjustment Mechanism. All other proposed changes to the electric tariff sheets for the adjusting price schedules are included in Exh. CTM-12.

In addition, Exh. CTM-9 and Exh. CTM-10 show electric decoupling allowed revenue and fixed power cost allowed revenue calculations.

Q. Are there any other tariff schedules that will be impacted by the outcome of this general rate case?

A. Yes. Several tariff sheets rely on the results of the rate case; these include:

- Electric Schedule 62, Substation and Related Equipment Capacity;
- Electric Schedule 85, Line Extensions and Service Lines; and
- Electric Schedule 87, Income Tax Rider.

Q. When will these tariff revisions be filed with the Commission?

A. PSE intends to file these tariff revisions within 30 days of the effective date of new base rates resulting from this general rate case.

IX. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.