Docket No. UE 433
Exhibit PAC/1900
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Robert M. Meredith

February 2024

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

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

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science degree in Business Administration and a minor in Economics from Oregon State University. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 19 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 13 years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In February 2022, I assumed my current position.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What are your responsibilities in these proceedings?

A. I am responsible for the Company's proposed revenue requirement for each of the unbundled service categories, the Company's functionalization procedures, the Oregon Marginal Cost Study and the design of the Company's proposed prices in this proceeding. The proposed tariffs incorporate the Company's proposed price increase and are designed consistent with the Public Utility Commission of Oregon's (Commission) rules under OAR 860-038-0200. I am sponsoring the Company's

Oregon electric tariff schedules submitted for approval in this filing. Exhibit PAC/1901 contains the proposed tariffs.

Q. Please summarize your testimony.

A. The overall rate increase proposed by the Company in this case, including the effect of the Insurance Cost Adjustment, the Catastrophic Fire Fund Adjustment, changes to the Wildfire Mitigation Plan Cost Recovery Adjustment, and the rebalancing of the Rate Mitigation Adjustment (RMA), is $322.3 million or 17.9 percent. The Company is proposing a base rate spread that is consistent with the cost-of-service study in this case. The Company's rate spread proposes continued use of the RMA to achieve a rate increase on January 1, 2025, where no customer rate class will see a rate increase more than 22.4 percent.

For rate design, the Company largely proposes applying the price change on an equal percentage basis across prices for each class for all schedules, except residential. For residential customers, the Company proposes increasing the single-family basic charge from $11 to $16 per month and the multi-family basic charge from $8 to $9.

As of the time of this filing, the Company has concluded its three-year pilot periods for three pilots it introduced in docket UE 374 (2021 Rate Case): 1) Interruptible Service Schedule 218; 2) Residential Time-of-Use Schedule 6; and 3) Non-Residential Time-of-Use Schedule 29. I address each of these pilots and present the Company's proposal to improve and consolidate its time-of-use options.

For large customers with load sizes greater than 25,000 kilowatts (kW) who did not receive a Line Extension Allowance more than the cost of metering, the Company proposes a Customer-Funded Substation Credit.

Finally, I support the Company's proposal to eliminate credit/debit card payment and pay station fees.

III. UNBUNDLED CLASS REVENUE REQUIREMENTS

Q. Please identify Exhibit PAC/1902 and explain what it shows.

A. Exhibit PAC/1902 shows the Company's proposed revenue requirement for each of the unbundled service categories required by OAR 860-038-0200: Generation (also referred to as Production), Transmission, Distribution, Ancillary Services, Consumer Services—Billing, Consumer Services—Metering, Consumer Services—Other, Retail Services, and Investment in Public Purposes.

No revenue requirement is shown for the Retail Services or Investment in Public Purposes categories. The Company separately accounts for the costs associated with unregulated retail activities and is not seeking regulatory cost recovery for these items. Public purpose revenues are collected under a separate tariff.

Q. How was the revenue requirement determined for each of the unbundled categories?

A. Rate base balances, revenues and expenses were either assigned or allocated to unbundled categories in accordance with Oregon regulations.[1] Traditional revenue requirement methodology, (i.e., recovery of costs plus a return on rate base), was then used to determine a revenue requirement for each category. Rate base balances,

[1] *See* OAR 860-038-0200.

revenues and expenses are from PacifiCorp's Oregon Results of Operations Report, as prepared under the direction of Company Sherona L. Cheung. The application of PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/1902.

Q. Please identify Exhibit PAC/1903 and explain what it shows.

A. Page 1 of Exhibit PAC/1903 is the summary page from PacifiCorp's December 2025 Functionalized Oregon Results of Operations Report (Functionalized Oregon Results of Operations Report) and is the basis for the unbundled revenue requirement in Exhibit PAC/1902. It separates the results of operations into the unbundled categories identified above.

Q. Please explain how the rate base balances, revenues and expenses in the Functionalized Oregon Results of Operations Report were apportioned among the unbundled categories.

A. The detail of PacifiCorp's Functionalized Results of Operations Report by Federal Energy Regulatory Commission (FERC) account is found on page 2 through 38 of Exhibit PAC/1903. The functionalization procedures in this case are consistent with those approved in Order No. 01-787 and implemented in Advice No. 01-020. Functional factors employed in the development of these results are provided in Exhibit PAC/1904.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's prices for Regulation and Frequency Response Service, Spinning Reserve Service, and Supplemental Reserve Service to the relevant billing determinants of PacifiCorp's total Oregon retail load. This is shown in

Exhibit PAC/1905. The costs associated with providing these services are included in the Generation function. The estimated revenue for Ancillary Services is treated as an offsetting revenue credit against the Generation revenue requirement.

Q. Please identify Exhibit PAC/1906.

A. Exhibit PAC/1906 contains a summary from PacifiCorp's State of Oregon December 2024 Marginal Cost Study (Marginal Cost Study). The Marginal Cost Study is described in more detail later in my testimony.

Q. Please identify Exhibit PAC/1907 and explain what it shows.

A. Page 1 of Exhibit PAC/1907 is the derivation of functionalized class revenue requirements and a comparison with current revenues. This exhibit is based on the results of both the Functionalized Oregon Results of Operations Report and the Marginal Cost Study. Present class revenues are shown on line 1 and megawatt-hours (MWh) are shown on line 2. Full long-run marginal costs for each customer class, separated by function, are shown on lines 4 through 11. Lines 13 through 24 show each class share of total marginal costs for each function as well as each class share of revenue and MWh. Lines 27 through 39 show the assignment of functional revenue requirement. The total revenue requirement for each unbundled category, as determined earlier, is shown in the total column. The total for each function is then allocated to a particular customer class based on that class share of total marginal cost for that function. For example, the residential class accounts for 40.60 percent of generation marginal costs and is assigned 40.60 percent of the generation revenue requirement. Regulatory and franchise fees are considered part of the distribution function; however, for the purpose of assigning cost responsibility, the fees have been broken out separately. Regulatory and franchise fees have been assigned on the basis of class revenue. Lines 41 through 48 compare the total revenue requirement by class to the present class revenues collected from base rates as shown on line 1.

Q. Please explain what is shown on pages 2 and 3 of Exhibit PAC/1907.

A. Pages 2 and 3 of Exhibit PAC/1907 provides a reconciliation between Operating Revenues and Target Revenue Requirement, as shown on page 1 of this exhibit, with those shown in Exhibits PAC/1902 and PAC/1903. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PAC/1907 accounts for all Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

IV. MARGINAL COST STUDY

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PAC/1908. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity, or to add one additional customer. Exhibit PAC/1908 contains a marginal cost and circuit model procedures narrative, various summary tables, and supporting calculations.

Q. Is this Marginal Cost Study similar to studies the Company has previously filed?

A. Yes. With the exception of the methodology for calculating marginal generation costs, this study is similar to the cost-of-service study the Company presented in docket UE 399 (2023 Rate Case).

Q. How are marginal costs calculated?

A. One-year marginal costs include only changes in operating costs while 10-year and 20-year marginal costs also include the cost of expanding facilities. The costs of these added facilities result in long-run costs that are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission or distribution costs. A detailed description of marginal cost procedures is included in pages 1 through 12 of Exhibit PAC/1908.

Q. Please describe the marginal cost summary tables included in pages 13 through 20 of Exhibit PAC/1908.

A. Tables 1 and 2 of Exhibit PAC/1908 summarize the one-year, 10-year and 20-year marginal costs on a mills-per-kilowatt-hour (kWh) or dollars-per-customer basis. Table 3 summarizes the unit costs based on the results of the long-run (20-year) marginal cost study. Unit costs are shown for generation, transmission, distribution and various customer service functional categories. Table 3 also includes energy usage, peak demand, and number of customers by customer class for the 12-month period ending December 31, 2025, test period. This information is used to calculate the annual long-run marginal costs by class shown at the bottom of Table 3.

Q. What changes does the Company propose for marginal generation costs?

A. Before this rate case, the Company based its marginal generation costs on the equivalent Peaker method that examined the cost characteristics of gas-fired generators. In the 2023 Rate Case, the Company received feedback from parties that relying upon fossil fuel resources for marginal generation costs is not appropriate in light of the transition to renewables.[2] The Company proposes that the marginal generation costs in this study be based upon forecast costs of a storage resource and

[2] See pages 3 through 7 of Alliance of Western Electric Consumers Witness Mr. Lance Kaufman's direct testimony in Docket No. UE 399, and pages 3 through 11 of Commission Staff Witness Mr. Curtis Dlouhy.

wholesale market purchases—specifically the cost of a four-hour Lithium-Ion battery from the Company's 2023 Integrated Resource Plan and the cost of a flat market purchase from the Mid-Columbia (Mid-C) hub from PacifiCorp's most recent Oregon avoided cost calculations. Marginal generation capacity costs are determined using the cost per kW-Year of a Lithium-Ion battery accounting for the battery's 77 percent capacity contribution. The forecast energy benefit from the battery is then deducted from this cost to arrive at the marginal generation capacity cost. Generation energy costs are calculated using forecast market prices from the Mid-C hub that are net of a capacity credit to recognize that a firm market purchase can be relied upon to meet the Company's peak load requirements. Marginal generation capacity and energy costs are summarized on Table 4 of Exhibit PAC/1908.

Q. How are transmission costs calculated?

A. Transmission costs are based on a five-year analysis of forecasted expenditures. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 5 of Exhibit PAC/1908.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 6 of Exhibit PAC/1908 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) demand-related, shown in dollars per kW/year; (2) commitment-related, shown in dollars per customer/year; and (3) billing-related, shown in dollars per customer/year. Commitment-related distribution costs consist of the costs of transformers, poles and conductors that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system.

Q. Please describe how the marginal costs of distribution line transformers are calculated.

A. Marginal transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by this statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Q. Please describe how the marginal costs of distribution circuits are calculated.

A. Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for Oregon. Customer locations are based on actual customer distances from the substation. The results are segregated into commitment-related and demand-related costs for each customer class. A detailed description of the updated circuit model is also included in the marginal cost procedures on pages 5 through 12 of Exhibit PAC/1908.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per kW cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth-related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class weighted by the load of substations peaking in each month.

Q. What is included in the service drop category?

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance (O&M). Current typical installed costs for service drops are determined for each customer load size.

Q. What is included in the metering category?

A. The metering category includes the marginal cost of metering equipment with associated O&M. Current typical installed metering costs are determined for each customer load size by analyzing service requirements, such as single- or three-phase service and voltage level. Meter O&M is based on historical expenditures.

Q. What is included in the billing and customer service/other categories?

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense, and all the remaining customer accounting and customer service activities. Marginal meter reading expense is assumed to be zero because Advanced Metering Infrastructure has been deployed for almost all customers. Customer accounting and customer service expense are based on historical expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

V. ALLOCATION OF THE FUNCTIONALIZED REVENUE REQUIREMENT

Q. How is the Company proposing to allocate the functionalized revenue requirement across classes of customers in this proceeding?

A. The Company is allocating the functionalized revenue requirement to classes consistent with the Commission's Direct Access Rules. These rules indicate that "rates for any class of consumer must be based on the unbundled costs to serve that class."[3] In this filing, the Company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study. The proposed rates for each rate schedule included in the cost-of-service study are targeted to collect the cost of service for that rate schedule in the test period. Therefore, the proposed base rates for each class are based on the unbundled costs to serve that class.

Q. Do you have an exhibit that summarizes the functionalized results of the cost-of-service study?

A. Yes. Pages 1 and 2 of Exhibit PAC/1909 summarize the functionalized results of the cost-of-service study in column (4). This summary is provided at the level used to

[4] OAR 860-038-0240(3)(b).

design rates. The cost of service for each rate schedule has been summarized into the following components: Transmission & Ancillary Services, System Usage, Distribution, Generation Energy Other Non-net Power Costs (Non-NPC), and Generation Energy NPC.

Q. What is the purpose of including this summary of cost components for the target functionalized revenue requirement?

A. The summary level for revenue requirement shown on pages 1 and 2 of Exhibit PAC/1909 summarize the cost-of-service results into the target revenue requirement components used in rate design.

The process of unbundling the Company's proposed prices is consistent with the method the Company first implemented in docket UE 116. For each rate schedule, the functionalized costs are applied to rates as follows: distribution, billing, metering, and customer costs are included in each proposed delivery service schedule's Distribution rates; the FERC regulated transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services rates; non-NPC generation costs are included in Schedule 200, Base Supply Service rates; and NPC are included in Schedule 201, Net Power Costs, Cost-Based Supply Service rates.

Q. Please explain the System Usage costs shown in exhibit PAC/1909 and how those costs are proposed to be recovered in rates.

A. In Order No. 12-500, the Commission directed the Company to develop a volumetric rate element for franchise fees that could be avoided by customers taking direct access. Consistent with past treatment, the amounts shown as System Usage costs in

Exhibit PAC/1909 are a portion of the Oregon Franchise Tax and Oregon Energy Supplier Assessment from FERC Account 408 in the results of operations.[4] The System Usage costs have been calculated as the portion of the franchise and energy supplier taxes associated with revenues not paid by direct access customers: NPC and transmission and ancillary services. A separate volumetric rate element is used to recover these costs, which is not paid by direct access customers.

Q. Have any adjustments been made to the functionalized revenue requirement by rate schedule resulting from the cost-of-service study?

A. Yes. Consistent with past cases, the functionalized revenue requirement has been adjusted to remove the proposed changes to NPC collected through Schedule 201. Changes to Schedule 201 are implemented through the TAM, which is a separate proceeding from this general rate case, and the Schedule 201 changes will be addressed in that proceeding. The modified cost of service results reflecting this adjustment to remove the NPC increase from the functionalized revenue requirement is shown in column (5) on pages 1 and 2 of Exhibit PAC/1909. This exhibit displays the target functionalized revenue requirement used in the design of rates proposed in this general rate case.

Q. Do the Company's proposed rates collect the target functionalized revenues?

A. Yes. The revenues calculated by multiplying the test period billing determinants by the proposed rates are summarized in column (6) on pages 1 and 2 of Exhibit PAC/1909. A direct comparison to the target functionalized revenues shown in

[5] The Oregon Energy Supplier Assessment is a fee paid to the Oregon Department of Energy under ORS 469.421(8). While this treatment for this assessment was not reflected in Order No. 12-500, the Company has included it in the System Usage Charge because it is assessed in the same manner (a percent of revenue) as franchise taxes in FERC Account 408. The Company is therefore using parallel treatment.

column (6) of this exhibit shows that the calculated revenues equal the target revenues with the exception of small differences due to the rounding of rates. The detailed calculation of proposed revenues based on billing determinants and proposed rates is shown on pages 3 through 11 of Exhibit PAC/1909.

Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?

A. Yes. The first three pages of Exhibit PAC/1910 show the estimated effect of the Company's proposed prices. It contains three summary tables. Table 1910-1 shows the effect of the proposed prices by delivery service rate schedule for the proposed rate increase on January 1, 2025, of approximately $322.3 million which includes approximately $66.0 million for the Insurance Cost Adjustment (base and deferred), $77.7 million for the Catastrophic Fire Fund Adjustment, $21.2 million additional for the Wildfire Mitigation Plan Cost Recovery Adjustment, minus $0.4 million for the impact of the RMA rebalancing. This table shows the effect of the price changes on both base revenues and net revenues. Base revenues show the effect before the impacts of any adjustment tariffs. Net revenues include the effect of adjustment tariffs (discussed directly below) and the RMA.

The adder columns in Table 1910-1 show revenues from adjustment tariff schedules (Schedules 80, 94, 96, 97, 190, 192, 193, 194, 198, 203, 204, 206, 207, and 299). Proposed new adjustment schedules and proposed changes to adjustment schedules are included in the Proposed adder column only. The adder revenue is added to base revenue to calculate net revenue including adjustment schedules. Table 1910-2 shows the calculation of the adjustment revenue included in the adder columns in Table 1910-1. These tables exclude the effects of pass-through adjustment schedules for Low Income Bill Payment Assistance Charge (Schedule 91), the Low-Income Discount Cost Recovery Adjustment (Schedule 92), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291). Table 1910-3 shows the rates for each of the adjustment schedules.

Beginning on page 4 of Exhibit PAC/1910 are the monthly billing comparisons for each of the major delivery service rate schedules showing the customer bill impacts of the proposed prices at various levels of usage. The monthly billing comparisons in Exhibit PAC/1910 show the expected rate increases for January 1, 2025, from proposed rates. The monthly billing comparisons also include the effects of all adjustment schedules including the pass-through adjustment schedules listed above.

Q. What is the Company's rate spread objectives in this case?

A. The Company's rate spread objectives in this case are to minimize price impacts on our customers while fairly reflecting cost of service and sending proper signals about increasing costs.

Q. What is the Company's rate spread proposal in this case?

A. Based on the cost-of-service results and in order to achieve the Company's rate spread objectives in this case, Table 1 below summarizes the Company's proposed net percentage price changes, including the impact of proposed new and updated adjustment schedules, for the major rate schedule classes.

TABLE 1

Residential Schedule 4	21.6%
General Service	
Schedule 23/723 (0-30kW)	22.4%
Schedule 28/728 (31-200kW)	10.4%
Schedule 30/730 (201-999kW)	11.3%
Large General Service Schedules 47/747, 48/748 (≥1,000kW)	14.1%
Agricultural Pumping Service Schedule 41/741	22.4%
Lighting Schedules	4.5%
Overall	17.9%

Under the Company's proposal, the rate change that takes effect January 1, 2025, will result in no customer rate schedule class receiving an increase greater than 22.4 percent. The Company's proposed rate spread strikes a balance between moderating rate impacts on customers, while sending proper price signals about increasing costs and minimizing subsidization across rate schedule classes. As a result, the Company proposes revisions to the RMA to achieve these goals.

Q. Please describe the RMA.

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net rates across rate schedules. Net rates are the rates that customers pay once all tariff riders (including the RMA) are taken into account. The RMA is designed to be revenue neutral overall at the time a general rate case price change is implemented, resulting in RMA credits for some rate schedule classes requiring rate mitigation with offsetting RMA charges for others. The RMA was first implemented in docket UE 116 to transition to cost of service rates under Senate Bill 1149. The Schedule 299 RMA tariff rider is included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

Q. Besides mitigation of rate changes across rate schedules, what other factors contribute to the adjustment of the RMA in a general rate case?

A. In each general rate case, the RMA must be rebalanced in order to achieve revenue neutrality so that the revenues from the RMA charges and the RMA credits are in balance. The present Schedule 299 RMA rates were designed to be revenue neutral in the calendar year 2023 forecast test period from the Company's 2023 Rate Case; however, due to changes in rate schedule loads, present Schedule 299 RMA rates are not projected to produce revenue neutrality in the calendar year 2025 test period of this case. The present RMA rates result in RMA charges that exceed RMA credits by $0.4 million for the 2025 test period loads (see Exhibit PAC/1910, Table 1910-2, Column 17, Row 18). Consistent with previous RMA revisions, the proposed RMA rates have been designed to be revenue neutral for the 2025 test period. As a result of this realignment, the proposed net rate increase in this case is lower by $0.4 million (Exhibit PAC/1910, Table 1910-1).

Q. Has the RMA required rebalancing in previous general rate cases?

A. Yes. For example, in the 2023 Rate Case the RMA required a rebalancing adjustment of $4.5 million.

Q. What are the present and proposed RMA revenues and rates in this case?

A. The present and proposed RMA revenues are shown in Exhibit PAC/1910, Table 1910-2, columns (17) and (18). Present and proposed RMA rates are shown in Exhibit PAC/1910, Table 1910-3, columns (18) and (19).

Q. What is the Company's RMA objective in this case?

A. The Company's RMA objective in this case is to minimize rate schedule subsidization through the RMA while minimizing impacts on customers. As a result, the Company has limited RMA charges and credits as much as possible. The Company proposes to move RMA rates closer to zero for all rate schedules except for General Service Schedule 23/723 and Agricultural Pumping Service Schedule 41/741. Increases to the RMA credit were necessary for these classes to minimize the rate impact and cap their net increase at 22.4 percent which is about 25 percent higher than the overall proposed net percentage increase of 17.9 percent.

For Large General Service Schedules 47/747 and 48/748 and Residential Schedule 4, the Company proposes eliminating the RMA. The proposed January 1 net increase for Schedules 47/747 and 48/748 is 14.1 percent. The proposed January 1 net increase for Schedule 4 is 21.6 percent.

For the Lighting Schedules 15, 51, 53, and 54, the Company proposes decreasing the very high RMA surcharge levels currently in rates for these customers while still giving them a price increase. Absent the RMA, the lighting schedules would receive a price decrease. In light of the overall price increase, the Company proposes a January 1 net increase for the lighting class of 4.5 percent, which is about 25 percent of the overall increase.

Finally, for General Service Schedules 28/728, and 30/730, the Company proposes setting their RMA surcharges at roughly half their present level which results in a net increase of 10.4 percent and 11.3 percent, respectively.

Overall, the Company believes that these proposals result in just and reasonable rates and will minimize rate impacts while reducing subsidization through the RMA.

VI. RATE DESIGN

Q. Please generally describe the process for designing rates to collect the proposed revenue requirement.

A. Proposed rates are designed to collect the target functionalized revenue requirement based on customer billing determinants including number of monthly bills, kW, and kWh consumed for the rate case test period. The billing determinants used in this case reflect the forecast test period for the 12 months ending December 2025.

Q. How are the forecast billing determinants developed?

A. Forecast test period billing determinants are developed based on the Company's forecast test period bills and energy forecasts along with the historical test period billing determinants.

A three-step process occurs in developing test period billing determinants. First, the Company forecasts monthly test period bills and energy by class and by rate schedule which is supported in the testimony of Company witness Kenneth Lee Elder, Jr.

Second, a full set of billing determinants, including all rate elements such as kW demand, load size, reactive power quantities and kWh by rate block, are retrieved at the customer invoice level from the Company's billing system for the base period—in this case, the 12 months ended June 2023. These historical billing determinants are summarized by class, rate schedule, and voltage level.

Finally, a full set of forecast billing determinants is developed using the historical base period data and the test period forecast. The forecast billing determinants are calculated based upon the ratio of historical bills and energy (temperature normalized) in the base period to the forecast bills and energy provided in the sales forecast.

Q. Have you provided an exhibit showing proposed rates and the billing determinants used to design rates?

A. Yes. Pages 3 through 11 of Exhibit PAC/1909 contain historical and forecast billing determinants along with present and proposed base rates.

Q. Please highlight and summarize the rate design changes proposed by the Company.

A. In this case the Company is proposing to increase the residential single-family basic charge from $11 to $16 and the multi-family basic charge from $8 to $9. For large non-residential customers with load sizes greater than 25,000 kW who did not receive a Line Extension Allowance more than the cost of metering, the Company is proposing a Customer-Funded Substation Credit.

For other rate schedules, the Company generally proposes applying the rate change on an equal percentage basis to the different functionalized prices.

The Company proposes improving and consolidating its time-of-use options.

A. <u>Residential Rate Design</u>

Q. Please explain the proposed tariffs for residential customers.

A. The standard rate schedule for residential customers is Delivery Service Schedule 4. The Company proposes increasing the basic charge from its current level of $11 per month to $16 for single-family customers and from $8 to $9 for multi-family customers. This change better reflects the fixed costs of serving residential customers and more fairly apportions cost between fixed and volumetric charges.

For residential customers, as well as for all classes of customers, Schedule 200, Base Supply Service, is proposed to reflect changes in the non-NPC generation revenue requirement as indicated in pages 1 and 2 of Exhibit PAC/1909.

Q. Why is the Company proposing an increase in its basic charge for residential customers?

A. The Company's marginal cost-of-service study which I present as Exhibit PAC/1908 shows on Table 3 that the annual marginal cost of billing- and commitment-related cost is $414.10 or about $34.51 per month. Exhibit PAC/1911 shows each of these marginal cost categories in total for the residential class as well as broken out for single-family and multi-family customers. The cost categories of line transformers and distribution poles and conductor were differentiated for single- and multi-family customers by weighting these categories by the number of customers per transformer and distance from substation, respectively. At the present prices of $11 for single family and $8 for multi-family, the Company's basic charge falls far short of cost. Making movement towards a cost-based basic charge is important, because this helps the Company keep energy more affordable for its customers. Given a fixed level of revenue to be collected from all residential customers, an increase in the basic charge will lower energy charges.

Q. How does the Company's current and proposed basic charge compare to other utilities in Oregon?

A. The Company's current and proposed basic charge compare very favorably to the basic charges of other Oregon electric utilities. The Company examined the residential rates of 15 other utilities which includes the other two electric investor-owned utilities (IOUs) in the state and 13 publicly owned electric utilities with service territory in close proximity to the Company's. Table 2 below shows those basic charges as well as an average for all 15 utilities.

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

Utility	Single Family Basic Charge	Multi-Family Basic Charge
Current Pacific Power	$11.00	$8.00
Proposed Pacific Power	$16.00	$9.00
Portland General Electric	$13.00	$10.00
Idaho Power	$8.00	Same
Central Electric Coop	$28.16	Same
Central Lincoln PUD	$27.00	Same
City of Ashland	$16.25	Same
City of Hermiston	$21.00	Same
City of Monmouth	$11.95	Same
Coos-Curry Electric Coop	$28.38	Same
Eugene Water and Electric Board	$23.50	Same
Hood River Electric Coop	$19.00	Same
Lane Electric Coop	$41.00	Same
Salem Electric	$20.00	Same
Springfield Utility Board	$17.40	Same
Tillamook PUD	$32.00	Same
Umatilla Electric Coop	$26.00	Same
Average	$22.18	

Note - Prices were those available from each utility's website as of January 25, 2024

The average single family basic charge of all 15 utilities examined is $22.18 which is well above the Company's proposed basic charge of $16 for single-family. Besides the Company, only Portland General Electric Company has a different basic charge for multi-family customers which is presently set at $10. This level is above both the Company's current and proposed price for multi-family customers.

Q. What rate design change does the Company propose for residential customers who receive three-phase service?

A. The Company proposes to replace the demand charge and demand charge minimum that are applicable to three-phase residential customers with a phase-differentiated basic charge. Under this new structure for three-phase customers, three-phase customers would pay a basic charge that is $9 higher per month than single-phase customers.

Q. Why is the Company proposing this change for three-phase residential customers?

A. A higher basic charge instead of a demand charge and associated minimum charge is easier for customers to understand, simplifies metering, and better aligns with cost causation.

Q. What is the basis for a basic charge for three-phase residential customers that is $9 higher than the basic charge for single-phase customers?

A. Three-phase residential customers typically require the Company to install a three-phase instead of a single-phase transformer. Per Section II.D of the Company's Rule 13 – Line Extensions, customers requesting three-phase service pay for the initial additional capital cost for three-phase facilities. However, the Company must continue to maintain this equipment. $9 per month represents the Company's estimate of the incremental cost to maintain a three-phase transformer. Exhibit PAC/1912 provides the details behind the Company's calculation.

Q. How many three-phase residential customers does the Company have?

A. Three-phase service for residential customers is fairly uncommon. The Company only has 240 three-phase residential customers, which is about 0.05 percent of the total residential customer count.

B. <u>Non-Residential Rate Design</u>

Q. What does the Company propose for the rate design for non-residential customers?

A. The Company is proposing a Capacity Reservation Charge and an Excess Demand Charge that would be applicable to large customers who reserve more power than they require or use more than the level for which they have contracted. Company witness Anna DeMers supports these two charges in her direct testimony. Besides the proposed Capacity Reservation Charge and the Excess Demand Charge, the Company is not proposing any changes to the underlying rate structures for existing non-residential customers. Prices were modified to collect the target revenue requirement and to track functionalized costs. Present and proposed rates for all schedules are detailed in Pages 3 through 11 of Exhibit PAC/1909.

Q. Is the Company making any rate design proposals that will be applicable to future non-residential customers?

A. Yes. In 2023, the Company requested, and the Commission approved changes to Rule 13 which limited the Line Extension Allowance that new load requests of 25,000 kW or greater receive to the cost of the metering necessary to measure their usage. In its order approving this change,[5] the Commission directed the Company "to change the

[5] Order No. 23-472 issued on December 12, 2023, in Docket No. UE 424

long-run incremental cost study in its next general rate case to ensure that distribution voltage customers larger than 25,000 kilowatts are not overallocated distribution and substation costs." In the forecast test period, there will be no customers energized who would have received the modified Line Extension Allowance treatment. The cost-of-service study itself was therefore not changed for this circumstance. However, the Company is proposing that distribution voltage customers with a load request greater than 25,000 kW who received a Line Extension Allowance equal to the cost of the metering necessary to measure their usage would receive a Customer-Funded Substation Credit to ensure that these customers are not overallocated distribution substation costs. The Company proposes that the Customer-Funded Substation Credit be set at $1.50 per kW of Facility Capacity[6] in Schedule 48. Exhibit PAC/1913 shows the calculation of the Customer-Funded Substation Credit. The Customer-Funded Substation Credit was set at a level that removes the cost of the return on and return of distribution substations that are in primary Schedule 48 rates. Notably, the operations and maintenance expense for distribution substations was not removed. If a large customer pays for the cost of the substation serving it upfront in its line extension advance, it is appropriate to remove that cost from rates for this customer, but the Company will still need to operate and maintain that substation.

C. <u>Adjustment Schedules</u>

Q. Please describe the proposed new adjustment schedules.

A. As discussed in the direct testimony of Company witness Joelle R. Steward, the Company is proposing an Insurance Cost Adjustment and a surcharge to collect funds

[6] In Schedule 48, "Facility Capacity" is defined as the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

for a Catastrophic Fire Fund. The Company proposes that insurance costs be recovered through Schedule 80 – Insurance Cost Adjustment. The Company proposes that funds for the Catastrophic Fire Fund be collected through Schedule 193 – Catastrophic Fire Fund Adjustment.

Q. How does the Company propose setting rates for Schedule 80 – Insurance Cost Adjustment?

A. Since insurance costs are the result of managing risk for all aspects of a utility's operations, the Company proposes allocating their costs to each class on an equal percentage of base revenue. The Company would collect these costs from customers through a cents per kWh surcharge. Page 12 of Exhibit PAC/1909 shows the allocation and prices for Schedule 80, which would recover approximately $50.4 million per year in base revenue and would recover approximately $15.5 million in deferred costs.

Q. How does the Company propose setting rates for Schedule 193 – Catastrophic Fire Fund?

A. The risk associated with catastrophic fires is correlated with the presence of overhead line infrastructure. The Company therefore proposes allocating the Catastrophic Fire Fund to each class based upon its share of unbundled distribution revenue requirement. The Company would collect these funds from customers through a cents per kWh surcharge. Page 13 of Exhibit PAC/1909 shows the allocation and prices for Schedule 193, which would recover approximately $77.8 million per year after the rounding of rates.

Q. What change does the Company propose for Schedule 190 – Wildfire Mitigation Plan Cost Recovery Adjustment?

A. As discussed in the direct testimony of Company witness Sherona L. Cheung, the Company is proposing moving costs out of base rates and into the Wildfire Mitigation Plan Automatic Adjustment Clause. Accordingly, the Company is proposing to recover approximately an additional $21.3 million from Schedule 190. Page 14 of Exhibit PAC/1909 shows the proposed price changes for Schedule 190.

D. <u>Time-of-Use Options</u>

Q. Please summarize the Company's proposed changes to its time-of-use offerings.

A. The Company proposes moving Schedule 6, Pilot for Residential Time-of-Use Service, from its status of being a pilot to being an ongoing program through Schedule 4. The Company proposes introducing a new time-of-use option for small general service customers on Schedule 23 that has the same structure as the residential time-of-use program. The Company proposes moving Schedule 29, Pilot for General Service Time-of-Use, from its status of being a pilot to being an ongoing program with some modifications that will enhance its time varying price signal. For the irrigation time-of-use option on Schedule 41, Agricultural Pumping Service, the Company proposes increasing the on- to off-peak price differential. Finally, the Company proposes eliminating legacy optional Schedule 210, Portfolio Time-of-Use Supply Service, by June 1, 2025—five months after the January 1, 2025, effective date of this general rate case to provide adequate notice to affected participants and give them an opportunity to transition to other applicable time-of-use options. Schedule 210 would be closed to new service beginning January 1, 2025.

Q. Please list all of the time-of-use options that are currently available to the Company's customers.

A. The following time-of-use options are available to customers:

- Schedule 210 – Portfolio Time-of-Use Option for Residential
- Schedule 210 – Portfolio Time-of-Use Option for Small General Service
- Schedule 210 – Portfolio Time-of-Use Option for Small Irrigation
- Schedule 6 – Residential Time-of-Use Pilot
- Schedule 29 – Non-Residential Time-of-Use Pilot
- Schedule 41 – Irrigation Time-of-Use Option
- Schedule 45 – Public DC Fast Charger Transitional Rate

Table 3 lists the eligibility of these different options to different customer types.

Table 3. Time-of-Use Option Eligibility

	Residential	Non-Residential (<31 kW)	Non-Residential (31-200 kW)	Non-Residential (201-1,000 kW)	Irrigation (<31 kW)	Irrigation (31 kW & greater)
Schedule 210 Portfolio TOU	X	X			X	
Schedule 6 TOU	X					
Schedule 29 TOU		X	X	X		
Schedule 41 TOU Option					X	X
Schedule 45 Transitional Rate		*	*	*		

X- Applicable
*- Applicable in limited circumstances

Residential and small irrigation customers have available to them two different time-of-use options. Mid-sized general service and larger irrigation have only one option available to them. There is also a time-of-use option (Schedule 45) that is only available to publicly available electric vehicle charging stations under limited circumstances.

Q. Are any of the time-of-use options pilots?

A. Yes. Residential Time-of-Use Schedule 6 and Non-Residential Time-of-Use Schedule 29 are pilot programs that were established in the 2021 Rate Case. A final report on each pilot is due after they have been in place for three years. Both became effective on January 1, 2021, so this initial three-year period has elapsed.

Q. Has the Company evaluated these pilots?

A. Yes. The Company has evaluated the Residential Time-of-Use Schedule 6 pilot and the Non-Residential Time-of-Use Schedule 29 pilot. The final reports for Schedule 6 and Schedule 29 are provided as Exhibit PAC/1914 and Exhibit PAC/1915, respectively.

Q. Was there another pilot that the Company conducted as a result of the 2021 Rate Case?

A. Yes. The Company also conducted a pilot for interruptible service for large customers which was offered under Schedule 218. No customers participated in this pilot.

Q. Did the Company evaluate the Interruptible Service pilot?

A. No. The Company proposed and the Commission approved a more robust suite of demand response options and discontinued the Schedule 218 Interruptible Service pilot.[7] No report was therefore prepared for Interruptible Service Schedule 218.

Q. Please present the Schedule 6 pilot evaluation.

A. The Company's final report on the Residential Time-of-Use Schedule 6 pilot is provided as Exhibit PAC/1914. The pilot experienced steadily increasing levels of

[7] See the Commission's Disposition Letter dated November 15, 2022, in Docket No. ADV 1436.

enrollment, high participant satisfaction, meaningful customer bill savings, and system cost savings. The evaluation recommends continuing the program.

Q. What does the Company propose for Residential Time-of-Use Schedule 6?

A. The Company proposes moving the design and program structure of the Schedule 6 from its status as a pilot to being an ongoing optional offering available to residential customers that is listed under Residential Schedule 4.

Q. Please describe the Company's proposal for a new time-of-use option for Small General Service Schedule 23 customers.

A. In light of the success of the Residential Time-of-Use Schedule 6 pilot, the Company believes that providing a very similar program for small general service customers is in the public interest. The Company proposes that a new time-of-use option for Small General Service Schedule 23 customers be made available that would have the same time-of-use hours and program structure to the time-of-use option for residential customers. On-peak hours would be 5:00 p.m. to 9:00 p.m. every day and all other hours would be considered off-peak. The proposed credit for off-peak usage for participants in the time-of-use option is set to be the difference in average Western Energy Imbalance Market (WEIM) prices between on- and off-peak hours for the 36 month period ended June 2023 of 2.532 cents per kWh which is about a cent higher than the off-peak credit of 1.438 cents per kW provided on legacy Schedule 210 for small general service customers. To achieve a revenue neutral rate design, the Company proposes an on-peak adder for Schedule 23 of 12.578 cents per kWh. The Company solved for the on-peak surcharge price by applying the off-peak credit price to the estimated off-peak energy for all of Schedule 23 and dividing this revenue by the estimated on-peak energy for all of Schedule 23. Exhibit PAC/1916 shows the calculations used to develop the on-peak surcharge and off-peak credit for the new Schedule 23 time-of-use option. Table 4 shows how the base energy prices for the time-of-use option would compare to standard Schedule 23 rates.

Table 4. Comparison of Proposed Energy Prices for the Time-of-Use Option and Standard Schedule 23

Description	Schedule 23 Time-of-Use Option	Standard Schedule 23 Pricing
1st 3,000 kWh, On-Peak, Secondary Voltage	28.135¢ per kWh	15.557¢ per kWh
1st 3,000 kWh, Off-Peak, Secondary Voltage	13.025¢ per kWh	15.557¢ per kWh
All additional kWh, On-Peak, Secondary Voltage	26.372¢ per kWh	13.794¢ per kWh
All additional, Off-Peak, Secondary Voltage	11.262¢ per kWh	13.794¢ per kWh

Q. Please present the Schedule 29 pilot evaluation.

A. The Company's final report on the Non-Residential Time-of-Use Schedule 29 pilot is provided as Exhibit PAC/1915. The Company only had one participant who had been on the program for a partial year. The analysis presented in the report was therefore fairly limited. The Company continues to believe though that the program holds promise particularly for transportation electrification customers with low levels of utilization.

Q. What does the Company propose for Non-Residential Time-of-Use Schedule 29?

A. The Company proposes that the same structure for Schedule 29 be preserved, but that the time-varying element of the program be structured similarly to the residential and small general service time-of-use options. This would standardize the time-of-use periods for residential, small general service and mid-sized general service customers.

Increasing the time use differential will also provide greater opportunities for customers who do have load shifting opportunities to save on their bills. On-peak hours would be 5:00 p.m. to 9:00 p.m. every day and all other hours would be considered off-peak. Off-peak usage for participants on Schedule 29 would receive the same 2.532 cent per kWh credit as small general service time-of-use option participants. To achieve a revenue neutral rate design with Schedule 28 and Schedule 30, the Company proposes an on-peak adder of 13.014 cents per kWh. Exhibit PAC/1916 shows the calculations used to develop the on-peak surcharge and off-peak credit for Schedule 29. Since small general service customers are not subject to a demand charge for all of their kW usage, Schedule 29 is unlikely to be a good option for Schedule 23 customers. The Company therefore proposes limiting eligibility for Schedule 29 participants to "Large Nonresidential Consumers", which is a defined term in the tariffed rules and generally means a non-residential customer with a load size larger than 30 kW.

Q. Please describe the Agricultural Pumping Service Schedule 41 time-of-use option?

A. Schedule 41 irrigation customers can enroll in a time-of-use option which has time varying energy charges during the peak irrigating months of July, August, and September. To provide flexibility for pumpers who take water from an irrigation project, two choices are provided for on-peak hours – Option A which sets on-peak from 2:00 p.m. to 6:00 p.m. every day during the season and Option B which sets on-peak from 6:00 p.m. to 10:00 p.m. every day during the season. Off-peak energy usage receives a credit against regular charges of 0.992 cents per kWh and on-peak usage incurs a charge of 4.989 cents per kWh on top of standard charges. In December 2023, 113 out of a total of 7,891 Schedule 41 customers participated in the time-of-use option.

Q. Does the Company propose any changes for the Agricultural Pumping Service Schedule 41 time-of-use option?

A. Yes. To encourage greater enrollment in the option and to send a stronger price signal to shift load away from on-peak periods, the Company proposes increasing the on- to off-peak differential. Using similar logic to the calculation of the off-peak price for the Schedule 23 time-of-use option and for Schedule 29, the Company took the difference of WEIM prices between Schedule 41's on- and off-peak times to develop a 2.696 cents per kWh off-peak credit. To achieve a revenue neutral rate design for the whole class, a 12.030 cents per kWh on-peak surcharge is required. Exhibit PAC/1916 shows the calculations used to develop the on-peak surcharge and off-peak credit for the Schedule 41 time-of-use option.

Q. Please describe legacy Portfolio Time-of-Use Schedule 210.

A. As a requirement of Oregon Administrative Rule 860-038-0220, the Company was required to provide residential and small non-residential customers with a portfolio of product and pricing options. Along with options that provided customers with access to renewables, time-of-use pricing was made available through Schedule 210 to residential, small general service, and small irrigation customers. Schedule 210 became effective on March 1, 2002, nearly 22 years ago. Schedule 210 has not been a very popular program. It has low levels of participation and bill savings for participants have been meager. Table 5 shows the average number of customers enrolled along with the average monthly bill savings for the historic base period of 12 months ended June 2023.

Table 5. Schedule 210 Enrollment and Bill Savings

	Average Customers	Average Monthly Savings
Residential	952	$0.98
Small General Service	211	$1.58
Irrigation	19	$2.78

The time-of-use periods for Schedule 210 are more complex than for the newer Residential Time-of-Use Schedule 6 pilot or the Agricultural Pumping Service Schedule 41 Time-of-Use Option. Under Schedule 210, between the winter months of November through March, on-peak periods are Monday through Friday, excluding holidays, from 6:00 a.m. to 10:00 a.m. and again from 5:00 p.m. to 8:00 p.m. Between the summer months of April through October, on-peak periods on Schedule 210 are Monday through Friday, excluding holidays, from 4:00 p.m. to 8:00 p.m. All other hours are considered off-peak.

Q. What does the Company propose for legacy Portfolio Time-of-Use Schedule 210?

A. The Company proposes eliminating legacy Schedule 210 by June 1, 2025, five months after the rate effective date of this proceeding, in order to give adequate notice to participants and provide them with sufficient time to consider transitioning to a different time-of-use option. Residential Schedule 210 could choose to move to the time-of-use option listed on Residential Schedule 4, Small General Service Schedule 210 could choose to move to the time-of-use option listed on Small General Service Schedule 23, and Agricultural Pumping Service Schedule 210 could choose to move to the time-of-use option listed on Agricultural Pumping Service Schedule 41. Under the Company's proposal, Schedule 210 would be closed to new service starting on the rate effective date in this rate case of January 1, 2025.

Q. Why does the Company propose eliminating legacy Portfolio Time-of-Use Schedule 210?

A. Schedule 210 has confusing time periods, offers only very limited savings, and has not been very popular. The Company believes that now is the right time to transition to more robust time-of-use options for its customers. Keeping legacy Schedule 210 along with other options would create confusion for customers.

VII. ELIMINATION OF PAYMENT FEES

Q. Do the Company's customers pay fees for some methods of payment that they use to pay their bills?

A. Yes. The Company's vendors charge fees to customers who make a payment at a pay station or pay their bills with a credit or debit card. These costs are passed onto customers making these types of payments to keep its rates lower for everyone. Customers can pay their bills without a fee if they pay by sending a check or transferring funds from a bank account electronically, which are options that have minimal cost to the Company.

Q. What are some of the consequences of charging fees for customers who pay at a pay station or with a credit or debit card?

A. Customers who use pay stations to make a payment can be in a crisis and need to make a fast payment to restore their power after a shut-off for non-payment. They may also be un-banked and not have the ability to pay with a check or an electronic draft. Customers who pay their power bill with a credit card may be doing so because they are in a tight spot financially and do not have the cash on hand to pay from a bank account. For vulnerable customers experiencing financial constraints, facing additional fees to pay their power bills can set them back further and increase their energy burden.

Q. In light of these consequences, what does the Company propose?

A. The Company proposes eliminating fees associated with using a pay station or making payment with a debit or credit card. Eliminating these fees will remove a hardship that vulnerable customers face and make it easier for them to pay their electricity bills using a method that is feasible for them in their situation. It is the Company's understanding that both Portland General Electric Company and Northwest Natural do not charge fees for payments made through a pay station or with a card.

Q. What is the cost of eliminating fees for pay stations and credit/debit card payments?

A. During the historic base period, customers paid about $4.8 million in fees for using a pay station and paying with a card. The Company's revenue requirement has been adjusted to reflect this additional cost. That adjustment is supported by Company witness Cheung. Exhibit PAC/1917 shows the details of this cost.

VIII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1901
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Tariffs

February 2024

Index No.

Schedule No.

Issued February 14, 2024
Matthew McVee, Vice President, Regulation

Effective for service on and after January 1, 2025
Advice No. 24-001/Docket No. UE 433

+Schedule No.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 4

RESIDENTIAL SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements when all service is supplied at one point of delivery. Three-phase service will be supplied only when service is available from Company's presently existing facilities, or where such facilities can be installed under Company's Line Extension Rules, and, in any event, only when deliveries can be made by using one service for Consumer's single-phase and three-phase requirements.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Single-Family Home Basic Charge, per month	$16.00	(I)
Multi-Family Home Basic Charge, per month	$9.00	(I)
Three-Phase Charge, per month	$9.00	(N)
		(D)
Distribution Energy Charge, per kWh	5.433¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.844¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.070¢	(R)
T&A and Schedule 201 Related, per kWh	0.132¢	(I)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule. (D)

Time-of-Use Option (N)

Consumers taking service under this schedule may also choose to participate in a time-of-use option, which provides time-varying energy rates. Rates and hours for this option are shown in Schedule 201. (N)(N)(N)

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

(D)

(continued)

Special Conditions (N)

1. The Consumer must have a time-of-use capable meter installed to participate in the time-of-use option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under the time-of-use option shall begin for the Consumer following the meter update and the initial meter reading.
2. Consumers requesting to participate in the time-of-use option agree to remain on the option for one year. The Consumer shall remain on the option until Consumer notifies the Company.
3. The Company shall guarantee against excessive increase of consumer costs for the first year of enrollment in the time-of-use option. If the total energy costs incurred on the option for the first year exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the end of the first year of service under the program. No Guarantee Payment shall be given if Consumer discontinues participation on the option before the end of the first year on the program. (N)

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from minimum monthly charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 5

SEPARATELY METERED ELECTRIC VEHICLE SERVICE FOR RESIDENTIAL CONSUMERS
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements supplied to electric vehicle charging installations where such service is supplied at a point of delivery separately metered from other residential service. Three-phase service will be supplied only when service is available from Company's presently existing facilities.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Single-Family Home Basic Charge, per month	$16.00	(I)
Multi-Family Home Basic Charge, per month	$9.00	(I)
Three-Phase Charge, per month	$9.00	(C)(I)
		(D)
Distribution Energy Charge, per kWh	5.433¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.844¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.070¢	(R)
T&A and Schedule 201 Related, per kWh	0.132¢	(I)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule. (D)

Time-of-Use Option (N)

Consumers taking service under this schedule may also choose to participate in a time-of-use option, which provides time-varying energy rates. Rates and hours for this option are shown in Schedule 201. (N)

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

(M) to pg. 2

(continued)

Special Conditions (N)

1. The Consumer must have a time-of-use capable meter installed to participate in the time-of-use option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under the time-of-use option shall begin for the Consumer following the meter update and the initial meter reading.
2. Consumers requesting to participate in the time-of-use option agree to remain on the option for one year. The Consumer shall remain on the option until Consumer notifies the Company.
3. The Company shall guarantee against excessive increase of consumer costs for the first year of enrollment in the time-of-use option. If the total energy costs incurred on the option for the first year exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the end of the first year of service under the program. No Guarantee Payment shall be given if Consumer discontinues participation on the option before the end of the first year on the program. (N)

Continuing Service (M) from pg. 1

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from minimum monthly charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

(M)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 6

PILOT FOR RESIDENTIAL TIME-OF-USE SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers otherwise receiving Delivery Service under Schedule 4, in conjunction with Supply Service Schedule 201. Service under this pilot will be limited to approximately twenty-five thousand (25,000) metered points of delivery.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge and System Usage Charge plus the applicable adjustments as specified in Schedule 90 for Schedule 4.

Distribution Charge	
Single Family Home Basic Charge, per month	$11.00
Multi-Family Home Basic Charge, per month	$8.00
Three Phase Demand Charge, per kW demand	$2.20
Three Phase Minimum Demand Charge, per month	$3.80
Distribution Energy Charge, per kWh	4.307¢
Transmission & Ancillary Services Charge	
Per kWh	0.919¢
System Usage Charge	
Schedule 200 Related, per kWh	0.077¢
T&A and Schedule 201 Related, per kWh	0.115¢

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall pay the applicable rates under Supply Service Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

On- and Off-Peak Definitions

On-Peak Period	All days 5 p.m. to 9 p.m.
Off-Peak Period	All other hours

CANCELED

(continued)

Issued December 22, 2022
Matthew McVee, Vice President, Regulation

Effective for service on and after January 1, 2023
Advice No. 22-017/Docket No. UE 399

Guarantee Payment

The Company shall guarantee against excessive increase of consumer costs for the first year of enrollment in the program. If the total energy costs incurred on this Schedule for the first year exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the end of the first year of serviced under the program. No Guarantee Payment shall be given if Consumer terminates service on the program before the end of the first year on the program.

Special Conditions

1. Consumers taking service under this schedule shall be subject to all conditions applicable to Schedule 4 of this tariff.

2. Participants for this program will be chosen on a first-come, first-served basis. Participation will be limited to approximately twenty-five thousand (25,000) metered points.

3. The Consumer must have a time-of-use capable meter installed to participate in this option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under this schedule shall begin for the Consumer following the meter update and the initial meter reading.

4. Consumers requesting service under this pilot program agree to remain on the pilot for one year. Consumers will have the option to opt out of the pilot after this date by notifying the Company. Service will continue under this schedule until Consumer notifies the Company to discontinue service or this schedule terminates.

5. All Consumers participating in this pilot program may be asked to complete a survey regarding participation. Survey responses will be used to further evaluate the potential of future time-of-use rates. Data gathered will be used for pilot evaluation only.

6. Consumers on this tariff schedule shall have a term of not less than one year. Service will continue under this schedule until Consumer notifies the Company to discontinue service.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from minimum monthly charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 7

LOW-INCOME DISCOUNT

Purpose

The purpose of this Schedule is to implement the Low-Income Discount for income qualified Residential Customers and General Service customers who qualify under Special Condition 10 of this tariff.

This discount is enabled by House Bill 2475 (2021 regular sessions), which modified ORS 757.230 to allow for differentiated rates for "low-income customers and other economic, social equity, or environmental justice factors that affect affordability for certain classes of utility customers."

Available

To Residential Customers and General Service Customers who qualify under Special Condition 10 of this tariff and are served by the Company within its service territory.

Applicable

To income-qualified Residential Customers with gross household income at or below 60% of Oregon State Median Income (SMI) adjusted for household size. For Customers in single-person households, eligibility is extended to those with gross household incomes up to the greater of 60% SMI or full-time wages at Portland minimum wage. Also applicable to General Service Customers who qualify under Special Condition 10 of this tariff.

Monthly Billing

Income-qualified Residential Customers will receive a monthly bill discount at one of two levels based on the Customer's household income as a percentage of SMI for the Residential Service Schedule charges for that Customer (Schedule 4 or 5). Customers with household incomes up to (D) 20% of SMI will receive a 40% discount on their electricity bill and customers with household incomes between 21% and 60% will receive a 20% discount on their electricity bill. The monthly bill discount will be applied prior to taxes and will not apply to Schedule 300 charges.

General Service Customers who qualify under Special Condition 10 of this tariff will receive a 30% discount on their electricity bill. The monthly bill discount will be applied prior to taxes and will not apply to Schedule 300 charges. General Service Customers receiving this discount must meet and comply with the terms of Special Condition 10 of this tariff.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Consumers for outdoor area lighting service furnished from dusk to dawn by means of Company-owned lamps which may be served by secondary voltage circuits from the Company's existing overhead distribution system. Luminaires shall be mounted on Company-owned wood poles and served in accordance with the Company's specifications as to equipment and installation. Lamp installations on any pole except an existing distribution pole are closed to new service.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate Per Lamp	
Level 1	0-5,000	19	$7.89	(I)
Level 2	5,001-12,000	34	$9.05	(I)
Level 3	12,001+	57	$10.74	(I)

Supply Service Option

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, Transmission & Ancillary Services, Schedule 201, Net Power Costs, and distribution charges are collected through rates in this schedule.

Special Conditions

1. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company's operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power's customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power's obligation to repair street lights is limited to this tariff.

2. The Company reserves the right to contract for the maintenance of lighting service provided hereunder.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers whose entire electric service requirements are supplied hereunder and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage** Secondary	Primary	
Basic Charge			
Single Phase, per month	$22.10	$22.10	(I)
Three Phase, per month	$32.95	$32.95	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	$2.10	$2.10	(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$6.87	$6.78	(I)
Distribution Energy Charge, per kWh	5.080¢	5.001¢	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	1.042¢	1.026¢	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.064¢	0.063¢	(R)
T&A and Schedule 201 Related, per kWh	0.128¢	0.126¢	(I)

kW Load Size

For determination of the Basic Charge and Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

(continued)

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Communication Devices

Communication devices with fixed loads that are installed on streetlights, traffic signals or elsewhere and connected to the Company's system for electric service may be unmetered and shall be served under this schedule in accordance with Rule 7.C. Such unmetered devices not exceeding 35 line watts per unit, served under multiple Points of Delivery to a single Consumer, may be grouped under a single Consumer account for billing purposes such that the Consumer pays a single Basic Charge for multiple units in addition to a per unit energy-based charge. Not more than 100 units shall be grouped under a single account.

All devices are required to be installed and maintained under a pole attachment agreement. The Consumer is required to notify the Company in writing and receive subsequent approval prior to installation, modification or removal of any device.

All devices mounted to Company owned facilities shall be installed, maintained, transferred or removed only by qualified personnel approved in advance by the Company. If approved qualified personnel are not available or at the Company's discretion, the Company may perform these functions at the Consumer's expense.

Supply Service Options

All Small Nonresidential Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 211, Schedule 212, Schedule 213, or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 723, Direct Access Delivery Service. (D)

(M) to pg. 3

Time-of-Use Option (N)

Consumers taking service under this schedule who choose Supply Service Schedule 201, 211, 212 or 213 may also choose to participate in a time-of-use option which provides time-varying energy rates. Rates and hours for this option are shown in Schedule 201. (N)

(continued)

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges. (M) from pg. 2 (M)

Special Conditions

1. The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs. (T)
2. The Consumer must have a time-of-use capable meter installed to participate in the time-of-use option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under the time-of-use option shall begin for the Consumer following the meter update and the initial meter reading. (N)
3. Consumers requesting to participate in the time-of-use option agree to remain on the option for one year. The Consumer shall remain on the option until Consumer notifies the Company. (N)

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 28

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW to 200 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤50 kW, per month	$ 25.00	$ 35.00	(I)
Load Size 51-100 kW, per month	$ 47.00	$ 60.00	(I)
Load Size 101 - 300 kW, per month	$111.00	$138.00	(I)
Load Size > 300 kW, per month	$156.00	$197.00	(I)
Load Size Charge			
≤50 kW, per kW Load Size	$ 1.60	$ 1.95	(I)
51 - 100 kW, per kW Load Size	$ 1.25	$ 1.55	(I)
101 – 300 kW, per kW Load Size	$ 0.75	$ 0.95	(I)
> 300 kW, per kW Load Size	$ 0.50	$ 0.50	(I)
Demand Charge, per kW	$ 5.31	$ 6.78	(I)
Distribution Energy Charge, per kWh	0.536¢	0.103¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	$ 1.74	$ 2.13	(R)(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.067¢	0.060¢	(R)
T&A and Schedule 201 Related, per kWh	0.126¢	0.111¢	(I)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 29

GENERAL SERVICE TIME-OF-USE
LARGE NONRESIDENTIAL
DELIVERY SERVICE (C)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 1,000 kW, more than three times in the preceding 12-month period or more than 2,000 kW more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. (C) (D)

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge and System Usage Charge plus the applicable adjustments as specified in Schedule 90 for Schedule 28.

Distribution Charge		
Basic Charge, per month	$49.00	(I)
Distribution Energy Charge		
First 50 kWh per kW demand, per kWh	24.942¢	(I)
All Additional kWh, per kWh	-1.758¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.582¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.067¢	(R)
T&A and Schedule 201 Related, per kWh	0.126¢	(I)

Minimum Charge

The minimum monthly charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

Demand

The kW shown by or computed from the readings of the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW, but not less than 15 kW.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall pay the applicable rates in Supply Service Schedule 201. Time-of-use rates and hours for Supply Service under this schedule are shown in Schedule 201. (N) (N)

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

(C)

(D)

Special Conditions

1. Consumers taking service under this schedule shall be subject to all conditions applicable to Schedule 28 of this tariff. (D)

2. The Consumer must have a time-of-use capable meter installed to participate in this option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under this schedule shall begin for the Consumer following the meter update and the initial meter reading. (T)

3. Consumers requesting service under this schedule agree to remain on the schedule for one year. Service will continue under this schedule until Consumer notifies the Company to discontinue service or this schedule terminates. (T)(C) (C)(D)

(D)

4. Meters taking service under this schedule will not be eligible to participate concurrently in net metering or any other generation related program offered by the Company. (T)(C)

Continuing Service

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal Consumer from minimum monthly charges.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 30

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW to 999 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤200 kW, per month	$704.00	$642.00	(I)
Load Size 201 - 300 kW, per month	$204.00	$202.00	(I)
Load Size > 300 kW, per month	$541.00	$527.00	(I)
Load Size Charge			
≤200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$2.50	$2.20	(I)
> 300 kW, per kW Load Size	$1.20	$1.10	(I)
Demand Charge, per kW	$5.92	$5.59	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kW	$2.45	$2.29	(R)
System Usage Charge			
Schedule 200 Related, per kWh	0.065¢	0.065¢	(R)
T&A and Schedule 201 Related, per kWh	0.121¢	0.121¢	(I)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 47 or 48. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the monthly billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$580.00	$570.00	(I)
Three Phase Load Size > 300 kW	$2,300.00	$2,270.00	(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$24.20	$23.90	(I)
Three Phase 51 - 300 kW, per kW Load Size	$16.60	$16.40	(I)
Three Phase > 300 kW, per kW Load Size	$10.20	$10.10	(I)
Single Phase, Minimum Charge	$105.00	$105.00	(I)
Three Phase, Minimum Charge	$170.00	$170.00	(I)
Distribution Energy Charge, per kWh	7.049¢	6.940¢	(I)
Reactive Power Charge, per kVar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.660¢	0.650¢	(R)
System Usage Charge			
Schedule 200 Related, per kWh	0.058¢	0.057¢	(R)
T&A and Schedule 201 Related, per kWh	0.107¢	0.105¢	(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of the Company's meter, or by appropriate test, for the 15-minute period of the Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

(continued)

kW Load Size *(continued)*

If Motor Size Is:	Monthly kW is:
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

In no case shall the Monthly kW be less than the average kW determined as:

$$\text{Average kW} = \frac{\text{kWh for billing month}}{\text{hours in billing month}}$$

Reactive Power Charge

The maximum 15-minute reactive takings for the billing month in kilovolt-amperes in excess of 40% of the Monthly kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. A Small Nonresidential Consumer taking Delivery Service under this schedule shall additionally specify Supply Service Schedule 201, Schedule 211, (D) Schedule 212, Schedule 213, or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. A Large Nonresidential Consumer taking Delivery Service under this Schedule shall additionally specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 741, Direct Access Delivery Service.

Time-of-Use Options

Consumers taking service under this schedule who choose Supply Service Schedule 201, 211, (N) 212 or 213 may also choose to participate in one of two time-of-use options, Option A and (N) Option B, which provide time-varying rates during the Summer months of July, August and September. Rates and hours for these options are shown in Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

(continued)

(T)

Special Conditions

1. For new or terminating service, the Basic Charge and the Load Size Charge shall be prorated based upon the length of time the account is active during the 12-month period December through November; provided, however, that proration of the Basic Charge and the Load Size Charge will be available on termination only if a full Basic Charge and Load Size Charge was paid for the delivery point for the preceding year.

2. For new service or for reestablishment of service, the Company will require a written contract.

3. In the absence of a Consumer or Applicant willing to contract for service, the Company may remove its facilities.

4. Energy use may be carried forward and be billed in a subsequent billing month; provided, however, that energy will not be carried forward and be charged for at a higher rate than was applicable for the billing months during which the energy was used.

5. A Consumer may not at the same time participate in one of the time-of-use options and Schedule 106 or any other demand response program. (C)

6. The Consumer must have a time-of-use capable meter installed to participate in the time-of-use options. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under the time-of-use option shall begin for the Consumer following the meter update and the initial meter reading. (N)

7. Consumers requesting to participate in the time-of-use options agree to remain on the option for one year. The Consumer shall remain on the option until Consumer notifies the Company. (N)

Term of Contract
Not less than three years.

Rules and Regulations
Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 47

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charge, Transmission & Ancillary Services Charge, and System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4,000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N) (N)
Reserves Charges				
Spinning Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company approved Self-Supply Agreement)				
Per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)				
Per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$2.07	$2.73	$3.13	(I)
System Usage Charge				
Schedule 200 Related, per kWh	0.066¢	0.061¢	0.059¢	(R)
T&A and Schedule 201 Related, per kWh	0.122¢	0.113¢	0.109¢	(I)

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. All remaining hours are Off-Peak.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage service, have a load size of 25,000 kW or greater, and received an Extension Allowance that was equal to the metering necessary to measure their usage. (N)

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.
A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer's peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer's plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

Facility Capacity shall be the average of the two greatest non-zero monthly Demands established during the 12 month period which includes and ends with the current Billing Month, but shall not be less than the Consumer's Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer's Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer's Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer's Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer's demand rises above Baseline Demand.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until the Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		**Delivery Voltage**		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4,000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N) (N)
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$2.61	$3.27	$3.67	(R)(I)(I)
System Usage Charge				
Schedule 200 Related, per kWh	0.066¢	0.061¢	0.059¢	(R)
T&A and Schedule 201 Related, per kWh	0.122¢	0.113¢	0.109¢	(I)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(M) to pg. 2

(continued)

Reactive Power Charge (M) from pg. 1

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. All remaining hours are Off-Peak.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage (N)
service, have a load size of 25,000 kW or greater, and received an Extension Allowance that (N)
was equal to the metering necessary to measure their usage. (N)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Supply Service Options

All Consumers taking Delivery Service under this Schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 748, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 51

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	
LED Equivalent Lumens	0-3,500	3,501-5,500	5,501-8,000	8,001-12,000	12,001-15,500	15,501+	
Monthly kWh	8	15	25	34	44	57	
Functional Lighting	$ 6.53	$ 6.92	$ 7.07	$ 7.20	$ 7.65	$ 9.34	(I)
Functional Lighting - Customer Funded Conversion	$ 3.53	$ 3.72	$ 3.86	$ 3.94	$ 4.21	$ 5.18	(I)
Decorative Series	N/A	$ 11.92	$ 12.05	N/A	N/A	N/A	(I)

Functional Lighting: Common less expensive luminaires that may be mounted either on wood, fiberglass or non-decorative metal poles. The Company will maintain a list of functional light fixtures that are available.

Customer-Funded Conversion: Street lights that have been converted to LED from another lighting type and whose conversion was funded by the Customer.

Decorative Series Lighting: More stylish luminaires mounted vertically on decorative metal poles. The Company will maintain a listing of standard decorative street light fixtures that are available under this Schedule.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 751, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, Transmission & Ancillary Services, Schedule 201, Net Power Costs, and distribution charges are collected through rates in this schedule.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.32	$ 1.87	$ 2.72	$ 3.62	$ 4.89	$ 7.49

(I)

Metal Halide					
Lumen Rating	9,000	12,000	19,500	32,000	107,800
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.66	$ 2.89	$ 4.00	$ 6.34	$ 15.06

(I)

For non-listed luminaires the cost will be calculated for 4167 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	4.255

(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At the Consumer's option, service for recreational field lighting may be taken under the Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.684¢	(I)
Transmission & Ancillary Services Charge		
per kWh	0.028¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.012¢	(R)
T&A and Schedule 201 Related, per kWh	0.020¢	

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 754, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

The Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

(continued)

LARGE GENERAL SERVICE - PARTIAL REQUIREMENTS SERVICE
ECONOMIC REPLACEMENT POWER RIDER
DELIVERY SERVICE

Purpose

To provide Consumers served on Schedule 47 with the opportunity of purchasing Energy from the Company to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement power except as explicitly agreed to between Company and Consumer.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 47 plus the applicable adjustments as specified in Schedule 90:

	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Transmission & Ancillary Services Charge				
Per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.081	$0.106	$0.122	(I)
Daily ERP Demand Charge				
Per kW of Daily ERP On-Peak Demand	$0.250	$0.310	$0.242	(I)

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 276R.

ERP and ENF

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Power Agreement (ERPA). ERP, ENF and ERPA are more fully described in Schedule 276R.

Daily ERP On-Peak Demand

Daily ERP On-Peak Demand shall not be less than the maximum ERP On-Peak Demand scheduled per day and shall not be greater than the difference between the Facility Capacity and the Baseline Demand. Daily ERP On-Peak Demand will be billed for each day in the month that the Company supplies ERP to the Consumer.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 80

INSURANCE COST ADJUSTMENT

 (N)

Purpose
The purpose of this schedule is recover base and deferred insurance costs.

Applicable
To all Residential and Nonresidential Consumers.

Monthly Billing
All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

	Base Adjustment	Deferred Adjustment
Schedule 4	0.404 ¢ per kWh	0.125 ¢ per kWh
Schedule 5	0.404 ¢ per kWh	0.125 ¢ per kWh
Schedule 15	0.630 ¢ per kWh	0.194 ¢ per kWh
Schedule 23, 723	0.421 ¢ per kWh	0.130 ¢ per kWh
Schedule 28, 728	0.296 ¢ per kWh	0.091 ¢ per kWh
Schedule 30, 730	0.264 ¢ per kWh	0.081 ¢ per kWh
Schedule 41. 741	0.449 ¢ per kWh	0.138 ¢ per kWh
Schedule 47, 747	0.225 ¢ per kWh	0.069 ¢ per kWh
Schedule 48, 748, 848	0.225 ¢ per kWh	0.069 ¢ per kWh
Schedule 51, 751	0.630 ¢ per kWh	0.194 ¢ per kWh
Schedule 53, 752	0.630 ¢ per kWh	0.194 ¢ per kWh
Schedule 54, 754	0.630 ¢ per kWh	0.194 ¢ per kWh

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 90

The following summarizes the applicability of the Company's adjustment schedules

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

(N)

Schedule	80	91	92	93	94	96	97	98*	190	192	193	194	198	202*	203*	204
4	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
5	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
15	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
23	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
28	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
30	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
41	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
47	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
48	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
51	x	x	x	x	x	x			x	x	x	x	x	x	x	x
53	x	x	x	x	x	x			x	x	x	x	x	x	x	x
54	x	x	x	x	x	x			x	x	x	x	x	x	x	x
60																
723	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
728	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
730	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
741	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
747	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
748	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
751	x	x	x	x	x	x			x	x	x	x	x	x	x	x
753	x	x	x	x	x	x			x	x	x	x	x	x	x	x
754	x	x	x	x	x	x			x	x	x	x	x	x	x	x
848	x	x	x		x		x		x	x	x					

(N)

*Not applicable to all consumers. See Schedule for details.

(continued)

The following summarizes the applicability of the Company's adjustment schedules

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

(D)

Schedule	206	207	290	291	293	294*	295*	296*	299
4	x	x	x	x					x
5	x	x	x	x					x
15	x	x	x	x		x			x
23	x	x	x	x		x			x
28	x	x	x	x		x			x
30	x	x	x	x		x			x
41	x	x	x	x		x			x
47	x	x	x	x		x			x
48	x	x	x	x		x			x
51	x	x	x	x		x			x
53	x	x	x	x		x			x
54	x	x	x	x		x			x
60			x						
723	x	x	x	x		x			x
728	x	x	x	x		x			x
730	x	x	x	x		x	x	x	x
741	x	x	x	x		x			x
747	x	x	x	x		x	x	x	x
748	x	x	x	x		x	x	x	x
751	x	x	x	x		x			x
753	x	x	x	x		x			x
754	x	x	x	x		x			x
848			x	x	x				

(D)

*Not applicable to all consumers. See Schedule for details.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 91

LOW INCOME BILL PAYMENT ASSISTANCE FUND

Purpose

The purpose of this Schedule is to collect funds for electric low-income bill payment assistance as specified in Oregon Laws 2021, Ch. 536, §2.

Applicable

To all bills for electric service calculated under all tariffs and contracts.

Adjustment Rates

The applicable Adjustment Rates are listed below. Retail electricity Consumers shall not be required to pay more than $500 per month per site for low-income electric bill payment assistance.

Schedule	Adjustment Rate
Residential Rate Schedules (4, 5)	$0.69 per month
Nonresidential Rate Schedules	0.069 cents per kWh for the first 724,638 kWh

(D)

Definition of Site (Order No. 01-073 entered January 3, 2001)

"Site" means:

(a) Buildings and related structures that are interconnected by facilities owned by a single retail electricity consumer and that are served through a single electric meter; or

(b) A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that:

i. Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;

ii. Buildings and structures in the site, and land containing and connecting buildings and structures in the site, are owned by a single retail electricity consumer who is billed for electricity use at the buildings and structures; and

iii. Land shall be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land, on which municipal infrastructure facilities exist (such as street lighting, sewerage transmission, and roadway controls), shall not be considered contiguous.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 92

LOW-INCOME DISCOUNT COST RECOVERY ADJUSTMENT

Purpose

The purpose of this Schedule is, in accordance with ORS 757.695, to collect funds for the electric low-income discount as specified in Schedule 7. This discount is enabled by House Bill 2475 (2021 regular sessions) which modified ORS 757.230 to allow for differentiated rates for "low-income customers and other economic, social equity, or environmental justice factors that affect affordability for certain classes of utility customers." This adjustment schedule is implemented as an automatic adjustment clause as provided for in ORS 757.210.

Applicable

To all bills for electric service calculated under all tariffs and contracts.

Adjustment Rates

The applicable Adjustment Rates are listed below.

Schedule	Adjustment Rate
Residential Rate Schedules (4, 5)	$0.34 per month
Nonresidential Rate Schedules	0.038 cents per kWh for the first 5,000,000 kWh per month

(D)

All bills of qualifying residential customers on Schedules 4 and 5 shall have deducted an amount equal to the product of kilowatt-hours of use multiplied by the following cents per kilowatt-hour up to a maximum of 2,000 kilowatt-hours each month: (D)

0-2,000 kWh	0.876¢ per kWh

All bills to qualifying nonresidential customers shall have deducted an amount equal to the product of all kilowatt-hours of use multiplied by the following cents per kilowatt-hour:

0.818¢ per kWh

Condition of Service

The eligibility of affected Customers for the rate credit specified in this tariff is as provided by the Pacific Northwest electric Power Planning and Conservation Act, Public Law 96-501.

Eligible Customers with usage at or above 100,000 kWh per year must complete and submit to the Company a certificate verifying eligibility in order to receive the rate credit. Certificate forms are available on the Company's website at www.pacificpower.net under Oregon Regulatory Information. Consistent with the requirements of the Bonneville Power Administration, a federal agency, customers using electricity to aid in growing one or more Cannabis plants are not eligible for the rate credit specified in this tariff. If, in the course of doing business, a utility discovers that one of its existing customers is not eligible for the rate credit specified in this tariff, the customer will no longer receive the credit.

Special Conditions

In no instance shall a farm's total qualifying irrigation load for any billing period exceed 222,000 kWh. Under the Northwest Power Act, any farm may receive REP benefits for up to a maximum of 400 horsepower (HP)/month (222,000 kWh/month) of qualified irrigation/pumping load (the "REP Benefits Qualified Irrigation/Pumping Load Cap" or "Irrigation/Pumping Load Cap").

Incentive Amounts (continued)

Income Eligible Rebate

L2 Charger	Up to $1,500, capped at 100 percent of qualified costs
240 V Outlet Rebate	$500 rebate for installation of a 240 V outlet, capped at 100 percent of qualified costs

Income Eligibility
Low-income qualified customers demonstrate eligibility through participation in low-income programming, including the Oregon Energy Fund, Low Income Home Energy Assistance Program, or the Oregon Energy Assistance program. Information on these programs is available at: https://www.pacificpower.net/my-account/payments/bill-payment-assistance.html

Special Conditions

1. Residential Customers receiving a Standard Rebate will automatically be enrolled in the time-of-use option for Schedule 4 for a minimum of one year. (C)
2. Residential Customers receiving an Income-Eligible Rebate will have the option to enroll in the time-of-use option for Schedule 4. (C)
3. To be eligible for an incentive, Customers must submit a Program Administrator approved post-purchase application and meet all Program requirements.
4. Incentives will be available on a first come first served basis with an overall port and three-year program cap.
5. The Company and its agents reserve the right to inspect installations.
6. Applications may be subject to charger and per project caps.

Incentive Amounts

The Pilot will provide a one-time rebate for the purchase and installation of a qualified L2 EVSE:

Standard EVSE Installation Rebate	Up to $1,000 per port; capped at 6 charging ports and 75 percent of EVSE eligible costs paid
MUD Eligible EVSE Installation Rebate	Up to $4,500 per port; capped at 12 charging ports and 75 percent of EVSE eligible costs paid

Special Conditions

1. Small Nonresidential Customers would be required to enroll the time-varying rate option for (C)
   Schedule 23 for a minimum of one year. (C)
2. To be eligible for an incentive, Customers must submit a Program Administrator approved application(s), provide all required documentation, and receive pre-approval.
3. Equipment purchased or installed prior to receipt of the Company's pre-approval may not be eligible for incentives.
4. Incentives will be available on a first come first served basis with an overall port and three-year program cap.
5. Customers must consent to provide charger usage data.
6. The Company and its agents reserve the right to inspect installations.
7. Applications may be subject to charger and per project caps.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 190

WILDFIRE MITIGATION PLAN COST RECOVERY ADJUSTMENT

Purpose

The purpose of this schedule is to implement cost recovery related to the Company's wildfire mitigation plan automatic adjustment clause consistent with OAR 860-300-0080 and ORS 757.210 and Order No. 23-173.

Applicable

To all Residential and Nonresidential Consumers.

Monthly Billing

All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Schedule 4	0.678 ¢ per kWh	(I)
Schedule 5	0.678 ¢ per kWh	
Schedule 15	3.612 ¢ per kWh	
Schedule 23, 723	0.760 ¢ per kWh	
Schedule 28, 728	0.309 ¢ per kWh	
Schedule 30, 730	0.211 ¢ per kWh	
Schedule 41. 741	0.841 ¢ per kWh	
Schedule 47, 747	0.134 ¢ per kWh	
Schedule 48, 748, 848	0.134 ¢ per kWh	
Schedule 51, 751	3.481 ¢ per kWh	
Schedule 53, 752	0.433 ¢ per kWh	
Schedule 54, 754	0.553 ¢ per kWh	(I)

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Matthew McVee, Vice President, Regulation
Effective for service on and after January 1, 2025
Advice No. 24-001/Docket No. UE 433

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 193

 (N)

Purpose

The purpose of this schedule is to collect revenues for the Catastrophic Fire Fund.

Applicable

To all Residential and Nonresidential Consumers.

Monthly Billing

All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Schedule 4	0.764 ¢ per kWh
Schedule 5	0.764 ¢ per kWh
Schedule 15	3.749 ¢ per kWh
Schedule 23, 723	0.856 ¢ per kWh
Schedule 28, 728	0.392 ¢ per kWh
Schedule 30, 730	0.278 ¢ per kWh
Schedule 41. 741	1.043 ¢ per kWh
Schedule 47, 747	0.178 ¢ per kWh
Schedule 48, 748, 848	0.178 ¢ per kWh
Schedule 51, 751	3.540 ¢ per kWh
Schedule 53, 752	0.460 ¢ per kWh
Schedule 54, 754	0.578 ¢ per kWh

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Residential Consumers and Nonresidential Consumers. This service may be taken only in conjunction with the applicable Delivery Service Schedule or Direct Access Delivery Service Schedule. Not applicable to energy usage under Delivery Service Schedule 76 which is billed at Economic Replacement Power rates under Schedule 276 or energy usage under Delivery Service Schedule 47 which is billed at Unscheduled Energy rates under Schedule 247.

Monthly Billing

The Monthly Billing shall be the Energy Charge and/or Demand Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.		**Delivery Voltage**			
		Secondary	**Primary**	**Transmission**	
4	All kWh, per kWh	2.613¢			(R)
5	All kWh, per kWh	2.613¢			(R)
					(D)
23, 723	First 3,000 kWh, per kWh	2.610¢	2.570¢		(R)
	All additional kWh, per kWh	1.938¢	1.908¢		(R)
					(M) to pg. 2

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Delivery Voltage Secondary	Primary	Transmission	
28, 728	All kWh, per kWh	2.445¢	2.371¢		(R)(M) from pg.1
29	All kWh, per kWh	2.445¢	2.445¢		(R)
30, 730	Demand Charge, per kW	$5.39	$5.24		(R)
	All kWh, per kWh	0.888¢	0.826¢		(R)
	Demand shall be as defined in the Delivery Service Schedule				
41, 741	All kWh	2.346¢	2.310¢		(R)
47/48, 747/748	Demand Charge, per kW of On-Peak Demand	$1.45	$1.52	$1.54	(R)
	Per kWh, On-Peak	1.989¢	1.991¢	1.908¢	(R)
	Per kWh, Off-Peak	1.989¢	1.991¢	1.908¢	(R)

Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. All remaining hours are Off-Peak.
On-Peak Demand shall be as defined in the Delivery Service Schedule.

15	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate Per Lamp	
	Level 1	0-5,500	19	$0.54	(R)
	Level 2	5,501-12,000	34	$0.97	(R)
	Level 3	12-001+	57	$1.62	(R)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
51, 751	Level 1	0-3,500	8	$0.21	(R)
	Level 2	3,501-5,500	15	$0.41	
	Level 3	5,501-8,000	25	$0.67	
	Level 4	8,001-12,000	34	$0.91	
	Level 5	12,001-15,500	44	$1.18	
	Level 6	15,501+	57	$1.53	(R)

	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53, 753	High Pressure Sodium	5,800	70	31	$0.11	(R)
	High Pressure Sodium	9,500	100	44	$0.15	
	High Pressure Sodium	16,000	150	64	$0.22	
	High Pressure Sodium	22,000	200	85	$0.30	
	High Pressure Sodium	27,500	250	115	$0.40	
	High Pressure Sodium	50,000	400	176	$0.61	
	Metal Halide	9,000	100	39	$0.14	
	Metal Halide	12,000	175	68	$0.24	
	Metal Halide	19,500	250	94	$0.33	
	Metal Halide	32,000	400	149	$0.52	
	Metal Halide	107,800	1,000	354	$1.24	(R)
	Non-Listed Luminaire, per kWh				0.349¢	(R)

54, 754	Per kWh	0.439¢	(R)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 201

NET POWER COSTS
COST-BASED SUPPLY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage** Secondary	Primary	Transmission	
4	All kWh, per kWh		4.227¢			
	Optional TOU Adders					(N)
	plus	per On-Peak kWh	14.270¢			
	plus	per Off-Peak kWh (credit)	-3.790¢			

Schedule 4 Consumers may choose to participate in the Time-of-Use rate option which provides time varying rate adders. On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours. (N)

			Secondary	Primary	Transmission	
5	All kWh, per kWh		4.227¢			
	Optional TOU Adders					(N)
	plus	per On-Peak kWh	14.270¢			
	plus	per Off-Peak kWh (credit)	-3.790¢			

Schedule 5 Consumers may choose to participate in the Time-of-Use rate option which provides time varying rate adders. On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours. (N)

			Secondary	Primary	Transmission	
23	First 3,000 kWh, per kWh		4.218¢	4.090¢		(D)
	All additional kWh, per kWh		3.127¢	3.033¢		
	Optional TOU Adders					(N)
	plus	per On-Peak kWh	12.578¢	12.578¢		
	plus	per Off-Peak kWh (credit)	-2.532¢	-2.532¢		

Schedule 23 Consumers may choose to participate in the Time-of-Use rate option which provides time varying rate adders. On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours. (N)

(M) to pg. 2

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Secondary	Delivery Voltage Primary	Transmission	
28	All kWh, per kWh	3.932¢	3.842¢		(M) from pg. 1
29	All kWh, per kWh	4.961¢	4.961¢		
	Plus per On-Peak kWh	13.014¢	13.014¢		(N)
	Plus per Off-Peak kWh (credit)	-2.532¢	-2.532¢		(I)

For Schedule 29, On-Peak hours are from 5 p.m. to 9 p.m., all days Off-Peak hours are all remaining hours. (C) (D)

		Secondary	Primary	Transmission	
30	All kWh, per kWh	3.856¢	3.843¢		
41	All kWh, per kWh	3.799¢	3.739¢		
	Optional TOU Adders				
	Plus per On-Peak kWh	12.030¢	12.030¢		(I)
	Plus per Off-Peak kWh (credit)	-2.696¢	-2.696¢		(I)

Schedule 41 Consumers may choose to participate in one of two Time-of-Use (TOU) rate options, Option A and Option B which provide time-varying rates in the Summer months of July, August and September. Consumers may choose to participate in Option A with On-Peak hours from 2 p.m. to 6 p.m. all days in Summer or Option B with On-Peak hours from 6 p.m. to 10 p.m. all days in Summer. Off-peak hours for each Option are all other Summer hours which are not On-Peak. All other months have no time-of-use periods or rate adders.

		Secondary	Primary	Transmission
47/48	Per kWh On-Peak	4.625¢	4.500¢	4.358¢
	Per kWh, Off-Peak	3.333¢	3.195¢	3.031¢

For Schedule 47 and Schedule 48, Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. Off-Peak hours are all remaining hours.

15	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp
	Level 1	0-5,000	19	$1.00
	Level 2	5,001-12,000	34	$1.78
	Level 3	12,001+	57	$2.99

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

Purpose
This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363.

Applicable
To all Residential Consumers and Nonresidential Consumers.

Energy Charge
The adjustment rate is listed below by Delivery Service Schedule and Direct Access Delivery Service Schedule.

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission
4	All kWh, per kWh	0.000¢		
5	All kwh, per kWh	0.000¢		
6	All kWh, per kWh	0.000¢		
23, 723	First 3,000 kWh, per kWh	0.000¢	0.000¢	
	All additional kWh, per kWh	0.000¢	0.000¢	
28, 728	All kWh, per kWh	0.000¢	0.000¢	

CANCELED

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission
29	All kWh, per kWh	0.000¢	0.000¢	
30, 730	All kWh, per kWh	0.000¢	0.000¢	
41, 741	All kWh, per kWh	0.000¢	0.000¢	
47/48	Per kWh On-Peak	0.000¢	0.000¢	0.000¢
747/748	Per kWh, Off-Peak	0.000¢	0.000¢	0.000¢

For Schedule 47 and Schedule 48, Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. Off-Peak hours are all remaining hours.

15	**Type of Lamp**	**LED Equivalent Lumens**	**Monthly kWh**	**Rate per Lamp**
	Level 1	0-5,000	19	$0.00
	Level 2	5,001-12,000	34	$0.00
	Level 3	12,001+	57	$0.00

CANCELED

(continued)

Energy Charge (continued)

Delivery Service Schedule No.

51, 751

Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp
Level 1	0-3,500	8	$0.00
Level 2	3,501-5,500	15	$0.00
Level 3	5,501-8,000	25	$0.00
Level 4	8,001-12,000	34	$0.00
Level 5	12,001-15,500	44	$0.00
Level 6	15,501+	57	$0.00

53, 753

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire
High Pressure Sodium	5,800	70	31	$0.00
High Pressure Sodium	9,500	100	44	$0.00
High Pressure Sodium	16,000	150	64	$0.00
High Pressure Sodium	22,000	200	85	$0.00
High Pressure Sodium	27,500	250	115	$0.00
High Pressure Sodium	50,000	400	176	$0.00
Metal Halide	9,000	100	39	$0.00
Metal Halide	12,000	175	68	$0.00
Metal Halide	19,500	250	94	$0.00
Metal Halide	32,000	400	149	$0.00
Metal Halide	107,800	1,000	354	$0.00

Non-Listed Luminaire, per kWh 0.000¢

54, 754 Per kWh 0.000¢

CANCELED

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 210

PORTFOLIO TIME-OF-USE SUPPLY SERVICE
CLOSED TO NEW SERVICE

 (N)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential and Small Nonresidential Consumers receiving Delivery Service under Schedules 4, 5, 23 or 41, in conjunction with Supply Service Schedule 201, who have elected to take this service. **This Schedule is closed to new service beginning January 1, 2025.** (N)

Monthly Billing

The Monthly Billing shall be the Energy Charge. The Monthly Billing is in addition to all other charges contained in Consumer's applicable Delivery Service schedule, Base Supply Service Schedule 200 and Supply Service Schedule 201.

Energy Charge

Delivery Service Schedule No.		Season: Winter	Season: Summer
4	On-Peak kWh, per kWh	3.316 ¢	6.124 ¢
	Off-Peak kWh, per kWh	(1.125)¢	(1.125)¢
5	On-Peak kWh, per kWh	3.316 ¢	6.124 ¢
	Off-Peak kWh, per kWh	(1.125)¢	(1.125)¢
23	On-Peak kWh, per kWh	4.365 ¢	9.350 ¢
	Off-Peak kWh, per kWh	(1.438)¢	(1.438)¢
41	On-Peak kWh, per kWh	3.737 ¢	8.004 ¢
	Off-Peak kWh, per kWh	(1.231)¢	(1.231)¢

Seasonal Definition

Winter months are defined as November 1 through March 31. Summer months are defined as April 1 through October 31.

Minimum Charge

The minimum monthly charge will be the Portfolio Service Charge.

On-Peak Period

Winter
Monday through Friday 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m.
Summer
Monday through Friday 4:00 p.m. to 8:00 p.m.

(continued)

Off-Peak Period

All non On-Peak Period plus the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Guarantee Payment

The Company shall guarantee against increase of consumer costs for the first 12 months of enrollment in the program. If the total annual energy costs incurred on this Schedule exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the last month of the one-year commitment. No Guarantee Payment shall be given if Consumer terminates service before the end of the initial one-year period.

Special Conditions

1. The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by written permission of the Company or as otherwise expressly provided in Company tariffs and where the Consumer meters and bills any of its tenants at the Company's regular tariff rate for the type of service which such tenant may actually receive.

2. The Company will recover any lost revenues and Guarantee Payment amounts incurred under the Portfolio Option through adjustment schedules.

3. Consumers on this tariff schedule shall have a term of not less than one year. Service will continue under this schedule until Consumer notifies the Company to discontinue service.

4. The Consumer must have a time-of-use meter installed to participate in this option. The Company anticipates that a delay may occur from the time a Consumer requests service under this option until the Company can provide the meter installation. In the interim, Consumers will receive service under the applicable Delivery Service schedule on Supply Service Schedule 201.

5. Billing under this schedule shall begin for the Consumer following installation of the time-of-use meter and the initial meter reading.

6. The Company will not accept enrollment for accounts that have:

    - Time-payment agreement in effect
    - Received two or more final disconnect notices
    - Been disconnected for non-payment within the last 12 months.

7. Service under this schedule will be labeled, "Time of Use".

8. Consumers taking service under this Schedule will be removed from time-of-use on June 1, 2025. The Consumer must notify the Company to enroll in a different time-of-use option. (N) (N)

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Available

In all territory served by the Company in the State of Oregon.

Applicable

To New Large Load for Nonresidential Consumers taking Delivery Service under Schedule 848 who have chosen to opt-out of the Company's Cost-Based Supply Service prior to the inception of electric service to the New Large Load. Consumer must officially notify the Company of its election for this program in accordance with Rule 22 of this tariff. New Large Load must be separately metered or have its usage measured based on a determination that has comparable accuracy and is mutually agreeable between the Company and the Consumer.

Total Eligible Load

A total of 89 aMW will be accepted under this program unless the Commission determines otherwise.

Administration Fee

Consumers taking service under this program will pay the following program Administration Fee:
$400 per month

Fixed Generation Transition Adjustment

A transition adjustment of 20 percent of fixed generation rates will be charged for the first five years of service to the Consumer under this program beginning when the Consumer's electric service is first energized. Fixed generation rates include Schedule 200, Base Supply Service rates along with any other rates which collect non-net power cost generation costs that are in effect during the five year transition period for each Consumer. The adjustment will be applied at 20 percent of the rates included in the Company's effective tariffs applicable to Delivery Service Schedule 48. At the end of the applicable five-year period, Consumers who have elected this option will no longer be subject to the fixed generation transition adjustment.

List of effective schedules with fixed generation rates which will incur a 20 percent Fixed Generation Transition Adjustment:
Schedule 200, Base Supply Service
Schedule 198, Deer Creek Mine Closure Deferred Amounts Adjustment
Schedule 203, Renewable Resource Deferral Adjustment
Schedule 204, Oregon Solar Incentive Program Deferral (D)
Schedule 207, Community Solar Start-Up Cost Recovery Adjustment

Existing Load Shortage Transition Adjustment

The Existing Load Shortage Transition Adjustment will be applied to the Existing Load Shortage of the Consumer and for the Existing Load Shortage for all of the Consumer's affiliated Consumers. An affiliated Consumer is a Consumer for which a controlling interest is held by another Consumer who is engaged in the same line of business as the holder of the controlling interest. Existing Load Shortage means the larger of zero or a Consumer's Average Historical Cost-of-Service Load plus Incremental Demand-Side Management less the average Cost-of-Service Eligible load during the previous 60 months. Average Historical Cost-of-Service Load means the average monthly Cost-of-Service Eligible Load during the 60 month period beginning five years prior to the date the Consumer gives binding notice of participation in this program.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 299

RATE MITIGATION ADJUSTMENT

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No. 36 shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt hour.

(C)

Schedule 4	0.000¢
Schedule 5	0.000¢
Schedule 15	3.900¢
Schedule 23, 723	(0.360¢)
Schedule 28, 728	0.324¢
Schedule 30, 730	0.324¢
Schedule 41, 741	(3.168¢)
Schedule 47, 747	0.000¢
Schedule 48, 748	0.000¢
Schedule 51, 751	5.150¢
Schedule 53, 753	1.260¢
Schedule 54, 754	1.840¢

(C)

Service Charges (continued)

Rule No.	Sheet No.	Description	Charge	
11B	R11B-5	**Tampering/Unauthorized Reconnection**	$75.00	
11D	R11D-7	**Non-Remote Service Connection Charge:**		
		Request for reconnect during regular business hours: Monday through Friday, except holidays 8:00 A.M. to 5:00 P.M.	No Charge	
		Request for reconnect during non-regular business hours: Monday through Friday, except holidays 5:00 P.M. to 6:00 P.M.	$75.00	
		Saturday, Sunday & Holidays 8:00 A.M. to 6:00 P.M.	$175.00	
		Remote Service Connection Charge:	No Charge	
11D	R11D-7	**Trouble Call Charge:**	Actual Costs May Be Charged	
11D	R11D-7	**Other Work at Consumer's Request:**	Actual Costs May Be Charged	
13	R13-1	**Capacity Reservation Charge:**	$4.91 per kW	(N)
13	R13-2	**Excess Demand Charge:**	$19.64 per kW	(N)
13	R13-2	**Facilities Charges:**		
		On Facilities at Less than 57,000 Volts		
		Installed at Consumer's expense	0.4% per month	
		Installed at Company's expense	1.2% per month	
		On Facilities at and above 57,000 Volts		
		Installed at Consumer's expense	0.2% per month	
		Installed at Company's expense	0.85% per month	
13	R13-11	**Temporary Service Charge:**		
		Service Drop and Meter only	$164.00	
13	R13-13	**Contract Administration Credit**	$250.00	
21	R21-3	**Pre-Enrollment Usage Information:**		
		Bill Register History per Meter	$2.00 per year	
		Validated Interval Data (15 – 60 minute) per Meter	$10.00 per month	
		Analyzed Interval Meter Data	Cost Based Price	
21	R21-3	**Pre-Enrollment Payment History:**	$2.00 per page	

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 723

GENERAL SERVICE – SMALL NONRESIDENTIAL
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers who have chosen to receive electricity from an ESS, and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Phase, per month	$22.10	$22.10	(I)
Three Phase, per month	$32.95	$32.95	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	$ 2.10	$ 2.10	(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$ 6.87	$ 6.78	(I)
Distribution Energy Charge, per kWh	5.080¢	5.001¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.064¢	0.063¢	(R)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 728

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW TO 200 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 50 kW, per month	$ 25.00	$ 35.00	(I)
Load Size 51-100 kW, per month	$ 47.00	$ 60.00	(I)
Load Size 101 - 300 kW, per month	$111.00	$138.00	(I)
Load Size > 300 kW, per month	$156.00	$197.00	(I)
Load Size Charge			
≤ 50 kW, per kW Load Size	$ 1.60	$ 1.95	(I)
51-100 kW, per kW Load Size	$ 1.25	$ 1.55	
101 – 300 kW, per kW Load Size	$ 0.75	$ 0.95	
> 300 kW, per kW Load Size	$ 0.50	$ 0.50	
Demand Charge, per kW	$ 5.31	$ 6.78	
Distribution Energy Charge, per kWh	0.536¢	0.103¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.067¢	0.060¢	(R)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 730

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW TO 999 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 200 kW, per month	$704.00	$642.00	(I)
Load Size 201 - 300 kW, per month	$204.00	$202.00	(I)
Load Size > 300 kW, per month	$541.00	$527.00	(I)
Load Size Charge			
≤ 200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 2.50	$ 2.20	(I)
> 300 kW, per kW Load Size	$ 1.20	$ 1.10	(I)
Demand Charge, per kW	$ 5.92	$ 5.59	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.065¢	0.065¢	(R)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW, but not less than 100 kW.

(continued)

AGRICULTURAL PUMPING SERVICE
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers who have chosen to receive electricity from an ESS and desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the Monthly Billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
Basic Charge (November billing only)	**Secondary**	**Primary**	
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$ 580.00	$ 570.00	(I)
Three Phase Load Size > 300 kW	$2,300.00	$2,270.00	(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$ 24.20	$ 23.90	(I)
Three Phase 51 - 300 kW, per kW Load Size	$ 16.60	$ 16.40	(I)
Three Phase > 300 kW, per kW Load Size	$ 10.20	$ 10.10	(I)
Single Phase, Minimum Charge	$ 105.00	$ 105.00	(I)
Three Phase, Minimum Charge	$ 170.00	$ 170.00	(I)
Distribution Energy Charge, per kWh	7.049¢	6.940¢	(I)
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.058¢	0.057¢	(R)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of Company's meter, or by appropriate test, for the 15-minute period of Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

If Motor Size Is:	**Monthly kW is:**
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 747

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charges, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4,000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charges				
Per kVar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N)(N)
Reserves Charges				
Spinning Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company-approved Self-Supply Agreement)				
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved load reduction plan or Self-Supply Agreement)				
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)	
System Usage Charge				
Schedule 200 Related, per kWh	0.066¢	0.061¢	0.059¢	

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. All remaining hours are Off-Peak.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage service, have a load size of 25,000 kW or greater, and received an Extension Allowance that was equal to the metering necessary to measure their usage. (N) (N) (N)

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer's peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer's plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

Facility Capacity shall be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Month, but shall not be less than the Consumer's Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer's Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer's Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer's Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer's demand rises above Baseline Demand.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 748

LARGE GENERAL SERVICE 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS, to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 747.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		**Delivery Voltage**		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N)(N)
System Usage Charge				
Schedule 200 Related, per kWh	0.066¢	0.061¢	0.059¢	(R)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. All remaining hours are Off-Peak.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage (N)
service, have a load size of 25,000 kW or greater, and received an Extension Allowance that (N)
was equal to the metering necessary to measure their usage. (N)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 751

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	
LED Equivalent Lumens	0-3,500	3,501-5,500	5,501-8,000	8,001-12,000	12,001-15,500	15,501+	
Monthly kWh	8	15	25	34	44	57	
Functional Lighting	$ 6.50	$ 6.88	$ 6.99	$ 7.10	$ 7.52	$ 9.17	(I)
Functional Lighting - Customer Funded Conversion	$ 3.50	$ 3.68	$ 3.78	$ 3.84	$ 4.08	$ 5.01	(I)
Decorative Series	N/A	$ 11.88	$ 11.97	N/A	N/A	N/A	(I)

Functional Lighting: Common less expensive luminaires that may be mounted either on wood, fiberglass or non-decorative metal poles. The Company will maintain a list of functional light fixtures that are available.

Customer-Funded Conversion: Street lights that have been converted to LED from another lighting type and whose conversion was funded by the Customer.

Decorative Series Lighting: More stylish luminaires mounted vertically on decorative metal poles. The Company will maintain a listing of standard decorative street light fixtures that are available under this Schedule.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this Schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, and distribution charges are collected through rates in this schedule.

(continued)

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Matthew McVee, Vice President, Regulation
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Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor							
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000	
Watts	70	100	150	200	250	400	
Monthly kWh	31	44	64	85	115	176	
Energy Only Service	$ 1.31	$ 1.86	$ 2.70	$ 3.58	$ 4.85	$ 7.42	(I)

Metal Halide						
Lumen Rating	9,000	12,000	19,500	32,000	107,800	
Watts	100	175	250	400	1,000	
Monthly kWh	39	68	94	149	354	
Energy Only Service	$ 1.64	$ 2.87	$ 3.96	$ 6.28	$ 14.93	(I)

For non-listed luminaires the cost will be calculated for 4167 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh	
Energy Only Service	4.217	(I)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At Consumer's option, service for recreational field lighting may be taken under Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.684¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.012¢	(R)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

Purpose

To provide Consumers served on Schedule 747 with the opportunity of purchasing Energy from an ESS to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement service except as explicitly agreed to between Company and Consumer.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers receiving Delivery Service under Schedule 747.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 747 plus the applicable adjustments as specified in Schedule 90:

		Delivery Voltage		
	Secondary	Primary	Transmission	
Daily ERS Demand Charge				
per kW of Daily ERS On-Peak Demand	$0.250	$0.310	$0.242	(I)

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

ERS and ENF

Economic Replacement Service (ERS) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Service Agreement (ERSA).

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS and are participating in the New Large Load Direct Access Program in Schedule 293 or to existing consumers who have completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296. Existing consumers who have completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296 must have electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the Distribution Charge plus the applicable adjustments as specified in Schedule 90.

<u>**Distribution Charge**</u>		<u>**Delivery Voltage**</u>		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N) (N)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. All remaining hours are Off-Peak.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage (N)
service, have a load size of 25,000 kW or greater, and received an Extension Allowance that (N)
was equal to the metering necessary to measure their usage. (N)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

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Matthew McVee, Vice President, Regulation
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Definitions (continued)

Customer: Any individual, partnership, corporation, firm, other organization or government agency who has applied for, been accepted and is currently receiving service from the Company at one location and at one point of delivery unless otherwise expressly provided in these rules, or in a rate schedule or contract. Any individual requesting service who has been a Customer within the last 20 days and voluntarily closed their account at the same or prior address. A Customer may not resell Electricity Services provided by the Company except as provided for in Company Tariffs.

Cost-Based Service: Has the meaning described in Rule 2, "Types of Service."

Cost-of-Service Eligible Load: as defined in OAR 860-038-0700, the load of a Consumer that is eligible for a cost-of-service rate.

Date of Presentation: The date upon which a bill is mailed, transmitted or delivered by the Company to the Consumer.

Delivery Service: Regulated distribution, transmission and related services provided using assets owned by the Company or its agent.

Delivery Voltage: Secondary Delivery Voltage is service delivery at less than the locally available distribution voltage, and is typically less than 11kV phase-phase. Primary Delivery Voltage is service delivery at the locally available distribution voltage, which is typically 11kV phase-phase or greater. Transmission Delivery Voltage is 46kV and greater. (C)(D)

Demand: The average rate in kilowatts at which electric energy is delivered during any period of time for specified length.

Detented: The condition of an electric meter which has a device installed to prevent reverse rotation or negative registration of the meter if electric current flows from Consumer's to Company's system.

Direct Access Consumer: A Consumer that purchases Electricity Services from an ESS.

Direct Access Service: Has the meaning described in Rule 2, "Types of Service."

Duplicate Service Facilities: Two services, including all associated distribution facilities, one duplicating part or all of the capacity of the other and providing a second possible path of supply of energy in the event of the failure of the first.

Electric Service: Electric power and energy at the point of delivery available for use by Consumer, irrespective of whether electric energy is actually utilized.

Electricity: Electric energy, measured in kilowatt-hours, or electric capacity measured in kilowatts, or both.

Electricity Services: Electricity distribution, transmission, generation or generation-related services.

Electricity Service Supplier or "ESS": A person or entity that offers to provide Electricity Services, certified by the Commission to provide such services, and meeting the requirements for service specified in Section IV of Rule 21. "Electricity Service Supplier" does not include the Company selling electricity to Consumers in its own service territory.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

I. Line Extensions - Conditions and Definitions

A. Capacity Reservation Charge (N)
Beginning July 1, 2025, the Company may charge Consumers a Capacity Reservation Charge for Excess Reserved Capacity. The Capacity Reservation Charge is specified in Schedule 300. (N)

B. Contracts (T)
Before building an Extension, the Company may require the Applicant to sign a contract. Where a tenant occupies the service location, the Company may require the property owner to sign the contract.

C. Contract Minimum Billing (T)
The Contract Minimum Billing is the greater of: (1) the Consumer's monthly bill; or, (2) 80% of the Consumer's monthly bill plus the Facilities Charges. Consumers on a seasonal rate receive an annual Contract Minimum Billing of the greater of: (1) the Consumer's annual bill; or, (2) 80% of the Consumer's annual bill plus the Annual Facilities Charge. The Annual Facilities Charge is twelve (12) times the Facilities Charges. Contract Minimum Billings begin on the date service is first made available by the Company, unless a later date is mutually agreed upon.

For Consumers electing Standard Offer or Direct Access Service, the charges for Supply Service, ESS charges and the Transition Adjustment are excluded from the Consumer's bill before calculating the Contract Minimum Bill. For these Consumers the Contract Minimum Billing is the greater of: (1) the Consumer's monthly bill; or, (2) 60% of the Consumer's monthly bill plus the Facilities Charges. Consumers on a seasonal rate receive an annual Contract Minimum Billing of the greater of: (1) the Consumer's annual bill; or, (2) 60% of the Consumer's annual bill plus the Annual Facilities Charge.

D. Direct Assigned Facilities (T)
Direct Assigned Facilities are those required facilities located between existing Company network facilities and the Consumer's point of delivery, and used for the sole use and benefit of the Consumer receiving service under the tariff and are owned and operated by the Company.

Extensions consisting of Direct Assigned Facilities are made at the Consumer's expense less their applicable Extension Allowance as provided in this Rule 13.

E. Engineering Costs (T)
The Company includes designing, engineering and estimating in its Extension Costs. The Company may require the Applicant to advance the Company's estimated Engineering Costs, but not less than $200. The Company will apply this advance payment to its Extension Costs. If, after applying the Extension Allowance, it is determined that the total advance required is less than the advance already received, the excess will be refunded to the Applicant.

If the Applicant or Consumer requests changes that require additional estimates, they must advance the Company's estimated Engineering Costs, but not less than $200 for each additional estimate. The Company will not refund or credit this payment.

(M) to pg. 2

(continued)

I. Line Extensions - Conditions and Definitions (continued)

F. Excess Demand Charge (N)

Beginning July 1, 2025, Consumers whose maximum recorded and billed demand exceeds their Reserved Capacity may be charged an Excess Demand Charge. The Excess Demand Charge is specified in Schedule 300.

G. Excess Reserved Capacity

Reserved Capacity, less the maximum recorded and billed Consumer demand in the most recent 12 months. Excess Reserved Capacity shall begin 12 months after the time Reserved Capacity commences.

The Company's tracking of Excess Reserved Capacity shall begin 36 months after the agreed upon capacity delivery date for Consumers who have executed a written Line Extension Contract prior to January 1, 2025. For Consumers who have executed a written Line Extension Contract prior to January 1, 2025, Excess Reserved Capacity shall be Reserved Capacity, less the maximum recorded and billed Consumer demand in the most recent 36 months. (N)

H. Extension or Line Extension (T)(M) from pg. 1

A branch from, a continuation of, or an increase in the capacity of an existing Company-owned transmission or distribution line. An extension may be single-phase, three-phase, or a conversion from a single-phase line to a three-phase line. An extension may also be the addition of, or increase in the capacity of other facilities. (M)

I. Extension Allowance (T)

The Extension Allowance is the portion of the Extension that the Company may provide, or allow, without cost to the Applicant. The portion will vary with the class of service that the Applicant requests and the Applicant's total load request, and shall not exceed the Extension Costs.

The Extension Allowance does not include additional costs resulting from: additional voltages; duplicate facilities; additional points of delivery; or any other Applicant requested facilities that add to, or substitute for, the Company's standard construction methods or preferred route. The Extension Allowance is not available to Consumers receiving electric service under special pricing contracts. Revenue used for calculating Extension Allowances will exclude charges and credits for Supply Service, ESS Charges and the Transition Adjustment.

J. Extension Costs (T)

Extension Costs are the Company's total costs for constructing an Extension using the Company's standard construction methods, including services, transformers and meters, labor, materials and overhead charges.

K. Extension Limits (T)

The provisions of this Rule apply to Line Extensions that require standard construction and will produce sufficient revenues to cover the ongoing costs associated with them. The Company will construct Line Extensions with special requirements or limited revenues under the terms of special contracts.

Examples of special requirements include, but are not limited to, unusual costs incurred for overtime wages, use of special equipment and facilities, accelerated work schedules to meet the Applicant's request, or non-standard construction requirements.

(M) to pg. 3

(continued)

I. Line Extensions - Conditions and Definitions (continued)

K. Extension Limits (continued)

Examples of limited revenues include, but are not limited to, jobs where the line extension cost is high relative to the revenue, speculative loads and service to loads that will not have permanent ongoing revenue. (N) (N) (N)

L. Facilities Charges (T)(M) from pg. 2

Line Extension Facilities Charges are those costs associated with the ownership and maintenance of facilities built to provide service. When assessed these Facilities Charges are in addition to standard rate schedule charges and are specified in Schedule 300.

M. Network Upgrades (T)

Network Upgrades are modifications or additions to existing Company facilities required to serve load that is requested by an Applicant and are integrated with and support the Company's overall transmission and distribution network(s) for the general benefit of all users of such network(s). However requests to change the nature of an existing line, such as rebuilding from single-phase to three-phase, will be treated as Direct Assigned Facilities for cost allocation purposes. Other than on low-voltage secondary network systems (≤ 750 volts), distribution transformers and secondary cable are not network facilities and are treated as Direct Assigned Facilities for cost allocation purposes.

Network Upgrades of transmission facilities of 230 kV and above and utilized and defined as a transmission path, or facilities that are on the Western Electric Coordinating Council (WECC) critical path list, and associated substations, will be made at Company expense. (M)

Network Upgrades on systems not exempted above are made as follows:

1. Distribution Networks greater than 750 volts

   a. Upgrades for Consumers with total loads of 1000 kVA or less will be made at Company expense.

   b. Upgrades for Consumers with total loads in excess of 1000 kVA will share in the Network Upgrade cost. The Consumer's share of the required Network Upgrade cost is proportional to the amount of the new requested load divided by the sum of the total capacity of the required Network Upgrade less the existing load on the existing network facility.

2. Upgrades for Consumers on low-voltage network systems (≤ 750 volts) will share in the Network Upgrade costs. The Consumer's share will be proportional to the new requested load in kVA divided by the total kVA capacity of the required Network Upgrade. Total kVA capacity is defined by the single Network element (transformer, primary cable, or secondary cable) with the largest kVA increase in capacity.

If the Extension Allowance of a Consumer who shares in the cost of a Network Upgrade does not cover their proportionate share of the Network Upgrade cost, they shall pay a nonrefundable advance of the difference.

(M) to pg. 4

(continued)

I. Line Extensions - Conditions and Definitions (continued)

N. Refunds (T)(M) from (N) pg. (N) 3

An Applicant who pays a refundable advance on an Extension is eligible for up to three refunds during the first five years. Customers requiring 25,000 kw or greater are eligible for up to three refunds during the first ten years. Within that five-year or ten-year period the Applicant may waive any refund that is less than 25% of the Applicant's total refundable advance in order to accept three (3) refunds offering greater value. An Applicant is not eligible for refunds from future Extension applications from themselves.

For non-waived refunds the additional Applicants must pay the Company, prior to connection, as provided in the section for the original Applicant. The Company will refund such payments to the Applicant(s) who paid the refundable advance. The Company will not collect from additional Applicants any portion of a waived refund.

An Applicant to who a refund is due, but who the Company has failed to identify or has been unable to locate, has 36 months from the connection of the additional Applicant to request their refund. (M)

O. Reserved Capacity (N)

Capacity reserved for a Consumer as specified in written agreements. (N)

P. Restrictions (T)(M) from pg.3

An Extension of the Company's facilities is subject to these rules and other rules and restrictions. These may include, but are not limited to: laws of the United States; State law; executive and administrative proclamations; Commission orders or regulations; or, any lawful requirement of a governmental body. (M)

Q. Routes, Easements and Rights-of-Way (T)

The Company will select the route of an Extension in cooperation with the Applicant. The Applicant will acquire and pay all costs, including renewal costs, of obtaining complete unencumbered rights-of-way, easements, or licenses to use land, and will pay all costs for any preparation or clearing of land the Company may require. All rights-of-way, easements or licenses shall be on Company-provided standard forms, subject to revisions acceptable to the Company, and shall not include indemnification of the Applicant. If requested by the Applicant, the Company will assist in obtaining rights-of-way, easements or licenses as described above at the Applicant's expense.

(T)

R. Rules Previously in Effect

Rule changes do not modify existing Extension contracts. If a Consumer advanced funds for an Extension under a rule or a contract previously in effect, the Company will make refunds for additional Consumers as specified in the previous rule or contract.

(T)

S. Service Conductors

The secondary-voltage conductors owned and maintained by the Company extending from the Company's facility to the Point of Delivery.

(M) to pg. 5

(continued)

II. Residential Extensions

A. Extension Allowances (M) from Pg. 4

The Extension Allowance for permanent residential applications is $1100 per residence. The Extension Allowance for permanent residential applications in a planned development with secondary to the lot line is $500, otherwise it is $1100. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction.

B. Additional Applicants, Advances and Refunds

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Applicants connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Applicants as given in section I.K. Refunds. Each of the next three (3) Applicants for which refunds are not waived, utilizing any portion of the initial Extension must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the initial Consumer.

C. Remote and Seasonal Service

1. Contracts

The Company will make Extensions for Remote and Seasonal Residential Service according to a written contract. The contract will require the Applicant to advance the estimated cost of facilities in excess of the Extension Allowance. The Applicant shall also pay a Contract Minimum Billing for as long as service is taken, but in no case less than five (5) years. Primary residences are not Remote when the density of such residences exceeds one residence per one-half mile of line. Facilities Charges will cease when Consumers are no longer Remote. (M)

The Contract Minimum Billing will not include Facilities Charges on the first one-half mile of line from the Company's existing distribution facilities. Where there are groups of remote facilities only the first one-half mile is exempt from Facilities Charges.

After the initial five year contract period, Remote Service Contract Minimum Billings may be canceled by termination of electric service to the Consumer's premises and Consumer payment of the removal costs of those inactive facilities originally installed to serve the Consumer.

2. Additional Applicants

During the first five years after the Company completes the Extension, each of the next three Applicants must pay an allocated share of the original Consumer's contribution. The Company will determine these shares taking into account: (a) how much of the original line the new Applicant shares; (b) the load sizes of the Applicant and the existing Consumers; and (c) the advances of the existing Consumers. The Applicant must pay this allocated share before the Company will provide service. The Company will refund this share to the existing Consumers.

(M) to pg. 6

(continued)

II. Residential Extensions (continued)

C. Remote and Seasonal Service (continued)

2. Additional Applicants (continued)

Additional Applicants also must also share the Facilities Charges of the existing Consumers. The Facilities Charges of the refund are allocated to the Applicant paying the refund. (M) from pg. 5

The Applicant also must pay the estimated cost of any facilities exceeding the Extension Allowance.

D. Three Phase Residential Service

Where three-phase residential service is requested, the Applicant shall pay the difference in cost between single phase and three-phase service.

E. Transformation Facilities

When an existing residential Consumer adds load, or a new residential Consumer builds in a subdivision where secondary is available at the lot line, either by the means of a transformer or a secondary junction box, and the cumulative loads exceed the existing transformer's, service conductor's or other equipment's rated design capacity:

1) The facility upgrade will be treated as a standard line extension if the Consumer's demand exceeds 25 kVA, or if the facilities serve only that Consumer.

2) The facility upgrade shall be treated as a system improvement and not be charged to the Consumer if the Consumer's demand does not exceed 25 kVA and the facilities are shared by two or more consumers.

Upgrades and modifications to correct service quality issues such as flicker are done at the expense of the Consumer causing the service quality issue. (M)

F. Underground Extensions

The Company will construct Extensions underground when requested by the Applicant or if required by local ordinance or conditions. The Applicant shall provide all trenching and back filling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension. If the Applicant requests, the Company will provide these items at the Applicant's expense. The Applicant must also pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule.

III. Nonresidential Extensions

A. Extension Allowance – Delivery at Transmission Voltage

The Company will grant Consumers taking service at 46,000 volts or above an Extension Allowance of the metering necessary to measure the Consumer's usage. (C)
Other than the allowance, Consumers taking delivery at transmission voltage are subject to the same line extension provisions as a Consumer requiring more than 1000 kW who takes service at less than 46,000 volts. (C)

B. Extension Allowance – Delivery at Secondary or Primary Voltage

1. 1,000 kW or less

The Company will grant Nonresidential Applicants requiring 1,000 kW or less an Extension Allowance equal to the estimated annual revenue the Applicant is expected to pay the Company in a year of normal operations under cost-based service. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction.

(M) to pg. 7

(continued)

III. Nonresidential Extensions (continued)

B. Extension Allowance – Delivery at Secondary or Primary Voltage (continued)

1. 1,000 kW or less (continued) (M) from pg. 6

The Company may require the Consumer to pay a Contract Minimum Billing for five years. If the Consumer is Remote they shall pay a Contract Minimum Bill for as long as service is taken, or until they no longer meet the criteria for Remote Service.

2. Over 1,000 kW and Less than 25,000 kW

The Company will grant Nonresidential Applicants requiring more than 1,000 kW but less than 25,000 kW an Extension Allowance equal to the estimated annual revenue which the Applicant is expected to pay the Company in a year of normal operations under cost-based service. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction. (N)(D)

The Applicant must pay a Contract Minimum Billing for as long as service is taken.

If service is terminated within the first ten (10) years, the Applicant must pay a termination charge equal to the Extension Allowance less 1/10th of the allowance for each year service was taken.

3. 25,000 kW and Greater

The Company will grant Nonresidential Applicants requiring 25,000 kW or more an Extension Allowance of the metering necessary to measure the Applicant's usage. Applicants who have been provided a written Line Extension Allowance estimate dated prior to September 26, 2023, shall be granted an Extension Allowance equal to the estimated annual revenue which the Applicant is expected to pay the Company in a year of normal operations under cost-based service, provided there are no material changes or updates to the Applicant's service request, and the Applicant enters into a written Line Extension agreement with the Company no later than six months following the date of the written estimate. (M)

Apart from the Extension Allowance, the Customer is subject to the same Extension provisions as a Customer with a load less than 25,000 kW.

4. Nonresidential Transportation Electrification Charging

The Company will grant Nonresidential Applicants, for which 80% or greater of the estimated annual load of Applicant's facilities' will be dedicated to serving transportation charging infrastructure, two times the estimated annual revenue which the Applicant is expected to pay the Company in a year of normal operations under cost-based service. The Applicant must advance the costs exceeding the Extension Allowance.

The Applicant must pay a Contract Minimum Billing for as long as service is taken.

If service is terminated within the first ten (10) years, the Applicant must pay a termination charge equal to the Extension Allowance less 1/10th of the allowance for each year service was taken.

(M) to pg. 8

(continued)

III. Nonresidential Extensions (continued)

B. Extension Allowance – Delivery at Secondary or Primary Voltage (continued) (M) from pg. 7

5. Additional Capacity

The Extension Allowance for Consumers, where it is necessary for the Company to increase the capacity of their facilities to serve the Consumer's additional load, is calculated on the increase in revenue estimated to occur as a result of the additional load. The Extension Allowance for Additional Capacity is subject to the same provisions of new line extensions, according to Customer service voltage, total load size, and permanency.

C. Additional Applicants, Advances and Refunds – All Voltages

1. Initial Consumer - 1,000 kW or less

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Applicants connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Applicants. Each of the next three Applicants, for which refunds are not waived, utilizing any portion of the initial Extension must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the initial Consumer.

2. Initial Consumer – Over 1,000 kW and less than 25,000 kW

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Applicants connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Applicants. Each of the next three Applicants, for which refunds are not waived, utilizing any portion of the initial Extension must pay the Company, prior to connection, a proportionate share of the cost of the shared facilities. The Company will refund such payments to the initial Consumer. (M)

Proportionate Share = (A + B) x C

Where:
A = [Shared footage of line] x [Average cost per foot of the line]
B = Cost of the other shared distribution equipment, if applicable
C = [New additional connected load]/[Total connected load]

3. Initial Consumer - 25,000 kW or greater (N)

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Applicants connect to the Extension. The Consumer is eligible for refunds during the first ten (10) years following construction of an Extension for up to three (3) additional Applicants. Apart from the time following construction that Consumers requiring 25,000 kW or greater are eligible for refunds, Consumers requiring 25,000 kW or more are subject to the provisions of Section III.C.2. (N)

4. Adjustment of Contract Minimum Billing (T)

The Facilities Charges of Consumers that receive a refund are reduced by the Facilities Charge amount associated with the refund and are allocated to the Applicant paying the refund.

(M) to pgs. 9&10

(continued)

III. Nonresidential Extensions (continued)

C. Additional Applicants, Advances and Refunds – All Voltages (continued) (M) from pg. 8

4. Adjustment of Contract Minimum Billing (continued)

Consumers that are no longer eligible for refunds, with ongoing Facilities Charges on Direct Assigned facilities, which subsequently are used to serve other consumers, may have their Facilities Charges adjusted based on their proportionate share of the extension costs. The Consumer's proportionate share is determined using the greater of their total contracted demand or two year historical peak demand for the "New additional connected load" in the proportional share formula above. (C)

If the Company releases reserved capacity under Section III.D. Consumers may have the basis of their Facilities Charges reduced by the value of the released capacity.

D. Contract Capacity or Demand (N)

Unless the Consumer has paid a Capacity Reservation Charge as outlined in Section I.A of this Rule, the Company is not obligated to reserve capacity in Company substations, or on Company lines, or maintain service facility capacity in place to serve a Consumer in excess of the maximum recorded and billed Consumer demand in the most recent 12 months, unless contract provisions providing for greater demand are less than 12 months old. For Consumers with an executed Line Extension Agreement prior to January 1, 2025, the Company is not obligated to reserve capacity in Company substations, or on Company lines, or maintain service facility capacity in place to serve a Consumer in excess of the maximum recorded and billed Consumer demand in the most recent 36 months, unless contract provisions providing for greater demand are less than 36 months old or unless the Consumer has paid a Capacity Reservation Charge. (N) (C) (C)(N) (N)

If there are contract provisions providing for additional incremental capacity in the future, the cost of which was included in the Consumer's allowance or advance, the incremental capacity will be reserved or made available by the date given in the contract and kept available for a period of 12 months, after which the Company is no longer obligated to keep available the unused portion of that incremental capacity. The incremental capacity will be reserved or made available by the date given in the contract and kept available for a period of 36 months for Consumers with an executed Line Extension Agreement prior to January 1, 2025. (C) (N) (M)

Prior to reducing Reserved Capacity for Consumers requiring greater than 1,000 kW but less than 25,000 kW, the Company shall present Consumers with the alternative of reducing the Reserved Capacity or paying a Capacity Reservation Charge for Excess Reserved Capacity.

If a Consumer's total Reserved Capacity is 25,000 kW or greater, the Consumer shall be subject to a Capacity Reservation Charge and an Excess Demand Charge. Consumer load served under Schedule 848 shall not be subject to the Capacity Reservation or Excess Demand Charge.

Consumers requiring more than 25,000 kW may request to reduce their Reserved Capacity. The Company may reduce a Consumer's Reserved Capacity by up to 10% of the Consumer's total load per year or 50 MW per year, whichever is smaller, or by a larger amount if mutually agreed upon by the Consumer and the Company. (N)

(continued)

(M) to pg. 10

III. Nonresidential Extensions (continued)

D. Contract Capacity or Demand (continued)

The Company may deny load requests depending on available system capacity. The Company is under no obligation to consider load requests more than five years in the future. Consumer requests to increase Reserved Capacity after energization may be considered at the discretion of the Company. (N)

E. Underground Extensions (M) from pg. 8&9

The Company will construct line Extensions underground when requested by the Applicant or if required by local ordinance or conditions. The Applicant must pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule. The Applicant must provide all trenching and backfilling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension. If the Applicant requests, the Company will provide these items at the Applicant's expense. When the Extension is to property which is not part of an improved development, the Company may require the Applicant to pay for facilities on Applicant's property to provide for additional service reliability or for future development.

F. Street Lighting

The Extension Allowance to streetlights taking service under Rate Schedules 51/751 or 53/753 or 54/754 is equal to five times the annual revenue from the lights to be added. The Applicant must provide a non-refundable advance for costs exceeding the Extension Allowance prior to the lights being added. Facilities charges and Contract Minimum Billings do not apply to streetlights. (M)

IV. Extensions to Planned Developments (M) from pg.9

A. General

Planned developments, including subdivisions and mobile home parks, are areas where groups of buildings or dwellings may be constructed at or about the same time. The Company will install facilities in developments before there are actual Applicants for service under the terms of a written contract.

When an existing development is re-platted or changes configuration or use, the revised portion of the development shall be designed to meet current standards. For impacted lots that have had been built upon and have Consumers who have been receiving service in excess of five years, the Applicant will be responsible for the costs of removal, and thereafter their request will be treated as a new construction request. Otherwise the request will be treated as a relocation.

B. Allowances and Advances

For nonresidential developments the Developer must pay a non-refundable advance equal to the Company's estimated installed costs to make primary service available to each lot. An Applicant, who contracts for service before or in conjunction with the Developer, may contract to use the excess of their allowance, if any, to help fund the primary voltage facilities necessary to serve them.

For residential developments the Company will provide the Developer an Extension Allowance of $600 for each lot to which secondary voltage service is made available. The Developer must pay an advance for all other costs.

For multi-unit residential buildings, the Company will provide a total Extension Allowance of $1100 for each residence.

For both nonresidential and residential developments the Company may require the Developer to pay for facilities to provide additional service reliability or future development. (M)

(M) to pgs. 11&12

(continued)

IV. Extensions to Planned Developments (continued)

C. Refunds (M) from pg. 9

The Company will make no refunds due to Applicants connecting within a development. Except for Network Upgrades, a Developer may receive refunds when Applicants outside the development connect to the Extension to the development, or to a feeder extending alongside or through the development, for which the Developer has paid an advance. The Developer is eligible for these refunds during the first five (5) years following construction of the Extension for up to three (3) additional Applicants. Each of the next three (3) Applicants, for which refunds are not waived, connecting to any portion of the refundable Extension, must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the Developer.

D. Underground Extensions

The Company will construct line Extensions underground when requested by the Developer or required by local ordinances or conditions. The Developer must pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule. The Developer must provide all trenching and backfilling, imported backfill material, conduits, and equipment foundations that the Company requires for the development. If the Developer requests, the Company will provide these items at the Developer's expense. (M) from pg.10 (M)

V. Extension Exceptions (M) from pg. 10

A. Applicant Built Line Extensions

1. General

An Applicant may contract with someone other than the Company to build a Line Extension. The following circumstances, however, are not an option for Applicant Built Line Extensions: relocations, conversions from overhead to underground, going from single-phase to three-phase, or increasing the capacity of facilities. The Applicant must contract with the Company before starting construction of an Applicant Built Line Extension. When the Applicant has completed construction of the Line Extension and the Company approves it, the Company will connect it to the Company's facilities and assume ownership.

2. Liability and Insurance

The Applicant assumes all risks for the construction of an Applicant Built Line Extension. Before starting construction, the Applicant must furnish a certificate naming the Company as an additional insured for a minimum of $1,000,000. The Applicant may cancel the policy after the Company accepts ownership of the Line Extension.

3. Advance for Design, Specifications, Material Standards and Inspections

The Applicant must advance the Company's estimated costs for design, specifications, material standards and inspections. When the Applicant has completed construction, the Company will determine its actual costs and may adjust that portion of the Applicant's advance. If the actual costs exceed the Applicant's advance, the Applicant must pay the difference before the Company will accept and energize the Line Extension. If the actual costs are less than the Applicant's advance, the Company will refund the difference.

The Company will estimate the frequency of inspections and convey this to the Applicant prior to the signing of the contract. For underground Line Extensions, the Company may require that an inspector be present whenever installation work is done. (M)

(continued) (M) to pgs.12& 13

V. **Extension Exceptions** (continued) (M) from pg. 10

A. **Applicant Built Line Extensions** (continued)

4. **Construction Standards**
The Applicant must construct the Line Extension in accordance with the Company's design, specifications, and material standards and along the Company's selected route. Otherwise, the Company will not accept or energize the Line Extension.

5. **Transfer of Ownership**
Upon approval of the construction, the Company will assume ownership of the Line Extension. The Applicant must provide the Company unencumbered title to the Line Extension.

6. **Rights-of-Way**
The Applicant must provide to the Company all required rights-of-way, easements and permits in accordance with paragraph 1. I. of this Rule.

7. **Contract Minimum Billing**
The Company may require the Applicant to pay a Contract Minimum Billing as defined in paragraph 1. B. of this Rule. (M)

8. **Deficiencies in Construction** (M) from pg. 11
If, within 24 months of the time the Company energized the Line Extension, it determines that the Applicant provided deficient material or workmanship, the Applicant must pay the cost to correct the deficiency.

9. **Line Extension Value**
The Company will calculate the value of a Line Extension using its standard estimating methods. The Company will use the Line Extension Value to calculate Contract Minimum Billings, reimbursements, and refunds.

10. **Line Extension Allowance**
After assuming ownership, the Company will calculate the appropriate Extension Allowance. The Company will then reimburse the Applicant for the construction costs covered by the Extension Allowance, less the cost of any Company provided equipment or services, but in no case more than the Line Extension Value.

B. **Duplicate Service Facilities**
The Company will furnish Duplicate Service Facilities if the Consumer advances the estimated costs for facilities in excess of those which the Company would otherwise provide. The Consumer also must pay Facilities Charges for the Duplicate Facilities for as long as service is taken, but in no case less than five years.

C. **Emergency Service**
The Company will grant Applicants requesting Emergency Service an Extension Allowance equal to the estimated increase in annual revenue the Applicant will pay the Company. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction. The Applicant must also pay a Contract Minimum Billing for as long as service is taken, but in no case less than five years. (M)

(M) to pgs. 13 & 14

(continued)

D. Intermittent Service Facilities

The Company will serve Intermittent loads provided the Consumer advances the estimated cost of facilities above the cost of facilities which the Company would otherwise install. The Consumer also must pay a Contract Minimum Billing for as long as service is taken, but in no case less than five years. If load fluctuations become a detriment to other Consumers, the Company may modify the facilities and adjust the Contract Minimum Billing. (M) from Pg.11

E. Temporary Service

For Temporary Service requests requiring only a service loop connection and where there are 120/240 volt facilities of adequate capacity available, the Applicant shall pay the Temporary Service charge specified in Schedule 300.

For all other Temporary Service requests the Applicant shall pay:
a) the estimated installation cost, plus
b) the estimated removal cost, plus
c) the estimated cost for rearranging any existing facilities, less
d) the estimated salvage value of the facilities required to provide Temporary Service.

The Applicant is also responsible for electric service supplied under the appropriate rate schedule; any advances required for sharing previous Extensions; and, depending on the customer class, Contract Minimum Billings. (M)

If a temporary Consumer takes service continuously for 60 consecutive months from the date the Company first delivered service, the Company will classify them as permanent and refund any payment the Consumer made over that required of a permanent Consumer. The Company will not refund the Facilities Charges. (M) from pg. 12

In response to the 2020 wildfires, the Company may waive the costs of Temporary Service to facilitate service restoration at an affected property and to make Temporary Service available for displaced residential customers at a temporary location. Provided, however, the Applicant requests service no later than December 31, 2023. The Applicant remains responsible for electric service supplied under the appropriate rate schedule and any advances required for sharing previous Extensions.

VI. Relocation or Replacement of Facilities

A. Relocation of Facilities

If requested by an Applicant or Consumer, and adequate clearances can be maintained and adequate easements/rights-of-way can be obtained, the Company will: relocate distribution facilities; and/or, replace existing overhead distribution facilities with comparable underground (overhead to underground conversion, or conversion). If existing easements are insufficient for the new facilities, the Applicant is responsible for obtaining new easements. Substation facilities and transmission voltage facilities will be relocated at the discretion of the Company.

For conversions, the new underground system must not impair the use of the remaining overhead system. The Applicant or Consumer must elect either: to provide all trenching and back filling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension; or, to pay the Company to provide these items. (M)

(M) to pgs. 14&15

(continued)

VI. Relocation or Replacement of Facilities (continued) (M) from pg. 12

A. Relocation of Facilities (continued)

In addition, for both relocations and conversions, the Applicant must advance the following:

1. The estimated installed cost of the new facilities plus the estimated removal expense of the existing facilities, less

2. The estimated salvage value of the removed facilities.

This Advance is not refundable. The Company is not responsible for allocating costs and responsibilities among multiple Applicants.

B. Local Governments – Relocations

When Company facilities located in the franchise easement require relocating due to a public project, the relocation is done without charge to the local government Applicant.

C. Local Governments – Conversions

The conversion costs to a local government Applicant, as part of a public project which would necessitate the relocation of Company's facilities, consist of: the costs of all necessary excavating, road crossings, trenching, backfilling, raceways, ducts, vaults, transformer pads, and other devices peculiar to underground service. If the conversion is not part of a public project necessitating relocation of Company's facilities the overhead retirement costs are included in the conversion costs charged to the local government. The overhead retirement costs are: the original cost, less depreciation, less salvage value, plus removal costs of the existing overhead distribution facilities no longer used or useful by reason of the conversion. (M)

In addition the local government shall by ordinance or other means provide that all Consumers, served from the overhead facilities to be removed, perform wiring changes on their Premises so the service may be furnished from the underground distribution system in accordance with the Company's rules, and have authorized the Company to discontinue its overhead service upon completion of the underground conversion. (M) from pg. 13

The Company will not charge the local government if the total conversion costs incurred by the Company during one calendar year for conversions does not exceed five-one hundredths of one percent (0.05%) of the Company's annual revenues derived from Consumers residing within the boundaries of the local government. Otherwise the local government shall, in advance, either pay the conversion costs or direct the Company to expense the conversion costs. When expensed said conversion shall be conditioned by the following:

1. Company shall collect the conversion costs from the Consumers located within the boundaries of the local government; however, the local government may direct Company to collect conversion costs from only a portion of the Consumers located within the boundaries of the local government.

2. Conversion costs incurred by the Company shall be accumulated in a separate account in Company's books with interest accruing from the date Company incurs the cost. The rate of such interest shall be equal to the effective cost of the senior security issue which most recently preceded the incurrence of the cost. (M)

(M) to pg. 15

(continued)

VI. Relocation or Replacement of Facilities (continued) (M) from pg. 13

C. Local Governments – Conversions (continued)

3. Company shall collect the conversion costs and interest over a reasonable period of time subject to approval of The Public Utility Commission of Oregon. Said pay-back shall not exceed the depreciable life of the facilities. Collection shall begin as soon as practicable after the end of the year in which the conversion costs are incurred.

4. Conversion costs to be recovered from each Consumer shall be calculated by applying a uniform percentage to each Consumer's total monthly bill for service rendered within the boundaries of the local government. Said conversion costs will be shown as a separate item on individual Consumer bills.

VII. Contract Administration Credit

Applicants may waive their right to receive refunds on a Line Extension advance. Applicants who waive this right will receive a Contract Administration Credit up to the amount specified in Schedule 300. The Applicant's choice to receive the Contract Administration Credit must be made at the time the Extension advance is paid.

(M)

Docket No. UE 433
Exhibit PAC/1902
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Unbundled Results of Operations - Summary and Detail

February 2024

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2025 Forecast

Function		Revenue Requirement	
Production		$	964,517,931
Transmission		$	318,359,981
Distribution		$	463,303,098
Distribution-Lighting		$	3,688,207
Distribution Total		$	466,991,304
Ancillary		$	24,138,546
Customer Billing		$	16,740,247
Customer Metering		$	19,538,124
Customer Other		$	10,050,398
Retail Service	a	$	-
Public Purposes	b	$	-
Total State of Oregon		$	1,820,336,533

a - Retail Services are conducted as unregulated activities.
b - DSM is collected by a separate tariff.
Public Purposes are collected by a separate tariff.

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2025 Forecast

										Customer			Distribution Components		
		ROR	ROE	Total $	Production	Transmission	Distribution	Distribution-Lighting	Ancillary	Billing	Metering	Other	Poles & Wires	Poles & Wires-Lighting	Franchise Fees
1	Functionalized Situs Revenues @ Earned	5.83%	6.47%	1,680,937,338	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	368,770,878	2,853,436	45,708,476
2	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
3	Total Oregon General Business Revenue			1,680,937,338	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	368,770,878	2,853,436	45,708,476
4															
5	Target Increase in Return	7.74%	10.30%	101,502,284	20,591,618	43,684,772	34,280,745	337,273	-	574,807	1,816,230	216,838	34,280,745	337,273	-
6															
7	Add														
8	Uncollectible Expense			872,291	172,885	366,772	307,711	3,027	-	4,826	15,249	1,821	287,817	2,832	20,089
9	Franchise Tax			3,172,871			3,141,958	30,912							3,172,871
10	Other Revenue Based Taxes			759,539	150,538	319,364	267,936	2,636	-	4,202	13,278	1,585	250,614	2,466	17,493
11	Inc Taxes - State			6,110,590	1,239,646	2,629,889	2,063,752	20,304	-	34,604	109,340	13,054	2,063,752	20,304	-
12	Inc Taxes - Federal			26,981,620	5,473,721	11,612,408	9,112,603	89,655	-	152,797	482,795	57,641	9,112,603	89,655	-
13	Total Increase Needed			139,399,195	27,628,408	58,613,205	49,174,706	483,808	-	771,236	2,436,892	290,939	45,995,532	452,530	3,210,453
14															
15	Total Oregon General Business Revenue @	7.74%	10.30%	1,820,336,533	964,517,931	318,359,981	463,303,098	3,688,207	24,138,546	16,740,247	19,538,124	10,050,398	414,766,409	3,305,966	48,918,929
16	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
17	Total Unbundled Revenue Requirement			1,820,336,533	964,517,931	318,359,981	463,303,098	3,688,207	24,138,546	16,740,247	19,538,124	10,050,398	414,766,409	3,305,966	48,918,929
18															
19	Rate Base			5,300,883,073	1,075,382,287	2,281,405,531	1,790,287,004	17,613,846	-	30,018,856	94,851,316	11,324,232	1,790,287,004	17,613,846	-
					20.29%	43.04%	33.77%	0.33%	0.00%	0.57%	1.79%	0.21%	33.77%	0.33%	0.00%

Notes:

Row 9: Franchise Tax @	2.28%
Row 11: Inc Taxes - State	4.54%
Row 12: Inc Taxes - Federal	21.00%

Docket No. UE 433
Exhibit PAC/1903
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Functionalized Oregon Results of Operations Report

February 2024

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2025 Forecast

		Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Other
Operating Revenues										
	General Business Revenues	1,680,937,338	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459
	Special Sales	92,078,056	92,078,056	-	-	-	-	-	-	-
	Other Operating Revenues	71,932,639	31,746,318	51,621,152	5,575,952	2,916	(24,138,546)	6,262,511	367,691	494,645
	Total Operating Revenues	1,844,948,033	1,060,713,897	311,367,927	419,704,344	3,207,315	-	22,231,523	17,468,923	10,254,105
Operating Expenses										
	Steam Production	236,350,339	236,350,339	-	-	-	-	-	-	-
	Nuclear Production	-	-	-	-	-	-	-	-	-
	Hydro Production	13,610,836	13,610,836	-	-	-	-	-	-	-
	Other Power Supply	602,291,370	602,291,370	-	-	-	-	-	-	-
	ECD	-	-	-	-	-	-	-	-	-
	Transmission	64,748,998	248,277	64,500,721	-	-	-	-	-	-
	Distribution	114,708,178	-	-	111,916,347	941,500	-	-	1,850,332	-
	Customer Accounts	31,422,542	5,881,550	1,726,503	2,327,218	17,784	-	14,299,271	3,535,910	3,634,305
	Customer Service	5,308,096	-	-	2,480,719	-	-	-	-	2,827,377
	Sales	-	-	-	-	-	-	-	-	-
	Administrative & General	61,612,724	12,135,653	5,818,005	40,343,603	69,006	-	1,581,282	1,119,438	545,737
	Total O & M Expenses	1,130,053,083	870,518,025	72,045,230	157,067,885	1,028,290	-	15,880,553	6,505,679	7,007,420
	Depreciation	317,077,683	191,324,243	57,044,901	64,948,371	786,058	-	659,438	2,050,031	264,640
	Amortization Expense	30,904,843	8,098,820	1,955,540	14,195,898	41,772	-	3,071,679	1,647,359	1,893,774
	Taxes Other Than Income	100,572,803	23,204,851	15,179,081	60,788,950	163,121	-	329,022	726,809	180,970
	Income Taxes - Federal	(42,794,680)	(79,450,171)	13,441,594	21,616,624	446,871	-	50,079	1,266,174	(165,852)
	Income Taxes - State	5,307,130	3,051,222	895,673	1,207,311	9,226	-	63,951	50,251	29,497
	Income Taxes - Def Net	(4,937,211)	(18,584,960)	17,915,865	(4,483,316)	(294,090)	-	428,100	(302,791)	383,980
	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-
	Misc Revenue & Expense	(30,006)	(92,792)	(9,553)	72,340	-	-	-	-	-
	Total Operating Expenses	1,536,153,644	998,069,238	178,468,330	315,414,063	2,181,248	-	20,482,823	11,943,512	9,594,430
Operating Revenue for Return		308,794,389	62,644,660	132,899,597	104,290,280	1,026,066	-	1,748,700	5,525,410	659,675
Rate Base										
	Electric Plant in Service	10,425,808,241	4,108,230,762	3,060,325,174	2,986,873,710	32,954,998	-	58,820,231	145,292,638	33,310,728
	Plant Held for Future Use	-	(79,561)	264,553	(175,384)	-	-	(4,456)	(5,152)	-
	Misc Deferred Debits	101,941,905	85,321,466	4,711,048	9,211,018	69,744	-	1,586,185	464,089	578,354
	Elec Plant Acq Adj	703,248	703,248	-	-	-	-	-	-	-
	Nuclear Fuel	-	-	-	-	-	-	-	-	-
	Prepayments	16,838,184	7,370,468	1,826,768	5,913,341	44,788	-	1,015,019	297,642	370,158
	Fuel Stock	37,268,548	37,268,548	-	-	-	-	-	-	-
	Material & Supplies	129,822,071	95,215,135	1,936,867	31,763,560	-	-	-	906,510	-
	Working Capital	47,868,648	26,780,000	4,277,696	13,865,898	99,664	-	1,628,199	590,300	626,890
	Weatherization Loans	-	-	-	-	-	-	-	-	-
	Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-
	Total Electric Plant	10,760,250,845	4,360,810,065	3,073,342,106	3,047,452,144	33,169,195	-	63,045,178	147,546,028	34,886,130
Rate Base Deductions										
	Accum Prov For Depr	(4,043,129,802)	(2,063,552,941)	(670,080,406)	(1,249,778,572)	(15,913,180)	-	(3,620,682)	(38,676,835)	(1,507,185)
	Accum Prov For Amort	(232,858,605)	(77,447,946)	(53,654,275)	(37,908,980)	(57,315)	-	(28,192,106)	(15,047,019)	(20,550,964)
	Accum Def Income Taxes	(703,568,427)	(715,212,123)	(26,272,350)	38,191,845	492,213	-	(793,199)	1,375,676	(1,350,487)
	Unamortized ITC	(40,918)	(17,136)	(2,957)	(16,110)	(122)	-	(2,772)	(811)	(1,011)
	Customer Adv for Const	(46,658,522)	-	(41,481,126)	(4,912,218)	(55,062)	-	-	(210,115)	-
	Customer Service Deposits	-	-	-	-	-	-	-	-	-
	Misc. Rate Base Deductions	(433,111,498)	(429,197,632)	(445,461)	(2,741,104)	(21,881)	-	(417,563)	(135,607)	(152,252)
	Total Rate Base Deductions	(5,459,367,773)	(3,285,427,778)	(791,936,575)	(1,257,165,140)	(15,555,348)	-	(33,026,322)	(52,694,712)	(23,561,898)
Total Rate Base		5,300,883,073	1,075,382,287	2,281,405,531	1,790,287,004	17,613,846	-	30,018,856	94,851,316	11,324,232
Return on Rate Base		5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%
Return on Equity		6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%

2020 PROTOCOL
RESULTS OF OPERATIONS SUMMARY
12 Months Ended December 31, 2025 Forecast

		Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
Operating Revenues											
	General Business Revenues	1,680,937,338	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	-
	General Business Revenues	-	-	-	-	-	-	-	-	-	-
	Interdepartmental	-	-	-	-	-	-	-	-	-	-
	Special Sales	92,078,056	92,078,056	-	-	-	-	-	-	-	-
	Other Operating Revenues	71,932,639	31,746,318	51,621,152	5,575,952	2,916	(24,138,546)	6,262,511	367,691	494,645	-
	Total Operating Revenues	1,844,948,033	1,060,713,897	311,367,927	419,704,344	3,207,315	-	22,231,523	17,468,923	10,254,105	-
Operating Expenses											
	Steam Production	236,350,339	236,350,339	-	-	-	-	-	-	-	-
Operating Expenses	Nuclear Production	-	-	-	-	-	-	-	-	-	-
	Hydro Production	13,610,836	13,610,836	-	-	-	-	-	-	-	-
	Other Power Supply	602,291,370	602,291,370	-	-	-	-	-	-	-	-
	ECD	-	-	-	-	-	-	-	-	-	-
	Transmission	64,748,998	248,277	64,500,721	-	-	-	-	-	-	-
	Distribution	114,708,178	-	-	111,916,347	941,500	-	-	1,850,332	-	-
	Customer Accounts	31,422,542	5,881,550	1,726,503	2,327,218	17,784	-	14,299,271	3,535,910	3,634,305	-
	Customer Service	5,308,096	-	-	2,480,719	-	-	-	-	2,827,377	-
	Sales	-	-	-	-	-	-	-	-	-	-
	Administrative & General	61,612,724	12,135,653	5,818,005	40,343,603	69,006	-	1,581,282	1,119,438	545,737	-
	Total O & M Expenses	1,130,053,083	870,518,025	72,045,230	157,067,885	1,028,290	-	15,880,553	6,505,679	7,007,420	-
	Depreciation	317,077,683	191,324,243	57,044,901	64,948,371	786,058	-	659,438	2,050,031	264,640	-
	Amortization Expense	30,904,843	8,098,820	1,955,540	14,195,898	41,772	-	3,071,679	1,647,359	1,893,774	-
	Taxes Other Than Income	100,572,803	23,204,851	15,179,081	60,788,950	163,121	-	329,022	726,809	180,970	-
	Income Taxes - Federal	(42,794,680)	(79,450,171)	13,441,594	21,616,624	446,871	-	50,079	1,266,174	(165,852)	-
	Income Taxes - State	5,307,130	3,051,222	895,673	1,207,311	9,226	-	63,951	50,251	29,497	-
	Income Taxes - Def Net	(4,937,211)	(18,584,960)	17,915,865	(4,483,316)	(294,090)	-	428,100	(302,791)	383,980	-
	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-	-
	Misc Revenue & Expense	(30,006)	(92,792)	(9,553)	72,340	-	-	-	-	-	-
	Total Operating Expenses	1,536,153,644	998,069,238	178,468,330	315,414,063	2,181,248	-	20,482,823	11,943,512	9,594,430	-
Operating Revenue for Return		308,794,389	62,644,660	132,899,597	104,290,280	1,026,066	-	1,748,700	5,525,410	659,675	-
Rate Base											
	Electric Plant in Service	10,425,808,241	4,108,230,762	3,060,325,174	2,986,873,710	32,954,998	-	58,820,231	145,292,638	33,310,728	-
Rate Base	Plant Held for Future Use	-	(79,561)	264,553	(175,384)	-	-	(4,456)	(5,152)	-	-
	Misc Deferred Debits	101,941,905	85,321,466	4,711,048	9,211,018	69,744	-	1,586,185	464,089	578,354	-
	Elec Plant Acq Adj	703,248	703,248	-	-	-	-	-	-	-	-
	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
	Prepayments	16,838,184	7,370,468	1,826,768	5,913,341	44,788	-	1,015,019	297,642	370,158	-
	Fuel Stock	37,268,548	37,268,548	-	-	-	-	-	-	-	-
	Material & Supplies	129,822,071	95,215,135	1,936,867	31,763,560	-	-	-	906,510	-	-
	Working Capital	47,868,648	26,780,000	4,277,696	13,865,898	99,664	-	1,628,199	590,300	626,890	-
	Weatherization Loans	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-	-
	Total Electric Plant	10,760,250,845	4,360,810,065	3,073,342,106	3,047,452,144	33,169,195	-	63,045,178	147,546,028	34,886,130	-

Rate Base Deductions											
	Accum Prov For Depr	(4,043,129,802)	(2,063,552,941)	(670,080,406)	(1,249,778,572)	(15,913,180)	-	(3,620,682)	(38,676,835)	(1,507,185)	-
Rate Base Deduction	Accum Prov For Amort	(232,858,605)	(77,447,946)	(53,654,275)	(37,908,980)	(57,315)	-	(28,192,106)	(15,047,019)	(20,550,964)	-
	Accum Def Income Taxes	(703,568,427)	(715,212,123)	(26,272,350)	38,191,845	492,213	-	(793,199)	1,375,676	(1,350,487)	-
	Unamortized ITC	(40,918)	(17,136)	(2,957)	(16,110)	(122)	-	(2,772)	(811)	(1,011)	-
	Customer Adv for Const	(46,658,522)	-	(41,481,126)	(4,912,218)	(55,062)	-	-	(210,115)	-	-
	Customer Service Deposits	-	-	-	-	-	-	-	-	-	-
	Misc. Rate Base Deductions	(433,111,498)	(429,197,632)	(445,461)	(2,741,104)	(21,881)	-	(417,563)	(135,607)	(152,252)	-
	Total Rate Base Deductions	(5,459,367,773)	(3,285,427,778)	(791,936,575)	(1,257,165,140)	(15,555,348)	-	(33,026,322)	(52,694,712)	(23,561,898)	-
Total Rate Base		5,300,883,073	1,075,382,287	2,281,405,531	1,790,287,004	17,613,846	-	30,018,856	94,851,316	11,324,232	-
Return on Rate Base		5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	0.0000%
Return on Equity		6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	0.0000%

RESULTS OF OPERATIONS SUMMARY
2020 PROTOCOL

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
Sales to Ultimate Customers													
440	Residential Sales												
			S	804,392,320	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	-
	Less Klamath Surcharge Revenue												
		P	S	-	-	-	-	-	-	-	-	-	-
				804,392,320	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	-
442	Commercial & Industrial Sales												
			S	872,999,594									
		P	SE	-	-	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
				872,999,594	-	-	-	-	-	-	-	-	-
444	Public Street & Highway Lighting												
			S	3,545,424									
			SO	-									
				3,545,424	-	-	-	-	-	-	-	-	-
445	Other Sales to Public Authority												
			S	-									
				-	-	-	-	-	-	-	-	-	-
448	Interdepartmental												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Sales to Ultimate Customers				**1,680,937,338**	**936,889,523**	**259,746,775**	**414,128,392**	**3,204,398**	**24,138,546**	**15,969,012**	**17,101,232**	**9,759,459**	**-**
447	Sales for Resale-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
447NPC	Sales for Resale-NPC												
		P	SG	92,078,056	92,078,056	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				92,078,056	92,078,056	-	-	-	-	-	-	-	-
	Total Sales for Resale			92,078,056	92,078,056	-	-	-	-	-	-	-	-
449	Provision for Rate Refund												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				-	-	-	-	-	-	-	-	-	-
Total Sales from Electricity				**1,773,015,394**	**1,028,967,579**	**259,746,775**	**414,128,392**	**3,204,398**	**24,138,546**	**15,969,012**	**17,101,232**	**9,759,459**	**-**
450	Forfeited Discounts & Interest												
		C_BILLING	S	5,583,122	-	-	-	-	-	5,583,122	-	-	-
		C_BILLING	SO	-	-	-	-	-	-	-	-	-	-
				5,583,122	-	-	-	-	-	5,583,122	-	-	-
451	Misc Electric Revenue												
		CSS_SYS	S	1,520,715	-	-	-	-	-	674,184	354,833	491,698	-
		C_METER	S	-	-	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				1,520,715	-	-	-	-	-	674,184	354,833	491,698	-
453	Water Sales												
		P	SG	1,339	1,339	-	-	-	-	-	-	-	-
				1,339	1,339	-	-	-	-	-	-	-	-
454	Rent of Electric Property												
		D	S	5,282,389	-	-	5,282,389	-	-	-	-	-	-
		T	SG	993,883	-	993,883	-	-	-	-	-	-	-
		GP	SO	922,589	363,541	270,811	264,311	2,916	-	5,205	12,857	2,948	-
				7,198,861	363,541	1,264,694	5,546,700	2,916	-	5,205	12,857	2,948	-
	Oregon Ancillary Services				24,138,546				(24,138,546)				
456	Other Electric Revenue												
		OTHSGR	S	-	-	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
		OTHSE	SE	9,890,899	-	9,890,899	-	-	-	-	-	-	-
		OTHSO	SO	27,369	-	-	27,369	-	-	-	-	-	-
		OTHSGR	SG	47,710,335	7,242,892	40,465,560	1,883	-	-	-	-	-	-
				57,628,602	7,242,892	50,356,458	29,252	-	-	-	-	-	-
	Total Other Electric Revenues			**71,932,639**	**31,746,318**	**51,621,152**	**5,575,952**	**2,916**	**(24,138,546)**	**6,262,511**	**367,691**	**494,645**	**-**
Total Electric Operating Revenues				**1,844,948,033**	**1,060,713,897**	**311,367,927**	**419,704,344**	**3,207,315**	**-**	**22,231,523**	**17,468,923**	**10,254,105**	**-**
Miscellaneous Revenues													
41160	Gain on Sale of Utility Plant - CR												
		D	S	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		G	SO	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
41170	Loss on Sale of Utility Plant												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				-	-	-	-	-	-	-	-	-	-
4118	Gain from Emission Allowances												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	(24)	(24)	-	-	-	-	-	-	-	-
				(24)	(24)	-	-	-	-	-	-	-	-
41181	Gain from Disposition of NOX Credits												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
4194	Impact Housing Interest Income												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
421	(Gain) / Loss on Sale of Utility Plant												
		D	S	80,879	-	-	80,879	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		PTD	SO	(30,170)	(12,078)	(9,553)	(8,539)	-	-	-	-	-	-
		P	SG	(80,690)	(80,690)	-	-	-	-	-	-	-	-
				(29,982)	(92,768)	(9,553)	72,340	-	-	-	-	-	-
Total Miscellaneous Revenues				**(30,006)**	**(92,792)**	**(9,553)**	**72,340**	**-**	**-**	**-**	**-**	**-**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
Miscellaneous Expenses													
4311	Interest on Customer Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Miscellaneous Expenses				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net Misc Revenue and Expense				**(30,006)**	**(92,792)**	**(9,553)**	**72,340**	**-**	**-**	**-**	**-**	**-**	**-**
500	Operation Supervision & Engineering												
		P	SG	4,147,697	4,147,697	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(306)	(306)	-	-	-	-	-	-	-	-
				4,147,391	4,147,391	-	-	-	-	-	-	-	-
501	Fuel Related-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	9,949,333	9,949,333	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				9,949,333	9,949,333	-	-	-	-	-	-	-	-
501NPC	Fuel Related-NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	146,184,550	146,184,550	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				146,184,550	146,184,550	-	-	-	-	-	-	-	-
	Total Fuel Related			156,133,883	156,133,883	-	-	-	-	-	-	-	-
502	Steam Expenses												
		P	SG	22,112,287	22,112,287	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(645)	(645)	-	-	-	-	-	-	-	-
				22,111,642	22,111,642	-	-	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC												
		P	SE	198	198	-	-	-	-	-	-	-	-
				198	198	-	-	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC												
		P	SE	1,426,328	1,426,328	-	-	-	-	-	-	-	-
				1,426,328	1,426,328	-	-	-	-	-	-	-	-
505	Electric Expenses												
		P	SG	202,393	202,393	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				202,393	202,393	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
506	Misc. Steam Expense												
		P	SG	10,101,178	10,101,178	-	-	-	-	-	-	-	-
		P	SG	(1,849,156)	(1,849,156)	-	-	-	-	-	-	-	-
		P	SE	1,385,726	1,385,726	-	-	-	-	-	-	-	-
				9,637,748	9,637,748	-	-	-	-	-	-	-	-
507	Rents												
		P	SG	(60,681)	(60,681)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(60,681)	(60,681)	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
510	Maint Supervision & Engineering												
		P	SG	1,402,228	1,402,228	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	536,941	536,941	-	-	-	-	-	-	-	-
				1,939,169	1,939,169	-	-	-	-	-	-	-	-
511	Maintenance of Structures												
		P	SG	6,206,527	6,206,527	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(1,062)	(1,062)	-	-	-	-	-	-	-	-
				6,205,465	6,205,465	-	-	-	-	-	-	-	-
512	Maintenance of Boiler Plant												
		P	SG	23,610,223	23,610,223	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(2,977,960)	(2,977,960)	-	-	-	-	-	-	-	-
				20,632,263	20,632,263	-	-	-	-	-	-	-	-
513	Maintenance of Electric Plant												
		P	SG	10,067,927	10,067,927	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(22)	(22)	-	-	-	-	-	-	-	-
				10,067,905	10,067,905	-	-	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant												
		P	SG	3,908,424	3,908,424	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(1,788)	(1,788)	-	-	-	-	-	-	-	-
				3,906,636	3,906,636	-	-	-	-	-	-	-	-
Total Steam Power Generation				**236,350,339**	**236,350,339**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
517	Operation Super & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
518	Nuclear Fuel Expense												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
519	Coolants and Water												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
520	Steam Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
523	Electric Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				-	-	-	-	-	-	-	-	-	-
524	Misc. Nuclear Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
528	Maintenance Super & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
529	Maintenance of Structures												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
530	Maintenance of Reactor Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
531	Maintenance of Electric Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
532	Maintenance of Misc Nuclear												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Nuclear Power Generation				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
535	Operation Super & Engineering												
		P	SG	256,728	256,728	-	-	-	-	-	-	-	-
		P	SG	(1,485)	(1,485)	-	-	-	-	-	-	-	-
		P	SG	(573,977)	(573,977)	-	-	-	-	-	-	-	-
		P	SG	2,530,042	2,530,042	-	-	-	-	-	-	-	-
		P	SG	982,825	982,825	-	-	-	-	-	-	-	-
				3,194,133	3,194,133	-	-	-	-	-	-	-	-
536	Water For Power												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	(27)	(27)	-	-	-	-	-	-	-	-
		P	SG	127,795	127,795	-	-	-	-	-	-	-	-
				127,768	127,768	-	-	-	-	-	-	-	-
537	Hydraulic Expenses												
		P	SG	(44)	(44)	-	-	-	-	-	-	-	-
		P	SG	1,133,091	1,133,091	-	-	-	-	-	-	-	-
		P	SG	93,456	93,456	-	-	-	-	-	-	-	-
		P	SG	(38)	(38)	-	-	-	-	-	-	-	-
				1,226,465	1,226,465	-	-	-	-	-	-	-	-
538	Electric Expenses												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	4,142,258	4,142,258	-	-	-	-	-	-	-	-
		P	SG	2,228,857	2,228,857	-	-	-	-	-	-	-	-
		P	SG	(1,396)	(1,396)	-	-	-	-	-	-	-	-
		P	SG	(1,270)	(1,270)	-	-	-	-	-	-	-	-
				6,368,450	6,368,450	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
540	Rents (Hydro Generation)												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	481,295	481,295	-	-	-	-	-	-	-	-
		P	SG	(36,500)	(36,500)	-	-	-	-	-	-	-	-
				444,795	444,795	-	-	-	-	-	-	-	-
541	Maint Supervision & Engineering												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	418	418	-	-	-	-	-	-	-	-
				418	418	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
542	Maintenance of Structures												
		P	SG	(13)	(13)	-	-	-	-	-	-	-	-
		P	SG	201,005	201,005	-	-	-	-	-	-	-	-
		P	SG	6,022	6,022	-	-	-	-	-	-	-	-
				207,015	207,015	-	-	-	-	-	-	-	-
543	Maintenance of Dams & Waterways												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	257,020	257,020	-	-	-	-	-	-	-	-
		P	SG	140,094	140,094	-	-	-	-	-	-	-	-
				397,113	397,113	-	-	-	-	-	-	-	-
544	Maintenance of Electric Plant												
		P	SG	(55)	(55)	-	-	-	-	-	-	-	-
		P	SG	401,687	401,687	-	-	-	-	-	-	-	-
		P	SG	95,952	95,952	-	-	-	-	-	-	-	-
				497,584	497,584	-	-	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant												
		P	SG	(213)	(213)	-	-	-	-	-	-	-	-
		P	SG	(35)	(35)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	898,824	898,824	-	-	-	-	-	-	-	-
		P	SG	248,518	248,518	-	-	-	-	-	-	-	-
				1,147,094	1,147,094	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation				**13,610,836**	**13,610,836**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
546	Operation Super & Engineering												
		P	SG	141,641	141,641	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(15)	(15)	-	-	-	-	-	-	-	-
				141,627	141,627	-	-	-	-	-	-	-	-
547	Fuel-Non-NPC												
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
547NPC	Fuel-NPC												
		P	SE	159,493,589	159,493,589	-	-	-	-	-	-	-	-
		P	SE	165,441	165,441	-	-	-	-	-	-	-	-
				159,659,030	159,659,030	-	-	-	-	-	-	-	-
548	Generation Expense												
		P	SG	6,399,927	6,399,927	-	-	-	-	-	-	-	-
		P	SG	248,635	248,635	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SG	(272)	(272)	-	-	-	-	-	-	-	-
				6,648,290	6,648,290	-	-	-	-	-	-	-	-
549	Miscellaneous Other												
		P	S	34,441	34,441	-	-	-	-	-	-	-	-
		P	SG	1,168,969	1,168,969	-	-	-	-	-	-	-	-
		P	SG	1,848,652	1,848,652	-	-	-	-	-	-	-	-
		P	SG	1,191,673	1,191,673	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				4,243,736	4,243,736	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
550	Maint Supervision & Engineering												
		P	S	390,750	390,750	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,190	11,190	-	-	-	-	-	-	-	-
		P	SG	2,985,382	2,985,382	-	-	-	-	-	-	-	-
				3,387,322	3,387,322	-	-	-	-	-	-	-	-
551	Maint Supervision & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
552	Maintenance of Structures												
		P	SG	665,752	665,752	-	-	-	-	-	-	-	-
		P	SG	32,730	32,730	-	-	-	-	-	-	-	-
		P	SG	(188)	(188)	-	-	-	-	-	-	-	-
				698,295	698,295	-	-	-	-	-	-	-	-
553	Maint of Generation & Electric Plant												
		P	SG	926,612	926,612	-	-	-	-	-	-	-	-
		P	SG	5,014,625	5,014,625	-	-	-	-	-	-	-	-
		P	SG	81,188	81,188	-	-	-	-	-	-	-	-
		P	SG	473,473	473,473	-	-	-	-	-	-	-	-
				6,495,898	6,495,898	-	-	-	-	-	-	-	-
554	Maintenance of Misc. Other												
		P	SG	605,871	605,871	-	-	-	-	-	-	-	-
		P	SG	488,080	488,080	-	-	-	-	-	-	-	-
		P	SG	35,869	35,869	-	-	-	-	-	-	-	-
		P	SG	(3)	(3)	-	-	-	-	-	-	-	-
				1,129,817	1,129,817	-	-	-	-	-	-	-	-
Total Other Power Generation				**182,404,015**	**182,404,015**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
555	Purchased Power-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC												
		P	S	(1,482,488)	(1,482,488)	-	-	-	-	-	-	-	-
		P	SG	393,560,814	393,560,814	-	-	-	-	-	-	-	-
		P	SE	20,221,942	20,221,942	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-	-	-
				412,300,269	412,300,269	-	-	-	-	-	-	-	-
	Total Purchased Power			412,300,269	412,300,269	-	-	-	-	-	-	-	-
556	System Control & Load Dispatch												
		P	SG	705,028	705,028	-	-	-	-	-	-	-	-
				705,028	705,028	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
557	Other Expenses												
		P	S	8,126,293	8,126,293	-	-	-	-	-	-	-	-
		P	SG	9,754,073	9,754,073	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SE	1,693	1,693	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				17,882,058	17,882,058	-	-	-	-	-	-	-	-
2017 Protocol Adjustment													
Baseline ECD		P	S	(11,000,000)	(11,000,000)	-	-	-	-	-	-	-	-
Equalization Adj.		P	S	-	-	-	-	-	-	-	-	-	-
				(11,000,000)	(11,000,000)	-	-	-	-	-	-	-	-
Total Other Power Supply				**419,887,355**	**419,887,355**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PRODUCTION EXPENSE				**852,252,545**	**852,252,545**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Embedded Cost Differentials												
	Company Owne	P	DGP	-	-	-	-	-	-	-	-	-	-
	Company Owne	P	SG	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-
	Existing QF Con	P	S	-	-	-	-	-	-	-	-	-	-
	Existing QF Con	P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Hydro Endowment Fixed Dollar Proposal												
	Klamath Surcharge	P	S	-	-	-	-	-	-	-	-	-	-
	ECD Hydro	P	S	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-
	Klamath Dam Remo	P	S	-	-	-	-	-	-	-	-	-	-
	Less Klamath Surcharge Expense												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
560	Operation Supervision & Engineering												
		T	SG	3,094,494	-	3,094,494	-	-	-	-	-	-	-
		T	SG	(2,551)	-	(2,551)	-	-	-	-	-	-	-
				3,091,943	-	3,091,943	-	-	-	-	-	-	-
561	Load Dispatching												
		T	SG	5,235,993	-	5,235,993	-	-	-	-	-	-	-
		T	SG	(591)	-	(591)	-	-	-	-	-	-	-
				5,235,402	-	5,235,402	-	-	-	-	-	-	-
562	Station Expense												
		T	SG	1,305,687	-	1,305,687	-	-	-	-	-	-	-
		T	SG	(5)	-	(5)	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				1,305,682	-	1,305,682	-	-	-	-	-	-	-
563	Overhead Line Expense												
		T	SG	487,058	-	487,058	-	-	-	-	-	-	-
		T	SG	(207)	-	(207)	-	-	-	-	-	-	-
				486,851	-	486,851	-	-	-	-	-	-	-
564	Underground Line Expense												
		T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
565	Transmission of Electricity by Others-Non NPC												
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
565NPC	Transmission of Electricity by Others-NPC												
		T	SG	41,968,377	-	41,968,377	-	-	-	-	-	-	-
		T	SE	3,147,225	-	3,147,225	-	-	-	-	-	-	-
				45,115,602	-	45,115,602	-	-	-	-	-	-	-
	Total Transmission of Electricity by Others			45,115,602	-	45,115,602	-	-	-	-	-	-	-
566	Misc. Transmission Expense												
		T	SG	1,071,510	-	1,071,510	-	-	-	-	-	-	-
		T	SG	(61)	-	(61)	-	-	-	-	-	-	-
				1,071,449	-	1,071,449	-	-	-	-	-	-	-
567	Rents - Transmission												
		T	SG	639,200	-	639,200	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				639,200	-	639,200	-	-	-	-	-	-	-
568	Maint Supervision & Engineering												
		T	SG	370,210	-	370,210	-	-	-	-	-	-	-
		T	SG	(380)	-	(380)	-	-	-	-	-	-	-
				369,830	-	369,830	-	-	-	-	-	-	-
569	Maintenance of Structures												
		T	SG	1,696,140	-	1,696,140	-	-	-	-	-	-	-
		T	SG	(4)	-	(4)	-	-	-	-	-	-	-
				1,696,136	-	1,696,136	-	-	-	-	-	-	-
570	Maintenance of Station Equipment												
		STEP_UP	SG	3,852,358	248,293	3,604,065	-	-	-	-	-	-	-
		STEP_UP	SG	(248)	(16)	(232)	-	-	-	-	-	-	-
				3,852,111	248,277	3,603,833	-	-	-	-	-	-	-
571	Maintenance of Overhead Lines												
		T	SG	4,193,358	-	4,193,358	-	-	-	-	-	-	-
		T	SG	(2,378,532)	-	(2,378,532)	-	-	-	-	-	-	-
				1,814,826	-	1,814,826	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
572	Maintenance of Underground Lines												
		T	SG	44,430	-	44,430	-	-	-	-	-	-	-
		T	SG	(24)	-	(24)	-	-	-	-	-	-	-
				44,406	-	44,406	-	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant												
		T	SG	25,561	-	25,561	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				25,561	-	25,561	-	-	-	-	-	-	-
TOTAL TRANSMISSION EXPENSE				**64,748,998**	**248,277**	**64,500,721**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
580	Operation Supervision & Engineering												
		D_SPLIT	S	1,483,689	-	-	1,407,697	15,779	-	-	60,213	-	-
		D_SPLIT	SNPD	3,798,276	-	-	3,603,735	40,395	-	-	154,146	-	-
				5,281,965	-	-	5,011,431	56,175	-	-	214,359	-	-
581	Load Dispatching												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	4,292,434	-	-	4,292,434	-	-	-	-	-	-
				4,292,434	-	-	4,292,434	-	-	-	-	-	-
582	Station Expense												
		D	S	1,137,499	-	-	1,137,499	-	-	-	-	-	-
		D	SNPD	131	-	-	131	-	-	-	-	-	-
				1,137,630	-	-	1,137,630	-	-	-	-	-	-
583	Overhead Line Expenses												
		D	S	2,684,199	-	-	2,684,199	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				2,684,199	-	-	2,684,199	-	-	-	-	-	-
584	Underground Line Expense												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
585	Street Lighting & Signal Systems												
		DL	S	-	-	-	-	-	-	-	-	-	-
		DL	SNPD	75,142	-	-	-	75,142	-	-	-	-	-
				75,142	-	-	-	75,142	-	-	-	-	-
586	Meter Expenses												
		C_Meter	S	1,388,283	-	-	-	-	-	-	1,388,283	-	-
		C_Meter	SNPD	-	-	-	-	-	-	-	-	-	-
				1,388,283	-	-	-	-	-	-	1,388,283	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
587	Customer Installation Expenses												
		D	S	7,565,964	-	-	7,565,964	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				7,565,964	-	-	7,565,964	-	-	-	-	-	-
588	Misc. Distribution Expenses												
		D	S	(296,944)	-	-	(296,944)	-	-	-	-	-	-
		D	SNPD	182,615	-	-	182,615	-	-	-	-	-	-
				(114,329)	-	-	(114,329)	-	-	-	-	-	-
589	Rents												
		D	S	1,871,412	-	-	1,871,412	-	-	-	-	-	-
		D	SNPD	101,222	-	-	101,222	-	-	-	-	-	-
				1,972,634	-	-	1,972,634	-	-	-	-	-	-
590	Maint Supervision & Engineering												
		D_SPLIT	S	1,028,357	-	-	975,686	10,937	-	-	41,734	-	-
		D_SPLIT	SNPD	836,083	-	-	793,260	8,892	-	-	33,931	-	-
				1,864,440	-	-	1,768,946	19,829	-	-	75,665	-	-
591	Maintenance of Structures												
		D	S	658,957	-	-	658,957	-	-	-	-	-	-
		D	SNPD	20,036	-	-	20,036	-	-	-	-	-	-
				678,993	-	-	678,993	-	-	-	-	-	-
592	Maintenance of Station Equipment												
		D	S	4,224,901	-	-	4,224,901	-	-	-	-	-	-
		D	SNPD	290,770	-	-	290,770	-	-	-	-	-	-
				4,515,671	-	-	4,515,671	-	-	-	-	-	-
593	Maintenance of Overhead Lines												
		D	S	70,302,494	-	-	70,302,494	-	-	-	-	-	-
		D	SNPD	842,729	-	-	842,729	-	-	-	-	-	-
				71,145,222	-	-	71,145,222	-	-	-	-	-	-
594	Maintenance of Underground Lines												
		D	S	9,446,513	-	-	9,446,513	-	-	-	-	-	-
		D	SNPD	2,422	-	-	2,422	-	-	-	-	-	-
				9,448,935	-	-	9,448,935	-	-	-	-	-	-
595	Maintenance of Line Transformers												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	272,218	-	-	272,218	-	-	-	-	-	-
				272,218	-	-	272,218	-	-	-	-	-	-
596	Maint of Street Lighting & Signal Sys.												
		DL	S	790,355	-	-	-	790,355	-	-	-	-	-
		DL	SNPD	-	-	-	-	-	-	-	-	-	-
				790,355	-	-	-	790,355	-	-	-	-	-
597	Maintenance of Meters												
		C_Meter	S	178,506	-	-	-	-	-	-	178,506	-	-
		C_Meter	SNPD	(6,481)	-	-	-	-	-	-	(6,481)	-	-
				172,025	-	-	-	-	-	-	172,025	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
598	Maint of Misc. Distribution Plant												
		D	S	667,240	-	-	667,240	-	-	-	-	-	-
		D	SNPD	869,157	-	-	869,157	-	-	-	-	-	-
				1,536,397	-	-	1,536,397	-	-	-	-	-	-
TOTAL DISTRIBUTION EXPENSE				**114,708,178**	**-**	**-**	**111,916,347**	**941,500**	**-**	**-**	**1,850,332**	**-**	**-**
901	Supervision												
		CUST901	S	-	-	-	-	-	-	-	-	-	-
		CUST901	CN	958,963	-	-	-	-	-	566,577	358,760	33,627	-
				958,963	-	-	-	-	-	566,577	358,760	33,627	-
902	Meter Reading Expense												
		C_Meter	S	2,093,427	-	-	-	-	-	-	2,093,427	-	-
		C_Meter	CN	234,949	-	-	-	-	-	-	234,949	-	-
				2,328,376	-	-	-	-	-	-	2,328,376	-	-
903	Customer Receipts & Collections												
		CUST903	S	5,419,367	-	-	-	-	-	4,119,186	227,573	1,072,608	-
		CUST903	CN	12,485,741	-	-	-	-	-	9,490,238	524,309	2,471,194	-
				17,905,108	-	-	-	-	-	13,609,423	751,882	3,543,802	-
904	Uncollectible Accounts												
		REVREQ	S	10,518,476	6,047,375	1,775,181	2,392,832	18,286	-	126,747	99,594	58,461	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		REVREQ	CN	(288,428)	(165,825)	(48,677)	(65,614)	(501)	-	(3,476)	(2,731)	(1,603)	-
				10,230,048	5,881,550	1,726,503	2,327,218	17,784	-	123,272	96,863	56,858	-
905	Misc. Customer Accounts Expense												
		CUST905	S	(0)	-	-	-	-	-	-	(0)	(0)	-
		CUST905	CN	47	-	-	-	-	-	-	30	18	-
				47	-	-	-	-	-	-	30	18	-
TOTAL CUSTOMER ACCOUNTS EXPENSE				**31,422,542**	**5,881,550**	**1,726,503**	**2,327,218**	**17,784**	**-**	**14,299,271**	**3,535,910**	**3,634,305**	**-**
907	Supervision												
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	395	-	-	-	-	-	-	-	395	-
				395	-	-	-	-	-	-	-	395	-
908	Customer Assistance												
		DSM	S	2,480,719	-	-	2,480,719	-	-	-	-	-	-
		C_Service	CN	1,034,910	-	-	-	-	-	-	-	1,034,910	-
				3,515,629	-	-	2,480,719	-	-	-	-	1,034,910	-
909	Informational & Instructional Adv												
		C_Service	S	816,425	-	-	-	-	-	-	-	816,425	-
		C_Service	CN	972,906	-	-	-	-	-	-	-	972,906	-
				1,789,331	-	-	-	-	-	-	-	1,789,331	-
910	Misc. Customer Service												

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	2,741	-	-	-	-	-	-	-	2,741	-
				2,741	-	-	-	-	-	-	-	2,741	-
TOTAL CUSTOMER SERVICE EXPENSE				**5,308,096**	**-**	**-**	**2,480,719**	**-**	**-**	**-**	**-**	**2,827,377**	**-**
911	Supervision												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
912	Demonstration & Selling Expense												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
913	Advertising Expense												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
916	Misc. Sales Expense												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL SALES EXPENSE				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Customer Service Exp Including Sales				**5,308,096**	**-**	**-**	**2,480,719**	**-**	**-**	**-**	**-**	**2,827,377**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
920	Administrative & General Salaries												
		LABOR	S	91,689	38,398	6,626	36,099	273	-	6,211	1,817	2,265	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	23,458,113	9,824,034	1,695,166	9,235,748	69,868	-	1,589,002	464,914	579,382	-
				23,549,802	9,862,432	1,701,792	9,271,847	70,141	-	1,595,213	466,731	581,646	-
921	Office Supplies & expenses												
		LABOR	S	(4,584)	(1,920)	(331)	(1,805)	(14)	-	(311)	(91)	(113)	-
		LABOR	CN	40,807	17,089	2,949	16,066	122	-	2,764	809	1,008	-
		LABOR	SO	5,070,467	2,123,463	366,410	1,996,305	15,102	-	343,463	100,491	125,233	-
				5,106,690	2,138,633	369,027	2,010,567	15,210	-	345,916	101,209	126,128	-
922	Office Supplies & expenses												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(14,016,494)	(5,869,974)	(1,012,881)	(5,518,466)	(41,747)	-	(949,447)	(277,791)	(346,187)	-
				(14,016,494)	(5,869,974)	(1,012,881)	(5,518,466)	(41,747)	-	(949,447)	(277,791)	(346,187)	-
923	Outside Services												
		LABOR	S	865,859	362,614	62,570	340,899	2,579	-	58,651	17,160	21,385	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	14,315,682	5,995,271	1,034,502	5,636,260	42,638	-	969,713	283,721	353,577	-
				15,181,541	6,357,885	1,097,072	5,977,160	45,217	-	1,028,365	300,881	374,962	-
924	Property Insurance												
		DPW	S	15,773,778	-	-	15,323,606	-	-	-	450,173	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		GP	SO	1,317,638	519,208	386,771	377,488	4,165	-	7,434	18,362	4,210	-
				17,091,416	519,208	386,771	15,701,094	4,165	-	7,434	468,535	4,210	-
925	Injuries & Damages												
		DPW	S	3,960,968	-	-	3,847,925	-	-	-	113,043	-	-
		LABOR	SO	4,415,850	1,849,316	319,105	1,738,575	13,152	-	299,120	87,517	109,065	-
				8,376,819	1,849,316	319,105	5,586,500	13,152	-	299,120	200,561	109,065	-
926	Employee Pensions & Benefits												
		LABOR	S	(5,733,248)	(2,401,029)	(414,305)	(2,257,250)	(17,076)	-	(388,358)	(113,627)	(141,603)	-
		LABOR	SG	797,657	334,051	57,641	314,047	2,376	-	54,032	15,809	19,701	-
		LABOR	SO	31,134,863	13,038,984	2,249,915	12,258,179	92,732	-	2,109,009	617,058	768,986	-
				26,199,272	10,972,005	1,893,252	10,314,976	78,032	-	1,774,682	519,240	647,084	-
927	Franchise Requirements												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
928	Regulatory Commission Expense												
		D	S	8,126,600	-	-	8,126,600	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		D	SO	475,120	-	-	475,120	-	-	-	-	-	-
		FERC	SG	1,750,313	856,312	894,001	-	-	-	-	-	-	-
				10,352,032	856,312	894,001	8,601,720	-	-	-	-	-	-
929	Duplicate Charges												

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(37,329,652)	(15,633,302)	(2,697,572)	(14,697,144)	(111,183)	-	(2,528,630)	(739,832)	(921,989)	-
				(37,329,652)	(15,633,302)	(2,697,572)	(14,697,144)	(111,183)	-	(2,528,630)	(739,832)	(921,989)	-
930	Misc General Expenses												
		LABOR	S	(1,024,126)	(428,894)	(74,007)	(403,211)	(3,050)	-	(69,372)	(20,297)	(25,294)	-
		C_SERVICE	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	540,113	226,194	39,030	212,649	1,609	-	36,586	10,704	13,340	-
				(484,014)	(202,700)	(34,977)	(190,562)	(1,442)	-	(32,786)	(9,593)	(11,954)	-
931	Rents												
		LABOR	S	333,350	139,604	24,089	131,244	993	-	22,580	6,607	8,233	-
		LABOR	SO	(1,185,930)	(496,656)	(85,699)	(466,915)	(3,532)	-	(80,332)	(23,504)	(29,291)	-
				(852,579)	(357,052)	(61,610)	(335,671)	(2,539)	-	(57,752)	(16,897)	(21,057)	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
935	Maintenance of General Plant												
		G	S	287,854	56,119	101,248	123,709	-	-	3,143	3,634	-	-
		B_Center	CN	10,987	-	-	-	-	-	7,158	-	3,830	-
		G	SO	8,139,050	1,586,771	2,862,779	3,497,874	-	-	88,866	102,760	-	-
				8,437,891	1,642,891	2,964,027	3,621,583	-	-	99,167	106,394	3,830	-
TOTAL ADMINISTRATIVE & GEN EXPENSE				**61,612,724**	**12,135,653**	**5,818,005**	**40,343,603**	**69,006**	**-**	**1,581,282**	**1,119,438**	**545,737**	**-**
TOTAL O&M EXPENSE				**1,130,053,083**	**870,518,025**	**72,045,230**	**157,067,885**	**1,028,290**	**-**	**15,880,553**	**6,505,679**	**7,007,420**	**-**
403SP	Steam Depreciation												
		P	SG	13,623,534	13,623,534	-	-	-	-	-	-	-	-
		P	SG	10,120,999	10,120,999	-	-	-	-	-	-	-	-
		P	SG	89,531,621	89,531,621	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				113,276,155	113,276,155	-	-	-	-	-	-	-	-
403NP	Nuclear Depreciation												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
403HP	Hydro Depreciation												
		P	SG	4,125,749	4,125,749	-	-	-	-	-	-	-	-
		P	SG	354,012	354,012	-	-	-	-	-	-	-	-
		P	SG	5,553,577	5,553,577	-	-	-	-	-	-	-	-
		P	SG	2,517,771	2,517,771	-	-	-	-	-	-	-	-
		P	SG	(3,059,099)	(3,059,099)	-	-	-	-	-	-	-	-
				9,492,011	9,492,011	-	-	-	-	-	-	-	-
403OP	Other Production Depreciation												
		P	S	61,373	61,373	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	18,450,653	18,450,653	-	-	-	-	-	-	-	-
		P	SG	1,151,516	1,151,516	-	-	-	-	-	-	-	-
		P	SG	43,640,253	43,640,253	-	-	-	-	-	-	-	-
				63,303,795	63,303,795	-	-	-	-	-	-	-	-
403TP	Transmission Depreciation												
		T_Split	S	-	-	-	-	-	-	-	-	-	-
		T_Split	SG	2,218,391	34,605	2,183,786	-	-	-	-	-	-	-
		T_Split	SG	2,776,526	43,311	2,733,215	-	-	-	-	-	-	-
		T_Split	SG	47,093,349	734,616	46,358,732	-	-	-	-	-	-	-
				52,088,266	812,533	51,275,733	-	-	-	-	-	-	-
403	Distribution Depreciation												
360	Land & Land Rights	D	S	105,224	-	-	105,224	-	-	-	-	-	-
361	Structures	D	S	597,644	-	-	597,644	-	-	-	-	-	-
362	Station Equipment	D	S	7,130,257	-	-	7,130,257	-	-	-	-	-	-
363	Storage Battery Equ	D	S	-	-	-	-	-	-	-	-	-	-
364	Poles & Towers	D	S	16,461,953	-	-	16,461,953	-	-	-	-	-	-
365	OH Conductors	D	S	7,035,472	-	-	7,035,472	-	-	-	-	-	-
366	UG Conduit	D	S	2,251,044	-	-	2,251,044	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
367	UG Conductor	D	S	4,997,445	-	-	4,997,445	-	-	-	-	-	-
368	Line Trans	D	S	12,697,496	-	-	12,697,496	-	-	-	-	-	-
369	Services	D	S	7,632,164	-	-	7,632,164	-	-	-	-	-	-
370	Meters	C_Meter	S	1,898,629	-	-	-	-	-	-	1,898,629	-	-
371	Inst Cust Prem	DL	S	119,651	-	-	-	119,651	-	-	-	-	-
372	Leased Property	D	S	-	-	-	-	-	-	-	-	-	-
373	Street Lighting	DL	S	643,654	-	-	-	643,654	-	-	-	-	-
				61,570,633	-	-	58,908,698	763,305	-	-	1,898,629	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
403GP	General Depreciation												
		TD	S	6,424,180	-	3,392,174	3,032,006	-	-	-	-	-	-
		G-DGP	SG	1,758	981	776	-	-	-	-	-	-	-
		G-DGU	SG	9,338	5,214	4,125	-	-	-	-	-	-	-
		P	SE	29,716	29,716	-	-	-	-	-	-	-	-
		B_Center	CN	217,934	-	-	-	-	-	141,972	-	75,962	-
		G-SG	SG	3,022,207	1,202,153	1,820,054	-	-	-	-	-	-	-
		LABOR	SO	7,639,251	3,199,245	552,039	3,007,667	22,753	-	517,466	151,401	188,678	-
		P	SG	2,441	2,441	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				17,346,823	4,439,750	5,769,168	6,039,673	22,753	-	659,438	151,401	264,640	-
403GV0	General Vehicles												
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
403MP	Mining Depreciation												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
403EP	Experimental Plant Depreciation												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
4031	ARO Depreciation												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DEPRECIATION EXPENSE				**317,077,683**	**191,324,243**	**57,044,901**	**64,948,371**	**786,058**	**-**	**659,438**	**2,050,031**	**264,640**	**-**
404GP	Amort of LT Plant - Capital Lease Gen												
		TD	S	139,579	-	73,702	65,877	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	11,344	4,751	820	4,466	34	-	768	225	280	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
				150,923	4,751	74,522	70,343	34	-	768	225	280	-
404SP	Amort of LT Plant - Cap Lease Steam												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
404IP	Amort of LT Plant - Intangible Plant												
		TD	S	11,216	-	5,922	5,294	-	-	-	-	-	-
		P	SE	248	248	-	-	-	-	-	-	-	-
		I-SG	SG	1,562,768	993,603	569,165	-	-	-	-	-	-	-
		LABOR	SO	14,013,506	5,868,723	1,012,665	5,517,290	41,738	-	949,245	277,732	346,113	-
		CSS_SYS	CN	4,785,713	-	-	-	-	-	2,121,666	1,116,666	1,547,381	-
		I-SG	SG	720,638	458,179	262,459	-	-	-	-	-	-	-
		I-SG	SG	84,585	53,779	30,806	-	-	-	-	-	-	-
		I-DGP	SG	21,143	21,143	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	3,353	3,353	-	-	-	-	-	-	-	-
				21,203,170	7,399,027	1,881,018	5,522,583	41,738	-	3,070,911	1,394,399	1,893,494	-
404MP	Amort of LT Plant - Mining Plant												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
404OP	Amort of LT Plant - Other Plant												
		P	S	70,641	70,641	-	-	-	-	-	-	-	-
				70,641	70,641	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
404HP	Amortization of Other Electric Plant												
		P	SG	84,383	84,383	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				84,383	84,383	-	-	-	-	-	-	-	-
Total Amortization of Limited Term Plant				**21,509,117**	**7,558,802**	**1,955,540**	**5,592,926**	**41,772**	**-**	**3,071,679**	**1,394,623**	**1,893,774**	**-**
405	Amortization of Other Electric Plant												
		GP	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
406	Amortization of Plant Acquisition Adj												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	20,258	20,258	-	-	-	-	-	-	-	-
		P	SO	-	-	-	-	-	-	-	-	-	-
				20,258	20,258	-	-	-	-	-	-	-	-
407	Amort of Prop Losses, Unrec Plant, etc												
		DPW	S	8,855,708	-	-	8,602,972	-	-	-	252,736	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		P	SG	519,760	519,760	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				9,375,468	519,760	-	8,602,972	-	-	-	252,736	-	-
TOTAL AMORTIZATION EXPENSE				**30,904,843**	**8,098,820**	**1,955,540**	**14,195,898**	**41,772**	**-**	**3,071,679**	**1,647,359**	**1,893,774**	**-**
408	Taxes Other Than Income												
		D	S	45,708,476	-	-	45,708,476	-	-	-	-	-	-
		GP	GPS	49,277,803	19,417,639	14,464,692	14,117,522	155,762	-	278,015	686,729	157,444	-
		REVREQ	SO	4,232,970	2,433,656	714,389	962,952	7,359	-	51,007	40,080	23,527	-
		P	SE	317,499	317,499	-	-	-	-	-	-	-	-
		P	SG	1,036,056	1,036,056	-	-	-	-	-	-	-	-
		DSM	OPRV-ID	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
				100,572,803	23,204,851	15,179,081	60,788,950	163,121	-	329,022	726,809	180,970	-
41140	Deferred Investment Tax Credit - Fed												
		PTD	DGU	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
41141	Deferred Investment Tax Credit - Idaho												
		PTD	DGU	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DEFERRED ITC				-	-	-	-	-	-	-	-	-	-
427	Interest on Long-Term Debt												
		NP	S	140,183,903	44,842,608	53,262,109	38,732,606	387,158	-	615,629	2,087,292	256,500	-
		NP	SNP	-	-	-	-	-	-	-	-	-	-
				140,183,903	44,842,608	53,262,109	38,732,606	387,158	-	615,629	2,087,292	256,500	-
428	Amortization of Debt Disc & Exp												
		NP	SNP	1,328,071	424,829	504,593	366,944	3,668	-	5,832	19,775	2,430	-
				1,328,071	424,829	504,593	366,944	3,668	-	5,832	19,775	2,430	-
429	Amortization of Premium on Debt												
		NP	SNP	(414)	(133)	(157)	(115)	(1)	-	(2)	(6)	(1)	-
				(414)	(133)	(157)	(115)	(1)	-	(2)	(6)	(1)	-
431	Other Interest Expense												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		NP	SNP	8,172,894	2,614,379	3,105,246	2,258,158	22,572	-	35,892	121,692	14,954	-
				8,172,894	2,614,379	3,105,246	2,258,158	22,572	-	35,892	121,692	14,954	-
432	AFUDC - Borrowed												
		NP	SNP	(12,419,040)	(3,972,654)	(4,718,547)	(3,431,363)	(34,299)	-	(54,539)	(184,915)	(22,724)	-
				(12,419,040)	(3,972,654)	(4,718,547)	(3,431,363)	(34,299)	-	(54,539)	(184,915)	(22,724)	-
	Total Electric Interest Deductions for Tax			137,265,413	43,909,030	52,153,245	37,926,231	379,098	-	602,812	2,043,837	251,160	-
	Non-Utility Portion of Interest												
	427	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	428	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	429	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	431	NUTIL	NUTIL	-	-	-	-	-	-	-	-	-	-
	Total Non-utility Interest			-	-	-	-	-	-	-	-	-	-
	Total Interest Deductions for Tax			137,265,413	43,909,030	52,153,245	37,926,231	379,098	-	602,812	2,043,837	251,160	-
419	Interest & Dividends												
		GP	S	-	-	-	-	-	-	-	-	-	-
		GP	SNP	(65,590,851)	(25,845,704)	(19,253,120)	(18,791,022)	(207,327)	-	(370,050)	(914,065)	(209,564)	-
	Total Operating Deductions for Tax			(65,590,851)	(25,845,704)	(19,253,120)	(18,791,022)	(207,327)	-	(370,050)	(914,065)	(209,564)	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
41010	Deferred Income Tax - Federal-DR												
		GP	S	(309,582)	(121,989)	(90,873)	(88,692)	(979)	-	(1,747)	(4,314)	(989)	-
		P	CHMDEX	-	-	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	178,417	74,720	12,893	70,245	531	-	12,086	3,536	4,407	-
		NP	SNP	23,454,306	7,502,661	8,911,335	6,480,390	64,776	-	103,002	349,227	42,915	-
		P	SE	4,202	4,202	-	-	-	-	-	-	-	-
		PT	SG	10,295,739	5,748,698	4,547,042	-	-	-	-	-	-	-
		GP	GPS	3,147,512	1,240,259	923,900	901,726	9,949	-	17,758	43,863	10,056	-
		TAXDEPR	TAXDEPR	90,338,073	39,348,590	25,471,400	23,527,116	31,559	-	775,675	682,594	501,139	-
		C_BILLING	BADDEBT	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				127,108,667	53,797,140	39,775,698	30,890,786	105,836	-	906,774	1,074,906	557,528	-
41110	Deferred Income Tax - Federal-CR												
		GP	S	(17,534,021)	(6,909,182)	(5,146,824)	(5,023,295)	(55,423)	-	(98,923)	(244,352)	(56,022)	-
		P	SE	(963,569)	(963,569)	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	(0)	-	-	-	-	-	(0)	-	-	-
		NP	SNP	(13,937,921)	(4,458,520)	(5,295,637)	(3,851,027)	(38,494)	-	(61,210)	(207,531)	(25,503)	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	(9,236,961)	-	-	(8,763,859)	(98,236)	-	-	(374,865)	-	-
		LABOR	SO	(3,813,604)	(1,597,101)	(275,584)	(1,501,463)	(11,358)	-	(258,325)	(75,581)	(94,191)	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	6,702	-	-	-	-	-	2,971	1,564	2,167	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	CHMDEX	(71,931,536)	(43,818,759)	(11,141,787)	(16,234,458)	(196,414)	-	(63,187)	(476,931)	-	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	(14,634,969)	(14,634,969)	-	-	-	-	-	-	-	-
		GP	GPS	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(132,045,879)	(72,382,100)	(21,859,833)	(35,374,101)	(399,926)	-	(478,673)	(1,377,697)	(173,548)	-
TOTAL DEFERRED INCOME TAXES				(4,937,211)	(18,584,960)	17,915,865	(4,483,316)	(294,090)	-	428,100	(302,791)	383,980	-
SCHMAF	Additions - Flow Through												
		SCHMAF	S	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SO	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SE	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMAP	Additions - Permanent												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	3,953	3,953	-	-	-	-	-	-	-	-
		PTD	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAP-SO	SO	520,374	327,647	23,962	130,553	988	-	22,462	6,572	8,190	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		SCHMAP	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	CHMDEX	35,183	21,432	5,450	7,941	96	-	31	233	-	-
				559,509	353,033	29,412	138,494	1,084	-	22,492	6,805	8,190	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
SCHMAT	Additions - Temporary												
		SCHMAT-SITU	S	21,050,906	12,468,624	2,748,609	4,956,524	20,875	-	474,763	208,403	173,108	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	37,569,085	-	-	35,644,859	399,553	-	-	1,524,673	-	-
		SCHMAT-SNP	SNP	56,689,096	25,322,437	15,132,853	15,769,087	-	-	674	463,584	461	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	0	-	-	-	-	-	0	-	-	-
		SCHMAT-SE	SE	3,919,087	4,019,851	(12,528)	(68,257)	(516)	-	(11,744)	(3,436)	(4,282)	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	(27,260)	-	-	-	-	-	(12,085)	(6,361)	(8,814)	-
		SCHMAT-SO	SO	10,928,291	4,574,506	774,688	4,311,524	32,779	-	745,488	217,486	271,820	-
		SCHMAT-SNP	SNPD	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEX	292,563,984	178,222,118	45,316,500	66,029,699	798,868	-	256,996	1,939,802	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,286,610	11,286,610	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				433,979,799	235,894,146	63,960,122	126,643,436	1,251,558	-	1,454,092	4,344,152	432,293	-
TOTAL SCHEDULE - M ADDITIONS				434,539,308	236,247,179	63,989,534	126,781,929	1,252,642	-	1,476,585	4,350,957	440,483	-
SCHMDF	Deductions - Flow Through												
		SCHMDF	S	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent												
		SCHMDP	S	-	-	-	-	-	-	-	-	-	-
		P	SE	151,388	151,388	-	-	-	-	-	-	-	-
		SCHMDP	SNP	28,210	27,722	235	245	-	-	-	7	-	-
		BOOKDEPR	SCHMDEX	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDP-SO	SO	-	-	-	-	-	-	-	-	-	-
				179,597	179,110	235	245	-	-	-	7	-	-
SCHMDT	Deductions - Temporary												
		SCHMDT-SITU	S	(1,259,158)	(1,314,632)	11,670	41,766	45	-	1,085	496	412	-
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	95,394,668	42,617,032	25,464,097	26,534,030	-	-	-	779,509	-	-
		SCHMDT	CN	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	41,875,413	43,016,005	(1,140,592)	-	-	-	-	-	-	-
		P	SE	17,092	17,092	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDT-GPS	GPS	12,801,734	5,719,103	3,417,220	3,560,803	-	-	-	104,608	-	-
		SCHMDT-SO	SO	725,671	304,691	(12,463)	306,352	3,357	-	76,274	19,671	27,789	-
		TAXDEPR	TAXDEPR	367,428,084	160,040,796	103,598,708	95,690,808	128,357	-	3,154,871	2,776,286	2,038,259	-
		SCHMDT-SNP	SNPD	(0)	(0)	(0)	(0)	-	-	-	(0)	-	-
				516,983,504	250,400,087	131,338,641	126,133,758	131,759	-	3,232,230	3,680,570	2,066,460	-
TOTAL SCHEDULE - M DEDUCTIONS				517,163,102	250,579,196	131,338,877	126,134,003	131,759	-	3,232,230	3,680,577	2,066,460	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
TOTAL SCHEDULE - M ADJUSTMENTS				(82,623,793)	(14,332,017)	(67,349,343)	647,926	1,120,883	-	(1,755,645)	670,380	(1,625,977)	-
40911	State Income Taxes												
		REVREQ		5,088,036	2,925,259	858,697	1,157,469	8,845	-	61,311	48,176	28,279	-
		REVREQ	S	219,094	125,963	36,976	49,841	381	-	2,640	2,074	1,218	-
	PTC	P	SG	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
TOTAL STATE TAXES				5,307,130	3,051,222	895,673	1,207,311	9,226	-	63,951	50,251	29,497	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
Calculation of Taxable Income:													
	Operating Revenues			1,844,948,033	1,060,713,897	311,367,927	419,704,344	3,207,315	-	22,231,523	17,468,923	10,254,105	-
	Operating Deductions:												
	O & M Expenses			1,130,053,083	870,518,025	72,045,230	157,067,885	1,028,290	-	15,880,553	6,505,679	7,007,420	-
	Depreciation Expense			317,077,683	191,324,243	57,044,901	64,948,371	786,058	-	659,438	2,050,031	264,640	-
	Amortization Expense			30,904,843	8,098,820	1,955,540	14,195,898	41,772	-	3,071,679	1,647,359	1,893,774	-
	Taxes Other Than Income			100,572,803	23,204,851	15,179,081	60,788,950	163,121	-	329,022	726,809	180,970	-
	Interest & Dividends (AFUDC-Equity)			(65,590,851)	(25,845,704)	(19,253,120)	(18,791,022)	(207,327)	-	(370,050)	(914,065)	(209,564)	-
	Misc Revenue & Expense			(30,006)	(92,792)	(9,553)	72,340	-	-	-	-	-	-
	Total Operating Deductions			1,512,987,554	1,067,207,442	126,962,078	278,282,423	1,811,914	-	19,570,643	10,015,813	9,137,240	-
	Other Deductions:												
	Interest Deductions			137,265,413	43,909,030	52,153,245	37,926,231	379,098	-	602,812	2,043,837	251,160	-
	Interest on PCRBS			-	-	-	-	-	-	-	-	-	-
	Schedule M Adjustments			(82,623,793)	(14,332,017)	(67,349,343)	647,926	1,120,883	-	(1,755,645)	670,380	(1,625,977)	-
	Income Before State Taxes			112,071,272	(64,734,592)	64,903,262	104,143,616	2,137,185	-	302,422	6,079,653	(760,273)	-
	State Income Taxes			5,307,130	3,051,222	895,673	1,207,311	9,226	-	63,951	50,251	29,497	-
Total Taxable Income				106,764,142	(67,785,814)	64,007,589	102,936,305	2,127,959	-	238,471	6,029,402	(789,770)	-
Tax Rate				0	0	0	0	0	0	0	0	0	0
Federal Income Tax - Calculated				22,420,470	(14,235,021)	13,441,594	21,616,624	446,871	-	50,079	1,266,174	(165,852)	-
Adjustments to Calculated Tax:													
40910	PMI	P	SE	(3,951)	(3,951)	-	-	-	-	-	-	-	-
40910	Renewable Energy (	P	SG	(65,202,036)	(65,202,036)	-	-	-	-	-	-	-	-
40910		P	SO	(9,163)	(9,163)	-	-	-	-	-	-	-	-
40910		P	S	-	-	-	-	-	-	-	-	-	-
Federal Income Tax				(42,794,680)	(79,450,171)	13,441,594	21,616,624	446,871	-	50,079	1,266,174	(165,852)	-
TOTAL OPERATING EXPENSES				**1,536,153,644**	**998,069,238**	**178,468,330**	**315,414,063**	**2,181,248**	**-**	**20,482,823**	**11,943,512**	**9,594,430**	**-**
310	Land and Land Rights												
		P	SG	625,603	625,603	-	-	-	-	-	-	-	-
		P	SG	9,078,654	9,078,654	-	-	-	-	-	-	-	-
		P	SG	14,611,953	14,611,953	-	-	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	340,582	340,582	-	-	-	-	-	-	-	-
				24,656,792	24,656,792	-	-	-	-	-	-	-	-
311	Structures and Improvements												
		P	SG	60,593,953	60,593,953	-	-	-	-	-	-	-	-
		P	SG	83,636,058	83,636,058	-	-	-	-	-	-	-	-
		P	SG	126,777,211	126,777,211	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				271,007,222	271,007,222	-	-	-	-	-	-	-	-
312	Boiler Plant Equipment												
		P	SG	157,159,755	157,159,755	-	-	-	-	-	-	-	-
		P	SG	124,342,847	124,342,847	-	-	-	-	-	-	-	-
		P	SG	943,094,422	943,094,422	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				1,224,597,024	1,224,597,024	-	-	-	-	-	-	-	-
314	Turbogenerator Units												
		P	SG	29,135,609	29,135,609	-	-	-	-	-	-	-	-
		P	SG	28,630,467	28,630,467	-	-	-	-	-	-	-	-
		P	SG	209,310,389	209,310,389	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				267,076,465	267,076,465	-	-	-	-	-	-	-	-
315	Accessory Electric Equipment												
		P	SG	23,035,108	23,035,108	-	-	-	-	-	-	-	-
		P	SG	35,774,993	35,774,993	-	-	-	-	-	-	-	-
		P	SG	56,398,152	56,398,152	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				115,208,253	115,208,253	-	-	-	-	-	-	-	-
316	Misc Power Plant Equipment												
		P	SG	631,332	631,332	-	-	-	-	-	-	-	-
		P	SG	1,293,918	1,293,918	-	-	-	-	-	-	-	-
		P	SG	7,206,889	7,206,889	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				9,132,139	9,132,139	-	-	-	-	-	-	-	-
317	Steam Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SP	Unclassified Steam Plant - Account 300												
		P	SG	4,782,433	4,782,433	-	-	-	-	-	-	-	-
				4,782,433	4,782,433	-	-	-	-	-	-	-	-
Total Steam Production Plant				**1,916,460,328**	**1,916,460,328**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
320	Land and Land Rights												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
321	Structures and Improvements												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
322	Reactor Plant Equipment												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
323	Turbogenerator Units												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
324	Land and Land Rights												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
325	Misc. Power Plant Equipment												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
NP	Unclassified Nuclear Plant - Acct 300												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Nuclear Production Plant				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
330	Land and Land Rights												
		P	SG	2,644,542	2,644,542	-	-	-	-	-	-	-	-
		P	SG	1,415,443	1,415,443	-	-	-	-	-	-	-	-
		P	SG	5,924,179	5,924,179	-	-	-	-	-	-	-	-
		P	SG	358,466	358,466	-	-	-	-	-	-	-	-
				10,342,631	10,342,631	-	-	-	-	-	-	-	-
331	Structures and Improvements												
		P	SG	4,079,017	4,079,017	-	-	-	-	-	-	-	-
		P	SG	1,277,614	1,277,614	-	-	-	-	-	-	-	-
		P	SG	65,964,688	65,964,688	-	-	-	-	-	-	-	-
		P	SG	4,669,579	4,669,579	-	-	-	-	-	-	-	-
				75,990,898	75,990,898	-	-	-	-	-	-	-	-
332	Reservoirs, Dams & Waterways												
		P	SG	33,938,250	33,938,250	-	-	-	-	-	-	-	-
		P	SG	5,019,638	5,019,638	-	-	-	-	-	-	-	-
		P	SG	102,845,475	102,845,475	-	-	-	-	-	-	-	-
		P	SG	31,689,163	31,689,163	-	-	-	-	-	-	-	-
		P	SG	(355,300)	(355,300)	-	-	-	-	-	-	-	-
				173,137,226	173,137,226	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
333	Water Wheel, Turbines, & Generators												
		P	SG	6,855,366	6,855,366	-	-	-	-	-	-	-	-
		P	SG	1,798,769	1,798,769	-	-	-	-	-	-	-	-
		P	SG	14,463,480	14,463,480	-	-	-	-	-	-	-	-
		P	SG	11,988,643	11,988,643	-	-	-	-	-	-	-	-
				35,106,257	35,106,257	-	-	-	-	-	-	-	-
334	Accessory Electric Equipment												
		P	SG	748,052	748,052	-	-	-	-	-	-	-	-
		P	SG	896,830	896,830	-	-	-	-	-	-	-	-
		P	SG	14,931,325	14,931,325	-	-	-	-	-	-	-	-
		P	SG	3,060,519	3,060,519	-	-	-	-	-	-	-	-
				19,636,726	19,636,726	-	-	-	-	-	-	-	-
335	Misc. Power Plant Equipment												
		P	SG	261,780	261,780	-	-	-	-	-	-	-	-
		P	SG	40,548	40,548	-	-	-	-	-	-	-	-
		P	SG	402,544	402,544	-	-	-	-	-	-	-	-
		P	SG	16,494	16,494	-	-	-	-	-	-	-	-
				721,366	721,366	-	-	-	-	-	-	-	-
336	Roads, Railroads & Bridges												
		P	SG	866,152	866,152	-	-	-	-	-	-	-	-
		P	SG	197,437	197,437	-	-	-	-	-	-	-	-
		P	SG	4,866,411	4,866,411	-	-	-	-	-	-	-	-
		P	SG	955,018	955,018	-	-	-	-	-	-	-	-
				6,885,019	6,885,019	-	-	-	-	-	-	-	-
337	Hydro Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Hydraulic Plant				**321,820,122**	**321,820,122**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
340	Land and Land Rights												
		P	S	74,986	74,986	-	-	-	-	-	-	-	-
		P	SG	10,490,871	10,490,871	-	-	-	-	-	-	-	-
		P	SG	3,638,315	3,638,315	-	-	-	-	-	-	-	-
		P	SG	63,213	63,213	-	-	-	-	-	-	-	-
				14,267,385	14,267,385	-	-	-	-	-	-	-	-
341	Structures and Improvements												
		P	S	3,756	3,756	-	-	-	-	-	-	-	-
		P	SG	45,093,476	45,093,476	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	27,047,066	27,047,066	-	-	-	-	-	-	-	-
		P	SG	1,148,760	1,148,760	-	-	-	-	-	-	-	-
				73,293,058	73,293,058	-	-	-	-	-	-	-	-
342	Fuel Holders, Producers & Accessories												
		P	SG	3,669,749	3,669,749	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	749,832	749,832	-	-	-	-	-	-	-	-
				4,419,581	4,419,581	-	-	-	-	-	-	-	-
343	Prime Movers												
		P	S	370,052	370,052	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	944,618,365	944,618,365	-	-	-	-	-	-	-	-
		P	SG	249,367,526	249,367,526	-	-	-	-	-	-	-	-
		P	SG	16,431,589	16,431,589	-	-	-	-	-	-	-	-
				1,210,787,532	1,210,787,532	-	-	-	-	-	-	-	-
344	Generators												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	44,415,479	44,415,479	-	-	-	-	-	-	-	-
		P	SG	108,382,133	108,382,133	-	-	-	-	-	-	-	-
		P	SG	4,785,333	4,785,333	-	-	-	-	-	-	-	-
				157,582,946	157,582,946	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
345	Accessory Electric Plant												
		P	S	516,566	516,566	-	-	-	-	-	-	-	-
		P	SG	53,612,432	53,612,432	-	-	-	-	-	-	-	-
		P	SG	66,576,326	66,576,326	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	780,042	780,042	-	-	-	-	-	-	-	-
				121,485,366	121,485,366	-	-	-	-	-	-	-	-
346	Misc. Power Plant Equipment												
		P	SG	3,311,693	3,311,693	-	-	-	-	-	-	-	-
		P	SG	3,189,422	3,189,422	-	-	-	-	-	-	-	-
				6,501,114	6,501,114	-	-	-	-	-	-	-	-
347	Other Production ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Other Production Plant				**1,588,336,982**	**1,588,336,982**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Experimental Plant													
103	Experimental Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
Total Experimental Plant				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PRODUCTION PLANT				**3,826,617,433**	**3,826,617,433**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
350	Land and Land Rights												
		T	SG	5,486,720	-	5,486,720	-	-	-	-	-	-	-
		T	SG	12,491,637	-	12,491,637	-	-	-	-	-	-	-
		T	SG	75,262,894	-	75,262,894	-	-	-	-	-	-	-
				93,241,252	-	93,241,252	-	-	-	-	-	-	-
352	Structures and Improvements												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	1,856,223	-	1,856,223	-	-	-	-	-	-	-
		T	SG	4,676,439	-	4,676,439	-	-	-	-	-	-	-
		T	SG	97,272,119	-	97,272,119	-	-	-	-	-	-	-
				103,804,780	-	103,804,780	-	-	-	-	-	-	-
353	Station Equipment												
		STEP_UP	SG	27,481,938	1,771,274	25,710,663	-	-	-	-	-	-	-
		STEP_UP	SG	39,242,560	2,529,274	36,713,286	-	-	-	-	-	-	-
		STEP_UP	SG	665,825,231	42,913,977	622,911,254	-	-	-	-	-	-	-
				732,549,729	47,214,525	685,335,204	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
354	Towers and Fixtures												
		T	SG	34,440,254	-	34,440,254	-	-	-	-	-	-	-
		T	SG	35,264,886	-	35,264,886	-	-	-	-	-	-	-
		T	SG	340,548,450	-	340,548,450	-	-	-	-	-	-	-
				410,253,591	-	410,253,591	-	-	-	-	-	-	-
355	Poles and Fixtures												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	15,721,805	-	15,721,805	-	-	-	-	-	-	-
		T	SG	30,308,612	-	30,308,612	-	-	-	-	-	-	-
		T	SG	1,150,049,256	-	1,150,049,256	-	-	-	-	-	-	-
				1,196,079,673	-	1,196,079,673	-	-	-	-	-	-	-
356	Clearing and Grading												
		T	SG	42,117,472	-	42,117,472	-	-	-	-	-	-	-
		T	SG	41,979,966	-	41,979,966	-	-	-	-	-	-	-
		T	SG	366,510,019	-	366,510,019	-	-	-	-	-	-	-
				450,607,457	-	450,607,457	-	-	-	-	-	-	-
357	Underground Conduit												
		T	SG	1,713	-	1,713	-	-	-	-	-	-	-
		T	SG	24,639	-	24,639	-	-	-	-	-	-	-
		T	SG	1,014,868	-	1,014,868	-	-	-	-	-	-	-
				1,041,220	-	1,041,220	-	-	-	-	-	-	-
358	Underground Conductors												
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	292,379	-	292,379	-	-	-	-	-	-	-
		T	SG	2,148,868	-	2,148,868	-	-	-	-	-	-	-
				2,441,247	-	2,441,247	-	-	-	-	-	-	-
359	Roads and Trails												
		T	SG	500,860	-	500,860	-	-	-	-	-	-	-
		T	SG	117,206	-	117,206	-	-	-	-	-	-	-
		T	SG	2,646,065	-	2,646,065	-	-	-	-	-	-	-
				3,264,131	-	3,264,131	-	-	-	-	-	-	-
TP	Unclassified Trans Plant - Acct 300												
		T	SG	33,452,905	-	33,452,905	-	-	-	-	-	-	-
				33,452,905	-	33,452,905	-	-	-	-	-	-	-
TS0	Unclassified Trans Sub Plant - Acct 300												
		T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL TRANSMISSION PLANT				**3,026,735,986**	**47,214,525**	**2,979,521,461**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
360	Land and Land Rights												
		D	S	16,501,049	-	-	16,501,049	-	-	-	-	-	-
				16,501,049	-	-	16,501,049	-	-	-	-	-	-
361	Structures and Improvements												
		D	S	36,865,601	-	-	36,865,601	-	-	-	-	-	-
				36,865,601	-	-	36,865,601	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
362	Station Equipment												
		D	S	321,458,778	-	-	321,458,778	-	-	-	-	-	-
				321,458,778	-	-	321,458,778	-	-	-	-	-	-
363	Storage Battery Equipment												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
364	Poles, Towers & Fixtures												
		D	S	537,021,123	-	-	537,021,123	-	-	-	-	-	-
				537,021,123	-	-	537,021,123	-	-	-	-	-	-
365	Overhead Conductors												
		D	S	326,142,454	-	-	326,142,454	-	-	-	-	-	-
				326,142,454	-	-	326,142,454	-	-	-	-	-	-
366	Underground Conduit												
		D	S	127,274,252	-	-	127,274,252	-	-	-	-	-	-
				127,274,252	-	-	127,274,252	-	-	-	-	-	-
367	Underground Conductors												
		D	S	249,806,557	-	-	249,806,557	-	-	-	-	-	-
				249,806,557	-	-	249,806,557	-	-	-	-	-	-
368	Line Transformers												
		D	S	553,956,506	-	-	553,956,506	-	-	-	-	-	-
				553,956,506	-	-	553,956,506	-	-	-	-	-	-
369	Services												
		D	S	373,239,647	-	-	373,239,647	-	-	-	-	-	-
				373,239,647	-	-	373,239,647	-	-	-	-	-	-
370	Meters												
		C_Meter	S	109,792,499	-	-	-	-	-	-	109,792,499	-	-
				109,792,499	-	-	-	-	-	-	109,792,499	-	-
371	Installations on Customers' Premises												
		DL	S	2,803,509	-	-	-	2,803,509	-	-	-	-	-
				2,803,509	-	-	-	2,803,509	-	-	-	-	-
372	Leased Property												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
373	Street Lights												
		DL	S	25,968,508	-	-	-	25,968,508	-	-	-	-	-
				25,968,508	-	-	-	25,968,508	-	-	-	-	-
DP	Unclassified Dist Plant - Acct 300												
		D	S	24,538,568	-	-	24,538,568	-	-	-	-	-	-
				24,538,568	-	-	24,538,568	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
DS0	Unclassified Dist Sub Plant - Acct 300												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DISTRIBUTION PLANT				**2,705,369,051**	**-**	**-**	**2,566,804,536**	**28,772,017**	**-**	**-**	**109,792,499**	**-**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
389	Land and Land Rights												
		D_SPLIT	S	6,116,556	-	-	5,803,276	65,051	-	-	248,229	-	-
		B_Center	CN	346,514	-	-	-	-	-	225,735	-	120,779	-
		G-DGU	SG	89	50	39	-	-	-	-	-	-	-
		G-SG	SG	330	131	199	-	-	-	-	-	-	-
		LABOR	SO	2,087,521	874,234	150,852	821,883	6,217	-	141,404	41,372	51,559	-
				8,551,011	874,415	151,090	6,625,159	71,268	-	367,139	289,602	172,338	-
390	Structures and Improvements												
		D_SPLIT	S	44,350,073	-	-	42,078,536	471,670	-	-	1,799,867	-	-
		P	SE	247,839	247,839	-	-	-	-	-	-	-	-
		G-DGP	SG	90,126	50,319	39,807	-	-	-	-	-	-	-
		G-DGU	SG	364,653	203,593	161,060	-	-	-	-	-	-	-
		B_Center	CN	2,523,635	-	-	-	-	-	1,644,012	-	879,623	-
		G-SG	SG	2,777,643	1,104,872	1,672,771	-	-	-	-	-	-	-
		LABOR	SO	30,989,684	12,978,184	2,239,424	12,201,020	92,300	-	2,099,174	614,181	765,401	-
				81,343,652	14,584,806	4,113,062	54,279,556	563,970	-	3,743,186	2,414,048	1,645,024	-
391	Office Furniture & Equipment												
		D_SPLIT	S	2,351,456	-	-	2,231,018	25,008	-	-	95,430	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	881,065	-	-	-	-	-	573,966	-	307,099	-
		G-SG	SG	1,227,944	488,443	739,501	-	-	-	-	-	-	-
		P	SE	7,002	7,002	-	-	-	-	-	-	-	-
		LABOR	SO	21,998,162	9,212,620	1,589,665	8,660,947	65,520	-	1,490,108	435,979	543,323	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	2,238	2,238	-	-	-	-	-	-	-	-
				26,467,867	9,710,304	2,329,165	10,891,965	90,528	-	2,064,074	531,409	850,422	-
392	Transportation Equipment												
		D_SPLIT	S	30,344,593	-	-	28,790,393	322,719	-	-	1,231,480	-	-
		LABOR	SO	1,904,071	797,407	137,595	749,656	5,671	-	128,978	37,737	47,028	-
		G-SG	SG	6,641,901	2,641,970	3,999,931	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	179,498	100,217	79,281	-	-	-	-	-	-	-
		P	SE	86,224	86,224	-	-	-	-	-	-	-	-
		G-DGP	SG	18,984	10,599	8,385	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	12,005	12,005	-	-	-	-	-	-	-	-
				39,187,276	3,648,422	4,225,191	29,540,049	328,391	-	128,978	1,269,217	47,028	-
393	Stores Equipment												
		D_SPLIT	S	2,998,461	-	-	2,844,885	31,889	-	-	121,687	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	66,627	27,903	4,815	26,232	198	-	4,513	1,320	1,646	-
		G-SG	SG	1,858,102	739,103	1,118,999	-	-	-	-	-	-	-
		P	SG	14,510	14,510	-	-	-	-	-	-	-	-
				4,937,700	781,516	1,123,813	2,871,117	32,088	-	4,513	123,008	1,646	-
394	Tools, Shop & Garage Equipment												
		D_SPLIT	S	10,911,877	-	-	10,352,989	116,049	-	-	442,839	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		G-DGP	SG	6,446	3,599	2,847	-	-	-	-	-	-	-
		G-SG	SG	6,168,407	2,453,627	3,714,780	-	-	-	-	-	-	-
		LABOR	SO	494,302	207,009	35,720	194,613	1,472	-	33,483	9,797	12,209	-
		P	SE	33,106	33,106	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	24,172	24,172	-	-	-	-	-	-	-	-
				17,638,311	2,721,514	3,753,347	10,547,601	117,522	-	33,483	452,635	12,209	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
395	Laboratory Equipment												
		D_SPLIT	S	10,321,264	-	-	9,792,626	109,768	-	-	418,870	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	1,390,682	582,404	100,496	547,529	4,142	-	94,202	27,562	34,348	-
		P	SE	349,480	349,480	-	-	-	-	-	-	-	-
		G-SG	SG	1,995,544	793,774	1,201,770	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	3,770	3,770	-	-	-	-	-	-	-	-
				14,060,740	1,729,428	1,302,265	10,340,155	113,910	-	94,202	446,432	34,348	-
396	Power Operated Equipment												
		D_SPLIT	S	52,665,956	-	-	49,968,493	560,111	-	-	2,137,352	-	-
		G-DGP	SG	70,436	39,326	31,110	-	-	-	-	-	-	-
		G-SG	SG	12,703,138	5,052,968	7,650,170	-	-	-	-	-	-	-
		LABOR	SO	1,279,032	535,647	92,427	503,571	3,809	-	86,639	25,349	31,590	-
		G-DGU	SG	198,848	111,021	87,828	-	-	-	-	-	-	-
		P	SE	62,341	62,341	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				66,979,751	5,801,302	7,861,535	50,472,064	563,920	-	86,639	2,162,701	31,590	-
397	Communication Equipment												
		D_SPLIT	S	124,669,936	-	-	118,284,549	1,325,884	-	-	5,059,503	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	37,439	20,903	16,536	-	-	-	-	-	-	-
		LABOR	SO	44,276,794	18,542,699	3,199,597	17,432,319	131,874	-	2,999,215	877,517	1,093,573	-
		B_Center	CN	470,976	-	-	-	-	-	306,815	-	164,161	-
		G-SG	SG	52,646,359	20,941,312	31,705,048	-	-	-	-	-	-	-
		P	SE	42,417	42,417	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	4,472	1,779	2,693	-	-	-	-	-	-	-
				222,148,393	39,549,109	34,923,874	135,716,868	1,457,758	-	3,306,030	5,937,020	1,257,734	-
398	Misc. Equipment												
		D_SPLIT	S	1,374,243	-	-	1,303,857	14,615	-	-	55,771	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	21,758	-	-	-	-	-	14,174	-	7,584	-
		LABOR	SO	431,943	180,894	31,214	170,061	1,287	-	29,259	8,561	10,668	-
		P	SE	1,045	1,045	-	-	-	-	-	-	-	-
		G-SG	SG	837,112	332,981	504,131	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				2,666,100	514,919	535,345	1,473,918	15,902	-	43,433	64,332	18,252	-
399	Coal Mine												
		P	SE	11,665,695	11,665,695	-	-	-	-	-	-	-	-
MP	Unckassified Mine Pla	P	SE	-	-	-	-	-	-	-	-	-	-
				11,665,695	11,665,695	-	-	-	-	-	-	-	-
399L	WIDCO Capital Lease												
		P	SE	-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
1011390	General Capital Leases												
		D_SPLIT	S	691,142	-	-	655,742	7,350	-	-	28,049	-	-
		P	SG	2,166,359	2,166,359	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				2,857,500	2,166,359	-	655,742	7,350	-	-	28,049	-	-
	Remove Capital Leases			(2,857,500)	(2,166,359)	-	(655,742)	(7,350)	-	-	(28,049)	-	-
				-	-	-	-	-	-	-	-	-	-
1011346	General Gas Line Capital Leases												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
GP	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	17,939,437	7,512,865	1,296,367	7,062,977	53,431	-	1,215,179	355,540	443,078	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				17,939,437	7,512,865	1,296,367	7,062,977	53,431	-	1,215,179	355,540	443,078	-
399G	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT				**513,585,933**	**99,094,295**	**61,615,055**	**319,821,430**	**3,408,687**	**-**	**11,086,856**	**14,045,943**	**4,513,667**	**-**
301	Organization												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
302	Franchise & Consent												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	4,368,333	2,777,371	1,590,962	-	-	-	-	-	-	-
		I-DGP	SG	27,790,447	27,790,447	-	-	-	-	-	-	-	-
		I-DGU	SG	2,622,724	2,622,724	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	128,398	128,398	-	-	-	-	-	-	-	-
				34,909,902	33,318,940	1,590,962	-	-	-	-	-	-	-
303	Miscellaneous Intangible Plant												
		D_SPLIT	S	4,606,407	-	-	4,370,474	48,990	-	-	186,943	-	-
		LABOR	SG	52,366,046	21,930,400	3,784,155	20,617,157	155,967	-	3,547,163	1,037,837	1,293,366	-
		LABOR	SO	191,155,091	80,053,928	13,813,541	75,260,113	569,338	-	12,948,434	3,788,482	4,721,255	-
		P	SE	1,241	1,241	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		CSS_SYS	CN	70,461,152	-	-	-	-	-	31,237,777	16,440,935	22,782,439	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
				318,589,936	101,985,569	17,597,696	100,247,744	774,295	-	47,733,375	21,454,197	28,797,060	-
303	Less Non-Utility Plant												
		I-SITUS	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
IP	Unclassified Intangible Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL INTANGIBLE PLANT				**353,499,838**	**135,304,509**	**19,188,658**	**100,247,744**	**774,295**	**-**	**47,733,375**	**21,454,197**	**28,797,060**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
TOTAL ELECTRIC PLANT IN SERVICE				**10,425,808,241**	**4,108,230,762**	**3,060,325,174**	**2,986,873,710**	**32,954,998**	**-**	**58,820,231**	**145,292,638**	**33,310,728**	**-**
105	Plant Held For Future Use												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	408,094	-	408,094	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		G	SG	(408,094)	(79,561)	(143,540)	(175,384)	-	-	(4,456)	(5,152)	-	-
				-	(79,561)	264,553	(175,384)	-	-	(4,456)	(5,152)	-	-
114	Electric Plant Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	38,902,639	38,902,639	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				38,902,639	38,902,639	-	-	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(38,199,390)	(38,199,390)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(38,199,390)	(38,199,390)	-	-	-	-	-	-	-	-
128	Pensions												
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
124	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
182W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
186W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	CN	-	-	-	-	-	-	-	-	-	-
		DSM	CNP	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Weatherization			-	-	-	-	-	-	-	-	-	-
151	Fuel Stock												
		P	DEU	-	-	-	-	-	-	-	-	-	-
		P	SE	38,308,735	38,308,735	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				38,308,735	38,308,735	-	-	-	-	-	-	-	-
152	Fuel Stock - Undistributed												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit												
		P	SE	63,275	63,275	-	-	-	-	-	-	-	-
				63,275	63,275	-	-	-	-	-	-	-	-
25317	DG&T Working Capital Deposit												
		P	SE	(1,103,462)	(1,103,462)	-	-	-	-	-	-	-	-
				(1,103,462)	(1,103,462)	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
25319	Provo Working Capital Deposit												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Fuel Stock			37,268,548	37,268,548	-	-	-	-	-	-	-	-
154	Materials and Supplies												
		MSS	S	92,111,560	67,557,192	1,374,249	22,536,931	-	-	-	643,188	-	-
		MSS	SG	(34,091)	(25,003)	(509)	(8,341)	-	-	-	(238)	-	-
		MSS	SE	-	-	-	-	-	-	-	-	-	-
		MSS	SO	(226,098)	(165,827)	(3,373)	(55,319)	-	-	-	(1,579)	-	-
		MSS	SG	36,041,827	26,434,083	537,722	8,818,352	-	-	-	251,670	-	-
		MSS	SG	9,124	6,692	136	2,232	-	-	-	64	-	-
		MSS	SNPD	(329,812)	(241,893)	(4,921)	(80,695)	-	-	-	(2,303)	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	2,322,954	1,703,720	34,657	568,357	-	-	-	16,221	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
				129,895,465	95,268,964	1,937,962	31,781,517	-	-	-	907,022	-	-
158	WA GHG Allocation Inventory												
		MSS	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit												
		MSS	SG	(73,394)	(53,829)	(1,095)	(17,957)	-	-	-	(512)	-	-
				(73,394)	(53,829)	(1,095)	(17,957)	-	-	-	(512)	-	-
	Total Materials & Supplies			129,822,071	95,215,135	1,936,867	31,763,560	-	-	-	906,510	-	-
165	Prepayments												
		LABOR	S	4,549,813	1,905,418	328,785	1,791,317	13,551	-	308,195	90,172	112,374	-
		GP	GPS	54,209	21,361	15,912	15,530	171	-	306	755	173	-
		PT	SG	1,649,178	920,830	728,348	-	-	-	-	-	-	-
		P	SE	154,795	154,795	-	-	-	-	-	-	-	-
		LABOR	SO	10,430,189	4,368,064	753,722	4,106,494	31,065	-	706,519	206,715	257,611	-
				16,838,184	7,370,468	1,826,768	5,913,341	44,788	-	1,015,019	297,642	370,158	-
182M	Misc Regulatory Assets												
		DDS2	S	75,123	87,365	(1,726)	(10,027)	(13)	-	(287)	(84)	(105)	-
		DEFSG	SG	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	33,785,672	33,785,672	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	23,420,768	9,808,394	1,692,467	9,221,045	69,757	-	1,586,472	464,174	578,459	-
				57,281,563	43,681,431	1,690,741	9,211,018	69,744	-	1,586,185	464,089	578,354	-
186M	Misc Deferred Debits												

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	44,579,610	41,559,303	3,020,307	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		P	SE	80,732	80,732	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
				44,660,342	41,640,035	3,020,307	-	-	-	-	-	-	-
Working Capital													
CWC	Cash Working Capital												
		CWC	S	36,025,180	24,677,978	3,066,513	7,267,027	49,744	-	492,869	258,123	212,927	-
		CWC	SO	-	-	-	-	-	-	-	-	-	-
		CWC	SE	-	-	-	-	-	-	-	-	-	-
				36,025,180	24,677,978	3,066,513	7,267,027	49,744	-	492,869	258,123	212,927	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
OWC	Other Work. Cap.												
131	Cash	GP	SNP	-	-	-	-	-	-	-	-	-	-
135	Working Funds	GP	SG	-	-	-	-	-	-	-	-	-	-
141	Notes Receivable	GP	SO	-	-	-	-	-	-	-	-	-	-
143	Other A/R	LABOR	SO	18,532,802	7,761,361	1,339,246	7,296,592	55,198	-	1,255,372	367,300	457,734	-
232	A/P	LABOR	S	-	-	-	-	-	-	-	-	-	-
232	A/P	LABOR	SO	(1,772,159)	(742,163)	(128,062)	(697,721)	(5,278)	-	(120,042)	(35,122)	(43,770)	-
232	A/P	P	SE	(741,683)	(741,683)	-	-	-	-	-	-	-	-
232	A/P	P	SG	(1,242,552)	(1,242,552)	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	S	-	-	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	SE	(2,932,940)	(2,932,940)	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	SE	-	-	-	-	-	-	-	-	-	-
230	Asset Retir. Oblig.	P	S	-	-	-	-	-	-	-	-	-	-
254	Decom. Reg Liability	P	SG	-	-	-	-	-	-	-	-	-	-
254	Reclam. Reg Liability	P	SE	-	-	-	-	-	-	-	-	-	-
2533	Cholla Reclamation	P	SE	-	-	-	-	-	-	-	-	-	-
				11,843,468	2,102,022	1,211,183	6,598,872	49,920	-	1,135,330	332,177	413,964	-
Total Working Capital				47,868,648	26,780,000	4,277,696	13,865,898	99,664	-	1,628,199	590,300	626,890	-
Miscellaneous Rate Base													
18221	Unrec Plant & Reg Study Costs												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
18222	Nuclear Plant - Trojan												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1869	Misc Deferred Debits-Trojan												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL MISCELLANEOUS RATE BASE				-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE ADDITIONS				**334,442,604**	**252,579,303**	**13,016,932**	**60,578,434**	**214,196**	**-**	**4,224,947**	**2,253,389**	**1,575,402**	**-**
235	Customer Service Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
2281	Prov for Property Insur	LABOR	S	31,639,210	13,250,199	2,286,361	12,456,746	94,234	-	2,143,172	627,054	781,443	-
2282	Prov for Injuries & Dar	LABOR	SO	-	-	-	-	-	-	-	-	-	-
2282	Prov for Injuries & Dar	LABOR	S	5,479,612	2,294,809	395,976	2,157,391	16,321	-	371,177	108,600	135,339	-
2283	Prov for Pensions and I	LABOR	SO	(343,535)	(143,869)	(24,825)	(135,254)	(1,023)	-	(23,270)	(6,808)	(8,485)	-
2283	Prov for Pensions and I	LABOR	S	-	-	-	-	-	-	-	-	-	-
25335	Pens Oblig	LABOR	SE	(30,321,356)	(12,698,295)	(2,191,128)	(11,937,891)	(90,309)	-	(2,053,903)	(600,936)	(748,894)	-
254	Reg Liabilities - Insura	LABOR	SO	(9,278,417)	(3,885,713)	(670,491)	(3,653,027)	(27,635)	-	(628,500)	(183,888)	(229,164)	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				(2,824,487)	(1,182,868)	(204,107)	(1,112,035)	(8,412)	-	(191,325)	(55,978)	(69,761)	-
22841	Accum Misc Oper Provisions - Other												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(63,148)	(63,148)	-	-	-	-	-	-	-	-
				(63,148)	(63,148)	-	-	-	-	-	-	-	-
254105	ARO	P	S	-	-	-	-	-	-	-	-	-	-
230	ARO	P	TROJD	(1,860,674)	(1,860,674)	-	-	-	-	-	-	-	-
254105	ARO	P	TROJD	-	-	-	-	-	-	-	-	-	-
254		P	S	(338,613,472)	(338,613,472)	-	-	-	-	-	-	-	-
				(340,474,146)	(340,474,146)	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
252	Customer Advances for Construction												
		D_SPLIT	S	(5,177,396)	-	-	(4,912,218)	(55,062)	-	-	(210,115)	-	-
		T	SE	-	-	-	-	-	-	-	-	-	-
		T	SG	(41,481,126)	-	(41,481,126)	-	-	-	-	-	-	-
		D_SPLIT	SO	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
				(46,658,522)	-	(41,481,126)	(4,912,218)	(55,062)	-	-	(210,115)	-	-
25398	SO2 Emissions												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25399	Other Deferred Credits												
		D_SPLIT	S	(331,064)	-	-	(314,108)	(3,521)	-	-	(13,436)	-	-
		LABOR	SO	(3,339,904)	(1,398,720)	(241,353)	(1,314,961)	(9,948)	-	(226,238)	(66,193)	(82,491)	-
		P	SG	(81,921,571)	(81,921,571)	-	-	-	-	-	-	-	-
		P	SE	(4,157,179)	(4,157,179)	-	-	-	-	-	-	-	-
				(89,749,718)	(87,477,470)	(241,353)	(1,629,069)	(13,469)	-	(226,238)	(79,629)	(82,491)	-
190	Accumulated Deferred Income Taxes												
		D_SPLIT	S	80,908,155	-	-	76,764,174	860,471	-	-	3,283,511	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	12,786,344	5,354,799	923,986	5,034,141	38,083	-	866,119	253,411	315,804	-
		P	GPS	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	2,482,069	-	-	-	-	-	2,482,069	-	-	-
		P	TROJD	308,510	308,510	-	-	-	-	-	-	-	-
		P	SG	432,428	432,428	-	-	-	-	-	-	-	-
		P	SE	1,118,875	1,118,875	-	-	-	-	-	-	-	-
		LABOR	SNP	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	SNPD	577,021	-	-	547,467	6,137	-	-	23,417	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				98,613,403	7,214,612	923,986	82,345,782	904,690	-	3,348,189	3,560,339	315,804	-
281	Accumulated Deferred Income Taxes												
		P	S	-	-	-	-	-	-	-	-	-	-
		PT	SG	(0)	(0)	(0)	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				(0)	(0)	(0)	-	-	-	-	-	-	-
282	Accumulated Deferred Income Taxes												
		GP	S	(67,722,863)	(26,685,811)	(19,878,937)	(19,401,818)	(214,066)	-	(382,078)	(943,777)	(216,376)	-
		CSS_SYS	CN	(6,702)	-	-	-	-	-	(2,971)	(1,564)	(2,167)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		ACCMDIT	DITBAL	(95,790)	(43,917)	(28,179)	(23,568)	-	-	(58)	(67)	-	-
		PT	SNPD	-	-	-	-	-	-	-	-	-	-
		PT	CIAC	-	-	-	-	-	-	-	-	-	-
		C_Service	SNP	(65,144)	-	-	-	-	-	-	-	(65,144)	-
		P	SG-U	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(45,915,370)	(19,228,919)	(3,318,007)	(18,077,446)	(136,755)	-	(3,110,208)	(909,992)	(1,134,043)	-
		P	SG	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SE	(327,393)	(327,393)	-	-	-	-	-	-	-	-
		P	SG	(667,471,869)	(667,471,869)	-	-	-	-	-	-	-	-
				(781,605,130)	(713,757,908)	(23,225,123)	(37,502,833)	(350,820)	-	(3,495,316)	(1,855,399)	(1,417,731)	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
283	Accumulated Deferred Income Taxes												
		GP	S	(8,897,652)	(3,506,069)	(2,611,760)	(2,549,074)	(28,125)	-	(50,199)	(123,996)	(28,428)	-
		P	SG	(413,127)	(413,127)	-	-	-	-	-	-	-	-
		P	SE	(161,499)	(161,499)	-	-	-	-	-	-	-	-
		LABOR	SO	(8,448,561)	(3,538,177)	(610,523)	(3,326,303)	(25,163)	-	(572,287)	(167,441)	(208,667)	-
		GP	GPS	(2,517,329)	(991,939)	(738,921)	(721,186)	(7,957)	-	(14,202)	(35,081)	(8,043)	-
		LABOR	SNP	(138,531)	(58,015)	(10,011)	(54,541)	(413)	-	(9,384)	(2,746)	(3,422)	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
				(20,576,699)	(8,668,827)	(3,971,214)	(6,651,104)	(61,658)	-	(646,072)	(329,264)	(248,560)	-
TOTAL ACCUMULATED DEF INCOME TAX				(703,568,427)	(715,212,123)	(26,272,350)	38,191,845	492,213	-	(793,199)	1,375,676	(1,350,487)	-
255	Accumulated Investment Tax Credit												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC84	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC85	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC86	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC88	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC89	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC90	-	-	-	-	-	-	-	-	-	-
		LABOR	SG	(40,918)	(17,136)	(2,957)	(16,110)	(122)	-	(2,772)	(811)	(1,011)	-
				(40,918)	(17,136)	(2,957)	(16,110)	(122)	-	(2,772)	(811)	(1,011)	-
TOTAL RATE BASE DEDUCTIONS				**(1,183,379,365)**	**(1,144,426,891)**	**(68,201,894)**	**30,522,412**	**415,147**	**-**	**(1,213,534)**	**1,029,143**	**(1,503,749)**	**-**
108SP	Steam Prod Plant Accumulated Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(221,760,155)	(221,760,155)	-	-	-	-	-	-	-	-
		P	SG	(206,798,180)	(206,798,180)	-	-	-	-	-	-	-	-
		P	SG	(1,074,640,597)	(1,074,640,597)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(1,503,198,932)	(1,503,198,932)	-	-	-	-	-	-	-	-
108NP	Nuclear Prod Plant Accumulated Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(39,230,371)	(39,230,371)	-	-	-	-	-	-	-	-
		P	SG	(8,751,803)	(8,751,803)	-	-	-	-	-	-	-	-
		P	SG	(59,903,905)	(59,903,905)	-	-	-	-	-	-	-	-
		P	SG	(23,614,451)	(23,614,451)	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SG	(1,779,628)	(1,779,628)	-	-	-	-	-	-	-	-
				(133,280,158)	(133,280,158)	-	-	-	-	-	-	-	-
108OP	Other Production Plant - Accum Depr												
		P	S	(173,154,068)	(173,154,068)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(24,587,538)	(24,587,538)	-	-	-	-	-	-	-	-
		P	SG	(172,503,291)	(172,503,291)	-	-	-	-	-	-	-	-
		P	SG	(13,478,790)	(13,478,790)	-	-	-	-	-	-	-	-
				(383,723,687)	(383,723,687)	-	-	-	-	-	-	-	-
108EP	Experimental Plant - Accum Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT DEPRECIATION				**(2,020,202,776)**	**(2,020,202,776)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108TP	Transmission Plant Accumulated Depr												
		T_Split	S	-	-	-	-	-	-	-	-	-	-
		T_Split	SG	(93,970,067)	(1,465,854)	(92,504,214)	-	-	-	-	-	-	-
		T_Split	SG	(113,175,930)	(1,765,449)	(111,410,482)	-	-	-	-	-	-	-
		T_Split	SG	(444,839,407)	(6,939,119)	(437,900,287)	-	-	-	-	-	-	-
TOTAL TRANS PLANT ACCUM DEPR				**(651,985,404)**	**(10,170,422)**	**(641,814,983)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108360	Land and Land Rights												
		D	S	(2,858,488)	-	-	(2,858,488)	-	-	-	-	-	-
				(2,858,488)	-	-	(2,858,488)	-	-	-	-	-	-
108361	Structures and Improvements												
		D	S	(10,548,995)	-	-	(10,548,995)	-	-	-	-	-	-
				(10,548,995)	-	-	(10,548,995)	-	-	-	-	-	-
108362	Station Equipment												
		D	S	(112,577,498)	-	-	(112,577,498)	-	-	-	-	-	-
				(112,577,498)	-	-	(112,577,498)	-	-	-	-	-	-
108363	Storage Battery Equipment												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108364	Poles, Towers & Fixtures												
		D	S	(276,584,933)	-	-	(276,584,933)	-	-	-	-	-	-
				(276,584,933)	-	-	(276,584,933)	-	-	-	-	-	-
108365	Overhead Conductors												
		D	S	(147,706,066)	-	-	(147,706,066)	-	-	-	-	-	-
				(147,706,066)	-	-	(147,706,066)	-	-	-	-	-	-
108366	Underground Conduit												
		D	S	(53,984,823)	-	-	(53,984,823)	-	-	-	-	-	-
				(53,984,823)	-	-	(53,984,823)	-	-	-	-	-	-
108367	Underground Conductors												

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		D	S	(107,614,232)	-	-	(107,614,232)	-	-	-	-	-	-
				(107,614,232)	-	-	(107,614,232)	-	-	-	-	-	-
108368	Line Transformers												
		D	S	(270,462,078)	-	-	(270,462,078)	-	-	-	-	-	-
				(270,462,078)	-	-	(270,462,078)	-	-	-	-	-	-
108369	Services												
		D	S	(161,639,339)	-	-	(161,639,339)	-	-	-	-	-	-
				(161,639,339)	-	-	(161,639,339)	-	-	-	-	-	-
108370	Meters												
		C_Meter	S	(34,040,310)	-	-	-	-	-	-	(34,040,310)	-	-
				(34,040,310)	-	-	-	-	-	-	(34,040,310)	-	-
108371	Installations on Customers' Premises												
		DL	S	(2,164,552)	-	-	-	(2,164,552)	-	-	-	-	-
				(2,164,552)	-	-	-	(2,164,552)	-	-	-	-	-
108372	Leased Property												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108373	Street Lights												
		DL	S	(12,616,113)	-	-	-	(12,616,113)	-	-	-	-	-
				(12,616,113)	-	-	-	(12,616,113)	-	-	-	-	-
108D00	Unclassified Dist Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
108DS	Unclassified Dist Sub Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300												
		D_SPLIT	S	685,999	-	-	650,863	7,296	-	-	27,840	-	-
				685,999	-	-	650,863	7,296	-	-	27,840	-	-
TOTAL DISTRIBUTION PLANT DEPR				**(1,192,111,426)**	**-**	**-**	**(1,143,325,587)**	**(14,773,369)**	**-**	**-**	**(34,012,470)**	**-**	**-**
108GP	General Plant Accumulated Depr												
		D_SPLIT	S	(96,741,359)	-	-	(91,786,427)	(1,028,859)	-	-	(3,926,073)	-	-
		G-DGP	SG	(127,180)	(71,007)	(56,173)	-	-	-	-	-	-	-
		G-DGU	SG	(562,467)	(314,036)	(248,431)	-	-	-	-	-	-	-
		G-SG	SG	(41,918,891)	(16,674,212)	(25,244,679)	-	-	-	-	-	-	-
		B_Center	CN	(1,684,429)	-	-	-	-	-	(1,097,314)	-	(587,115)	-
		LABOR	SO	(37,251,967)	(15,600,768)	(2,691,958)	(14,666,558)	(110,952)	-	(2,523,368)	(738,293)	(920,070)	-
		P	SE	(503,748)	(503,748)	-	-	-	-	-	-	-	-
		G-SG	SG	(40,155)	(15,973)	(24,182)	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
				(178,830,195)	(33,179,743)	(28,265,424)	(106,452,985)	(1,139,811)	-	(3,620,682)	(4,664,365)	(1,507,185)	-
108MP	Mining Plant Accumulated Depr.												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108MP	Less Centralia Situs Depreciation												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1081390	Accum Depr - Capital Lease												
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
1081399	Accum Depr - Capital Lease												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT ACCUM DEPR				**(178,830,195)**	**(33,179,743)**	**(28,265,424)**	**(106,452,985)**	**(1,139,811)**	**-**	**(3,620,682)**	**(4,664,365)**	**(1,507,185)**	**-**
TOTAL ACCUM DEPR - PLANT IN SERVICE				**(4,043,129,802)**	**(2,063,552,941)**	**(670,080,406)**	**(1,249,778,572)**	**(15,913,180)**	**-**	**(3,620,682)**	**(38,676,835)**	**(1,507,185)**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
111OP	Accum Prov for Amort-Steam												
		P	S	(198,109)	(198,109)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(198,109)	(198,109)	-	-	-	-	-	-	-	-
111GP	Accum Prov for Amort-General												
		D_SPLIT	S	(5,273,651)	-	-	(5,003,544)	(56,086)	-	-	(214,022)	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(412,712)	(172,840)	(29,824)	(162,490)	(1,229)	-	(27,956)	(8,179)	(10,193)	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				(5,686,363)	(172,840)	(29,824)	(5,166,033)	(57,315)	-	(27,956)	(222,201)	(10,193)	-
111HP	Accum Prov for Amort-Hydro												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(1,138,696)	(1,138,696)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(1,138,696)	(1,138,696)	-	-	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant												
		I-SITUS	S	(159,409)	-	(103,996)	(53,831)	-	-	-	(1,581)	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	(113,451)	(113,451)	-	-	-	-	-	-	-	-
		P	SE	(770)	(770)	-	-	-	-	-	-	-	-
		I-SG	SG	(31,378,917)	(19,950,608)	(11,428,309)	-	-	-	-	-	-	-
		I-SG	SG	(13,378,910)	(8,506,265)	(4,872,645)	-	-	-	-	-	-	-
		I-SG	SG	(1,777,279)	(1,129,988)	(647,291)	-	-	-	-	-	-	-
		CUST	CN	(63,528,158)	-	-	-	-	-	(28,164,150)	(14,823,237)	(20,540,771)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		PTD	SO	(115,498,543)	(46,237,218)	(36,572,209)	(32,689,116)	-	-	-	-	-	-
				(225,835,437)	(75,938,301)	(53,624,451)	(32,742,946)	-	-	(28,164,150)	(14,824,818)	(20,540,771)	-
111IP	Less Non-Utility Plant												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
				(225,835,437)	(75,938,301)	(53,624,451)	(32,742,946)	-	-	(28,164,150)	(14,824,818)	(20,540,771)	-
111390	Accum Amtr - Capital Lease												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Lease Amtr			-	-	-	-	-	-	-	-	-	-
TOTAL ACCUM PROV FOR AMORTIZATION				**(232,858,605)**	**(77,447,946)**	**(53,654,275)**	**(37,908,980)**	**(57,315)**	**-**	**(28,192,106)**	**(15,047,019)**	**(20,550,964)**	**-**

Docket No. UE 433
Exhibit PAC/1904
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Functional Factors

February 2024

Functional Factors

Function	Description	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM	Total
				Internal Factors							
CWC	Cash Working Capital	68.5020%	8.5121%	20.1721%	0.1381%	0.0000%	1.3681%	0.7165%	0.5910%	0.0000%	100%
D_SPLIT	Distribution Split between Functions	0.0000%	0.0000%	94.8782%	1.0635%	0.0000%	0.0000%	4.0583%	0.0000%	0.0000%	100%
GP	Gross Plant	39.4044%	29.3534%	28.6488%	0.3161%	0.0000%	0.5642%	1.3936%	0.3195%	0.0000%	100%
IBT	Income Before Taxes	-57.7620%	57.9125%	92.9262%	1.9070%	0.0000%	0.2698%	5.4248%	-0.6784%	0.0000%	100%
NP	Net Plant	31.9884%	37.9945%	27.6299%	0.2762%	0.0000%	0.4392%	1.4890%	0.1830%	0.0000%	100%
PT	Production / Transmission	55.8357%	44.1643%								100%
PTD	Prod, Trans, Dist Plant	40.0327%	31.6646%	28.3026%							100%
REVREQ	Revenue Requirement	57.4929%	16.8768%	22.7488%	0.1738%	0.0000%	1.2050%	0.9469%	0.5558%	0.0000%	100%
T_SPLIT	Transmission Split	1.5599%	98.4401%								100%
TD	Transmission / Distribution		52.8032%	47.1968%							100%
	External Factors										
ACCMDIT	Deferred Income Tax - Balance	45.8475%	29.4179%	24.6038%	0.0000%	0.0000%	0.0607%	0.0701%	0.0000%	0.0000%	100%
ANC	Ancillary Function	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
B_CENTER	Business Centers	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	65.1446%	0.0000%	34.8554%	0.0000%	100%
BOOKDEPR	Book Depreciation	60.9173%	15.4894%	22.5693%	0.2731%	0.0000%	0.0878%	0.6630%	0.0000%	0.0000%	100%
C_BILLING	Customer Billing	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	100%
C_METER	Customer Metering	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	100%
C_SERVICE	Customer Other	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100%
CSS_SYS	CSS System	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%	100%
CUST	Customer	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%	100%
CUST901	Supervision	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	59.0822%	37.4112%	3.5066%	0.0000%	100%
CUST903	Cust. Records & Coll. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	76.0086%	4.1993%	19.7921%	0.0000%	100%
CUST905	Misc. Customer Acct. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	62.6614%	37.3386%	0.0000%	100%
D	Distribution Only	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
DL	Distribution Only-LGT	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
DDS2	Deferred Debits - Situs	116.2955%	-2.2975%	-13.3470%	-0.0168%	0.0000%	-0.3826%	-0.1120%	-0.1395%	0.0000%	100%
DDS6	Deferred Debits - Situs	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
DDSO2	Deferred Debits - System Overhead	39.5923%	7.5555%	43.1967%	0.2496%	0.0000%	5.6758%	1.6606%	2.0695%	0.0000%	100%
DDSO6	Deferred Debits - System Overhead	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
DEFSG	Deferred Debit - System Generation	93.2249%	6.7751%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
DSM	Demand Side Management	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
DPW	Distribution Poles & Wires	0.0000%	0.0000%	97.1461%	0.0000%	0.0000%	0.0000%	2.8539%	0.0000%	0.0000%	100%
ESD	Environmental Services Department	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
FERC	FERC Fees	48.9234%	51.0766%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
G	General Plant	19.4958%	35.1734%	42.9764%	0.0000%	0.0000%	1.0919%	1.2625%	0.0000%	0.0000%	100%
G-DGP	General Plant - DGP Factor	55.8319%	44.1681%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
G-DGU	General Plant - DGU Factor	55.8319%	44.1681%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
G-SG	General Plant - SG Factor	39.7773%	60.2227%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
G-SITUS	General Plant - SITUS Factor	0.0000%	28.5980%	69.3642%	0.0000%	0.0000%	0.0000%	2.0378%	0.0000%	0.0000%	100%
I	Intangible Plant	39.6408%	20.0496%	15.6606%	0.0000%	0.0000%	7.9092%	10.3921%	6.3476%	0.0000%	100%
I-DGP	Intangible Plant - DGP Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
I-DGU	Intangible Plant - DGU Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
I-SG	Intangible Plant - SG Factor	63.5797%	36.4203%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
I-SITUS	Intangible Plant - SITUS Factor	0.0000%	65.2389%	33.7690%	0.0000%	0.0000%	0.0000%	0.9921%	0.0000%	0.0000%	100%
LABOR	Direct Labor Expense	41.8790%	7.2264%	39.3712%	0.2978%	0.0000%	6.7738%	1.9819%	2.4699%	0.0000%	100%
MSS	Materials & Supplies	73.3428%	1.4919%	24.4670%	0.0000%	0.0000%	0.0000%	0.6983%	0.0000%	0.0000%	100%
NONE	Not Functionalized	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
NUTIL	Non-Utility	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
OTHDGP	Other Revenues - DGP Factor	15.1810%	84.8151%	0.0039%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHDGU	Other Revenues - DGU Factor	15.1810%	84.8151%	0.0039%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSE	Other Revenues - SE Factor	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSG	Other Revenues - SG Factor	15.1810%	84.8151%	0.0039%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSGR	Other Revenues - Rolled-In SG Factor	15.1810%	84.8151%	0.0039%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSITUS	Other Revenues - SITUS	3.6445%	87.7238%	8.6317%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSO	Other Revenues - SO Factor	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
P	Production	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
SCHMA	Schedule M Additions	32.1161%	26.0678%	39.5366%	0.0034%	0.0000%	0.7803%	1.2944%	0.2014%	0.0000%	100%
SCHMAF	Schedule M Additions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
SCHMAP	Schedule M Additions - Permanent	61.8426%	4.7442%	25.8479%	0.1955%	0.0000%	4.4471%	1.3011%	1.6215%	0.0000%	100%
SCHMAP-SO	Schedule M Additions - Permanent-SO	62.9639%	4.6048%	25.0883%	0.1898%	0.0000%	4.3164%	1.2629%	1.5739%	0.0000%	100%
SCHMAT	Schedule M Additions - Temporary	32.0433%	26.1201%	39.5701%	0.0029%	0.0000%	0.7713%	1.2944%	0.1979%	0.0000%	100%
SCHMAT-SG	Schedule M Additions - Temporary-SG	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
SCHMAT-SE	Schedule M Additions - Temporary-SE	102.5711%	-0.3197%	-1.7417%	-0.0132%	0.0000%	-0.2997%	-0.0877%	-0.1093%	0.0000%	100%
SCHMAT-SITUS	Schedule M Additions - Temporary-SITUS	59.2308%	13.0570%	23.5454%	0.0992%	0.0000%	2.2553%	0.9900%	0.8223%	0.0000%	100%
SCHMAT-SNP	Schedule M Additions - Temporary-SNP	44.6690%	26.6945%	27.8168%	0.0000%	0.0000%	0.0012%	0.8178%	0.0008%	0.0000%	100%
SCHMAT-SO	Schedule M Additions - Temporary-SO	41.8593%	7.0888%	39.4529%	0.2999%	0.0000%	6.8216%	1.9901%	2.4873%	0.0000%	100%
SCHMD	Schedule M Deductions	60.7520%	24.4791%	16.0175%	-0.0531%	0.0000%	-1.1623%	0.2161%	-0.2494%	0.0000%	100%
SCHMDF	Schedule M Deductions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
SCHMDP	Schedule M Deductions - Permanent	98.2709%	0.8343%	0.8693%	0.0000%	0.0000%	0.0000%	0.0255%	0.0000%	0.0000%	100%
SCHMDP-SO	Schedule M Deductions - Permanent- SO	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
SCHMDT	Schedule M Deductions - Temporary	60.6749%	24.5277%	16.0486%	-0.0532%	0.0000%	-1.1647%	0.2165%	-0.2499%	0.0000%	100%
SCHMDT-GPS	Schedule M Deductions - Temporary-GPS	44.6744%	26.6934%	27.8150%	0.0000%	0.0000%	0.0000%	0.8171%	0.0000%	0.0000%	100%
SCHMDT-SG	Schedule M Deductions - Temporary-SG	102.7238%	-2.7238%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
SCHMDT-SITUS	Schedule M Deductions - Temporary-SITUS	104.4057%	-0.9268%	-3.3169%	-0.0036%	0.0000%	-0.0862%	-0.0394%	-0.0327%	0.0000%	100%
SCHMDT-SNP	Schedule M Deductions - Temporary-SNP	44.6744%	26.6934%	27.8150%	0.0000%	0.0000%	0.0000%	0.8171%	0.0000%	0.0000%	100%
SCHMDT-SO	Schedule M Deductions - Temporary-SO	41.9875%	-1.7174%	42.2164%	0.4626%	0.0000%	10.5108%	2.7108%	3.8294%	0.0000%	100%
STEP_UP	Step-up Transformers	6.4452%	93.5548%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
T	Transmission	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
TAXDEPR	Tax Depreciation	43.5570%	28.1956%	26.0434%	0.0349%	0.0000%	0.8586%	0.7556%	0.5547%	0.0000%	100%

Docket No. UE 433
Exhibit PAC/1905
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Ancillary Services Revenue Requirement

February 2024

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Ancillary Services Revenue
12 Months Ended December 31, 2025 Forecast

Oregon Annual Ancillary Service Revenue $24,138,546

Calculation below per the PacifiCorp Open Access Transmission Tariff (OATT) Load and Generation prices on Schedule 3 (Regulation and Frequency Response Service), Schedule 3A (Generator Regulation and Frequency Response Service), Schedule 5 (Operating Reserve - Spinning Reserve Service) and Schedule 6 (Operating Reserve - Supplemental Reserve Service)

Load[1]

Line	Description	Calculation	Value
1	Sum of 12 Oregon Monthly Peaks (MW)		29,457
2	Total Oregon Retail Load (MWh)		17,203,230
3			
4	Schedule 3 Load Rate ($/MW-month)		$115
5	Schedule 3 Revenue	1*4	$3,402,039
6			
7	Schedule 5 Rate ($/MWh)		$0.168
8	Schedule 5 Revenue	2*7	$2,884,982
9			
10	Schedule 6 Rate ($/MWh)		$0.168
11	Schedule 6 Revenue	2*10	$2,884,982
12			
13			
14	Total Oregon Load Revenue	5+8+11	$9,172,002

Generation

Line	Description	Calculation	Value
1	Sum of 12 Total System Solar VER Generator Nameplate Capacities (MW)[2]		21,662
2	Sum of 12 Total System Wind VER Generator Nameplate Capacities (MW)[2]		42,550
3	Sum of 12 Total System Non-VER Generator Nameplate Capacities (MW)		9,306
4	Total System Generation MWh at input		57,900,603
5			
6	Schedule 3A Solar VER Rate ($/MW-month)		$465
7	Schedule 3A VER Revenue	1*6	$10,079,542
8			
9	Schedule 3A Wind VER Rate ($/MW-month)		$558
10	Schedule 3A VER Revenue	2*9	$23,729,612
11			
12	Schedule 3A Non-VER Rate ($/MW-month)		$262
13	Schedule 3A Non-VER Revenue	3*12	$2,441,482
14			
15	Schedule 5 Rate ($/MWh)		$0.168
16	Schedule 5 Revenue	4*15	$9,709,931
17			
18	Schedule 6 Rate ($/MWh)		$0.168
19	Schedule 6 Revenue	4*18	$9,709,931
20			
21			
22	Total Generation Revenue	6+9+12+15	$55,670,499
23			
24	Oregon JAM SG Factor		27%
25	Oregon-allocated Total Generation Revenue	18*20	$14,966,544

[1]Load is Oregon's Contributions to Monthly Firm System Retail Load at input
[2]All VER Generation is assumed to be Uncommitted (see OATT Schedule 3A requirements for Committed and Uncommitted)

Docket No. UE 433
Exhibit PAC/1906
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Oregon Marginal Cost of Service Study Summary

February 2024

-

STATE OF OREGON
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2025 Forecast
(Dollars in 000s)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Lighting
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		Sch 15, 51,
Line	Class / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	53, 54 (sec)
1	Demand Related Marginal Cost																			
2	Generation	$387,461	$173,067	$14,432	$15,502	$47	$11,010	$16,705	$23,893	$512	$4,244	$26,009	$1,788	$10,619	$11,751	$2,401	$34,151	$36,040	$5,291	$0
3	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
4	Distribution	$192,240	$102,489	$10,734	$10,646	$29	$6,019	$9,285	$12,889	$245	$1,834	$10,883	$719	$6,332	$6,747	$402	$4,773	$0	$8,182	$35
5	Poles	$53,771	$28,252	$3,137	$3,390	$10	$1,710	$2,564	$3,602	$76	$449	$2,630	$187	$2,125	$2,364	$0	$0	$0	$3,272	$3
6	Conductor	$68,757	$37,460	$3,646	$3,939	$12	$2,205	$3,307	$4,646	$98	$668	$3,956	$278	$2,459	$2,736	$0	$0	$0	$3,344	$4
7	Substations	$53,986	$28,220	$2,102	$2,271	$7	$1,618	$2,426	$3,408	$72	$608	$3,671	$254	$1,481	$1,648	$336	$4,773	$0	$1,093	$0
8	Transformers	$15,726	$8,557	$1,849	$1,045	$0	$485	$988	$1,232	$0	$108	$627	$0	$267	$0	$66	$0	$0	$473	$28
9	Total Demand	$789,543	$385,907	$36,554	$37,497	$106	$23,547	$36,033	$50,757	$1,026	$8,104	$48,956	$3,308	$23,764	$25,780	$3,313	$45,248	$37,677	$21,895	$71
10																				
11																				
12	Energy Related Marginal Cost																			
13	Generation	$1,282,011	$641,433	$244,673	$23,481	$25,569	$78	$17,980	$27,744	$40,656	$893	$7,215	$45,734	$3,238	$19,281	$34,643	$4,779	$56,265	$78,417	$9,931
14	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Total Energy	$1,282,011	$641,433	$244,673	$23,481	$25,569	$78	$17,980	$27,744	$40,656	$893	$7,215	$45,734	$3,238	$19,281	$34,643	$4,779	$56,265	$78,417	$9,931
16																				
17	Customer Related Marginal Cost																			
18	Poles	$64,407	$48,393	$10,282	$2,191	$7	$461	$367	$227	$6	$13	$39	$3	$11	$8	$0	$0	$0	$2,400	$0
19	Conductor	$27,995	$21,034	$4,469	$952	$3	$200	$159	$99	$3	$6	$17	$1	$5	$4	$0	$0	$0	$1,043	$0
20	Transformers	$105,698	$62,918	$18,212	$4,883	$0	$4,108	$3,664	$2,477	$0	$258	$781	$0	$102	$0	$5	$0	$0	$8,290	$0
21	Service Drops	$58,411	$43,193	$8,142	$3,242	$0	$990	$805	$1,138	$0	$72	$548	$0	$268	$0	$13	$0	$0	$0	$0
22	Meters	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
23	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Billing & Collections	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
25	Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
26	Customer Service / Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
27	Total Customer (Commitment & Billing)	$302,921	$212,673	$45,903	$12,344	$99	$6,199	$5,352	$4,555	$114	$422	$1,605	$81	$548	$216	$27	$85	$227	$12,200	$271
28																				
29																				
30	Total Revenue @ Full MC																			
31	Generation	$1,028,894	$417,741	$37,913	$41,071	$125	$28,990	$44,449	$64,549	$1,405	$11,459	$71,742	$5,027	$29,900	$46,394	$7,180	$90,416	$114,457	$15,222	$855
32	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
33	Distribution	$448,751	$278,027	$51,839	$21,914	$39	$11,777	$14,279	$16,830	$254	$2,183	$12,267	$723	$6,717	$6,759	$420	$4,773	$0	$19,915	$35
34	Customer - Billing	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
35	Customer - Metering	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
36	Customer - Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
37	Revenue (less Uncollectables)	$1,534,981	$734,807	$95,092	$64,741	$255	$41,631	$59,783	$83,040	$1,786	$13,886	$85,346	$5,904	$37,150	$53,811	$7,711	$96,792	$116,310	$35,774	$1,161
38																				
39	Customer - Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
40	Total Revenue	$1,541,658	$740,765	$95,205	$64,765	$255	$41,708	$59,845	$83,079	$1,787	$13,907	$85,412	$5,908	$37,262	$53,892	$7,717	$96,825	$116,321	$35,843	$1,161

Docket No. UE 433
Exhibit PAC/1907
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Unbundled Revenue Requirement Allocation

February 2024

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2025 Unbundled Revenue Requirement Allocation by Load Class

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			Residential	General Service		General Service		General Service		Large Power Service			Irrigation	Lighting
		Total		Sch 23		Sch 28		Sch 30		Sch 48			Sch 41	Schs 15, 51,
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	53, and 54
1	Total Operating Revenues	$1,670,831	$786,075	$159,656	$230	$209,460	$1,874	$112,053	$6,920	$51,960	$169,230	$136,366	$32,687	$4,319
2	MWh	15,276,984	5,787,620	1,160,255	1,877	2,043,261	21,451	1,252,474	77,805	570,908	2,171,323	1,934,880	234,910	20,221
3														
4	Functionalized 20 Year Full Marginal Costs - Class $													
5	Generation	$1,028,894	$417,741	$78,984	$125	$137,988	$1,405	$83,201	$5,027	$37,079	$136,811	$114,457	$15,222	$855
6	Transmission	$17,603	$7,863	$1,360	$2	$2,345	$23	$1,374	$81	$591	$2,085	$1,637	$240	$0
7	Distribution	$448,751	$278,027	$73,752	$39	$42,886	$254	$14,450	$723	$7,137	$11,532	$0	$19,915	$35
8	Customer - Billing	$16,127	$12,891	$2,507	$1	$359	$2	$27	$1	$24	$23	$2	$96	$191
9	Customer - Metering	$16,951	$12,794	$2,326	$86	$758	$102	$167	$71	$23	$145	$213	$264	$3
10	Customer - Other	$6,655	$5,492	$903	$1	$119	$1	$12	$1	$6	$6	$1	$37	$77
11	Total	$1,534,981	$734,807	$159,834	$255	$184,454	$1,786	$99,232	$5,904	$44,861	$150,602	$116,310	$35,774	$1,161
12														
13	Functional Revenue Requirement Allocation Factors													
14	Functionalized 20 Year Full Marginal Costs - Class % of Total													
15	Generation	100.00%	40.60%	7.68%	0.01%	13.41%	0.14%	8.09%	0.49%	3.60%	13.30%	11.12%	1.48%	0.08%
16	Transmission	100.00%	44.67%	7.73%	0.01%	13.32%	0.13%	7.81%	0.46%	3.36%	11.85%	9.30%	1.37%	0.00%
17	Distribution	100.00%	61.96%	16.44%	0.01%	9.56%	0.06%	3.22%	0.16%	1.59%	2.57%	0.00%	4.44%	0.01%
18	Distribution Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
19	Ancillary Service	100.00%	40.60%	7.68%	0.01%	13.41%	0.14%	8.09%	0.49%	3.60%	13.30%	11.12%	1.48%	0.08%
20	Customer - Billing	100.00%	79.94%	15.55%	0.01%	2.22%	0.01%	0.17%	0.01%	0.15%	0.15%	0.01%	0.60%	1.19%
21	Customer - Metering	100.00%	75.47%	13.72%	0.51%	4.47%	0.60%	0.99%	0.42%	0.13%	0.86%	1.26%	1.56%	0.02%
22	Customer - Other	100.00%	82.53%	13.57%	0.01%	1.79%	0.01%	0.18%	0.01%	0.09%	0.09%	0.01%	0.56%	1.15%
23	Embedded DSM - (MWh)	100.00%	37.88%	7.59%	0.01%	13.37%	0.14%	8.20%	0.51%	3.74%	14.21%	12.67%	1.54%	0.13%
24	Regulatory & Franchise - (Total Operating Revenues)	100.00%	47.05%	9.56%	0.01%	12.54%	0.11%	6.71%	0.41%	3.11%	10.13%	8.16%	1.96%	0.26%
25														
26														
27	Functionalized Class Revenue Requirement - (Target)													
28	Generation	$957,412	$388,719	$73,497	$116	$128,401	$1,307	$77,421	$4,677	$34,503	$127,306	$106,505	$14,164	$795
29	Transmission	$316,015	$141,155	$24,414	$38	$42,092	$417	$24,674	$1,458	$10,619	$37,438	$29,394	$4,315	$0
30	Distribution	$411,711	$255,078	$67,665	$36	$39,346	$233	$13,258	$663	$6,548	$10,580	$0	$18,271	$32
31	Distribution Lighting	$3,282	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,282
32	Distribution Total	$414,992	$255,078	$67,665	$36	$39,346	$233	$13,258	$663	$6,548	$10,580	$0	$18,271	$3,314
33	Ancillary Services	$23,961	$9,728	$1,839	$3	$3,213	$33	$1,938	$117	$864	$3,186	$2,665	$354	$20
34	Customer - Billing	$16,617	$13,283	$2,584	$2	$369	$2	$28	$1	$25	$24	$2	$99	$197
35	Customer - Metering	$19,394	$14,637	$2,662	$99	$867	$117	$191	$81	$26	$166	$244	$302	$3
36	Customer - Other	$9,976	$8,233	$1,354	$1	$179	$1	$18	$1	$9	$9	$1	$56	$115
37	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	Franchise Fees	$48,559	$22,845	$4,640	$7	$6,087	$54	$3,257	$201	$1,510	$4,918	$3,963	$950	$126
39	Total	$1,806,926	$853,679	$178,655	$301	$220,556	$2,164	$120,784	$7,201	$54,104	$183,627	$142,775	$38,512	$4,570
40														
41	Ratio of Operating Revn to Revenue Requirement-(Target)	92.47%	92.08%	89.37%	76.53%	94.97%	86.58%	92.77%	96.09%	96.04%	92.16%	95.51%	84.87%	94.52%
42	(Line 1 / Line 39)													
43	Increase or (Decrease)	$136,095	$67,604	$18,998	$71	$11,095	$290	$8,730	$281	$2,144	$14,397	$6,409	$5,825	$251
44	(Line 39 - Line 1)													
45														
46														
47	Percent Increase (Decrease)	8.15%	8.60%	11.90%	30.67%	5.30%	15.50%	7.79%	4.07%	4.13%	8.51%	4.70%	17.82%	5.80%
48	(Line 43 / Line 1)													

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2025 Functionalized Revenue - Earned
($ 000)

		A	B	C	D	E	F	G	I	J	K
Line No.	Description	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C Billing	C Metering	C Other	Franchise Fees	Total
1	Earned Functional Revenue Requirement	$936,890	$259,747	$368,771	$2,853	$24,139	$15,969	$17,101	$9,759	$45,708	$1,680,937
2											
3	Percent of Total	55.74%	15.45%	21.94%	0.17%	1.44%	0.95%	1.02%	0.58%	2.72%	100.00%
4											
5	Revenue From Classes Included in MC Study	$931,257	$258,185	$366,554	$2,836	$23,993	$15,873	$16,998	$9,701	$45,434	$1,670,831
6											
7	Other Revenues										
8	Schedule 4 - Employee Discount										($445)
9	Partial Requirements - Sch. 47 pri										$3,850
10	Partial Requirements - Sch. 47 trn										$1,198
11	Sch 848										$1,517
12	Oregon Direct Access Opt Out Amortization										$1,769
13	AGA										$4,071
14	Paperless Credit										($1,855)
15	Total Oregon Situs Revenue										$1,680,937

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2025 Functionalized Revenue - Target
($ 000)

Line No.	Description	A Production	B Transmission	C Distribution	D Dist-Lighting	E Ancillary	F C Billing	G C Metering	I C Other	J Franchise Fees	K Total	
1	Target Functional Revenue Requirement	$964,518	$318,360	$414,766	$3,306	$24,139	$16,740	$19,538	$10,050	$48,919	$1,820,337	
2												
3	Percent of Total	52.99%	17.49%	22.79%	0.18%	1.33%	0.92%	1.07%	0.55%	2.69%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$957,412	$316,015	$411,711	$3,282	$23,961	$16,617	$19,394	$9,976	$48,559	$1,806,926	$136,095
6												
7	Other Revenues											$139,399
8	Schedule 4 - Employee Discount										($482)	($37)
9	Partial Requirements - Sch. 47 pri										$4,544	$694
10	Partial Requirements - Sch. 47 trn										$1,533	$335
11	Sch 848										$3,829	$2,312
12	Oregon Direct Access Opt Out Amortization										$1,769	$0
13	AGA										$4,071	$0
14	Paperless Credit										($1,855)	$0
15	Total Oregon Situs Revenue										$1,820,336	

PACIFICORP
State of Oregon
December 31, 2025 Unbundled Revenue Requirement Allocation by Load Class
FERC Transmission Revenue ($ 000)

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
		Total	Residential	General Service Schedule 23		General Service Schedule 28		General Service Schedule 30		Large Power Service Schedule 48			Schedule 41	Lighting
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	Irrigation	(sec)
1	Total Transmission Revenue Requirement	$316,015	$141,155	$24,414	$38	$42,092	$417	$24,674	$1,458	$10,619	$37,438	$29,394	$4,315	$0
2														
3	FERC Transmission													
4	Peak MW @ Input	2,579	1,107	192	99	330	3	194	11	83	294	231	34	1
5	% of Total		42.94%	7.43%	3.85%	12.80%	0.13%	7.51%	0.44%	3.23%	11.39%	8.94%	1.31%	0.04%
6	FERC Transmission Revenues ($ 000)	$91,066	$39,102	$6,763	$3,502	$11,660	$116	$6,835	$404	$2,942	$10,371	$8,143	$1,195	$33
7														
8	Other Transmission Revenue Requirement	$224,949	$102,053	$17,651	($3,464)	$30,432	$302	$17,839	$1,054	$7,677	$27,067	$21,252	$3,120	($33)

	OR CP (MW)
Jan	2,814
Feb	2,631
Mar	2,502
Apr	2,365
May	1,993
Jun	2,319
Jul	2,745
Aug	2,591
Sep	2,093
Oct	2,190
Nov	2,580
Dec	2,634
Annual Average	2,455

Network service rate ($/MW-year)[1]	$37,098
FERC Transmission Revenues	$91,066,068

[1]From 2023 Transmission Formula Rate Annual Update p.14

Docket No. UE 433
Exhibit PAC/1908
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Oregon Marginal Cost of Service Study

February 2024

PacifiCorp
Marginal Cost Study & Circuit Model Procedures

INTRODUCTION

Customer class marginal costs are developed to illustrate the resources required to produce one additional unit of electricity or add one additional customer to the system. One, five, ten and twenty years marginal costs are calculated because the Company believes the Commission should have information about the Company's marginal costs over different time periods. Twenty-year (or long run) marginal costs, however, are the primary time frame used in setting retail tariff prices.

The one-year marginal costs include only changes in operating costs, while ten- and twenty-year marginal costs also include the cost of expanding facilities. The cost of added facilities results in long-run costs, which are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. There are no short-run demand-related generation, transmission or distribution costs. Long-run costs include ten or twenty years of generation costs, transmission and distribution costs.

One, ten and twenty-year marginal costs are summarized by customer class and load size group and shown in mills/kilowatt-hour (kWh). Marginal commitment costs and billing expenses, which are sometimes referred to as customer costs, are shown in dollars per customer per year. Costs are shown for both the one-year and the long-run time periods.

Unit costs are adjusted to 2025 values and are shown by generation, transmission, and distribution functional categories and by demand, energy, and commitment and billing costing classifications. Also included are energy usage, peak demand, and number of customers by customer class for the 12 month period ending December 2025.

One, ten and twenty-year marginal costs in mills/kilowatt-hour (kWh) are shown on "Summary of Marginal Costs Demand & Energy in Mills/kWh" (Sheet 'Table 1'). Marginal commitment costs and billing expenses are shown on "Summary of Marginal Costs Commitment and Billing in $ / Customer / Month" (Sheet 'Table 2'). Billing information, unit costs, and total marginal costs are shown on "20 Year Marginal Cost" (Sheet 'Table 3').

MARGINAL GENERATION COSTS

The development of marginal generation costs for this study are based on a forecast cost of a storage resource, described in the Company's Integrated Resource Plan, and wholesale market purchases consistent with the Company's most recent avoided cost calculations. The marginal generation capacity costs are determined using the cost per kW-year of the storage resource adjusted for the capacity contribution of the resource and the forecast energy benefit. The generation energy costs are determined by deducting a capacity credit from the forecast market prices recognizing that a firm market purchase can be relied upon to meet the company's peak load requirements.

The marginal generation calculation can be seen in the marginal cost study on page "Marginal Generation Costs" (Sheet 'Generation'). A summarized version of this page is "Summary of Marginal Costs in Nominal Dollars" (Sheet 'Table 4').

MARGINAL TRANSMISSION COSTS

The calculation of transmission costs are based on a five-year (2024-2028) analysis of forecasted expenditures to meet increased load on the transmission system. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand.

Unlike growth-related system support and local transmission investments, the Company's investment in bulk power lines is classified both to demand and energy in the same proportions as twenty-year marginal costs of generation resources. Bulk transmission costs are classified this way because they are thought to be an integral part of the generation system. The Company's investments in high voltage bulk transmission lines are being made to move both energy and capacity. It is usually not possible to site a thermal plant close to the customers the plant is intended to serve. Instead, bulk power lines are constructed to transmit the energy being generated, along with the accompanying capacity.

Each year's growth-related transmission investments are adjusted to 2025 dollars and the five years are totaled. The total transmission investment is divided by the capacity added by the investment to determine the marginal investment per kilowatt (kW). An annual charge for including an A&G expense loading factor and a transmission O&M loading factor are added to the per kW investment to arrive at long-run transmission marginal cost.

The marginal transmission calculation including the split between demand and energy can be seen in the marginal cost study on page "Marginal Transmission Investment and O&M Expenses" (Sheet 'Transm'). A summarized version of this page is "Marginal Cost of Transmission Investment and Associated Expenses" (Sheet 'Table 5').

MARGINAL DISTRIBUTION COSTS

Distribution costs are classified into three components: Demand-related, shown in dollars per kW/year, commitment-related, shown in dollars per customer/year, and billing-related, shown in dollars per customer/year. Commitment costs consist of the costs of transformers, poles, and conductor that are not determined by the level of demand customers place on the system. Demand-related costs are the additional costs of larger transformers, substations, poles, and conductors with sufficient capacity to serve the level of demand a customer class places on the system. Billing costs are the costs of meters, service drops, and customer accounting functions.

A summary of distribution marginal costs showing these three components is on page "Marginal Distribution & Billing Costs" (Sheet 'Table 6').

Marginal line transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers.

Commitment and demand costs are separated by the nature of the statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Line transformer regression results are shown on page “Calculation of Escalation Factors for Transformers” (Sheet ‘XFMR2’). Transformer demand costs and commitment costs are shown on page “Transformer Demand and Commitment Costs” (Sheet ‘XFMR1’).

Marginal costs of distribution poles and wires are calculated using the Company’s Distribution Circuit Model (Sheets ‘PC2’ through ‘PC8’). The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics for the state of Oregon. The model determines the cost of the circuit by using current cost estimates to construct one mile of distribution facilities using each of the Company’s single and three phase wire sizes. The results are segregated into commitment related and demand related costs for each customer class. A more detailed description of the circuit model is included as an appendix to this narrative.

Marginal poles and wire costs are shown on page "Hypothetical Circuit Study Results Annual Demand and Commitment Costs” (Sheet ‘PC1’).

Marginal substation costs are determined using the per kW cost of budgeted and forecasted substation additions for the five year period 2024 - 2028. As part of the capital budgeting process the company determines which substations are approaching their maximum design loading. When load can no longer be shifted to adjacent substations, an upgrade, either greater capacity at the substation or a new substation, is required. The capital investment in common year dollars is totaled across all projects and across the budget-planning horizon to produce total substation investment.

This substation investment is then multiplied by a substation utilization factor. The substation utilization factor is calculated by dividing the maximum distribution peak by the installed capacity of existing distribution substations. The distribution peak is expanded by transmission voltage level losses and substation thermal loading. Applying a utilization factor to distribution substation costs reflects the fact that substation capacity additions are typically done in blocks which result in some substations being close to being fully utilized and others operating well below peak capacity. This weighted substation investment is, finally, divided by the associated incremental substation capacity to get dollars / kW. The dollars per kW is adjusted to an annual value by applying a real levelized carrying charge. Substation marginal costs are classified entirely to demand, and are allocated to customer classes based on the distribution peak load for each class.

Page "Distribution Substation Costs / kW 2025 Dollars” (Sheet ‘DistSub’) shows the annualized cost in $/kW and the detail of the substation calculation.

The marginal cost of services includes the costs of new service drop investment plus associated O&M expense. Average service drop investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Incremental service drop O&M is based on the average of ten years of historical expenditures.

The metering category includes the marginal cost of metering equipment with associated O&M expense. Average meter investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M expense is based on historical expenditures.

The billing customer service/other category includes the costs of billing, payment processing, debt recovery, meter reading expenses and all remaining customer accounting and customer service activities. Customer accounting and customer service expense are based on the most recent five years of expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

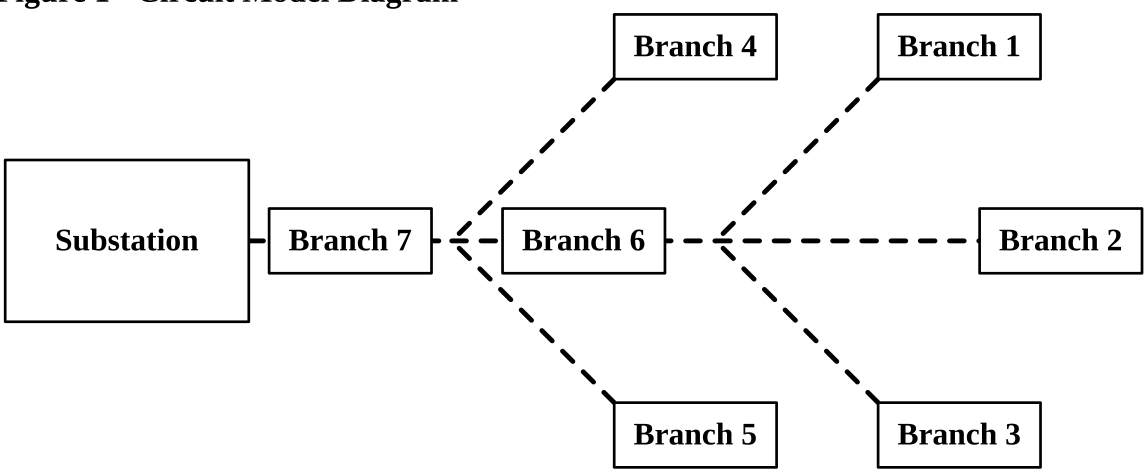
Weighted average installed service drop cost calculations are located on Sheet ‘Services’ and the weighted average installed meter cost calculations are included on Sheet ‘Meters’. The customer accounting and informational expense calculation is on page "Summary of Customer Accounting Expense by Schedule” (Sheet ‘CustExpense’). These calculations are brought together on "Marginal Distribution & Billing Costs” (Sheet ‘Table 6’) to calculate metering reading, billing, collections and customer service related costs ($/Customer/Yr).

PacifiCorp
Distribution Circuit Model
PacifiCorp Distribution Circuit Model

General Overview

The PacifiCorp Distribution Circuit Model is included in Exhibit PAC/1908, Sheets PC 2 through PC 8 and calculates the cost of building a hypothetical circuit (Figure 1, below) with seven branches of equal length using the composite line statistics for a chosen state or service area. A hypothetical circuit is used rather than a sampling of actual existing circuits. This is because the diverse characteristics of PacifiCorp's six state service area, consisting of over 2,000 distribution circuits, makes the selection of any single, or small number of typical circuits impractical. The fundamental concept of the hypothetical circuit is to create a model that reduces the elements of distribution cost assignment to a workable form.

Figure 1 - Circuit Model Diagram



The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and perhaps most importantly, customer location on the circuit. Each customer is assigned cost responsibility for all distribution facilities between the customer's location and the substation (upstream facilities), but no facilities beyond the customer's service location (downstream facilities). The model performs three basic functions. First, it estimates the total cost to build the composite circuit using current construction costs and state specific characteristics. Second, it divides the cost of each branch of the circuit between demand and commitment related costs. Third, it assigns the various types of costs to customer classes.

Required Engineering & Statistical Data

Listed below are the basic statistics that we use to calculate the composite circuit for a given state:

1. Current One Mile Line Construction Cost Estimates for Each Conductor Size
2. Economic Conductor Loading for Each Conductor Size

3. Overhead and Underground Line Miles
4. Number of Poles
5. Number of Circuits -- distribution line points of origin radiating from a substation.
6. Actual Customer Distances from Distribution Substations
7. Number of Customers and Loads by Class
8. Percentages of Three-Phase and Single-Phase Customers by Class

One Mile Line Estimate
The model determines the cost of the circuit by using cost estimates to construct one mile of distribution facilities using each of the Company's single and three-phase wire sizes. These cost estimates are based on typical topography and equipment configuration for an average mile of line construction. Since the number of poles per mile varies between states, we use a factor to adjust the line cost estimate from the system wide average of 26.89 poles per mile to the state average poles per mile. For example, Oregon has an average of 26.56 poles per mile. Figure 2 shows the circuit cost per mile calculation for Oregon.

Figure 2 – Adjusted Oregon Line Costs per Mile

	State Specific Account 364 Pole Statistics				Adjustment
	Poles	Pole Feet	Pole Miles	Poles / Mile	Factor
California	55,482	12,544,659	2,376	23.35	0.884
Idaho	97,406	21,318,575	4,038	24.12	0.913
Oregon	377,374	74,711,073	14,150	26.67	1.009
Utah	332,602	61,493,319	11,646	28.56	1.081
Washington	99,980	16,626,029	3,149	31.75	1.202
Wyoming	157,847	37,272,116	7,059	22.36	0.846
Total	1,120,691	223,965,771	42,418	26.42	1.000
	Account 364 Pole Cost per Mile			Account 365	Total Line
	Pole Cost	Adjustment	Adjusted	Conductor	Construction
Wire Size	per Mile	Factor	Pole Cost	Cost per Mile	Cost
1 Phase - 1/0 ACSR	$25,517	1.009	$25,758	$12,789	$38,547
3 Phase - 1/0 ACSR	$48,426	1.009	$48,883	$28,548	$77,431
3 Phase - 447 AAC & 4\0 AAC	$54,011	1.009	$54,521	$62,952	$117,473
3 Phase -795 AAC & 477 AAC	$56,143	1.009	$56,673	$110,173	$166,846

Customer Placement

One of the most significant cost drivers of marginal distribution costs is the distance between the customer and the substation. Costs increase as the distance from the substation increases.

The circuit model takes distance into account by assigning customers to the different branches of the circuit based upon actual customer locations. The actual customer distances are derived from PacifiCorp's outage management system (CADOPS). The system is able to accurately trace the flow of electricity from substation to customer as well as ascertain the exact distance it must travel.
Figure 3 shows the Customer Distribution on the Hypothetical Circuit Branch for Oregon.

Figure 3 Customer Distribution

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				Hypothetical Circuit Branch				Branch
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	0.37%	0.37%	0.37%	1.81%	1.81%	1.81%	93.46%	100.00%
GS - Schedule 23 - 0-15 kW (sec)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
GS - Schedule 23 - 15+ kW (sec)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
GS - Schedule 23 - Primary (pri)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
GS - Schedule 28 - 0-50 kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
GS - Schedule 28 - 51-100 kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
GS - Schedule 28 - 100 + kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
GS - Schedule 28 - Primary (pri)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
GS - Schedule 30 - 0-300 kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
GS - Schedule 30 - 300+ kW (sec)	0.28%	0.28%	0.28%	0.85%	0.85%	0.85%	96.61%	100.00%
GS - Schedule 30 - Primary (pri)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
Irrigation - Sch 41	1.08%	1.08%	1.08%	7.97%	7.97%	7.97%	72.85%	100.00%
LPS - Schedule 48 - 1 - 4 MW (sec)	0.85%	0.85%	0.85%	1.52%	1.52%	1.52%	92.89%	100.00%
LPS - Schedule 48 - 1 - 4 MW (pri)	0.85%	0.85%	0.85%	1.52%	1.52%	1.52%	92.89%	100.00%
LPS - Schedule 48 - > 4 MW (sec)			Large Customers are on dedicated circuits and are not included here					
LPS - Schedule 48 - > 4 MW (pri)			Large Customers are on dedicated circuits and are not included here					

Customer Density

The next significant driver of distribution costs is customer density. The model uses state specific line and customer statistics to calculate the average number of customers by circuit branch. Total state distribution line miles and state customers, by class, are divided by the number of distribution circuits in the state to determine the average length of the composite circuit (line miles / number of circuits) and the number of customers on the circuit (customers / circuits). Figure 4 shows the average number of customers located on each of the seven circuit branches for Oregon.

Figure 4 – Oregon Average Customers by Hypothetical Circuit Branch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	3.71	3.71	3.71	18.21	18.21	18.21	939.93	1,005.68
GS - Schedule 23 - 0-15 kW (sec)	0.93	0.93	0.93	3.45	3.45	3.45	121.01	134.17
GS - Schedule 23 - 15+ kW (sec)	0.20	0.20	0.20	0.74	0.74	0.74	25.79	28.59
GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
GS - Schedule 28 - 0-50 kW (sec)	0.04	0.04	0.04	0.13	0.13	0.13	8.06	8.57
GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.10	0.10	0.10	6.41	6.82
GS - Schedule 28 - 100 + kW (sec)	0.02	0.02	0.02	0.06	0.06	0.06	3.98	4.23
GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.37
GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	1.09	1.13
GS - Schedule 30 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.08
Irrigation - Sch 41	0.13	0.13	0.13	0.92	0.92	0.92	8.45	11.60
LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.15
LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
Total	5.06	5.06	5.06	23.65	23.65	23.65	1,115.58	1,201.72

Load Accumulation

The kW load that a customer or class places on the system influences the size of the conductor necessary to serve the load. At each point on the circuit, the conductor must be sized to carry the entire downstream load. At the far ends of the outer branches, loads are minimal. As you move upstream closer to the substation, the load on the circuit becomes greater requiring larger conductor sizes. In the model, load can accumulate two ways. The first occurs as customers accumulate on a branch of the circuit. When enough customers, or load, accumulate it is necessary to increment up to the next wire size. Upstream from that point, customer segments increase in cost due to the increase in wire size. The second method of load accumulation is when several branches converge at a central point on the trunk of the circuit. The trunk branches must be of adequate size to carry the load of the customers on that branch plus all downstream branches.

Figure 5 shows the circuit kW loading on each of the circuit branches for Oregon. Loads are for customers located on that branch. Accumulated loads for branch 6 would be the combined loads of branches 1, 2, 3 and 6. Accumulated loads for branch 7 would be the combined loads of all branches.

Figure 5 – Oregon Circuit kW Load by Branch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	8.43	8.43	8.43	41.45	41.45	41.45	2,139.10	2,288.76
GS - Schedule 23 - 0-15 kW (sec)	1.18	1.18	1.18	4.39	4.39	4.39	153.76	170.48
GS - Schedule 23 - 15+ kW (sec)	1.28	1.28	1.28	4.74	4.74	4.74	166.14	184.21
GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.01	0.01	0.01	0.50	0.56
GS - Schedule 28 - 0-50 kW (sec)	0.63	0.63	0.63	1.99	1.99	1.99	123.35	131.23
GS - Schedule 28 - 51-100 kW (sec)	0.95	0.95	0.95	2.99	2.99	2.99	184.95	196.76
GS - Schedule 28 - 100 + kW (sec)	1.33	1.33	1.33	4.20	4.20	4.20	259.85	276.44
GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.09	0.09	0.09	5.54	5.90
GS - Schedule 30 - 0-300 kW (sec)	0.14	0.14	0.14	0.48	0.48	0.48	47.47	49.33
GS - Schedule 30 - 300+ kW (sec)	0.84	0.84	0.84	2.53	2.53	2.53	287.59	297.70
GS - Schedule 30 - Primary (pri)	0.06	0.06	0.06	0.20	0.20	0.20	20.05	20.84
Irrigation - Sch 41	0.96	0.96	0.96	7.06	7.06	7.06	64.56	88.61
LPS - Schedule 48 - 1 - 4 MW (sec)	1.02	1.02	1.02	1.83	1.83	1.83	111.61	120.14
LPS - Schedule 48 - 1 - 4 MW (pri)	1.15	1.15	1.15	2.06	2.06	2.06	125.83	135.45
LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
Total	17.99	17.99	17.99	74.03	74.03	74.03	3,690.31	3,966.39

Circuit Model Cost Assignment

Line statistics for the PacifiCorp service area show that the distribution system is predominately overhead. To calculate the cost of branch construction, miles per branch is calculated by taking the distance per circuit (total line miles / total number of circuits) and dividing it by the number of branches per circuit (7 branches, see figure 1). Next, using an assumption from distribution engineers that the typical outer branches are 25% single phase, the circuit branch length is split between single and three-phase. The total branch construction cost can then be calculated by taking the single and three-phase distances per branch and multiplying them by the one mile construction costs for poles and conductors, as shown in figure 6. Costs are split between demand and commitment by assuming that the cost of constructing the branch with the smallest single-phase conductor and smallest pole is the commitment related portion and all costs above this amount are demand related. Trunk branches 6 and 7 are shown as 100% three-phase. Figure 6 shows the circuit costs per mile, costs for each branch and miles per branch broken out by single and three-phase for Oregon.

Figure 6 – Adjusted Oregon Line Costs per Mile

	Account 364 Pole Cost per Mile			Account 365	Total Line
Wire Size	Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Conductor Cost per Mile	Construction Cost
1 Phase - 1/0 ACSR	$29,797	0.988	$29,425	$12,789	$42,214
3 Phase - 1/0 ACSR	$56,836	0.988	$56,127	$28,548	$84,675
3 Phase - 447 AAC & 4\0 AAC	$63,338	0.988	$62,548	$62,952	$125,500
3 Phase -795 AAC & 477 AAC	$65,804	0.988	$64,984	$110,173	$175,157

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	$55,405	$196,266	$251,670
Conductors	$24,080	$99,826	$123,907
Total	$79,485	$296,092	$375,577

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4\0 AAC	3 Phase -795 AAC & 477 AAC
Poles	$336,490	$349,591
Conductors	$338,662	$592,695
Total	$675,151	$942,286

Miles per Branch	5.38
Single Phase Miles Per Branch	1.88
Three Phase Miles Per Branch	3.50

Customer Circuit Costs

After calculating the cost per mile for single and three-phase construction for all of the branches, we compile the data and create a hypothetical circuit model branch cost sheet, as shown in figure 7. Figure 7 includes the total cost per circuit branch in columns (A) and (B), and the allocation of total cost between commitment and demand in columns (C) through (F) for Oregon.

Figure 7 – Oregon Hypothetical Circuit Model Branch Costs

	Poles			Conductor			
	Total Cost	Commitment	Demand	Total Cost	Commitment	Demand	Total
Branches 1,2,3,4,5							
1 Phase - 1/0 ACSR	$55,405	$55,405	$0	$24,080	$24,080	$0	$79,485
3 Phase - 1/0 ACSR	$196,266	$102,895	$93,371	$99,826	$44,720	$55,106	$296,092
Total Branches 1,2,3,4,5	$251,670	$158,300	$93,371	$123,907	$68,801	$55,106	$375,577
Branch 6							$0
3 Phase - 447 AAC & 4\0 AAC	$336,490	$158,300	$178,190	$338,662	$68,801	$269,861	$675,151
Branch 7							$0
3 Phase -795 AAC & 477 AAC	$349,591	$158,300	$191,291	$592,695	$68,801	$523,895	$942,286
Total All Branches	$1,944,433	$1,108,097	$836,335	$1,550,890	$481,605	$1,069,285	$3,495,323

Cost Sharing Calculation

As mentioned before, one of the critical factors of cost-responsibility is the location of a customer or class on the circuit branches. Customer classes that locate on all branches share cost responsibility for all branches of the circuit including the trunk. Large industrial customers, who locate on the trunk of the circuit, share cost responsibility for only the trunk. Cost responsibility is determined by calculating the percentage of demand, or percentage of customers, by class that share a particular branch of the circuit. The total branch costs are then multiplied by the share percentage, and the branch costs are totaled by class. To calculate the total branch cost, the applicable cost of branches 6 and 7 are assigned to customers on branches 1, 2, 3, 4 and 5. Demand costs calculated in an earlier step are allocated between customer classes at this point. Figure 8 shows this calculation along with the allocation of branch costs to the individual customer classes for Oregon. Demand costs are totaled for each customer class and divided by circuit kW to get demand cost in dollars per kW.

Figure 8 – Oregon Poles and Conductors Demand Calculations, Cost Assignment

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Poles								
	1	2	3	4	5	6	7	Total	
% customer	14.06%	14.06%	14.06%			57.83%		100.00%	
Branch 6 Cost	$ 25,045	$ 25,045	$ 25,045			$ 103,055		$ 178,190	$ / kW
% customer	0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%	
Branch 7 Cost	$ 868	$ 868	$ 868	$ 3,571	$ 3,571	$ 3,571	$ 177,976	$ 191,291	
Branch Commitment Cost	$ 93,371	$ 93,371	$ 93,371	$ 93,371	$ 93,371				Average
Total	$ 119,284	$ 119,284	$ 119,284	$ 96,941	$ 96,941	$ 106,625	$ 177,976	$ 836,335	$ 210.86
Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	$ Per kW
Res - Schedule 4 (sec)	$ 55,912	$ 55,912	$ 55,912	$ 54,276	$ 54,276	$ 59,698	$ 103,165	$ 439,152	$ 191.87
GS - Schedule 23 - 0-15 kW (sec)	$ 7,847	$ 7,847	$ 7,847	$ 5,747	$ 5,747	$ 6,321	$ 7,416	$ 48,771	$ 286.09
GS - Schedule 23 - 15+ kW (sec)	$ 8,479	$ 8,479	$ 8,479	$ 6,210	$ 6,210	$ 6,830	$ 8,013	$ 52,700	$ 286.09
GS - Schedule 23 - Primary (pri)	$ 26	$ 26	$ 26	$ 19	$ 19	$ 21	$ 24	$ 159	$ 286.09
GS - Schedule 28 - 0-50 kW (sec)	$ 4,180	$ 4,180	$ 4,180	$ 2,612	$ 2,612	$ 2,873	$ 5,949	$ 26,584	$ 202.58
GS - Schedule 28 - 51-100 kW (sec)	$ 6,267	$ 6,267	$ 6,267	$ 3,916	$ 3,916	$ 4,307	$ 8,920	$ 39,859	$ 202.58
GS - Schedule 28 - 100 + kW (sec)	$ 8,805	$ 8,805	$ 8,805	$ 5,502	$ 5,502	$ 6,051	$ 12,532	$ 56,002	$ 202.58
GS - Schedule 28 - Primary (pri)	$ 188	$ 188	$ 188	$ 117	$ 117	$ 129	$ 267	$ 1,195	$ 202.58
GS - Schedule 30 - 0-300 kW (sec)	$ 912	$ 912	$ 912	$ 631	$ 631	$ 694	$ 2,289	$ 6,981	$ 141.52
GS - Schedule 30 - 300+ kW (sec)	$ 5,583	$ 5,583	$ 5,583	$ 3,308	$ 3,308	$ 3,639	$ 13,870	$ 40,874	$ 137.30
GS - Schedule 30 - Primary (pri)	$ 385	$ 385	$ 385	$ 266	$ 266	$ 293	$ 967	$ 2,949	$ 141.52
Irrigation - Sch 41	$ 6,363	$ 6,363	$ 6,363	$ 9,242	$ 9,242	$ 10,165	$ 3,113	$ 50,853	$ 573.90
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 6,739	$ 6,739	$ 6,739	$ 2,396	$ 2,396	$ 2,635	$ 5,383	$ 33,025	$ 274.88
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 7,597	$ 7,597	$ 7,597	$ 2,701	$ 2,701	$ 2,971	$ 6,068	$ 37,233	$ 274.88
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 119,284	$ 119,284	$ 119,284	$ 96,941	$ 96,941	$ 106,625	$ 177,976	$ 836,335	

	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	Conductors								
	1	2	3	4	5	6	7	Total	
% customer	14.06%	14.06%	14.06%			57.83%		100.00%	
Branch 6 Cost	$ 37,929.76	$ 37,929.76	$ 37,929.76	$ -	$ -	$ 156,071.59	$ -	$ 269,861	$ / kW
% customer	0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%	
Branch 7 Cost	$ 2,377	$ 2,377	$ 2,377	$ 9,779	$ 9,779	$ 9,779	$ 487,429	$ 523,895	
Branch Commitment Cost	$ 55,106	$ 55,106	$ 55,106	$ 55,106	$ 55,106				Average
Total	$ 95,412	$ 95,412	$ 95,412	$ 64,885	$ 64,885	$ 165,850	$ 487,429	$ 1,069,285	$ 269.59
Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	$ Per kW
Res - Schedule 4 (sec)	$ 44,723	$ 44,723	$ 44,723	$ 36,328	$ 36,328	$ 92,857	$ 282,540	$ 582,222	$ 254.38
GS - Schedule 23 - 0-15 kW (sec)	$ 6,277	$ 6,277	$ 6,277	$ 3,846	$ 3,846	$ 9,832	$ 20,309	$ 56,664	$ 332.38
GS - Schedule 23 - 15+ kW (sec)	$ 6,782	$ 6,782	$ 6,782	$ 4,156	$ 4,156	$ 10,623	$ 21,945	$ 61,228	$ 332.38
GS - Schedule 23 - Primary (pri)	$ 20	$ 20	$ 20	$ 13	$ 13	$ 32	$ 66	$ 185	$ 332.38
GS - Schedule 28 - 0-50 kW (sec)	$ 3,343	$ 3,343	$ 3,343	$ 1,748	$ 1,748	$ 4,468	$ 16,293	$ 34,287	$ 261.28
GS - Schedule 28 - 51-100 kW (sec)	$ 5,013	$ 5,013	$ 5,013	$ 2,621	$ 2,621	$ 6,699	$ 24,429	$ 51,408	$ 261.28
GS - Schedule 28 - 100 + kW (sec)	$ 7,043	$ 7,043	$ 7,043	$ 3,682	$ 3,682	$ 9,413	$ 34,322	$ 72,228	$ 261.28
GS - Schedule 28 - Primary (pri)	$ 150	$ 150	$ 150	$ 79	$ 79	$ 201	$ 732	$ 1,541	$ 261.28
GS - Schedule 30 - 0-300 kW (sec)	$ 730	$ 730	$ 730	$ 422	$ 422	$ 1,079	$ 6,270	$ 10,382	$ 210.47
GS - Schedule 30 - 300+ kW (sec)	$ 4,466	$ 4,466	$ 4,466	$ 2,214	$ 2,214	$ 5,660	$ 37,986	$ 61,471	$ 206.49
GS - Schedule 30 - Primary (pri)	$ 308	$ 308	$ 308	$ 178	$ 178	$ 456	$ 2,648	$ 4,385	$ 210.47
Irrigation - Sch 41	$ 5,090	$ 5,090	$ 5,090	$ 6,186	$ 6,186	$ 15,812	$ 8,527	$ 51,980	$ 586.62
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 5,390	$ 5,390	$ 5,390	$ 1,603	$ 1,603	$ 4,099	$ 14,741	$ 38,217	$ 318.09
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 6,077	$ 6,077	$ 6,077	$ 1,808	$ 1,808	$ 4,621	$ 16,620	$ 43,087	$ 318.09
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 95,412	$ 95,412	$ 95,412	$ 64,885	$ 64,885	$ 165,850	$ 487,429	$ 1,069,285	

Commitment costs are calculated using a similar method. Commitment costs calculated in an earlier step are allocated to classes using percent of customers on a given branch. Commitment dollars are totaled by customer class then divided by the number of customers in the class to get commitment costs in dollars per customer. Figure 9 shows these calculations for Oregon.

Figure 9–Oregon Poles and Conductors Commitment Calculations, Cost Assignment

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Poles								
	1	2	3	4	5	6	7	Total	
% customer	13.04%	13.04%	13.04%			60.89%		100.00%	
Branch 6 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ Per
% customer	0.42%	0.42%	0.42%	1.97%	1.97%	1.97%	92.83%	100.00%	Customer
Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Branch Commitment Cost	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300		Average
Total	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 1,108,097	$ 922.10
Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	$ Per Customer
Res - Schedule 4 (sec)	$ 115,850	$ 115,850	$ 115,850	$ 121,921	$ 121,921	$ 121,921	$ 133,375	$ 846,687	$ 841.90
GS - Schedule 23 - 0-15 kW (sec)	$ 29,122	$ 29,122	$ 29,122	$ 23,121	$ 23,121	$ 23,121	$ 17,171	$ 173,902	$ 1,296.15
GS - Schedule 23 - 15+ kW (sec)	$ 6,205	$ 6,205	$ 6,205	$ 4,927	$ 4,927	$ 4,927	$ 3,659	$ 37,055	$ 1,296.15
GS - Schedule 23 - Primary (pri)	$ 21	$ 21	$ 21	$ 16	$ 16	$ 16	$ 12	$ 123	$ 1,296.15
GS - Schedule 28 - 0-50 kW (sec)	$ 1,287	$ 1,287	$ 1,287	$ 872	$ 872	$ 872	$ 1,143	$ 7,621	$ 889.19
GS - Schedule 28 - 51-100 kW (sec)	$ 1,024	$ 1,024	$ 1,024	$ 694	$ 694	$ 694	$ 909	$ 6,063	$ 889.19
GS - Schedule 28 - 100 + kW (sec)	$ 636	$ 636	$ 636	$ 431	$ 431	$ 431	$ 564	$ 3,763	$ 889.19
GS - Schedule 28 - Primary (pri)	$ 17	$ 17	$ 17	$ 11	$ 11	$ 11	$ 15	$ 98	$ 889.19
GS - Schedule 30 - 0-300 kW (sec)	$ 33	$ 33	$ 33	$ 24	$ 24	$ 24	$ 51	$ 222	$ 594.22
GS - Schedule 30 - 300+ kW (sec)	$ 100	$ 100	$ 100	$ 64	$ 64	$ 64	$ 155	$ 649	$ 572.81
GS - Schedule 30 - Primary (pri)	$ 7	$ 7	$ 7	$ 5	$ 5	$ 5	$ 10	$ 45	$ 594.22
Irrigation - Sch 41	$ 3,929	$ 3,929	$ 3,929	$ 6,187	$ 6,187	$ 6,187	$ 1,199	$ 31,546	$ 2,718.91
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 40	$ 40	$ 40	$ 15	$ 15	$ 15	$ 20	$ 187	$ 1,231.08
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 29	$ 29	$ 29	$ 11	$ 11	$ 11	$ 14	$ 135	$ 1,231.08
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 1,108,097	

	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	Conductors								
	1	2	3	4	5	6	7	Total	
% customer	13.04%	13.04%	13.04%	0.00%	0.00%	60.89%	0.00%	100.00%	
Branch 6 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ Per
% customer	0.42%	0.42%	0.42%	1.97%	1.97%	1.97%	92.83%	100.00%	Customer
Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Branch Commitment Cost	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801		Average
Total	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 481,605	$ 400.76
Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	$ Per Customer
Res - Schedule 4 (sec)	$ 50,351	$ 50,351	$ 50,351	$ 52,990	$ 52,990	$ 52,990	$ 57,968	$ 367,990	$ 365.91
GS - Schedule 23 - 0-15 kW (sec)	$ 12,657	$ 12,657	$ 12,657	$ 10,049	$ 10,049	$ 10,049	$ 7,463	$ 75,582	$ 563.34
GS - Schedule 23 - 15+ kW (sec)	$ 2,697	$ 2,697	$ 2,697	$ 2,141	$ 2,141	$ 2,141	$ 1,590	$ 16,105	$ 563.34
GS - Schedule 23 - Primary (pri)	$ 9	$ 9	$ 9	$ 7	$ 7	$ 7	$ 5	$ 53	$ 563.34
GS - Schedule 28 - 0-50 kW (sec)	$ 559	$ 559	$ 559	$ 379	$ 379	$ 379	$ 497	$ 3,312	$ 386.46
GS - Schedule 28 - 51-100 kW (sec)	$ 445	$ 445	$ 445	$ 302	$ 302	$ 302	$ 395	$ 2,635	$ 386.46
GS - Schedule 28 - 100 + kW (sec)	$ 276	$ 276	$ 276	$ 187	$ 187	$ 187	$ 245	$ 1,635	$ 386.46
GS - Schedule 28 - Primary (pri)	$ 7	$ 7	$ 7	$ 5	$ 5	$ 5	$ 6	$ 43	$ 386.46
GS - Schedule 30 - 0-300 kW (sec)	$ 14	$ 14	$ 14	$ 11	$ 11	$ 11	$ 22	$ 97	$ 258.26
GS - Schedule 30 - 300+ kW (sec)	$ 44	$ 44	$ 44	$ 28	$ 28	$ 28	$ 67	$ 282	$ 248.96
GS - Schedule 30 - Primary (pri)	$ 3	$ 3	$ 3	$ 2	$ 2	$ 2	$ 5	$ 20	$ 258.26
Irrigation - Sch 41	$ 1,708	$ 1,708	$ 1,708	$ 2,689	$ 2,689	$ 2,689	$ 521	$ 13,711	$ 1,181.70
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 17	$ 17	$ 17	$ 7	$ 7	$ 7	$ 9	$ 81	$ 535.06
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 13	$ 13	$ 13	$ 5	$ 5	$ 5	$ 6	$ 59	$ 535.06
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 481,605	

Large Industrial Customers

Distribution studies have shown that very large industrial customers are not placed on a circuit in the same manner as residential or smaller commercial and industrial customers. Rather the customer is located very close to a substation (the average distance in Oregon is 2/3 of a mile) and has a dedicated circuit for their exclusive use. Since they have a dedicated circuit, they do not share in the costs of other common distribution investments, but they are responsible for the entire cost of the dedicated circuit. Dividing the total cost of a 2/3 of a mile circuit by the customer's kW determines the demand cost in dollars per kW for these customers. Table 10 shows this calculation for Oregon.

Table 10 – Oregon Dedicated Circuit Trunk Costs for Large Customers

	Voltage Delivery	
	Large GS + 4 MW	
	Poles	Conductor
Construction Cost Per Mile	$64,984	$110,173
Average Trunk Length	0.67 miles	
Total Construction Cost	$43,539	$73,816
Customer Peak Demand (Sec)	3,591 kW	
Customer Peak Demand (Pri)	8,630 kW	
Demand Cost $/kW (Sec)	$12.13	$20.56
Demand Cost $/kW (Pri)	$5.04	$8.55

Summary

The final step in the circuit model is to bring the various results together in a single summary page. Table 11 shows the results calculated earlier in the study. Note that the $/customer and $/circuit kW is the distribution investment to serve that customer and not the price that the customer is expected to pay.

Table 11 – Oregon Summary of Results

Load Class		Demand						Commitment					
				Investment $ / kW[1]		Annual $ / kW[1]				Investment $ / Customer		Annual $ / Customer	
		Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
Res - Schedule 4	(sec)	$ 191.87	$ 254.38	$ 200.68	$ 266.06	$ 14.91	$ 19.77	$ 841.90	$ 365.91	$ 880.56	$ 382.71	$ 65.43	$ 28.44
GS - Schedule 23													
0-15 kW	(sec)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
15+ kW	(sec)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
Primary	(pri)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
GS - Schedule 28													
0-50 kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
51-100 kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
100 + kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
Primary	(pri)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
GS - Schedule 30													
0-300 kW	(sec)	$ 141.52	$ 210.47	$ 148.02	$ 220.13	$ 11.00	$ 16.36	$ 594.22	$ 258.26	$ 621.50	$ 270.12	$ 46.18	$ 20.07
300+ kW	(sec)	$ 137.30	$ 206.49	$ 143.60	$ 215.97	$ 10.67	$ 16.05	$ 572.81	$ 248.96	$ 599.11	$ 260.39	$ 44.51	$ 19.35
Primary	(pri)	$ 141.52	$ 210.47	$ 148.02	$ 220.13	$ 11.00	$ 16.36	$ 594.22	$ 258.26	$ 621.50	$ 270.12	$ 46.18	$ 20.07
LPS - Schedule 48													
1 - 4 MW	(sec)	$ 274.88	$ 318.09	$ 287.50	$ 332.70	$ 21.36	$ 24.72	$ 1,231.08	$ 535.06	$ 1,287.60	$ 559.62	$ 95.67	$ 41.58
1 - 4 MW	(pri)	$ 274.88	$ 318.09	$ 287.50	$ 332.70	$ 21.36	$ 24.72	$ 1,231.08	$ 535.06	$ 1,287.60	$ 559.62	$ 95.67	$ 41.58
> 4 MW	(sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
> 4 MW	(pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Irrigation - Schedule 41	(sec)	$ 573.90	$ 586.62	$ 600.25	$ 613.55	$ 44.60	$ 45.59	$ 2,718.91	$ 1,181.70	$ 2,843.75	$ 1,235.96	$ 211.29	$ 91.83

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2025 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	$89.56	$48.34	$42.28	$89.56	$96.03	$91.25
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	$89.56	$48.34	$42.28	$89.56	$93.72	$88.76
5	15+ kW	(sec)	$89.56	$48.34	$42.28	$89.56	$91.64	$86.67
6	Primary	(pri)	$88.17	$47.59	$41.62	$88.17	$87.84	$82.94
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	$89.56	$48.34	$42.28	$89.56	$88.45	$83.49
10	51-100 kW	(sec)	$89.56	$48.34	$42.28	$89.56	$88.01	$83.03
11	100 + kW	(sec)	$89.56	$48.34	$42.28	$89.56	$86.65	$81.65
12	Primary	(pri)	$88.17	$47.59	$41.62	$88.17	$82.95	$78.01
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	$89.56	$48.34	$42.28	$89.56	$84.01	$79.01
16	300+ kW	(sec)	$89.56	$48.34	$42.28	$89.56	$82.50	$77.47
17	Primary	(pri)	$88.17	$47.59	$41.62	$88.17	$79.88	$74.89
18								
19	LPS - Schedule 48							
20	1 - 4 MW	(sec)	$89.56	$48.34	$42.28	$89.56	$85.56	$80.50
21	1 - 4 MW	(pri)	$88.17	$6.67	$42.28	$88.17	$29.28	$65.50
22	> 4 MW	(sec)	$89.56	$344.97	$41.62	$89.56	$369.44	$66.98
23	> 4 MW	(pri)	$88.17	$47.59	$41.62	$88.17	$76.45	$71.56
24	Trans	(trm)	$85.86	$46.34	$40.53	$85.86	$67.64	$60.00
25								
26								
27	Schedule 41- Irrigation	(sec)	$89.56	$48.34	$42.28	$89.56	$105.75	$100.65
28								
29	Lighting	(sec)	$89.56	$48.34	$42.28	$89.56	$57.04	$44.02

Energy costs include both generation and transmission energy-related costs.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2025 Dollars

Line	Description		(A) 1 Year	(B) 10 & 20 Year
1	Res - Schedule 4	(sec)	$13.03	$34.51
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	$15.21	$53.97
5	15+ kW	(sec)	$23.83	$68.11
6	Primary	(pri)	$171.38	$164.90
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	$25.74	$111.58
10	51-100 kW	(sec)	$26.30	$121.10
11	100 + kW	(sec)	$63.87	$166.06
12	Primary	(pri)	$149.27	$161.16
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	$73.78	$175.66
16	300+ kW	(sec)	$105.65	$220.82
17	Primary	(pri)	$157.18	$165.13
18				
19	LPS - Schedule 48			
20	1 - 4 MW	(sec)	$437.19	$557.32
21	1 - 4 MW	(pri)	$287.25	$303.72
22	> 4 MW	(sec)	$437.19	$540.85
23	> 4 MW	(pri)	$287.25	$287.25
24	Trans	(trn)	$2,360.30	$2,360.30
25				
26				
27	Schedule 41- Irrigation	(sec)	$7.89	$131.86
28				
29	Lighting	(sec)	$5.21	$36.50

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead, maintenance, service drops, service drop overhead and maintenance, customer accounting, informational expenses, and billing expenses.

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost
December 2025 Dollars

Line	Calculation Component	Class	Units Description / Function	Total	(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) 15+ kW (sec)	(D) Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) 51-100 kW (sec)	(G) 100 + kW (sec)	(H) Primary (pri)	(I) General Service - Schedule 30 0-300 kW (sec)	(J) 300+ kW (sec)	(K) Primary (pri)	(L) Large Power Service - Schedule 48 1 - 4 MW (sec)	(M) 1 - 4 MW (pri)	(N) > 4 MW (sec)	(O) > 4 MW (pri)	(P) Trn (trn)	(Q) Irrg - Sch 41 (sec)	(R) Lighting Schs 15, 51, 53, 54 (sec)
1	Units	Demand	Peak MW @ Input-System		1,107	92	99	0	70	107	153	3	27	166	11	68	75	15	219	231	34	1
2	Units	Demand	Peak MW @ Input-Distribution		1,316	98	106	0	75	113	159	3	28	171	12	69	77	16	223	-	51	0
3	Units	Demand	Peak MW @ Input-Transformer		3,665	792	448	-	208	423	528	-	46	268	-	114	-	28	-	-	203	12
4																						
5	Units	Energy	Annual MWh @ Input		6,248,604	599,673	652,997	1,995	459,186	708,531	1,038,290	22,801	184,262	1,167,972	82,702	492,415	884,743	122,047	1,436,937	2,002,659	253,620	21,832
6																						
7	Units	Customer	Average		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	3,311	7,437
8	Units	Customer	Annual - Metered		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	7,887	98
9																						
10																						
11	$/Unit	Demand	Generation ($/System Peak kW)		$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28
12	$/Unit	Demand	Transmission ($/System Peak kW)		$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$0.00
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$21.47	$32.01	$32.01	$32.01	$22.67	$22.67	$22.67	$22.67	$15.84	$15.37	$15.84	$30.76	$30.76	$0.00	$0.00	$0.00	$64.23	$32.01
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$28.47	$37.20	$37.20	$37.20	$29.23	$29.23	$29.23	$29.23	$23.56	$23.11	$23.56	$35.60	$35.60	$0.00	$0.00	$0.00	$65.65	$37.20
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$0.00	$21.45	$0.00
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$0.00	$2.33	$0.00	$2.33	$0.00	$0.00	$2.33	$2.33
17																						
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916
19	$/Unit	Energy	Transmission Energy @ Input ($/kWh)		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
20																						
21	$/Unit	Customer	Dist-Poles ($/Customer)		$94.23	$145.06	$145.06	$145.06	$99.51	$99.51	$99.51	$99.51	$66.50	$64.10	$66.50	$137.77	$137.77	$0.00	$0.00	$0.00	$304.28	$145.06
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$40.96	$63.05	$63.05	$63.05	$43.25	$43.25	$43.25	$43.25	$28.90	$27.87	$28.90	$59.88	$59.88	$0.00	$0.00	$0.00	$132.24	$63.05
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$122.51	$256.94	$323.32	$0.00	$887.22	$994.75	$1,083.62	$0.00	$1,286.48	$1,289.98	$0.00	$1,243.96	$0.00	$1,243.96	$0.00	$0.00	$1,051.07	$167.43
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$84.10	$114.88	$214.66	$0.00	$213.77	$218.49	$497.73	$0.00	$362.07	$903.85	$0.00	$3,265.83	$0.00	$3,265.83	$0.00	$0.00	$0.00	$0.00
25	$/Unit	Customer	Meters ($/Customer)		$24.91	$26.43	$30.00	$1,729.42	$33.37	$35.35	$206.86	$1,729.42	$207.21	$207.30	$1,729.42	$262.83	$1,729.42	$262.83	$1,729.42	$26,606.01	$33.45	$26.43
26	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
27	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
28	$/Unit	Customer	Uncollectables ($/Customer)		$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
30																						
31																						
32	$000	Demand	Generation	$387,461	$173,067	$14,432	$15,502	$47	$11,010	$16,705	$23,893	$512	$4,244	$26,009	$1,788	$10,619	$11,751	$2,401	$34,151	$36,040	$5,291	$0
33	$000	Demand	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
34	$000	Demand	Dist-Poles	$53,771	$28,252	$3,137	$3,390	$10	$1,710	$2,564	$3,602	$76	$449	$2,630	$187	$2,125	$2,364	$0	$0	$0	$3,272	$3
35	$000	Demand	Dist-Conductor	$68,757	$37,460	$3,646	$3,939	$12	$2,205	$3,307	$4,646	$98	$668	$3,956	$278	$2,459	$2,736	$0	$0	$0	$3,344	$4
36	$000	Demand	Dist-Substations	$53,986	$28,220	$2,102	$2,271	$7	$1,618	$2,426	$3,408	$72	$608	$3,671	$254	$1,481	$1,648	$336	$4,773	$0	$1,093	$0
37	$000	Demand	Dist-Transformers	$15,726	$8,557	$1,849	$1,045	$0	$485	$988	$1,232	$0	$108	$627	$0	$267	$0	$66	$0	$0	$473	$28
38	$000	Demand	Total Demand	$597,303	$283,419	$25,821	$26,852	$78	$17,529	$26,749	$37,868	$780	$6,270	$38,073	$2,589	$17,433	$19,032	$2,912	$40,475	$37,677	$13,713	$35
39																						
40	$000	Energy	Generation	$641,433	$244,673	$23,481	$25,569	$78	$17,980	$27,744	$40,656	$893	$7,215	$45,734	$3,238	$19,281	$34,643	$4,779	$56,265	$78,417	$9,931	$855
41	$000	Energy	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	$000	Energy	Total Energy	$641,433	$244,673	$23,481	$25,569	$78	$17,980	$27,744	$40,656	$893	$7,215	$45,734	$3,238	$19,281	$34,643	$4,779	$56,265	$78,417	$9,931	$855
43																						
44	$000	Customer	Dist-Poles	$64,407	$48,393	$10,282	$2,191	$7	$461	$367	$227	$6	$13	$39	$3	$11	$8	$0	$0	$0	$2,400	$0
45	$000	Customer	Dist-Conductor	$27,995	$21,034	$4,469	$952	$3	$200	$159	$99	$3	$6	$17	$1	$5	$4	$0	$0	$0	$1,043	$0
46	$000	Customer	Dist-Transformers	$105,698	$62,918	$18,212	$4,883	$0	$4,108	$3,664	$2,477	$0	$258	$781	$0	$102	$0	$5	$0	$0	$8,290	$0
47	$000	Customer	Dist-Service Drop	$58,411	$43,193	$8,142	$3,242	$0	$990	$805	$1,138	$0	$72	$548	$0	$268	$0	$13	$0	$0	$0	$0
48	$000	Customer	Meters	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
49	$000	Customer	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50	$000	Customer	Billing & Collections	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
51	$000	Customer	Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
52	$000	Customer	Customer Service / Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
53	$000	Customer	Total Customer (Commitment & Billing)	$302,921	$212,673	$45,903	$12,344	$99	$6,199	$5,352	$4,555	$114	$422	$1,605	$81	$548	$216	$27	$85	$227	$12,200	$271
54																						
55																						
56			Total Revenue @ Full MC ($000)																			
57			Generation	$1,028,894	$417,741	$37,913	$41,071	$125	$28,990	$44,449	$64,549	$1,405	$11,459	$71,742	$5,027	$29,900	$46,394	$7,180	$90,416	$114,457	$15,222	$855
58			Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
59			Distribution	$448,751	$278,027	$51,839	$21,914	$39	$11,777	$14,279	$16,830	$254	$2,183	$12,267	$723	$6,717	$6,759	$420	$4,773	$0	$19,915	$35
60			Customer - Billing	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
61			Customer - Metering	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
62			Customer - Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
63			Total Revenue (less Uncollectables)	$1,534,981	$734,807	$95,092	$64,741	$255	$41,631	$59,783	$83,040	$1,786	$13,886	$85,346	$5,904	$37,150	$53,811	$7,711	$96,792	$116,310	$35,774	$1,161
64																						
65			Customer - Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
66			Total Revenue	$1,541,658	$740,765	$95,205	$64,765	$255	$41,708	$59,845	$83,079	$1,787	$13,907	$85,412	$5,908	$37,262	$53,892	$7,717	$96,825	$116,321	$35,843	$1,161

Table 4

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs in Nominal Dollars

	(B)	(D)
	Energy Only ($/MWh)	Capacity Only ($/kW)
2023 (1 Year)	82.95	104.74
2023 - 2027 (5 Year, Short Run)	54.03	134.01
2023 - 2032 (10 Year, Medium Run)	44.77	149.62
2023 - 2042 (20 Year, Long Run)	39.16	156.28

Table 5

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item	$	
1	Growth Related Investments - (2024 to 2028 in $000s)	$271,101	
2			
3	System Growth MW from 2022 to 2026	3,211	
4			
5	Marginal Investment (line 1/line 3)	$84.43	/ kW
6			
7	Annualized Investment @ 6.75%	$5.70	/ kW
8	Admin. & General Factor @ 0.58%	$0.49	
9	Annual O&M Expenses @ 1.080%	$0.91	/ kW
10	Annualized Marginal Cost	$7.10	/ kW
11			
12	Marginal Cost of Demand-Related Transmission	$7.10	/ kW
13			
14	Marginal Cost of Energy-Related Transmission (Line 10 - Line 12)	$0.00	/ kW
15	Marginal Cost of Energy-Related Transmission	$0.00000	/ kWh
16	$0.00 / (8760 x 77.88% LF))		

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs
2025 Dollars

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
		Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg Sch 41	Lighting
			0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans		
Line	Description	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
1	Demand Costs ($/kW)																		
2																			
3	Dist-Poles	$14.91	$22.23	$22.23	$22.23	$15.74	$15.74	$15.74	$15.74	$11.00	$10.67	$11.00	$21.36	$21.36	$0.00	$0.00	$0.00	$44.60	
4	Dist-Conductors	$19.77	$25.83	$25.83	$25.83	$20.30	$20.30	$20.30	$20.30	$16.36	$16.05	$16.36	$24.72	$24.72	$0.00	$0.00	$0.00	$45.59	
5	Dist-Substation	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$0.00	$14.89	$14.89
6	Dist. O&M @ 44.01% of Investment	$21.82	$27.71	$27.71	$27.71	$22.42	$22.42	$22.42	$22.42	$18.60	$18.31	$18.60	$26.83	$26.83	$6.55	$6.55	$0.00	$46.25	$6.55
7	Total $/Dist. kW	$71.39	$90.66	$90.66	$90.66	$73.35	$73.35	$73.35	$73.35	$60.85	$59.93	$60.85	$87.81	$87.81	$21.45	$21.45	$0.00	$151.33	$21.45
8																			
9	Dist-Transformers	$1.62	$1.62	$1.62	$0.00	$1.62	$1.62	$1.62	$0.00	$1.62	$1.62	$0.00	$1.62	$0.00	$1.62	$0.00	$0.00	$1.62	$1.62
10	Dist. O&M @ 44.01% of Investment	$0.71	$0.71	$0.71	$0.00	$0.71	$0.71	$0.71	$0.00	$0.71	$0.71	$0.00	$0.71	$0.00	$0.71	$0.00	$0.00	$0.71	$0.71
11	Total $/Transformer kW	$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$0.00	$2.33	$0.00	$2.33	$0.00	$0.00	$2.33	$2.33
12																			
13																			
14																			
15	Customer Costs ($/Customer)																		
16																			
17	Commitment																		
18	Dist-Poles	$65.43	$100.73	$100.73	$100.73	$69.10	$69.10	$69.10	$69.10	$46.18	$44.51	$46.18	$95.67	$95.67	$0.00	$0.00	$0.00	$211.29	
19	Dist-Conductors	$28.44	$43.78	$43.78	$43.78	$30.03	$30.03	$30.03	$30.03	$20.07	$19.35	$20.07	$41.58	$41.58	$0.00	$0.00	$0.00	$91.83	
20	Dist-Transformers	$85.07	$178.42	$224.51	$0.00	$616.08	$690.75	$752.46	$0.00	$893.33	$895.76	$0.00	$863.80	$863.80	$0.00	$0.00	$0.00	$729.86	$116.26
21	Dist. O&M @ 44.01% of Investment	$78.75	$142.12	$162.41	$63.60	$314.76	$347.63	$374.78	$43.63	$422.31	$422.33	$29.16	$440.56	$440.56	$0.00	$0.00	$0.00	$454.61	$51.17
22	Total Commitment	$257.69	$465.05	$531.43	$208.11	$1,029.97	$1,137.51	$1,226.37	$142.76	$1,381.89	$1,381.95	$95.41	$1,441.61	$1,441.61	$0.00	$0.00	$0.00	$1,487.59	$167.43
23	Monthly Commitment	$21.47	$38.75	$44.29	$17.34	$85.83	$94.79	$102.20	$11.90	$115.16	$115.16	$7.95	$120.13	$120.13	$0.00	$0.00	$0.00	$123.97	$13.95
24																			
25	Billing																		
26	Dist-Service Drop	$58.40	$79.77	$149.06	$0.00	$148.44	$151.72	$345.62	$0.00	$362.07	$627.63	$0.00	$2,267.78	$2,267.78	$0.00	$0.00	$0.00	$0.00	$0.00
27	Dist. O&M @ 44.01% of Investment	$25.70	$35.11	$65.60	$0.00	$65.33	$66.77	$152.11	$0.00	$159.35	$276.22	$0.00	$998.05	$998.05	$0.00	$0.00	$0.00	$0.00	$0.00
28	Meter	$17.22	$18.27	$20.74	$1,195.51	$23.07	$24.44	$143.00	$1,195.51	$143.24	$143.30	$1,195.51	$181.69	$1,195.51	$181.69	$1,195.51	$18,392.10	$23.12	$18.27
29	Meter O&M @ 44.66% of Investment	$7.58	$8.04	$9.13	$526.14	$10.15	$10.76	$62.93	$526.14	$63.04	$63.07	$526.14	$79.96	$526.14	$79.96	$526.14	$8,094.36	$10.18	$8.04
30	Meter Reading	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
31	Billing & Collections	$29.16	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
32	Uncollectables	$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
33	Customer Service / Other	$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
34	Total Billing	$160.36	$182.45	$285.79	$1,762.91	$308.79	$315.48	$765.46	$1,783.45	$884.40	$1,266.92	$1,878.36	$5,245.04	$6,705.05	$1,979.21	$3,439.22	$28,204.02	$94.59	$62.35
35	Monthly Billing	$13.36	$15.20	$23.82	$146.91	$25.73	$26.29	$63.79	$148.62	$73.70	$105.58	$156.53	$437.09	$558.75	$164.93	$286.60	$2,350.34	$7.88	$5.20
36																			
37	Total Customer (Commitment & Billing)	$418.05	$647.50	$817.21	$1,971.02	$1,338.76	$1,452.99	$1,991.83	$1,926.21	$2,266.29	$2,648.87	$1,973.76	$6,686.66	$8,146.66	$1,979.21	$3,439.22	$28,204.02	$1,582.18	$229.77
38	Monthly Customer (Commitment & Billing)	$34.84	$53.96	$68.10	$164.25	$111.56	$121.08	$165.99	$160.52	$188.86	$220.74	$164.48	$557.22	$678.89	$164.93	$286.60	$2,350.34	$131.85	$19.15
39																			

Table 7

PacifiCorp
Oregon Marginal Cost Study
20 Year Demand Costs Divided by Billing kW
December 2025 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Lighting
				0-15 kW	15+ kW		0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		
Line	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
1	Marginal Cost ($000)																			
2																				
3	Generation	$387,461	$173,067	$14,432	$15,502	$47	$11,010	$16,705	$23,893	$512	$4,244	$26,009	$1,788	$10,619	$11,751	$2,401	$34,151	$36,040	$5,291	$0
4	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
5	Dist-Poles, Wire, Sub	$176,514	$93,932	$8,885	$9,600	$29	$5,533	$8,297	$11,657	$245	$1,726	$10,256	$719	$6,065	$6,747	$336	$4,773	$0	$7,709	$7
6	Dist-Transformers	$15,726	$8,557	$1,849	$1,045	$0	$485	$988	$1,232	$0	$108	$627	$0	$267	$0	$66	$0	$0	$473	$28
7																				
8	Average Billing kW @ Sales	$8,989,495	5,042,753	947,994	535,908	11,400	191,574	390,191	486,664	39,149	55,540	321,463	53,025	105,438	26,117	114,319	155,107	317,201	186,770	8,881
9																				
10	Generation ($/kW)		$34.32	$2.86	$3.07	$0.01	$2.18	$3.31	$4.74	$0.10	$0.84	$5.16	$0.35	$2.11	$2.33	$0.48	$6.77	$7.15	$1.05	$0.00
11	Transmission ($/kW)		$1.56	$0.13	$0.14	$0.00	$0.10	$0.15	$0.22	$0.00	$0.04	$0.23	$0.02	$0.10	$0.11	$0.02	$0.31	$0.32	$0.05	$0.00
12	Dist-Poles, Wire, Sub ($/kW)		$18.63	$1.76	$1.90	$0.01	$1.10	$1.65	$2.31	$0.05	$0.34	$2.03	$0.14	$1.20	$1.34	$0.07	$0.95	$0.00	$1.53	$0.00
13	Dist-Transformers ($/kW)		$1.70	$0.37	$0.21	$0.00	$0.10	$0.20	$0.24	$0.00	$0.02	$0.12	$0.00	$0.05	$0.00	$0.01	$0.00	$0.00	$0.09	$0.01
14																				
15	Total Demand Related		$56.20	$5.12	$5.32	$0.02	$3.48	$5.30	$7.51	$0.15	$1.24	$7.55	$0.51	$3.46	$3.77	$0.58	$8.03	$7.47	$2.72	$0.01
16	Monthly Demand Related		$4.68	$0.43	$0.44	$0.00	$0.29	$0.44	$0.63	$0.01	$0.10	$0.63	$0.04	$0.29	$0.31	$0.05	$0.67	$0.62	$0.23	$0.00

Table 8

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage
December 2025 Dollars

Line	Description	(A) Marginal Cost (000s)	(B) Mills / kWh	(C) % of Total
1	Demand Related Marginal Cost			
2	Generation	$387,461	25.36	25%
3	Transmission	$17,603	1.15	1%
4	Dist. Poles, Cond., Subst.	$176,514	11.55	11%
5	Dist. Transformers	$15,726	1.03	1%
6	Total Demand Related	$597,303	39.09	39%
7				
8	Energy Related Marginal Cost			
9	Generation	$641,433	41.99	42%
10	Transmission	$0	-	0%
11	Total Energy Related	641432.9875	41.99	42%
12				
13	Commitment & Billing			
14	Commitment	$198,100	12.97	13%
15	Billing	$104,821	6.86	7%
16	Total Commitment & Billing	302921.2976	19.83	20%
17				
18				
19	TOTAL MARGINAL COST	$1,541,658	100.91	100%
20				
21				
22		Note: Total MWh @ Sales =	15,276,984	

10 Year MC

PacifiCorp
Oregon Marginal Cost Study
10 Year Marginal Cost
December 2023 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Lighting
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,107	92	99	0	70	107	153	3	27	166	11	68	75	15	219	231	34	1
2	Units	Demand	Peak MW @ Input-Distribution		1,316	98	106	0	75	113	159	3	28	171	12	69	77	16	223	237	51	0
3	Units	Demand	Peak MW @ Input-Transformer		3,665	792	448	12	208	423	528	42	46	268	57	114	122	28	166	329	203	12
4																						
5	Units	Energy	Annual MWh @ Input		6,248,604	599,673	652,997	1,995	459,186	708,531	1,038,290	22,801	184,262	1,167,972	82,702	492,415	122,047	884,743	1,436,937	2,002,659	253,620	21,832
6																						
7	Units	Customer	Average		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	3,311	7,437
8	Units	Customer	Annual - Metered		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	7,887	98
9																						
10																						
11	$/Unit	Demand	Generation ($/System Peak kW)		$ 149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62
12	$/Unit	Demand	Transmission ($/System Peak kW)		$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$0.00
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$21.47	$32.01	$32.01	$32.01	$22.67	$22.67	$22.67	$22.67	$15.84	$15.37	$15.84	$30.76	$30.76	$0.00	$0.00	$0.00	$64.23	$32.01
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$28.47	$37.20	$37.20	$37.20	$29.23	$29.23	$29.23	$29.23	$23.56	$23.11	$23.56	$35.60	$35.60	$0.00	$0.00	$0.00	$65.65	$37.20
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$0.00
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$0.00	$2.33	$0.00	$2.33	$0.00	$0.00	$2.33	$2.33
17																						
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477
19																						
20																						
21	$/Unit	Customer	Dist-Poles ($/Customer)		$94.23	$145.06	$145.06	$145.06	$99.51	$99.51	$99.51	$99.51	$66.50	$64.10	$66.50	$137.77	$137.77	$0.00	$0.00	$0.00	$304.28	$145.06
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$40.96	$63.05	$63.05	$63.05	$43.25	$43.25	$43.25	$43.25	$28.90	$27.87	$28.90	$59.88	$59.88	$0.00	$0.00	$0.00	$132.24	$63.05
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$122.51	$256.94	$323.32	$0.00	$887.22	$994.75	$1,083.62	$0.00	$1,286.48	$1,289.98	$0.00	$1,243.96	$0.00	$1,243.96	$0.00	$0.00	$1,051.07	$167.43
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$84.10	$114.88	$214.66	$0.00	$213.77	$218.49	$497.73	$0.00	$362.07	$903.85	$0.00	$3,265.83	$0.00	$3,265.83	$0.00	$0.00	$0.00	$0.00
25	$/Unit	Customer	Meters ($/Customer)		$24.91	$26.43	$30.00	$1,729.42	$33.37	$35.35	$206.86	$1,729.42	$207.21	$207.30	$1,729.42	$262.83	$1,729.42	$262.83	$1,729.42	$26,606.01	$33.45	$26.43
26	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
27	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
28	$/Unit	Customer	Uncollectables ($/Customer)		$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
30																						
31																						
32	$000	Demand	Generation	$371,080	$165,688	$13,816	$14,841	$45	$10,541	$15,993	$22,874	$490	$4,063	$24,900	$1,712	$10,166	$11,250	$2,298	$32,695	$34,503	$5,065	$141
33	$000	Demand	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
34	$000	Demand	Dist-Poles	$53,771	$28,252	$3,137	$3,390	$10	$1,710	$2,564	$3,602	$76	$449	$2,630	$187	$2,125	$2,364	$0	$0	$0	$3,272	$3
35	$000	Demand	Dist-Conductor	$68,757	$37,460	$3,646	$3,939	$12	$2,205	$3,307	$4,646	$98	$668	$3,956	$278	$2,459	$2,736	$0	$0	$0	$3,344	$4
36	$000	Demand	Dist-Substations	$59,062	$28,220	$2,102	$2,271	$7	$1,618	$2,426	$3,408	$72	$608	$3,671	$254	$1,481	$1,648	$336	$4,773	$5,075	$1,093	$0
37	$000	Demand	Dist-Transformers	$15,726	$8,557	$1,849	$1,045	$0	$485	$988	$1,232	$0	$108	$627	$0	$267	$0	$66	$0	$0	$473	$28
38	$000	Demand	Total Demand	$585,998	$276,039	$25,206	$26,191	$76	$17,059	$26,036	$36,849	$759	$6,089	$36,964	$2,513	$16,980	$18,531	$2,809	$39,019	$41,216	$13,487	$176
39																						
40	$000	Energy	Generation	$733,380	$279,746	$26,847	$29,234	$89	$20,557	$31,721	$46,484	$1,021	$8,249	$52,289	$3,703	$22,045	$5,464	$39,609	$64,331	$89,658	$11,354	$977
41	$000	Energy	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	$000	Energy	Total Energy	$733,380	$279,746	$26,847	$29,234	$89	$20,557	$31,721	$46,484	$1,021	$8,249	$52,289	$3,703	$22,045	$5,464	$39,609	$64,331	$89,658	$11,354	$977
43																						
44	$000	Customer	Dist-Poles	$64,422	$48,393	$10,282	$2,191	$7	$461	$367	$227	$6	$13	$39	$3	$11	$8	$0	$0	$0	$2,400	$14
45	$000	Customer	Dist-Conductor	$28,001	$21,034	$4,469	$952	$3	$200	$159	$99	$3	$6	$17	$1	$5	$4	$0	$0	$0	$1,043	$6
46	$000	Customer	Dist-Transformers	$105,715	$62,918	$18,212	$4,883	$0	$4,108	$3,664	$2,477	$0	$258	$781	$0	$102	$0	$5	$0	$0	$8,290	$16
47	$000	Customer	Dist-Service Drop	$58,411	$43,193	$8,142	$3,242	$0	$990	$805	$1,138	$0	$72	$548	$0	$268	$0	$13	$0	$0	$0	$0
48	$000	Customer	Meters	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
49	$000	Customer	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50	$000	Customer	Billing & Collections	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
51	$000	Customer	Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
52	$000	Customer	Customer Service / Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
53	$000	Customer	Total Customer (Commitment & Billing)	$302,958	$212,673	$45,903	$12,344	$99	$6,199	$5,352	$4,555	$114	$422	$1,605	$81	$548	$216	$27	$85	$227	$12,200	$307
54																						
55																						
56			Total Revenue @ Full MC ($000)	$1,622,336	$768,459	$97,956	$67,770	$264	$43,816	$63,109	$87,888	$1,894	$14,761	$90,859	$6,296	$39,573	$24,211	$42,445	$103,434	$131,100	$37,041	$1,461

5 Year MC

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Cost
December 2025 Dollars

Line	Calculation Component	Class	Units Description / Function	Total	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Streetlighting
						0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		
					(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,107	92	99	0	70	107	153	3	27	166	11	68	75	15	219	231	34	0
2	Units	Energy	Annual MWh @ Input		6,248,604	599,673	652,997	1,995	459,186	708,531	1,038,290	22,801	184,262	1,167,972	82,702	492,415	122,047	884,743	1,436,937	2,002,659	253,620	21,832
3	Units	Customer	Average		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	4	59	25	8	3,311	7,437
4	Units	Customer	Annual		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	4	59	25	8	7,887	7,437
5	Units	Customer	Metered Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	98
6																						
7																						
8	$/Unit	Demand	Generation ($/System Peak kW)		$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01
9	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403
10	$/Unit	Customer	Dist-Service Drop ($/Customer)		$84.10	$114.88	$214.66	$0.00	$213.77	$218.49	$497.73	$0.00	$521.42	$903.85	$0.00	$3,265.83	$0.00	$3,265.83	$0.00	$0.00	$0.00	$0.00
11	$/Unit	Customer	Meters ($/Customer)		$24.91	$26.43	$30.00	$1,729.42	$33.37	$35.35	$206.86	$1,729.42	$207.21	$207.30	$1,729.42	$262.83	$1,729.42	$262.83	$1,729.42	$26,606.01	$33.45	$26.43
12	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
13	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
14	$/Unit	Customer	Uncollectables ($/Customer)		$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
15	$/Unit	Customer	Customer Service / Other ($/Customer)		$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
16																						
17																						
18	($000)	Demand	Total Demand	$332,261	$148,402	$12,375	$13,293	$40	$9,441	$14,324	$20,488	$439	$3,639	$22,302	$1,533	$9,105	$10,076	$2,059	$29,284	$30,904	$4,537	$20
19	($000)	Energy	Total Energy	$885,093	$337,617	$32,401	$35,282	$108	$24,810	$38,282	$56,100	$1,232	$9,956	$63,106	$4,468	$26,606	$6,594	$47,803	$77,639	$108,205	$13,703	$1,180
20	($000)	Customer	Total Customer (Billing)	$104,952	$80,328	$12,940	$4,318	$89	$1,430	$1,163	$1,752	$106	$177	$768	$77	$430	$14	$312	$85	$227	$467	$271
21			Total Revenue @ Full MC ($000)	$1,322,306	$566,347	$57,716	$52,893	$236	$35,681	$53,769	$78,339	$1,776	$13,772	$86,177	$6,079	$36,141	$16,685	$50,173	$107,007	$139,335	$18,707	$1,471

1 Year MC

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs
December 2025 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Streetlighting
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
1	Units	Energy	Annual MWh @ Input		6,248,604	599,673	652,997	1,995	459,186	708,531	1,038,290	22,801	184,262	1,167,972	82,702	492,415	871,049	123,965	1,436,937	2,002,659	253,620	21,832
2	Units	Customer	Average		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	3,311	7,437
3	Units	Customer	Annual		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	7,887	7,437
4	Units	Customer	Metered Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	98
5																						
6																						
7	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295
8	$/Unit	Customer	Dist-Service Drop ($/Customer)		$84.10	$114.88	$214.66	$0.00	$213.77	$218.49	$497.73	$0.00	$521.42	$903.85	$0.00	$3,265.83	$0.00	$3,265.83	$0.00	$0.00	$0.00	$0.00
9	$/Unit	Customer	Meters ($/Customer)		$24.91	$26.43	$30.00	$1,729.42	$33.37	$35.35	$143.00	$1,729.42	$207.21	$207.30	$1,729.42	$262.83	$1,729.42	$262.83	$1,729.42	$26,606.01	$33.45	$26.43
10	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
11	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
12	$/Unit	Customer	Uncollectables ($/Customer)		$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
13	$/Unit	Customer	Customer Service / Other ($/Customer)		$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
14																						
15																						
16	($000)	Energy	Total Energy	$1,357,904	$518,343	$49,745	$54,168	$166	$38,091	$58,775	$86,130	$1,891	$15,285	$96,887	$6,860	$40,847	$72,256	$10,283	$119,199	$166,127	$21,039	$1,811
17	($000)	Customer	Total Customer (Billing)	$104,707	$80,328	$12,940	$4,318	$89	$1,430	$1,163	$1,606	$106	$177	$768	$77	$430	$205	$21	$85	$227	$467	$271
18			Total Revenue @ Full MC ($000)	$1,462,611	$598,671	$62,685	$58,487	$254	$39,521	$59,938	$87,735	$1,997	$15,462	$97,655	$6,938	$41,277	$72,461	$10,305	$119,284	$166,354	$21,505	$2,082

Generation

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Costs

Line	**Lithium-Ion, 4-Hour, 1000MW[1]**	
1	Total Capital Cost $/kW	$1,816.49
2	Payment Factor	5.557%
3	Total Capital Cost $/kW-Yr	$100.94
4	O&M cost per kW-Yr	43.12
5	Total Cost per kW-Yr	$144.06
6	Capacity Contribution[2]	77%
7	Capacity Cost $/kW-Yr	$187.77

		Flat Market Price (MidC Hub)[3]	**Energy Benefit of Storage**
8	2025	94.91	83.03
9	2026	79.81	84.92
10	2027	59.47	53.33
11	2028	54.69	24.26
12	2029	55.12	28.57
13	2030	56.40	25.92
14	2031	56.99	26.60
15	2032	55.36	16.12
16	2033	47.28	17.65
17	2034	48.89	18.77
18	2035	49.70	19.81
19	2036	51.27	18.93
20	2037	54.44	18.91
21	2038	57.74	22.18
22	2039	58.76	22.06
23	2040	62.06	27.23
24	2041	63.08	44.68
25	2042	64.76	42.84
26	2043	66.23	43.81
27	2044	67.73	44.80

Marginal Costs

		Energy Benefit of Storage $/kW-Yr	**Net Capacity Cost $/kW-Yr**	Cost per MWh	Capacity Contribution of Energy	Capacity Credit	**Cost per MWh**
28	1 Year	(83.03)	**$104.74**	94.91	100%	-$11.96	**$82.95**
29	5 Years	(53.77)	**$134.01**	65.99	100%	-$15.30	**$54.03**
30	10 Years	(38.16)	**$149.62**	56.73	100%	-$17.08	**$44.77**
31	20 Years	(31.49)	**$156.28**	51.11	100%	-$17.84	**$39.16**

[1]2023 Intergrated Resource Plan Volume I
[2]PacifiCorp's 2021 Integrated Resource Plan Volume II, Appendix K
[3]PacifiCorps's March 2023 Official Forward Price Curve in the Avoided Cost Study effective September 2023

Transm

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
2025 Dollars (000s)

		Forecast Transmission					
Line	Description	2024	2025	2026	2027	2028	2024-2028
1	Bulk Power Lines (grid)	$0	$0	$0	$0	$0	$0
2	Growth Related Major Projects (local)	$9,279	$32,815	$83,834	$93,000	$40,273	$259,200
3							
4	Adjusted Bulk Power Lines (grid)	$0	$0	$0	$0	$0	$0
5	Adjusted Growth Related Major Projects (local)	$9,705	$34,321	$87,683	$97,270	$42,122	$271,102
6							
	Total Growth Related Investments - Demand	$9,705	$34,321	$87,683	$97,270	$42,122	$271,101
	Total Growth Related Investments - Energy	$0	$0	$0	$0	$0	$0
	Total Marginal Transmission Investment	$9,705	$34,321	$87,683	$97,270	$42,122	$271,101

Description	Total	Demand Related	Energy Related
Marginal Investment ($/KW)	$84.43	$84.43	$0.00
Annualized Investment ($/KW)	$5.70	$5.70	$0.00
Admin. & General Factor ($/KW)	$0.49	$0.49	$0.00
Annual O&M Expenses ($/KW)	$0.91	$0.91	$0.00
Annualized Marginal Cost ($/KW)	$7.10	$7.10	$0.00
Marginal Cost of Energy-Related Transmission ($/KWh)			$0.00

Escalation Factor
2023-2025
1.0459

Footnotes:

Bulk power line & growth related projects data provided in 2023 dollars for each year

Demand Portion of Transmission = PV of Long Run Capacity Costs / PV of Total Long Run Costs = 156.28 / (156.28+39.16) = 79.96%

Energy Portion of Transmission = PV of Long Run Energy Costs / PV of Total Long Run Costs = 39.16 / (156.28+39.16) = 20.04%

Capacity Addition MW from 2024-2028 = 3,211

TransOM

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

Line	Description	Calculation	(A) 2013	(B) 2014	(C) 2015	(D) 2016	(E) 2017	(F) 2018	(G) 2019	(H) 2020	(I) 2021	(J) 2022	(K) =AVERAGE of (A) thru (J)
1	Transmission O&M Exp.		198,670	211,984	215,664	203,261	204,806	206,506	218,367	210,892	232,302	239,534	
2	Wheeling		137,182	151,336	148,425	130,789	134,473	135,022	145,825	141,188	159,058	163,235	
3	Net Transmission O&M	1-2	61,488	60,648	67,239	72,472	70,333	71,484	72,541	69,703	73,243	76,299	
4	Transmission Plant		5,231,106	5,387,871	5,910,756	6,051,720	6,222,286	6,353,045	6,478,620	7,630,241	7,892,551	8,048,836	
5	Tran. O&M Loading	3/4	1.175%	1.126%	1.138%	1.198%	1.130%	1.125%	1.120%	0.914%	0.928%	0.948%	1.080%

Source:
PacifiCorp FERC Form 1
(1) page 321, line 112
(2) page 321, line 96
(4) page 206-07, line 58

TransLF

PacifiCorp
System Load Factor

Line No.	Month	Total Monthly Energy	Associated Losses		MW
	(A)	(B)	(C)	(D) (B)-(C)	(E)
1	January	5,930,733	495,061	5,435,672	8,514
2	February	5,316,777	456,082	4,860,695	8,805
3	March	5,393,979	539,851	4,854,128	8,249
4	April	4,994,632	424,178	4,570,454	7,819
5	May	5,002,715	304,332	4,698,383	8,135
6	June	5,470,102	583,233	4,886,869	10,216
7	July	6,444,768	259,229	6,185,539	11,017
8	August	6,252,889	267,669	5,985,220	10,623
9	September	5,311,089	312,697	4,998,392	10,593
10	October	4,979,242	311,904	4,667,338	7,476
11	November	5,382,263	258,567	5,123,696	8,447
12	December	6,008,903	350,219	5,658,684	9,026
13		66,488,092	4,563,022	61,925,070	
14					
15				Average Monthly MW	9,077
16				Load Factor	77.88%

Source: FERC Form 1, December 31, 2022
Page 401b

DistSub

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
2023 Dollars

Line	Description	Calculation	Value
1	Incremental Substation Cost ($/kVA)		$366.57
2	Power Factor		0.95
3	Installed Capacity (MVA)		5172
4	Installed Capacity (MW)		4914
5	Distribution Peak Load		2553
6	Substation Utilization Factor		51.95%
7	Incremental Substation Cost ($/kW)	1/2*3	$200.45
8			
9	Annual Distribution Carrying Charge		7.43%
10			
11	Substation Marginal Cost ($/kW)	4*6	$14.89

Substation Investment

(A)	(B)	(C)	(D)	(E)	(F) =(E)/(D)
In Service Year	Substation Capacity Project	State	Capacity Increase (MVA)	Installed Cost (000)	Installed Cost/MVA (000)
2024	Medford	OR	25.0	$3,100	$124.02
2025	Teiton	WA	25.0	$5,073	$202.93
2025	Bond	OR	25.0	$7,221	$288.85
2025	Rickreall	OR	30.0	$9,376	$312.54
2026	Mill City	OR	25.0	$9,065	$362.62
2026	Fort Jones	CA	7.0	$2,712	$387.41
2026	Banfield	OR	25.0	$9,909	$396.35
2026	China Hat	OR	25.0	$6,821	$272.85
2026	Ahtanum	WA	25.0	$9,285	$371.41
2027	Culver Sub	OR	12.5	$5,165	$413.21
2027	Empire and State	OR	25.0	$7,699	$307.97
2027	Glendale	OR	12.5	$3,596	$287.65
2027	Overpass	OR	13.0	$7,879	$606.07
2027	Redmond	OR	25.0	$11,226	$449.05
2027	Sulphur Creek	WA	30.0	$8,331	$277.69
2027	Wake Robin	OR	30.0	$19,686	$656.20
2027	Whetstone	OR	30.0	$10,300	$343.33
2027	Lebanon	OR	10.0	$6,028	$602.81
2028	Tangent Area	OR	30.0	$10,274	$342.46
2028	Walla Walla	WA	30.0	$8,470	$282.34
		Western States Total	460.0	$161,218	$350.47

Incremental Substation Cost ($/KVA) $350.47

Escalation Factor
2023-2025
1.0459

PC1

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Hypothetical Circuit Study Results Annual Demand and Commitment Costs

Line	Load Class		Demand						Commitment					
					Investment $ / kW[1]		Annual $ / kW[1]				Investment $ / Customer		Annual $ / Customer	
			Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
1	Res - Schedule 4	(sec)	$ 191.87	$ 254.38	$ 200.68	$ 266.06	$ 14.91	$ 19.77	$ 841.90	$ 365.91	$ 880.56	$ 382.71	$ 65.43	$ 28.44
2														
3	GS - Schedule 23													
4	0-15 kW	(sec)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
5	15+ kW	(sec)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
6	Primary	(pri)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
7														
8	GS - Schedule 28													
9	0-50 kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
10	51-100 kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
11	100 + kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
12	Primary	(pri)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
13														
14	GS - Schedule 30													
15	0-300 kW	(sec)	$ 141.52	$ 210.47	$ 148.02	$ 220.13	$ 11.00	$ 16.36	$ 594.22	$ 258.26	$ 621.50	$ 270.12	$ 46.18	$ 20.07
16	300+ kW	(sec)	$ 137.30	$ 206.49	$ 143.60	$ 215.97	$ 10.67	$ 16.05	$ 572.81	$ 248.96	$ 599.11	$ 260.39	$ 44.51	$ 19.35
17	Primary	(pri)	$ 141.52	$ 210.47	$ 148.02	$ 220.13	$ 11.00	$ 16.36	$ 594.22	$ 258.26	$ 621.50	$ 270.12	$ 46.18	$ 20.07
18														
19	LPS - Schedule 48													
20	1 - 4 MW	(sec)	$ 274.88	$ 318.09	$ 287.50	$ 332.70	$ 21.36	$ 24.72	$ 1,231.08	$ 535.06	$ 1,287.60	$ 559.62	$ 95.67	$ 41.58
21	1 - 4 MW	(pri)	$ 274.88	$ 318.09	$ 287.50	$ 332.70	$ 21.36	$ 24.72	$ 1,231.08	$ 535.06	$ 1,287.60	$ 559.62	$ 95.67	$ 41.58
22	> 4 MW	(sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	> 4 MW	(pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24														
25	Irrigation - Schedule 41	(sec)	$ 573.90	$ 586.62	$ 600.25	$ 613.55	$ 44.60	$ 45.59	$ 2,718.91	$ 1,181.70	$ 2,843.75	$ 1,235.96	$ 211.29	$ 91.83

Escalation Factor
2023-2025
1.0459

PC 2

PacifiCorp
Oregon Marginal Cost Study
Circuit Distribution Model
Inputs & Calculations

Line	Class	(A)	(B)	(C)	(D)	(E)	(F)
1			Number	Average	Distribution	Average	Percent
2		Annual	of	MWh per	Peak	kW per	Single
3		MWh	Customers	Customer	MW	customer	Phase
4	Class			(A) / (B)		(D)/(B) * 1,000	
5	Res - Schedule 4 (sec)	5,814,272	533,013	10.91	1,213.04	2.28	100.00%
6	GS - Schedule 23 - 0-15 kW (sec)	586,948	71,109	8.25	90.35	1.27	80.77%
7	GS - Schedule 23 - 15+ kW (sec)	639,141	15,152	42.18	97.63	6.44	54.22%
8	GS - Schedule 23 - Primary (pri)	1,955	50	38.86	0.30	5.87	0.62%
9	GS - Schedule 28 - 0-50 kW (sec)	434,116	4,543	95.57	69.55	15.31	29.27%
10	GS - Schedule 28 - 51-100 kW (sec)	669,847	3,614	185.36	104.28	28.86	14.60%
11	GS - Schedule 28 - 100 + kW (sec)	981,603	2,243	437.7	146.51	65.33	2.48%
12	GS - Schedule 28 - Primary (pri)	21,809	59	372.57	3.13	53.40	(0.79%)
13	GS - Schedule 30 - 0-300 kW (sec)	170,220	198	857.81	26.14	131.75	0.42%
14	GS - Schedule 30 - 300+ kW (sec)	1,078,967	600	1797.27	157.78	262.82	0.06%
15	GS - Schedule 30 - Primary (pri)	76,532	40	1893.06	11.04	273.15	1.06%
16	Irrigation - Sch 41	196,326	6,149	31.93	46.96	7.64	15.70%
17	LPS - Schedule 48 - 1 - 4 MW (sec)	456,583	81	5670.86	63.68	790.87	0.15%
18	LPS - Schedule 48 - 1 - 4 MW (pri)	509,238	58	8766.52	71.79	1,235.87	0.41%
19	LPS - Schedule 48 - > 4 MW (sec)	114,945	4	28616.96	14.42	3,590.54	0.37%
20	LPS - Schedule 48 - > 4 MW (pri)	840,070	24	34873.74	207.89	8,630.13	(1.08%)
21	Total	12,592,571	636,937		2,324.50		
22							
23							

Line	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
24	Customer Distribution on the Hypothetical Circuit Branch								
25		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
26				Hypothetical Circuit Branch					Branch
27	Class	1	2	3	4	5	6	7	Total
28	Res - Schedule 4 (sec)	0.37%	0.37%	0.37%	1.81%	1.81%	1.81%	93.46%	100.00%
29	GS - Schedule 23 - 0-15 kW (sec)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
30	GS - Schedule 23 - 15+ kW (sec)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
31	GS - Schedule 23 - Primary (pri)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
32	GS - Schedule 28 - 0-50 kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
33	GS - Schedule 28 - 51-100 kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
34	GS - Schedule 28 - 100 + kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
35	GS - Schedule 28 - Primary (pri)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
36	GS - Schedule 30 - 0-300 kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
37	GS - Schedule 30 - 300+ kW (sec)	0.28%	0.28%	0.28%	0.85%	0.85%	0.85%	96.61%	100.00%
38	GS - Schedule 30 - Primary (pri)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
39	Irrigation - Sch 41	1.08%	1.08%	1.08%	7.97%	7.97%	7.97%	72.85%	100.00%
40	LPS - Schedule 48 - 1 - 4 MW (sec)	0.85%	0.85%	0.85%	1.52%	1.52%	1.52%	92.89%	100.00%
41	LPS - Schedule 48 - 1 - 4 MW (pri)	0.85%	0.85%	0.85%	1.52%	1.52%	1.52%	92.89%	100.00%
42	LPS - Schedule 48 - > 4 MW (sec)		Large Customers are on dedicated circuits and are not included here						
43	LPS - Schedule 48 - > 4 MW (pri)		Large Customers are on dedicated circuits and are not included here						
44									

45		
46	System property records & engineering information	
47	Number of pole feet in Oregon	75,736,758
48	Number of pole miles in Oregon	14,344
49	Number of trench feet in Oregon	29,644,711
50	Number of trench miles in Oregon	5,615
51	Total miles in Oregon	19,959
52	Number of circuits in Oregon	530
53	Number of poles in Oregon	380,944
54	Poles per mile	26.56
55	Customers per mile	31.91
56	MWh per customer	19.77
57	MWh per circuit	23,760
58	Branches per circuit	7
59	Miles per circuit	37.66
60	Miles per branch	5.38
61	Single Phase Miles per Branch[1]	1.88
62	Average Trunk Length	0.67

[1] A 12 KV circuit 12 miles long has approx. 3 miles of single phase, which is approx. 25 percent of circuit distance, so applying 25% to the Miles per Circuit and dividing this amount by the 5 outer branches gives the Single Phase Miles per Branch.

PC 3

PacifiCorp
Oregon Circuit Model Study
Average Customers by Hypothetical Circuit Branch

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1					Hypothetical Circuit Branch				
2	Class	1	2	3	4	5	6	7	Total
3	Res - Schedule 4 (sec)	3.71	3.71	3.71	18.21	18.21	18.21	939.93	1,005.68
4	GS - Schedule 23 - 0-15 kW (sec)	0.93	0.93	0.93	3.45	3.45	3.45	121.01	134.17
5	GS - Schedule 23 - 15+ kW (sec)	0.20	0.20	0.20	0.74	0.74	0.74	25.79	28.59
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
7	GS - Schedule 28 - 0-50 kW (sec)	0.04	0.04	0.04	0.13	0.13	0.13	8.06	8.57
8	GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.10	0.10	0.10	6.41	6.82
9	GS - Schedule 28 - 100 + kW (sec)	0.02	0.02	0.02	0.06	0.06	0.06	3.98	4.23
10	GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
11	GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.37
12	GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	1.09	1.13
13	GS - Schedule 30 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.08
14	Irrigation - Sch 41	0.13	0.13	0.13	0.92	0.92	0.92	8.45	11.60
15	LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.15
16	LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	5.06	5.06	5.06	23.65	23.65	23.65	1,115.58	1,201.72
20									

21 Source - 'Circuit Distribution Model Inputs & Calculations' (PC 2)
22 Source - 'Customer Distribution on the Hypothetical Circuit Branch' (PC 2)
23 Customers multiplied by Customer Distribution on the Hypothetical Circuit Branch divided by circuits in the state.
24 For Example 3.71 is 533,013 Residential Customers X .368% customers on Branch 1 divided by 530 circuits.
25

26	Percent of Customers								
27	Res - Schedule 4 (sec)	73.18%	73.18%	73.18%	77.02%	77.02%	77.02%	84.25%	83.69%
28	GS - Schedule 23 - 0-15 kW (sec)	18.40%	18.40%	18.40%	14.61%	14.61%	14.61%	10.85%	11.16%
29	GS - Schedule 23 - 15+ kW (sec)	3.92%	3.92%	3.92%	3.11%	3.11%	3.11%	2.31%	2.38%
30	GS - Schedule 23 - Primary (pri)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
31	GS - Schedule 28 - 0-50 kW (sec)	0.81%	0.81%	0.81%	0.55%	0.55%	0.55%	0.72%	0.71%
32	GS - Schedule 28 - 51-100 kW (sec)	0.65%	0.65%	0.65%	0.44%	0.44%	0.44%	0.57%	0.57%
33	GS - Schedule 28 - 100 + kW (sec)	0.40%	0.40%	0.40%	0.27%	0.27%	0.27%	0.36%	0.35%
34	GS - Schedule 28 - Primary (pri)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
35	GS - Schedule 30 - 0-300 kW (sec)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.03%	0.03%
36	GS - Schedule 30 - 300+ kW (sec)	0.06%	0.06%	0.06%	0.04%	0.04%	0.04%	0.10%	0.09%
37	GS - Schedule 30 - Primary (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
38	Irrigation - Sch 41	2.48%	2.48%	2.48%	3.91%	3.91%	3.91%	0.76%	0.97%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	0.03%	0.03%	0.03%	0.01%	0.01%	0.01%	0.01%	0.01%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	0.02%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%
41	LPS - Schedule 48 - > 4 MW (sec)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
42	LPS - Schedule 48 - > 4 MW (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44									
45	Sum of Branch Customers								
46	1,2,3,6	5.06	5.06	5.06			23.65		38.84
47	1,2,3,4,5,6,7	5.06	5.06	5.06	23.65	23.65	23.65	1,115.58	1,201.72
48									
49	1,2,3,6	13.0%	13.0%	13.0%	0.0%	0.0%	60.9%	0.0%	100.0%
50	1,2,3,4,5,6,7	0.4%	0.4%	0.4%	2.0%	2.0%	2.0%	92.8%	100.0%

PacifiCorp
Oregon Circuit Model Study
Circuit kW Load by Branch

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1					Hypothetical Circuit Branch				
2	Class	1	2	3	4	5	6	7	Total
3	Res - Schedule 4 (sec)	8.43	8.43	8.43	41.45	41.45	41.45	2,139.10	2,288.76
4	GS - Schedule 23 - 0-15 kW (sec)	1.18	1.18	1.18	4.39	4.39	4.39	153.76	170.48
5	GS - Schedule 23 - 15+ kW (sec)	1.28	1.28	1.28	4.74	4.74	4.74	166.14	184.21
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.01	0.01	0.01	0.50	0.56
7	GS - Schedule 28 - 0-50 kW (sec)	0.63	0.63	0.63	1.99	1.99	1.99	123.35	131.23
8	GS - Schedule 28 - 51-100 kW (sec)	0.95	0.95	0.95	2.99	2.99	2.99	184.95	196.76
9	GS - Schedule 28 - 100 + kW (sec)	1.33	1.33	1.33	4.20	4.20	4.20	259.85	276.44
10	GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.09	0.09	0.09	5.54	5.90
11	GS - Schedule 30 - 0-300 kW (sec)	0.14	0.14	0.14	0.48	0.48	0.48	47.47	49.33
12	GS - Schedule 30 - 300+ kW (sec)	0.84	0.84	0.84	2.53	2.53	2.53	287.59	297.70
13	GS - Schedule 30 - Primary (pri)	0.06	0.06	0.06	0.20	0.20	0.20	20.05	20.84
14	Irrigation - Sch 41	0.96	0.96	0.96	7.06	7.06	7.06	64.56	88.61
15	LPS - Schedule 48 - 1 - 4 MW (sec)	1.02	1.02	1.02	1.83	1.83	1.83	111.61	120.14
16	LPS - Schedule 48 - 1 - 4 MW (pri)	1.15	1.15	1.15	2.06	2.06	2.06	125.83	135.45
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	17.99	17.99	17.99	74.03	74.03	74.03	3,690.31	3,966.39
20									

21 Source - 'Circuit Distribution Model Inputs & Calculations' (PC 2)
22 Source - 'Average Customers by Hypothetical Circuit Branch' (PC 3)
23 Customers multiplied by circuit kW per customer.
24 For Example 8.4 is 3.71 Residential Customers multiplied by 2.28 average Dist. kW per Customer.

25									
26	Percent of Branch Load								
27	Res - Schedule 4 (sec)	46.87%	46.87%	46.87%	55.99%	55.99%	55.99%	57.97%	57.70%
28	GS - Schedule 23 - 0-15 kW (sec)	6.58%	6.58%	6.58%	5.93%	5.93%	5.93%	4.17%	4.30%
29	GS - Schedule 23 - 15+ kW (sec)	7.11%	7.11%	7.11%	6.41%	6.41%	6.41%	4.50%	4.64%
30	GS - Schedule 23 - Primary (pri)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.01%	0.01%
31	GS - Schedule 28 - 0-50 kW (sec)	3.50%	3.50%	3.50%	2.69%	2.69%	2.69%	3.34%	3.31%
32	GS - Schedule 28 - 51-100 kW (sec)	5.25%	5.25%	5.25%	4.04%	4.04%	4.04%	5.01%	4.96%
33	GS - Schedule 28 - 100 + kW (sec)	7.38%	7.38%	7.38%	5.68%	5.68%	5.68%	7.04%	6.97%
34	GS - Schedule 28 - Primary (pri)	0.16%	0.16%	0.16%	0.12%	0.12%	0.12%	0.15%	0.15%
35	GS - Schedule 30 - 0-300 kW (sec)	0.76%	0.76%	0.76%	0.65%	0.65%	0.65%	1.29%	1.24%
36	GS - Schedule 30 - 300+ kW (sec)	4.68%	4.68%	4.68%	3.41%	3.41%	3.41%	7.79%	7.51%
37	GS - Schedule 30 - Primary (pri)	0.32%	0.32%	0.32%	0.27%	0.27%	0.27%	0.54%	0.53%
38	Irrigation - Sch 41	5.33%	5.33%	5.33%	9.53%	9.53%	9.53%	1.75%	2.23%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	5.65%	5.65%	5.65%	2.47%	2.47%	2.47%	3.02%	3.03%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	6.37%	6.37%	6.37%	2.79%	2.79%	2.79%	3.41%	3.42%
41	LPS - Schedule 48 - > 4 MW (sec)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
42	LPS - Schedule 48 - > 4 MW (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44									
45	Sum of Branch Loads								
46	1,2,3,6	17.99	17.99	17.99			74.03		128.01
47	1,2,3,4,5,6,7	17.99	17.99	17.99	74.03	74.03	74.03	3,690.31	3,966.39
48									
49	1,2,3,6	14.06%	14.06%	14.06%			57.83%		100.00%
50	1,2,3,4,5,6,7	0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%

PC 4

PacifiCorp
Oregon Circuit Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

	State Specific Account 364 Pole Statistics				Adjustment
	Poles	Pole Feet	Pole Miles	Poles / Mile	Factor
California	55,683	12,642,710	2,394	23.26	0.865
Idaho	97,904	21,437,890	4,060	24.11	0.897
Oregon	380,944	75,736,758	14,344	26.56	0.988
Utah	351,303	60,938,569	11,541	30.44	1.132
Washington	100,586	16,791,482	3,180	31.63	1.176
Wyoming	159,614	37,458,548	7,094	22.50	0.837
Total	1,146,034	225,005,957	42,615	26.89	1.000

	Account 364 Pole Cost per Mile			Account 365	Total Line
Wire Size	Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Conductor Cost per Mile	Construction Cost
1 1 Phase - 1/0 ACSR	$29,797	0.988	$29,425	$12,789	$42,214
2 3 Phase - 1/0 ACSR	$56,836	0.988	$56,127	$28,548	$84,675
3 · 447 AAC & 4\0 AAC	$63,338	0.988	$62,548	$62,952	$125,500
4 ·795 AAC & 477 AAC	$65,804	0.988	$64,984	$110,173	$175,157

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	$55,405	$196,266	$251,670
Conductors	$24,080	$99,826	$123,907
Total	$79,485	$296,092	$375,577

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4\0 AAC	3 Phase -795 AAC & 477 AAC
Poles	$336,490	$349,591
Conductors	$338,662	$592,695
Total	$675,151	$942,286

Miles per Branch 5.38
Single Phase Miles Per Branch 1.88
Three Phase Miles Per Branch 3.50

Commitment and Demand Costs Per Branch

	Poles			Conductor			
	Total Cost	Commitment	Demand	Total Cost	Commitment	Demand	Total
Branches 1,2,3,4,5							
1 Phase - 1/0 ACSR	$55,405	$55,405	$0	$24,080	$24,080	$0	$79,485
3 Phase - 1/0 ACSR	$196,266	$102,895	$93,371	$99,826	$44,720	$55,106	$296,092
Total Branches 1,2,3,4,5	$251,670	$158,300	$93,371	$123,907	$68,801	$55,106	$375,577
Branch 6							$0
3 Phase - 447 AAC & 4\0 AAC	$336,490	$158,300	$178,190	$338,662	$68,801	$269,861	$675,151
Branch 7							$0
3 Phase -795 AAC & 477 AAC	$349,591	$158,300	$191,291	$592,695	$68,801	$523,895	$942,286
Total All Branches	$1,944,433	$1,108,097	$836,335	$1,550,890	$481,605	$1,069,285	$3,495,323

Branch pole and conductor commitment costs equals single or three Phase Miles Per Branch Multiplied by 1 Phase - 1/0 ACSR Cost

PC 5

PacifiCorp
Oregon Circuit Model Study
Demand Calculations

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Poles								
Line		1	2	3	4	5	6	7	Total	
1	% customer	14.06%	14.06%	14.06%			57.83%		100.00%	
2	Branch 6 Cost	$ 25,045	$ 25,045	$ 25,045			$ 103,055		$ 178,190	$ / kW
3	% customer	0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%	
4	Branch 7 Cost	$ 868	$ 868	$ 868	$ 3,571	$ 3,571	$ 3,571	$ 177,976	$ 191,291	
5	Branch Commitment Cost	$ 93,371	$ 93,371	$ 93,371	$ 93,371	$ 93,371				Average
6	Total	$ 119,284	$ 119,284	$ 119,284	$ 96,941	$ 96,941	$ 106,625	$ 177,976	$ 836,335	$ 210.86
7										
8									Total	
9									Demand	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
11	Res - Schedule 4 (sec)	$ 55,912	$ 55,912	$ 55,912	$ 54,276	$ 54,276	$ 59,698	$ 103,165	$ 439,152	$ 191.87
12	GS - Schedule 23 - 0-15 kW (sec)	$ 7,847	$ 7,847	$ 7,847	$ 5,747	$ 5,747	$ 6,321	$ 7,416	$ 48,771	$ 286.09
13	GS - Schedule 23 - 15+ kW (sec)	$ 8,479	$ 8,479	$ 8,479	$ 6,210	$ 6,210	$ 6,830	$ 8,013	$ 52,700	$ 286.09
14	GS - Schedule 23 - Primary (pri)	$ 26	$ 26	$ 26	$ 19	$ 19	$ 21	$ 24	$ 159	$ 286.09
15	GS - Schedule 28 - 0-50 kW (sec)	$ 4,180	$ 4,180	$ 4,180	$ 2,612	$ 2,612	$ 2,873	$ 5,949	$ 26,584	$ 202.58
16	GS - Schedule 28 - 51-100 kW (sec)	$ 6,267	$ 6,267	$ 6,267	$ 3,916	$ 3,916	$ 4,307	$ 8,920	$ 39,859	$ 202.58
17	GS - Schedule 28 - 100 + kW (sec)	$ 8,805	$ 8,805	$ 8,805	$ 5,502	$ 5,502	$ 6,051	$ 12,532	$ 56,002	$ 202.58
18	GS - Schedule 28 - Primary (pri)	$ 188	$ 188	$ 188	$ 117	$ 117	$ 129	$ 267	$ 1,195	$ 202.58
19	GS - Schedule 30 - 0-300 kW (sec)	$ 912	$ 912	$ 912	$ 631	$ 631	$ 694	$ 2,289	$ 6,981	$ 141.52
20	GS - Schedule 30 - 300+ kW (sec)	$ 5,583	$ 5,583	$ 5,583	$ 3,308	$ 3,308	$ 3,639	$ 13,870	$ 40,874	$ 137.30
21	GS - Schedule 30 - Primary (pri)	$ 385	$ 385	$ 385	$ 266	$ 266	$ 293	$ 967	$ 2,949	$ 141.52
22	Irrigation - Sch 41	$ 6,363	$ 6,363	$ 6,363	$ 9,242	$ 9,242	$ 10,165	$ 3,113	$ 50,853	$ 573.90
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 6,739	$ 6,739	$ 6,739	$ 2,396	$ 2,396	$ 2,635	$ 5,383	$ 33,025	$ 274.88
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 7,597	$ 7,597	$ 7,597	$ 2,701	$ 2,701	$ 2,971	$ 6,068	$ 37,233	$ 274.88
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 119,284	$ 119,284	$ 119,284	$ 96,941	$ 96,941	$ 106,625	$ 177,976	$ 836,335	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 3)
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4) for178,190
Line 1 X 178,190
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4) for191,291
Line 3 X 191,291
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4)
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 3)

PacifiCorp
Oregon Circuit Model Study
Demand Calculations

(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
Conductors								
1	2	3	4	5	6	7	Total	
14.06%	14.06%	14.06%			57.83%		100.00%	
$ 37,929.76	$ 37,929.76	$ 37,929.76	$ -	$ -	$ 156,071.59	$ -	$ 269,861	$ / kW
0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%	
$ 2,377	$ 2,377	$ 2,377	$ 9,779	$ 9,779	$ 9,779	$ 487,429	$ 523,895	
$ 55,106	$ 55,106	$ 55,106	$ 55,106	$ 55,106				Average
$ 95,412	$ 95,412	$ 95,412	$ 64,885	$ 64,885	$ 165,850	$ 487,429	$ 1,069,285	$ 269.59
1	2	3	4	5	6	7	Total Demand Cost	$ Per kW
$ 44,723	$ 44,723	$ 44,723	$ 36,328	$ 36,328	$ 92,857	$ 282,540	$ 582,222	$ 254.38
$ 6,277	$ 6,277	$ 6,277	$ 3,846	$ 3,846	$ 9,832	$ 20,309	$ 56,664	$ 332.38
$ 6,782	$ 6,782	$ 6,782	$ 4,156	$ 4,156	$ 10,623	$ 21,945	$ 61,228	$ 332.38
$ 20	$ 20	$ 20	$ 13	$ 13	$ 32	$ 66	$ 185	$ 332.38
$ 3,343	$ 3,343	$ 3,343	$ 1,748	$ 1,748	$ 4,468	$ 16,293	$ 34,287	$ 261.28
$ 5,013	$ 5,013	$ 5,013	$ 2,621	$ 2,621	$ 6,699	$ 24,429	$ 51,408	$ 261.28
$ 7,043	$ 7,043	$ 7,043	$ 3,682	$ 3,682	$ 9,413	$ 34,322	$ 72,228	$ 261.28
$ 150	$ 150	$ 150	$ 79	$ 79	$ 201	$ 732	$ 1,541	$ 261.28
$ 730	$ 730	$ 730	$ 422	$ 422	$ 1,079	$ 6,270	$ 10,382	$ 210.47
$ 4,466	$ 4,466	$ 4,466	$ 2,214	$ 2,214	$ 5,660	$ 37,986	$ 61,471	$ 206.49
$ 308	$ 308	$ 308	$ 178	$ 178	$ 456	$ 2,648	$ 4,385	$ 210.47
$ 5,090	$ 5,090	$ 5,090	$ 6,186	$ 6,186	$ 15,812	$ 8,527	$ 51,980	$ 586.62
$ 5,390	$ 5,390	$ 5,390	$ 1,603	$ 1,603	$ 4,099	$ 14,741	$ 38,217	$ 318.09
$ 6,077	$ 6,077	$ 6,077	$ 1,808	$ 1,808	$ 4,621	$ 16,620	$ 43,087	$ 318.09
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 95,412	$ 95,412	$ 95,412	$ 64,885	$ 64,885	$ 165,850	$ 487,429	$ 1,069,285	

PC 6

PacifiCorp
Oregon Circuit Model Study
Commitment Calculations

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Poles								
Line		1	2	3	4	5	6	7	Total	
1	% customer	13.04%	13.04%	13.04%			60.89%		100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ Per
3	% customer	0.42%	0.42%	0.42%	1.97%	1.97%	1.97%	92.83%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300		Average
6	Total	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 1,108,097	$ 922.10
7										
8									Total	
9									Demand	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	Customer
11	Res - Schedule 4 (sec)	$ 115,850	$ 115,850	$ 115,850	$ 121,921	$ 121,921	$ 121,921	$ 133,375	$ 846,687	$ 841.90
12	GS - Schedule 23 - 0-15 kW (sec)	$ 29,122	$ 29,122	$ 29,122	$ 23,121	$ 23,121	$ 23,121	$ 17,171	$ 173,902	$ 1,296.15
13	GS - Schedule 23 - 15+ kW (sec)	$ 6,205	$ 6,205	$ 6,205	$ 4,927	$ 4,927	$ 4,927	$ 3,659	$ 37,055	$ 1,296.15
14	GS - Schedule 23 - Primary (pri)	$ 21	$ 21	$ 21	$ 16	$ 16	$ 16	$ 12	$ 123	$ 1,296.15
15	GS - Schedule 28 - 0-50 kW (sec)	$ 1,287	$ 1,287	$ 1,287	$ 872	$ 872	$ 872	$ 1,143	$ 7,621	$ 889.19
16	GS - Schedule 28 - 51-100 kW (sec)	$ 1,024	$ 1,024	$ 1,024	$ 694	$ 694	$ 694	$ 909	$ 6,063	$ 889.19
17	GS - Schedule 28 - 100 + kW (sec)	$ 636	$ 636	$ 636	$ 431	$ 431	$ 431	$ 564	$ 3,763	$ 889.19
18	GS - Schedule 28 - Primary (pri)	$ 17	$ 17	$ 17	$ 11	$ 11	$ 11	$ 15	$ 98	$ 889.19
19	GS - Schedule 30 - 0-300 kW (sec)	$ 33	$ 33	$ 33	$ 24	$ 24	$ 24	$ 51	$ 222	$ 594.22
20	GS - Schedule 30 - 300+ kW (sec)	$ 100	$ 100	$ 100	$ 64	$ 64	$ 64	$ 155	$ 649	$ 572.81
21	GS - Schedule 30 - Primary (pri)	$ 7	$ 7	$ 7	$ 5	$ 5	$ 5	$ 10	$ 45	$ 594.22
22	Irrigation - Sch 41	$ 3,929	$ 3,929	$ 3,929	$ 6,187	$ 6,187	$ 6,187	$ 1,199	$ 31,546	$ 2,718.91
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 40	$ 40	$ 40	$ 15	$ 15	$ 15	$ 20	$ 187	$ 1,231.08
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 29	$ 29	$ 29	$ 11	$ 11	$ 11	$ 14	$ 135	$ 1,231.08
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 1,108,097	

PacifiCorp
Oregon Circuit Model Study
Commitment Calculations

(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
Conductors								
1	2	3	4	5	6	7	Total	
13.04%	13.04%	13.04%	0.00%	0.00%	60.89%	0.00%	100.00%	
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ Per
0.42%	0.42%	0.42%	1.97%	1.97%	1.97%	92.83%	100.00%	Customer
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801		Average
$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 481,605	$ 400.76
							Total Demand Cost	$ Per Customer
1	2	3	4	5	6	7		
$ 50,351	$ 50,351	$ 50,351	$ 52,990	$ 52,990	$ 52,990	$ 57,968	$ 367,990	$ 365.91
$ 12,657	$ 12,657	$ 12,657	$ 10,049	$ 10,049	$ 10,049	$ 7,463	$ 75,582	$ 563.34
$ 2,697	$ 2,697	$ 2,697	$ 2,141	$ 2,141	$ 2,141	$ 1,590	$ 16,105	$ 563.34
$ 9	$ 9	$ 9	$ 7	$ 7	$ 7	$ 5	$ 53	$ 563.34
$ 559	$ 559	$ 559	$ 379	$ 379	$ 379	$ 497	$ 3,312	$ 386.46
$ 445	$ 445	$ 445	$ 302	$ 302	$ 302	$ 395	$ 2,635	$ 386.46
$ 276	$ 276	$ 276	$ 187	$ 187	$ 187	$ 245	$ 1,635	$ 386.46
$ 7	$ 7	$ 7	$ 5	$ 5	$ 5	$ 6	$ 43	$ 386.46
$ 14	$ 14	$ 14	$ 11	$ 11	$ 11	$ 22	$ 97	$ 258.26
$ 44	$ 44	$ 44	$ 28	$ 28	$ 28	$ 67	$ 282	$ 248.96
$ 3	$ 3	$ 3	$ 2	$ 2	$ 2	$ 5	$ 20	$ 258.26
$ 1,708	$ 1,708	$ 1,708	$ 2,689	$ 2,689	$ 2,689	$ 521	$ 13,711	$ 1,181.70
$ 17	$ 17	$ 17	$ 7	$ 7	$ 7	$ 9	$ 81	$ 535.06
$ 13	$ 13	$ 13	$ 5	$ 5	$ 5	$ 6	$ 59	$ 535.06
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 481,605	

PC 7

PacifiCorp
Oregon Circuit Model Study
Dedicated Circuit Trunk Costs
For Large Customers

		Voltage Delivery	
		Large GS + 4 MW	
		Poles	Conductor
1	Construction Cost Per Mile	$64,984	$110,173
2	Average Trunk Length	0.67	miles
3	Total Construction Cost	$43,539	$73,816
5	Customer Peak Demand (Sec)	3,591	kW
4	Customer Peak Demand (Pri)	8,630	kW
7	Demand Cost $/kW (Sec)	$12.13	$20.56
6	Demand Cost $/kW (Pri)	$5.04	$8.55

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (PC 4)
Line 2 - Distribution Engineering Studies
Line 3 - Line 1 multiplied by Line 2
Line 4 - 'Circuit Distribution Model Inputs & Calculations' (PC 2)
Line 5 - Line 3 divided by Line 4

PC 8

PacifiCorp
Oregon Circuit Model Study
Trunk All Demand Costs
Outer Branches Commitment & Demand
Three Phase As Needed

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
								=(C)*(F)	=(D)*(F)
		Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Line	Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
1	Res - Schedule 4 (sec)	$ 841.90	$ 365.91	$ 191.87	$ 254.38	1,005.7	2,288.76	$ 439,152	$ 582,222
2	GS - Schedule 23 - 0-15 kW (sec)	$ 1,296.15	$ 563.34	$ 286.09	$ 332.38	134.2	170.48	$ 48,771	$ 56,664
3	GS - Schedule 23 - 15+ kW (sec)	$ 1,296.15	$ 563.34	$ 286.09	$ 332.38	28.6	184.21	$ 52,700	$ 61,228
4	GS - Schedule 23 - Primary (pri)	$ 1,296.15	$ 563.34	$ 286.09	$ 332.38	0.1	0.56	$ 159	$ 185
5	GS - Schedule 28 - 0-50 kW (sec)	$ 889.19	$ 386.46	$ 202.58	$ 261.28	8.6	131.23	$ 26,584	$ 34,287
6	GS - Schedule 28 - 51-100 kW (sec)	$ 889.19	$ 386.46	$ 202.58	$ 261.28	6.8	196.76	$ 39,859	$ 51,408
7	GS - Schedule 28 - 100 + kW (sec)	$ 889.19	$ 386.46	$ 202.58	$ 261.28	4.2	276.44	$ 56,002	$ 72,228
8	GS - Schedule 28 - Primary (pri)	$ 889.19	$ 386.46	$ 202.58	$ 261.28	0.1	5.90	$ 1,195	$ 1,541
9	GS - Schedule 30 - 0-300 kW (sec)	$ 594.22	$ 258.26	$ 141.52	$ 210.47	0.4	49.33	$ 6,981	$ 10,382
10	GS - Schedule 30 - 300+ kW (sec)	$ 572.81	$ 248.96	$ 137.30	$ 206.49	1.1	297.70	$ 40,874	$ 61,471
11	GS - Schedule 30 - Primary (pri)	$ 594.22	$ 258.26	$ 141.52	$ 210.47	0.1	20.84	$ 2,949	$ 4,385
12	Irrigation - Sch 41	$ 2,718.91	$ 1,181.70	$ 573.90	$ 586.62	11.6	88.61	$ 50,853	$ 51,980
13	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 1,231.08	$ 535.06	$ 274.88	$ 318.09	0.2	120.14	$ 33,025	$ 38,217
14	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 1,231.08	$ 535.06	$ 274.88	$ 318.09	0.1	135.45	$ 37,233	$ 43,087
15	Total -	$ 922.10	$ 400.76	$ 210.86	$ 269.59	1,201.7	3,966.39	$ 836,335	$ 1,069,285
16									
17	Large GS + 4 MW (sec)	$ -	$ -	$ 12.13	$ 20.56	-	3,590.54	$ 43,539	$ 73,816
18	Large GS + 4 MW (pri)	$ -	$ -	$ 5.04	$ 8.55	-	8,630.13	$ 43,539	$ 73,816
								$ 923,413	$ 1,216,917

	Commitment	Demand	Total
Poles	$ 1,108,097	$ 923,413	$ 2,031,511
Conductor	$ 481,605	$ 1,216,917	$ 1,698,522
Total	$ 1,589,702	$ 2,140,330	$ 3,730,033

Source : Column (A) - Pole Commitment Calculations' (PC 6)
Column (B) - Conductor Commitment Calculations' (PC 6)
Column (C) - Pole Demand Calculations' (PC 5)
Column (D) - Conductor Demand Calculations' (PC 5)
Column (E) - Average Customers by Hypothetical Circuit Branch' (PC 3)
Column (F) - Circuit kW Load by Branch' (PC 3)

XFMR 1

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand and Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted $ / Tran. (A) x (B)	(D) # Cust. / Tran.	(E) Transformer $ / Cust. (C) / (D)	(F) Average Customers	(G) Tot. Trans. Commitment $ (E) x (F)	(H) Weighted $ / kW	(I) Transformer Peak kW	(J) Tot. Trans. Demand $ (H) x (I)
1	Res - Schedule 4	100.00%	350.24	350.24	4.12	85.07	513,581	43,690,336	1.62	3,378,644	5,477,821
2											
3	GS - Schedule 23										
4	1 Phase	80.77%	350.24	282.87	2.41	117.14					
5	3 Phase	19.23%	956.84	184.04	3.00	61.28					
6	0-15 kW					178.42	70,880	12,646,410	1.62	729,955	1,183,482
7											
8	1 Phase	54.22%	350.24	189.89	2.41	78.64					
9	3 Phase	45.78%	956.84	438.07	3.00	145.87					
10	15+ kW					224.51	15,103	3,390,774	1.62	412,650	669,032
11											
12	GS - Schedule 28										
13	1 Phase	29.27%	350.24	102.51	1.37	74.93					
14	3 Phase	70.73%	956.84	676.77	1.25	541.15					
15	0-50 kW					616.08	4,630	2,852,426	1.62	191,574	310,601
16											
17	1 Phase	14.60%	350.24	51.15	1.37	37.39					
18	3 Phase	85.40%	956.84	817.10	1.25	653.36					
19	51-100 kW					690.75	3,683	2,544,217	1.62	390,191	632,620
20											
21	1 Phase	2.48%	350.24	8.69	1.37	6.35					
22	3 Phase	97.52%	956.84	933.10	1.25	746.11					
23	100 + kW					752.46	2,286	1,719,951	1.62	486,664	789,031
24											
25	GS - Schedule 30										
26	1 Phase	0.42%	350.24	1.48	1.52	0.97					
27	3 Phase	99.58%	956.84	952.80	1.07	892.36					
28	0-300 kW					893.33	200	178,873	1.62	42,766	69,337
29											
30	1 Phase	0.06%	350.24	0.20	1.52	0.13					
31	3 Phase	99.94%	956.84	956.30	1.07	895.63					
32	300+ kW					895.76	606	542,623	1.62	247,527	401,317
33											
34	LPS - Schedule 48										
35	1 - 4 MW (sec)	100.00%	956.84	956.84	1.11	863.80	82	70,757	1.62	105,438	170,948
36	> 4 MW (sec)	100.00%	956.84	956.84	1.11	863.80	4	3,530	1.62	26,117	42,343
37											
38	Schedule 41- Irrigation										
39	1 Phase	15.70%	350.24	54.98	1.23	44.63					
40	3 Phase	84.30%	956.84	806.63	1.18	685.23					
41	Total					729.86	7,887	5,756,517	1.62	186,770	302,811
42											
43	Lighting	100.00%	350.24	350.24	3.01	116.26	7,437	864,633	1.62	11	18

XFMR2

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors for Transformers
(Regression weighted by number of transformer banks)

Line	Description	(A) Demand Related	(B) Adjusted for System Power Factor of 0.95	(C) Commitment Related	(D) Indexed to 2023	(E) Annualized $ @ 7.43%
			(A) / 0.95		(B) or (C) x 1.0459	(D) x 7.43%
1	1 Phase $/kW	$19.82	$20.86		$21.82	$1.62
2						
3	3 Phase $/kW	$19.82	$20.86		$21.82	$1.62
4						
5	1 Phase			$4,506.90	$4,713.84	$350.24
6	$/Transformer					
7						
8	3 Phase			$7,805.77		
9	Dummy Variable					
10						
11	3 Phase			$12,312.67	$12,878.01	$956.84
12	$/Transformer					

Escalation Factor 2023-2025
1.046

PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	68,689,786	70,580,614	69,136,197	61,535,374	61,513,756	61,139,370	68,212,991	83,124,296	90,983,613	114,178,049
2	Less:										
3	586 Meter Expense	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281	1,305,324	1,394,304
4	587 Customer Installation Expense	4,352,166	4,244,231	4,157,616	5,227,622	5,089,251	5,107,333	5,763,027	6,702,788	6,553,641	6,997,994
5	597 Main. of Meters	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408	231,001	235,870	158,233	185,682
6											
7	Total Adjusted Distribution O & M Expense										
8	Line 1 - (Lines 3 through 5)	59,717,552	61,562,315	61,163,438	54,652,362	55,285,614	55,063,083	61,563,205	74,906,357	82,966,414	105,600,068
9											
10											
11	Distribution Plant										
12	Total Distribution Plant	1,823,007,262	1,866,641,345	1,916,622,378	1,970,302,647	2,040,304,183	2,128,892,665	2,179,547,153	2,311,229,537	2,411,640,782	2,512,503,433
13	Less:										
14	370 Meters	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523	97,893,679	101,011,391
15											
16	Adjusted Distribution Plant										
17	Line 12 - Line 14	1,763,300,899	1,806,531,062	1,855,628,755	1,907,760,892	1,974,512,380	2,051,964,719	2,088,697,950	2,214,927,014	2,313,747,103	2,411,492,042
18											
19											
20	O & M Expense Loading Factor										
21	Distribution O & M Loading	3.39%	3.41%	3.30%	2.86%	2.80%	2.68%	2.95%	3.38%	3.59%	4.38%
22	Line 8 / Line 17										
23											
24	Average Distribution O & M Loading										
25	Average of Line 22	3.27%									
26											
27	Distribution Annual Charge	7.43%									
28											
29	Annualized Distribution O & M Loading Factor										
30	Line 24 / Line 27	44.01%									

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

Services

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs

Line	Load Class	(A) Customers	(B) % 1 & 3 Phase	(C) Overhead Service Drop Cost	(D) Underground Service Drop Cost	(E) % Overhead	(F) % Underground	(G) Weighted Service Drop Cost	(H) Weighted Service Drop Cost 1 & 3 Phase	(I) Weighted Service Drop Cost 1 Phase	(J) Weighted Service Drop Cost 3 Phase
1	Res - Schedule 4	533,013	100.00%					786	786	786	
2	Annualized - Line 1 x 7.43%								58	58	
3											
4	GS - Schedule 23										
5	0-15 kW										
6	kW = 0, 1 Phase	3,724	5.24%	976	826	60.7%	39.3%	917	48	59	
7	kW = 0, 3 Phase	4	0.01%	1,187	1,123	60.7%	39.3%	1,162	0		0
8	kW > 1, 1 Phase	53,708	75.53%	1,111	918	60.7%	39.3%	1,035	782	968	
9	kW > 1, 3 Phase	13,673	19.23%	1,309	1,203	60.7%	39.3%	1,268	244		1,267
10	Total 0-15 kW	71,109	100.00%						1,074	1,028	1,268
11	Annualized - Line 10 x 7.43%								80	76	94
12											
13	15+ kW										
14	1 Phase	8,215	54.22%	2,025	1,628	60.7%	39.3%	1,869	1,013	1,869	
15	3 Phase	6,937	45.78%	2,321	1,933	60.7%	39.3%	2,168	993		2,168
16	Total 15+ kW	15,152	100.00%						2,006	1,869	2,168
17	Annualized - Line 16 x 7.43%								149	139	161
18											
19	GS - Schedule 28										
20	0-50 kW										
21	1 Phase	1,328	29.24%	2,025	1,628	39.4%	60.6%	1,785	522	1,785	
22	3 Phase	3,213	70.76%	2,321	1,933	39.4%	60.6%	2,086	1,476		2,086
23	Total 0-50 kW	4,541	100.00%						1,998	1,785	2,086
24	Annualized - Line 23 x 7.43%								148	133	155
25											
26	51-100 kW										
27	1 Phase	527	14.59%	2,025	1,628	39.4%	60.6%	1,785	260	1,785	
28	3 Phase	3,086	85.41%	2,321	1,933	39.4%	60.6%	2,086	1,782		2,086
29	Total 51-100 kW	3,613	100.00%						2,042	1,785	2,086
30	Annualized - Line 29 x 7.43%								152	133	155
31											
32	100 + kW										
33	1 Phase	56	2.50%	3,745	4,150	39.4%	60.6%	3,991	100	3,991	
34	3 Phase	2,187	97.50%	4,106	5,035	39.4%	60.6%	4,669	4,552		4,669
35	Total 100 + kW	2,243	100.00%						4,652	3,991	4,669
36	Annualized - Line 35 x 7.43%								346	297	347
37											
38	GS - Schedule 30										
39											
40	0-300 kW										
41	1 Phase	1	0.50%	3,745	4,150	17.0%	83.0%	4,081	21		
42	3 Phase	198	99.50%	4,106	5,035	17.0%	83.0%	4,877	4,853		
43	Total 0-300 kW	199	100.00%						4,873		
44	Annualized - Line 43 x 7.43%								362		
45											
46	300+ kW										
47	1 Phase	-	0.00%	9,834	8,163	17.0%	83.0%	8,447	-		
48	3 Phase	600	100.00%	9,834	8,163	17.0%	83.0%	8,447	8,447		
49	Total 300+ kW	600	100.00%						8,447		
50	Annualized - Line 49 x 7.43%								628		
51											
52	LPS - Schedule 48										
53	1 - 4 MW (sec)	81	100.00%		30,522	0.0%	100.0%	30,522	30,522		
54	Annualized - Line 53 x 7.43%								2,268		
55											
56	> 4 MW (sec)	4	100.00%		30,522	0.0%	100.0%	30,522	30,522		
57	Annualized - Line 56 x 7.43%								2,268		

Meters

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	533,013	100.00%	100.00%		231.80	231.80	231.80	
3	Annualized - (Line 1) x 7.43%						17.22	17.22	
4									
5	GS - Schedule 23								
6	0-15 kW								
7	kW = 0, 1 Phase	3,724	5.24%	6.48%		221.73	11.61	14.38	
8	kW = 0, 3 Phase	4	0.01%		0.03%	347.24	0.02		0.10
9	kW > 1, 1 Phase	53,708	75.53%	93.52%		221.73	167.47	207.36	
10	kW > 1, 3 Phase	13,673	19.23%		99.97%	347.24	66.77		347.14
11	Total 0-15 kW	71,109	100.00%	100.00%	100.00%		245.87	221.74	347.24
12	Annualized - (Line 11) x 7.43%						18.27	16.48	25.80
13									
14	15+ kW								
15	1 Phase	8,215	54.22%	100.00%		221.73	120.22	221.73	
16	3 Phase W/O KVAR	3,591	23.70%		51.77%	347.24	82.30		179.75
17	3 Phase With KVAR	3,346	22.08%		48.23%	347.24	76.68		167.49
18	Total 15+ kW	15,152	100.00%	100.00%	100.00%		279.20	221.73	347.24
19	Annualized - (Line 18) x 7.43%						20.74	16.47	25.80
20									
21	Primary								
22	12.47 KV 4-wire Wye	50	100.00%		100.00%	16,090.36	16,090.36		16,090.36
23	Annualized - (Line 22) x 7.43%						1,195.51		1,195.51
24									

Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
25	GS - Schedule 28								
26	0-50 kW								
27	kW = 0, 1 Phase	7	0.15%	0.53%		221.73	0.34	1.17	
28	kW = 0, 3 Phase	10	0.22%		0.31%	347.24	0.76		1.08
29	kW > 1, 1 Phase	1,321	29.09%	99.47%		221.73	64.50	220.57	
30	kW > 1, 3 Phase	3,203	70.54%		99.69%	347.24	244.93		346.16
31	Total 0-50 kW	4,541	100.00%	100.00%	100.00%		310.53	221.74	347.24
32	Annualized - (Line 31) x 7.43%						23.07	16.48	25.80
33									
34	51-100 kW								
35	1 Phase	527	14.59%	100.00%		221.73	32.34	221.73	
36	3 Phase W/O KVAR	1,431	39.61%		46.37%	347.24	137.53		161.02
37	3 Phase With KVAR	1,655	45.81%		53.63%	347.24	159.06		186.22
38	Total 51-100 kW	3,613	100.00%	100.00%	100.00%		328.93	221.73	347.24
39	Annualized - (Line 38) x 7.43%						24.44	16.47	25.80
40									
41	100 + kW								
42	1 Phase	56	2.50%	100.00%		1,767.60	44.13	1,767.60	
43	3 Phase W/O KVAR	936	41.73%		42.80%	1,928.67	804.83		825.44
44	3 Phase With KVAR	1,251	55.77%		57.20%	1,928.67	1,075.69		1,103.23
45	Total 100 + kW	2,243	100.00%	100.00%	100.00%		1,924.65	1,767.60	1,928.67
46	Annualized - (Line 45) x 7.43%						143.00	131.33	143.30
47									
48	Primary								
49	12.47 KV 4-wire Wye	59	100.00%		100.00%	16,090.36	16,090.36		16,090.36
50	Annualized - (Line 49) x 7.43%						1,195.51		1,195.51
51									

Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
52	GS - Schedule 30								
53	0-300 kW								
54	1 Phase	1	0.50%	100.00%		1,767.60	8.90	1,767.60	
55	3 Phase W/O KVAR	43	21.50%		21.61%	1,928.67	414.59		416.69
56	3 Phase With KVAR	155	78.00%		78.39%	1,928.67	1,504.36		1,511.98
57	Total 0-300 kW	199	100.00%	100.00%	100.00%		1,927.85	1,767.60	1,928.67
58	Annualized - (Line 57) x 7.43%						143.24	131.33	143.30
59									
60	300+ kW								
61	1 Phase	-	0.00%	100.00%		2,325.07	-	2,325.07	
62	3 Phase W/O KVAR	155	25.83%		25.83%	1,928.67	498.24		498.24
63	3 Phase With KVAR	445	74.17%		74.17%	1,928.67	1,430.43		1,430.43
64	Total 300+ kW	600	100.00%	100.00%	100.00%		1,928.67	2,325.07	1,928.67
65	Annualized - (Line 64) x 7.43%						143.30	172.75	143.30
66									
67	Primary								
68	12.47 KV 4-wire Wye	40	100.00%		100.00%	16,090.36	16,090.36		16,090.36
69	Annualized - (Line 68) x 7.43%						1,195.51		1,195.51
70									
71	LPS - Schedule 48								
72	1 - 4 MW (sec)	81	100.00%		100.00%	2,445.35	2,445.35		2,445.35
73	Annualized - (Line 72) x 7.43%						181.69		181.69
74									
75	1 - 4 MW (pri)	58	100.00%		100.00%	16,090.36	16,090.36		16,090.36
76	Annualized - (Line 75) x 7.43%						1,195.51		1,195.51
77									
78	> 4 MW (sec)	4	100.00%		100.00%	2,445.35	2,445.35		2,445.35
79	Annualized - (Line 78) x 7.43%						181.69		181.69
80									
81	> 4 MW (pri)	24	100.00%		100.00%	16,090.36	16,090.36		16,090.36
82	Annualized - (Line 81) x 7.43%						1,195.51		1,195.51
83									
84	Trans (trn)	7	100.00%		100.00%	247,538.33	247,538.33		247,538.33
85	Annualized - (Line 84) x 7.43%						18,392.10		18,392.10
86									

Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
87									
88	Irrigation - Schedule 41 (Annual)								
89	0 - 50 kW								
90	kW = 0, 1 Phase	-	0.00%	0.00%		221.73	-	-	
91	kW = 0, 3 Phase	-	0.00%		0.00%	347.24	-		-
92	kW > 1, 1 Phase	965	14.69%	100.00%		221.73	32.57	221.73	
93	kW > 1, 3 Phase	4,255	64.78%		82.08%	347.24	224.93		285.02
94									
95	51 - 300 kW								
96	1 Phase	-	0.00%	0.00%		221.73	-	-	
97	3 Phase W/O KVAR	147	2.24%		2.84%	347.24	7.77		9.85
98	3 Phase With KVAR	763	11.62%		14.72%	347.24	40.33		51.11
99									
100	> 300 kW								
101	1 Phase	-	0.00%	0.00%		2,325.07	-	-	
102	3 Phase W/O KVAR	4	0.06%		0.08%	1,928.67	1.17		1.49
103	3 Phase With KVAR	15	0.23%		0.29%	1,928.67	4.40		5.58
104	Total Irrigation	6,569	100.00%	100.00%	100.00%	1,928.67	311.17	221.73	353.05
105							23.12	16.47	26.23
106									
107	Primary	-	100.00%		100.00%	-	-		-
108							-		-
109									
110	Lighting - Schedule 54	98	100.00%		100.00%		18.27		
111									

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2023.

Meter&ServiceCost

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Meters

		(A)	(B)	(C)	(D)	(E)
Line	Load Class	Metering Standard	Meter Cost in 2023 Dollars	Indexed to 2025 Dollars	Percent Use	Total Installed Cost per Meter
	Residential					
1	Small Load	DM221J	$212	221.73	49.36%	109.45
2	All Electric	DM221K	$231	241.61	50.64%	122.35
3					100.00%	231.80
4						
5	0 - 15 kW					
6	kW = 0, 1 Phase	DM221J	$212	221.73	100.00%	221.73
7						
8	kW = 0, 3 Phase	DM241D	$332	347.24	100.00%	347.24
9						
10	kW > 1, 1 Phase	DM221J	$212	221.73	100.00%	221.73
11						
12	kW > 1, 3 Phase	DM241D	$332	347.24	100.00%	347.24
13						
14						
15	15 - 100 kW					
16	1 Phase	DM221J	$212	221.73	100.00%	221.73
17						
18	3 Phase wo / KVAR	DM241D	$332	347.24	100.00%	347.24
19						
20	3 Phase with KVAR	DM241D	$332	347.24	100.00%	347.24
21						

100 - 300 kW					
1 Phase	DM231FBB	$1,690	1,767.60	100.00%	1,767.60
3 Phase wo / KVAR	DM271DEC	$1,844	1,928.67	100.00%	1,928.67
3 Phase with KVAR	DM271DEC	$1,844	1,928.67	100.00%	1,928.67
300-1000 kW					
W/O KVAR, 1 Phase	DM231FFE	$2,223	2,325.07	100.00%	2,325.07
W/O KVAR, 3 Phase	DM271DEC	$1,844	1,928.67	100.00%	1,928.67
W/KVAR, 3 Phase	DM271DEC	$1,844	1,928.67	100.00%	1,928.67
1000 kW and over					
Secondary Volt	DM271DEG	$2,338	2,445.35	100.00%	2,445.35
Primary Metering					
'13.8 KV 3-wire	DM101ACBA	$11,109	11,619.07		11,619.07
'12.47 KV 4-wire Wye	DM121ACJAD	$15,384	16,090.36		16,090.36
24.9 KV 4-wire Wye	DM121BFIAD	$15,060	15,751.48		15,751.48
35 KV 4-wire Wye	DM131BBAH	$21,819	22,820.83		22,820.83
Transmission		247,538			

Escalation
Factor
2023 - 2025
1.0459

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Service Drops

		(A)	(B)	(C)	(D)	(E)
Line	Load Class	Service Conductor	Cost in 2023 Dollars	Indexed to 2025 Dollars	Percent Use	Total Cost per Service
				(B) x 1.0459		
	Residential					
1	OH - small load	#2 Triplex*	642	671.48	29.9%	200.59
2	OH - all electric	1/0 Triplex	732	765.61	26.6%	203.45
3	UG - small load	1/0 Triplex	790	826.27	19.5%	161.03
4	UG - all electric	4/0 Triplex	878	918.31	24.1%	221.00
5						786.06
6	0 - 15 kW					
7	kW = 0, 1 Phase	OH - 1/0 Triplex	933	975.84		
8	kW = 0, 1 Phase	UG - 1/0 Triplex	790	826.27		
9	kW = 0, 3 Phase	OH - 1/0 Quadruplex	1,135	1,187.11		
10	kW = 0, 3 Phase	UG - 1/0 Quadruplex	1,074	1,123.31		
11	kW > 1, 1 Phase	OH - 4/0 Triplex	1,062	1,110.76		
12	kW > 1, 1 Phase	UG - 4/0 Triplex	878	918.31		
13	kW > 1, 3 Phase	OH - 4/0 Quadruplex	1,252	1,309.49		
14	kW > 1, 3 Phase	UG - 4/0 Quadruplex	1,150	1,202.80		
15						
16	16 - 100 kW					
17	1 Phase	OH - 2-4/0 Triplex	1,936	2,024.89		
18	1 Phase	UG - 2-4/0 Triplex	1,557	1,628.49		
19	3 Phase	OH - 2-4/0 Quadruplex	2,219	2,320.89		
20	3 Phase	UG - 2-4/0 Quadruplex	1,848	1,932.85		
21						

101 - 300 kW			
1 Phase	3-500 & 350N	3,581	3,745.42
1 Phase	3- 750 & 500 N	3,968	4,150.19
3 Phase	OH - 3-4/0 Quadruplex	3,926	4,106.26
3 Phase	4-350 Quad	4,814	5,035.04
301 - 1000 kW			
3 Phase	3-750 kcmil Quad.	9,402	9,833.70
3 Phase	4-750 kcmil Quad.	7,805	8,163.37
1000 kW and Over			
Secondary Voltage	12-1000 kcmil Quad.	29,182	30,521.90
Primary Voltage	---	---	---

		Weighted %
Residential Overhead % =	56.4%	
% of Overhead Which Are Small Load=	52.9%	29.9%
% of Overhead Which Are All Electric=	47.1%	26.6%
Residential Underground % =	43.6%	
% of Underground Which Are Small Load=	44.7%	19.5%
% of Underground Which Are All Electric=	55.3%	24.1%
Total OH & UG		100.0%

DistMeters

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

Line	Description	(A) 2013	(B) 2014	(C) 2015	(D) 2016	(E) 2017	(F) 2018	(G) 2019	(H) 2020	(I) 2021	(J) 2022
	Distribution Meters Expenses										
1	586 Meter Expense	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281	1,305,324	1,394,304
2	597 Main. of Meters	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408	231,001	235,870	158,233	185,682
3											
4	Total Adjusted Distribution Meters Expense	4,620,067	4,774,068	3,815,143	1,655,390	1,138,890	968,955	886,759	1,515,150	1,463,558	1,579,986
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523	97,893,679	101,011,391
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	7.74%	7.94%	6.25%	2.65%	1.73%	1.26%	0.98%	1.57%	1.50%	1.56%
16	Line 4 / Line 10										
17											
18	Average Meter O&M Loading	3.32%									
19	Average of Line 15										
20											
21	Distribution Annual Charge	7.43%									
22											
23	Annualized Meter O&M Loading Factor	44.66%									
24	Line 18 / Line 21										

CustExpense

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2025 Dollars

Line	FERC Account	Description	Calculation Description	(A) Sch. 4 Residential	(B) Sch. 23 General Service	(C) Sch. 28 General Service	(D) Sch. 30 General Service	(E) Sch. 48 General Service	(F) Sch. 41 Irrigation	(G) Streetlighting	(H) Total
1			Average Number of Customers	513,581	86,033	10,658	847	178	3,311	7,437	622,045
2			Write-offs By Schedule	3,547,018	81,618	105,993	54,523	144,768	41,210	-	3,975,129
3											
4											
5	901	Supervision	Account 902 + 903 + 904	18,345,139	2,646,042	538,628	120,240	292,903	165,711	191,305	22,299,968
6	901		% of Total 902 + 903 + 904	82.27%	11.87%	2.42%	0.54%	1.31%	0.74%	0.86%	100.00%
7	901		Total 901 $	695,382	100,300	20,417	4,558	11,103	6,281	7,252	845,292
8	901		$ Per Customer	1.35	1.17	1.92	5.38	62.37	1.90	0.98	1.36
9											
10	902	Meter Reading Expense	902 Weighting Factor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
11	902		Weighted Customers	-	-	-	-	-	-	-	-
12	902		% of Total $	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	902		Total 902 $	-	-	-	-	-	-	-	-
14	902		$ Per Customer	-	-	-	-	-	-	-	-
15											
16	903	Cust. Receipts & Collect.	903 Weighting Factor	1.00	1.21	1.40	1.40	11.58	1.21	1.07	
17	903		Weighted Customers	513,581	104,023	14,950	1,188	2,062	4,001	7,932	647,736
18	903		% of Total $	79.29%	16.06%	2.31%	0.18%	0.32%	0.62%	1.22%	100.00%
19	903		Total 903 $	12,387,179	2,508,948	360,591	28,656	49,735	96,490	191,305	15,622,905
20	903		$ Per Customer	25.10	29.16	33.83	33.83	279.41	29.14	25.72	25.12
21											
22	904	Uncollectibles	% of Write-offs	89.23%	2.05%	2.67%	1.37%	3.64%	1.04%	0.00%	100.00%
23	904		Total 904 $	5,957,960	137,094	178,037	91,583	243,168	69,221	-	6,677,063
24	904		$ Per Customer	11.60	1.59	16.70	108.13	1,366.11	20.91	-	10.73
25											
26	905	Misc Cust Acct Expense	Account 902 + 903 + 904	18,345,139	2,646,042	538,628	120,240	292,903	165,711	191,305	22,299,968
27	905		% of Total 902 + 903 + 904	82.27%	11.87%	2.42%	0.54%	1.31%	0.74%	0.86%	100.00%
28	905		Total 905 $	3,699	534	109	24	59	33	39	4,497
29	905		$ Per Customer	0.01	0.01	0.01	0.03	0.33	0.01	0.01	0.01
30											
31	907-910	Supervision, Cust. Assist.	Average Number of customers	513,581	86,033	10,658	847	178	3,311	7,437	622,045
32	907-910	Info & Instructional Exp.,	% of Total	82.56%	13.83%	1.71%	0.14%	0.03%	0.53%	1.20%	100.00%
33	907-910	Misc Cust Svc & Info Exp.	Total 907-910 $	4,792,775	802,866	99,461	7,904	1,661	30,896	69,403	5,804,967
34	907-910		$ Per Customer	9.33	9.33	9.33	9.33	9.33	9.33	9.33	9.33
35											
36											
37	901 - 910		Total 901 - 910 $	23,836,996	3,549,741	658,615	132,726	305,726	202,922	267,999	28,954,724
38											
39			$ Per Customer	47.40	41.26	61.80	156.70	1,717.56	61.29	36.04	46.55

	2018	2019	2020	2021	2022	Actual Year Adjusted 2025
Customer Accounting						
901 Supervision	776,328	712,826	706,833	699,844	884,456	845,292
902 Meter Reading Expense	9,772,620	4,869,243	2,245,673	2,432,215	2,193,524	4,905,160
903 Cust Records & Collection	15,706,759	15,074,984	13,295,839	12,573,679	12,954,582	15,622,905
904 Uncollectible Accounts	4,639,879	5,061,708	6,263,999	5,394,731	8,652,079	6,677,063
905 Misc Cust Acct Expense	4,809	5,606	8,479	830	47	4,497
Total	30,900,395	25,724,366	22,520,822	21,101,299	24,684,688	28,054,917
Customer Service & Info Expense						
907 Supervision	36,862	2,105	208	(166)	491	9,223
908 Cust Assistance Expense	2,730,139	3,325,682	3,466,926	3,935,825	3,415,781	3,767,567
909 Info & Instructional Expense	2,077,877	2,316,089	1,879,350	1,307,108	1,409,632	2,024,348
910 Misc Cust Svc & Info Expense	12,955	1,416	541	394	1,242	3,829
Total	4,857,833	5,645,291	5,347,026	5,243,161	4,827,146	5,804,967
Inflation Adjustment	1.1701	1.1442	1.1188	1.0939	1.0697	

Source:
Source: State of Oregon results of operations

AG Expenses

PacifiCorp
Oregon Marginal Cost Study
Administrative & General Expense
Loading Factor

Year	(A) Administrative and General Expenses ($000)	(B) Electric Plant in Service ($000)	(C) Admin. & General to Electric Plant In Service Loading Factor (A) / (B)
2013	175,800	24,578,893	0.72%
2014	103,887	25,826,088	0.40%
2015	134,217	26,518,617	0.51%
2016	129,633	27,064,435	0.48%
2017	142,110	27,658,984	0.51%
2018	135,363	28,221,394	0.48%
2019	123,137	28,629,755	0.43%
2020	291,921	30,542,983	0.96%
2021	173,646	32,098,210	0.54%
2022	260,189	32,845,783	0.79%
10 Year Average A&G to EPIS Loading Factor			0.58%

Footnotes:
(A) FERC Form 1 Page 323, line 197
(B) FERC Form 1 Page 207, line 104

Charge

PacifiCorp
Oregon Marginal Cost Study
Calculation of Annual Charges

Line	Description	(A) System Transmission	(B) Distribution
1	Levelized Income Taxes	1.05%	0.96%
2	Levelized Property Tax	0.82%	0.75%
3	Total	1.87%	1.71%
4			
5	Levelized Income & Property Taxes	$18.70	$17.10
6	(per $1,000 of Investment)		
7			
8	Expected Life	65	54
9			
10	Nominal Interest Rate	7.74%	7.74%
11			
12	Present Value: Income **	$239.70	$216.98
13	Taxes & Property Taxes per	(PV of $18.70 per year	(PV of $17.10 per year
14	$1,000 of Investment		for 54 years at 7.74%)
15			
16	Removal Cost Per $1,000 Investment	$180.83	$452.69
17			
18	Present Value: Removal Cost	$1.42	$8.08
19	at End of Useful Life	(PV of $180.83 per year	(PV of $452.69 per year
20		65 years at 7.74%)	54 years at 7.74%)
21			
22	Investment and Taxes	$1,241.12	$1,225.06
23	w/o PVCD (Line 12 + Line 18 + $1000)		
24			
25	PVCD Factor	0.035332	0.035688
26			
27	PVCD $ (Line 22 x Line 25)	$43.85	$43.72
28			
29	Total (Line 22 + Line 27)	$1,284.97	$1,268.78
30			
31	EOY Annual Charge ***	$67.52	$68.53
32			
33	Annual Economic Carrying	6.75%	6.85%
34	Adm &Gen Expense Loading Factor	0.58%	0.58%
35			
36	Annual Econ Carrying + A&G Loading	7.33%	7.43%

Footnotes:

From Financial Analysis - 18.70*(1/0.0774-(1/0.0774)/(1+0.0774)^65)
** PV = Ln(5) x [1/r - (1/r)/(1+r)^a] 17.10*(1/0.0774-(1/0.0774)/(1+0.0774)^54)

Where:
r = Nominal Interest Rate
a = Expected Investment Life

*** The Annual Charge Formula: AC% = Ln(11) x k x {1/[1 - 1/(1+k)^a]}/(1+k)

Where:
k = real interest rate = (1 + r) / (1 + i) - 1
i = inflation rate
a = expected investment life
r = nominal interest rate

Financial Inputs	
Weighted Cost of Capital	7.74%
Borrowing Rate	7.74%
Average Inflation	2.27%
Real Cost of Capital	
(1+0.0774)/(1+0.0227)-1 =	5.35%

Levelized	
Income Taxes	
Transmission	1.05%
Distribution	0.96%
Property Taxes	
Transmission	0.82%
Distribution	0.75%

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: 2023 Use of Facilities Report
PacifiCorp's 2023 IRP

Iowa Curves

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor

Iowa Curve R 2 & 65 Year Average Life

Real Cost of Capital = 5.35%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0535 ^Year	(C) / (D)	(B)	1.0535 ^62	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.00071	7.82%	0.0782	1.05349	0.07423	0.0782	25.29412	0.00309	0.07114	99.9218
2	0.00206	15.63%	0.1563	1.10984	0.14083	0.1563	25.29412	0.00618	0.13465	99.7655
3	0.00333	15.63%	0.1563	1.16920	0.13368	0.1563	25.29412	0.00618	0.12750	99.6092
4	0.00459	16.32%	0.1632	1.23174	0.13250	0.1632	25.29412	0.00645	0.12604	99.4460
5	0.00594	18.40%	0.1840	1.29762	0.14180	0.1840	25.29412	0.00727	0.13452	99.2620
6	0.00721	18.40%	0.1840	1.36702	0.13460	0.1840	25.29412	0.00727	0.12732	99.0780
7	0.00842	18.40%	0.1840	1.44014	0.12777	0.1840	25.29412	0.00727	0.12049	98.8940
8	0.00976	21.60%	0.2160	1.51717	0.14237	0.2160	25.29412	0.00854	0.13383	98.6780
9	0.01102	21.60%	0.2160	1.59832	0.13514	0.2160	25.29412	0.00854	0.12660	98.4620
10	0.01222	21.60%	0.2160	1.68381	0.12828	0.2160	25.29412	0.00854	0.11974	98.2460
11	0.01349	24.28%	0.2428	1.77387	0.13688	0.2428	25.29412	0.00960	0.12728	98.0032
12	0.01474	25.17%	0.2517	1.86875	0.13469	0.2517	25.29412	0.00995	0.12474	97.7515
13	0.01592	25.17%	0.2517	1.96871	0.12785	0.2517	25.29412	0.00995	0.11790	97.4998
14	0.01712	27.18%	0.2718	2.07401	0.13105	0.2718	25.29412	0.01075	0.12030	97.2280
15	0.01834	29.20%	0.2920	2.18494	0.13364	0.2920	25.29412	0.01154	0.12210	96.9360
16	0.01949	29.20%	0.2920	2.30181	0.12686	0.2920	25.29412	0.01154	0.11531	96.6440
17	0.02063	30.33%	0.3033	2.42493	0.12508	0.3033	25.29412	0.01199	0.11308	96.3407
18	0.02181	33.72%	0.3372	2.55463	0.13200	0.3372	25.29412	0.01333	0.11866	96.0035
19	0.02293	33.73%	0.3373	2.69127	0.12533	0.3373	25.29412	0.01334	0.11200	95.6662
20	0.02399	33.72%	0.3372	2.83522	0.11893	0.3372	25.29412	0.01333	0.10560	95.3290
21	0.02513	38.71%	0.3871	2.98687	0.12960	0.3871	25.29412	0.01530	0.11430	94.9419
22	0.02621	38.71%	0.3871	3.14663	0.12302	0.3871	25.29412	0.01530	0.10772	94.5548
23	0.02722	38.70%	0.3870	3.31493	0.11674	0.3870	25.29412	0.01530	0.10144	94.1678
24	0.02828	42.91%	0.4291	3.49224	0.12287	0.4291	25.29412	0.01696	0.10591	93.7387
25	0.02931	44.31%	0.4431	3.67903	0.12044	0.4431	25.29412	0.01752	0.10292	93.2956
26	0.03028	44.31%	0.4431	3.87582	0.11432	0.4431	25.29412	0.01752	0.09681	92.8525
27	0.03125	47.40%	0.4740	4.08312	0.11609	0.4740	25.29412	0.01874	0.09735	92.3785
28	0.03223	50.49%	0.5049	4.30152	0.11738	0.5049	25.29412	0.01996	0.09742	91.8736
29	0.03314	50.49%	0.5049	4.53160	0.11142	0.5049	25.29412	0.01996	0.09146	91.3687
30	0.03403	52.20%	0.5220	4.77398	0.10934	0.5220	25.29412	0.02064	0.08871	90.8467
31	0.03494	57.32%	0.5732	5.02933	0.11397	0.5732	25.29412	0.02266	0.09131	90.2735
32	0.03580	57.33%	0.5733	5.29833	0.10820	0.5733	25.29412	0.02267	0.08554	89.7002
33	0.03660	57.32%	0.5732	5.58173	0.10269	0.5732	25.29412	0.02266	0.08003	89.1270
34	0.03744	64.83%	0.6483	5.88028	0.11025	0.6483	25.29412	0.02563	0.08462	88.4787
35	0.03823	64.83%	0.6483	6.19480	0.10465	0.6483	25.29412	0.02563	0.07902	87.8304
36	0.03897	64.83%	0.6483	6.52614	0.09934	0.6483	25.29412	0.02563	0.07371	87.1821
37	0.03972	70.97%	0.7097	6.87521	0.10323	0.7097	25.29412	0.02806	0.07517	86.4724
38	0.04044	73.02%	0.7302	7.24295	0.10082	0.7302	25.29412	0.02887	0.07195	85.7422
39	0.04111	73.01%	0.7301	7.63035	0.09568	0.7301	25.29412	0.02886	0.06682	85.0121
40	0.04177	77.46%	0.7746	8.03848	0.09636	0.7746	25.29412	0.03062	0.06574	84.2375
41	0.04241	81.91%	0.8191	8.46844	0.09672	0.8191	25.29412	0.03238	0.06434	83.4184
42	0.04301	81.91%	0.8191	8.92139	0.09181	0.8191	25.29412	0.03238	0.05943	82.5993
43	0.04357	84.31%	0.8431	9.39857	0.08971	0.8431	25.29412	0.03333	0.05637	81.7562
44	0.04413	91.50%	0.9150	9.90128	0.09241	0.9150	25.29412	0.03617	0.05624	80.8412
45	0.04465	91.51%	0.9151	10.43087	0.08773	0.9151	25.29412	0.03618	0.05155	79.9261
46	0.04512	91.51%	0.9151	10.98879	0.08328	0.9151	25.29412	0.03618	0.04710	79.0110
47	0.04559	101.66%	1.0166	11.57656	0.08782	1.0166	25.29412	0.04019	0.04762	77.9944
48	0.04603	101.66%	1.0166	12.19576	0.08336	1.0166	25.29412	0.04019	0.04317	76.9778
49	0.04641	101.66%	1.0166	12.84807	0.07912	1.0166	25.29412	0.04019	0.03893	75.9612
50	0.04679	109.65%	1.0965	13.53529	0.08101	1.0965	25.29412	0.04335	0.03766	74.8647
51	0.04714	112.31%	1.1231	14.25925	0.07876	1.1231	25.29412	0.04440	0.03436	73.7416

52	0.04744	112.31%	1.1231	15.02194	0.07476	1.1231	25.29412	0.04440	0.03036	72.6185
53	0.04772	117.73%	1.1773	15.82543	0.07439	1.1773	25.29412	0.04654	0.02785	71.4412
54	0.04797	123.17%	1.2317	16.67189	0.07388	1.2317	25.29412	0.04870	0.02518	70.2095
55	0.04818	123.17%	1.2317	17.56362	0.07013	1.2317	25.29412	0.04870	0.02143	68.9778
56	0.04837	125.87%	1.2587	18.50306	0.06803	1.2587	25.29412	0.04976	0.01826	67.7191
57	0.04852	133.97%	1.3397	19.49274	0.06873	1.3397	25.29412	0.05296	0.01576	66.3794
58	0.04865	133.97%	1.3397	20.53535	0.06524	1.3397	25.29412	0.05296	0.01227	65.0397
59	0.04874	133.97%	1.3397	21.63374	0.06193	1.3397	25.29412	0.05296	0.00896	63.7000
60	0.04880	144.25%	1.4425	22.79087	0.06329	1.4425	25.29412	0.05703	0.00626	62.2575
61	0.04883	144.24%	1.4424	24.00989	0.06008	1.4424	25.29412	0.05703	0.00305	60.8151
62	0.04883	144.25%	1.4425	25.29412	0.05703	1.4425	25.29412	0.05703	-	59.3726
63	0.04880	151.14%	1.5114	26.64704	0.05672	1.5114	25.29412	0.05975	(0.00303)	57.8612
64	0.04874	153.45%	1.5345	28.07232	0.05466	1.5345	25.29412	0.06067	(0.00600)	56.3267
65	0.04865	153.45%	1.5345	29.57383	0.05189	1.5345	25.29412	0.06067	(0.00878)	54.7922
66	0.04853	157.20%	1.5720	31.15566	0.05046	1.5720	25.29412	0.06215	(0.01169)	53.2202
67	0.04839	160.95%	1.6095	32.82210	0.04904	1.6095	25.29412	0.06363	(0.01459)	51.6107
68	0.04822	160.95%	1.6095	34.57767	0.04655	1.6095	25.29412	0.06363	(0.01708)	50.0012
69	0.04802	162.24%	1.6224	36.42714	0.04454	1.6224	25.29412	0.06414	(0.01960)	48.3788
70	0.04780	166.10%	1.6610	38.37553	0.04328	1.6610	25.29412	0.06567	(0.02238)	46.7178
71	0.04755	166.09%	1.6609	40.42814	0.04108	1.6609	25.29412	0.06566	(0.02458)	45.0569
72	0.04729	166.09%	1.6609	42.59053	0.03900	1.6609	25.29412	0.06566	(0.02667)	43.3960
73	0.04699	168.18%	1.6818	44.86859	0.03748	1.6818	25.29412	0.06649	(0.02901)	41.7142
74	0.04669	168.19%	1.6819	47.26849	0.03558	1.6819	25.29412	0.06649	(0.03091)	40.0323
75	0.04636	168.18%	1.6818	49.79676	0.03377	1.6818	25.29412	0.06649	(0.03272)	38.3505
76	0.04602	167.10%	1.6710	52.46026	0.03185	1.6710	25.29412	0.06606	(0.03421)	36.6795
77	0.04566	166.74%	1.6674	55.26623	0.03017	1.6674	25.29412	0.06592	(0.03575)	35.0121
78	0.04529	166.74%	1.6674	58.22227	0.02864	1.6674	25.29412	0.06592	(0.03728)	33.3447
79	0.04491	164.06%	1.6406	61.33643	0.02675	1.6406	25.29412	0.06486	(0.03811)	31.7041
80	0.04452	161.39%	1.6139	64.61716	0.02498	1.6139	25.29412	0.06381	(0.03883)	30.0902
81	0.04412	161.38%	1.6138	68.07336	0.02371	1.6138	25.29412	0.06380	(0.04009)	28.4764
82	0.04371	159.09%	1.5909	71.71443	0.02218	1.5909	25.29412	0.06290	(0.04071)	26.8855
83	0.04331	152.22%	1.5222	75.55025	0.02015	1.5222	25.29412	0.06018	(0.04003)	25.3633
84	0.04290	152.21%	1.5221	79.59123	0.01912	1.5221	25.29412	0.06018	(0.04105)	23.8412
85	0.04248	152.22%	1.5222	83.84836	0.01815	1.5222	25.29412	0.06018	(0.04203)	22.3190
86	0.04208	139.60%	1.3960	88.33319	0.01580	1.3960	25.29412	0.05519	(0.03939)	20.9230
87	0.04168	139.60%	1.3960	93.05791	0.01500	1.3960	25.29412	0.05519	(0.04019)	19.5270
88	0.04127	139.60%	1.3960	98.03533	0.01424	1.3960	25.29412	0.05519	(0.04095)	18.1310
89	0.04089	128.13%	1.2813	103.27899	0.01241	1.2813	25.29412	0.05066	(0.03825)	16.8497
90	0.04051	124.31%	1.2431	108.80312	0.01143	1.2431	25.29412	0.04915	(0.03772)	15.6066
91	0.04013	124.31%	1.2431	114.62271	0.01085	1.2431	25.29412	0.04915	(0.03830)	14.3635
92	0.03977	115.84%	1.1584	120.75358	0.00959	1.1584	25.29412	0.04580	(0.03620)	13.2051
93	0.03943	107.39%	1.0739	127.21238	0.00844	1.0739	25.29412	0.04246	(0.03401)	12.1312
94	0.03908	107.38%	1.0738	134.01664	0.00801	1.0738	25.29412	0.04245	(0.03444)	11.0574
95	0.03875	103.02%	1.0302	141.18484	0.00730	1.0302	25.29412	0.04073	(0.03343)	10.0272
96	0.03845	89.94%	0.8994	148.73645	0.00605	0.8994	25.29412	0.03556	(0.02951)	9.1278
97	0.03816	89.94%	0.8994	156.69198	0.00574	0.8994	25.29412	0.03556	(0.02982)	8.2284
98	0.03785	89.94%	0.8994	165.07303	0.00545	0.8994	25.29412	0.03556	(0.03011)	7.3290
99	0.03761	72.86%	0.7286	173.90236	0.00419	0.7286	25.29412	0.02881	(0.02462)	6.6004
100	0.03736	72.86%	0.7286	183.20394	0.00398	0.7286	25.29412	0.02881	(0.02483)	5.8718
101	0.03711	72.86%	0.7286	193.00304	0.00378	0.7286	25.29412	0.02881	(0.02503)	5.1432
102	0.03690	60.84%	0.6084	203.32628	0.00299	0.6084	25.29412	0.02405	(0.02106)	4.5348
103	0.03670	56.83%	0.5683	214.20167	0.00265	0.5683	25.29412	0.02247	(0.01981)	3.9665
104	0.03650	56.83%	0.5683	225.65876	0.00252	0.5683	25.29412	0.02247	(0.01995)	3.3982
105	0.03633	49.42%	0.4942	237.72867	0.00208	0.4942	25.29412	0.01954	(0.01746)	2.9040
106	0.03618	42.00%	0.4200	250.44416	0.00168	0.4200	25.29412	0.01660	(0.01493)	2.4840
107	0.03603	42.00%	0.4200	263.83976	0.00159	0.4200	25.29412	0.01660	(0.01501)	2.0640
108	0.03589	38.63%	0.3863	277.95187	0.00139	0.3863	25.29412	0.01527	(0.01388)	1.6777
109	0.03579	28.52%	0.2852	292.81879	0.00097	0.2852	25.29412	0.01128	(0.01030)	1.3925
110	0.03568	28.53%	0.2853	308.48091	0.00092	0.2853	25.29412	0.01128	(0.01035)	1.1072
111	0.03558	28.52%	0.2852	324.98075	0.00088	0.2852	25.29412	0.01128	(0.01040)	0.8220
112	0.03552	16.68%	0.1668	342.36313	0.00049	0.1668	25.29412	0.00659	(0.00611)	0.6552
113	0.03546	16.67%	0.1667	360.67525	0.00046	0.1667	25.29412	0.00659	(0.00613)	0.4885
114	0.03539	16.68%	0.1668	379.96683	0.00044	0.1668	25.29412	0.00659	(0.00616)	0.3217
115	0.03536	9.57%	0.0957	400.29027	0.00024	0.0957	25.29412	0.00378	(0.00354)	0.2260
116	0.03533	7.20%	0.0720	421.70076	0.00017	0.0720	25.29412	0.00285	(0.00268)	0.1540
		99.8460	99.8460							

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor

Iowa Curve R 2 & 54 Year Average Life

Real Cost of Capital = 5.35%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0535 ^Year	(C) / (D)	(B)	1.0535 ^52	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.00083	9.41%	0.0941	1.05349	0.08930	0.0941	15.02194	0.00626	0.08304	99.9059
2	0.00240	18.81%	0.1881	1.10984	0.16953	0.1881	15.02194	0.01252	0.15700	99.7178
3	0.00388	18.81%	0.1881	1.16920	0.16092	0.1881	15.02194	0.01252	0.14840	99.5296
4	0.00549	21.48%	0.2148	1.23174	0.17440	0.2148	15.02194	0.01430	0.16010	99.3148
5	0.00704	22.15%	0.2215	1.29762	0.17068	0.2215	15.02194	0.01474	0.15594	99.0933
6	0.00854	22.53%	0.2253	1.36702	0.16483	0.2253	15.02194	0.01500	0.14983	98.8680
7	0.01018	26.00%	0.2600	1.44014	0.18054	0.2600	15.02194	0.01731	0.16323	98.6080
8	0.01172	26.00%	0.2600	1.51717	0.17137	0.2600	15.02194	0.01731	0.15406	98.3480
9	0.01327	27.72%	0.2772	1.59832	0.17342	0.2772	15.02194	0.01845	0.15497	98.0708
10	0.01486	30.30%	0.3030	1.68381	0.17993	0.3030	15.02194	0.02017	0.15976	97.7679
11	0.01637	30.30%	0.3030	1.77387	0.17079	0.3030	15.02194	0.02017	0.15062	97.4649
12	0.01795	33.69%	0.3369	1.86875	0.18029	0.3369	15.02194	0.02243	0.15787	97.1280
13	0.01950	35.15%	0.3515	1.96871	0.17853	0.3515	15.02194	0.02340	0.15514	96.7765
14	0.02096	35.15%	0.3515	2.07401	0.16947	0.3515	15.02194	0.02340	0.14607	96.4250
15	0.02255	40.59%	0.4059	2.18494	0.18578	0.4059	15.02194	0.02702	0.15876	96.0191
16	0.02404	40.59%	0.4059	2.30181	0.17635	0.4059	15.02194	0.02702	0.14933	95.6131
17	0.02551	42.39%	0.4239	2.42493	0.17482	0.4239	15.02194	0.02822	0.14660	95.1892
18	0.02702	46.59%	0.4659	2.55463	0.18238	0.4659	15.02194	0.03102	0.15137	94.7233
19	0.02844	46.59%	0.4659	2.69127	0.17312	0.4659	15.02194	0.03102	0.14211	94.2574
20	0.02989	50.64%	0.5064	2.83522	0.17860	0.5064	15.02194	0.03371	0.14489	93.7510
21	0.03132	53.33%	0.5333	2.98687	0.17856	0.5333	15.02194	0.03550	0.14306	93.2177
22	0.03266	53.33%	0.5333	3.14663	0.16949	0.5333	15.02194	0.03550	0.13399	92.6843
23	0.03407	60.03%	0.6003	3.31493	0.18110	0.6003	15.02194	0.03996	0.14114	92.0840
24	0.03541	60.78%	0.6078	3.49224	0.17404	0.6078	15.02194	0.04046	0.13358	91.4762
25	0.03669	62.42%	0.6242	3.67903	0.16967	0.6242	15.02194	0.04155	0.12812	90.8520
26	0.03801	69.00%	0.6900	3.87582	0.17803	0.6900	15.02194	0.04593	0.13209	90.1620
27	0.03924	69.00%	0.6900	4.08312	0.16899	0.6900	15.02194	0.04593	0.12306	89.4720
28	0.04046	73.52%	0.7352	4.30152	0.17091	0.7352	15.02194	0.04894	0.12197	88.7368
29	0.04166	78.04%	0.7804	4.53160	0.17221	0.7804	15.02194	0.05195	0.12026	87.9564
30	0.04278	78.04%	0.7804	4.77398	0.16346	0.7804	15.02194	0.05195	0.11151	87.1761
31	0.04391	85.92%	0.8592	5.02933	0.17084	0.8592	15.02194	0.05720	0.11364	86.3169
32	0.04499	87.89%	0.8789	5.29833	0.16588	0.8789	15.02194	0.05851	0.10737	85.4380
33	0.04599	88.96%	0.8896	5.58173	0.15938	0.8896	15.02194	0.05922	0.10016	84.5484
34	0.04701	98.59%	0.9859	5.88028	0.16767	0.9859	15.02194	0.06563	0.10203	83.5625
35	0.04795	98.59%	0.9859	6.19480	0.15915	0.9859	15.02194	0.06563	0.09352	82.5766
36	0.04884	103.21%	1.0321	6.52614	0.15816	1.0321	15.02194	0.06871	0.08945	81.5444
37	0.04971	110.15%	1.1015	6.87521	0.16021	1.1015	15.02194	0.07332	0.08689	80.4429
38	0.05050	110.15%	1.1015	7.24295	0.15208	1.1015	15.02194	0.07332	0.07875	79.3414
39	0.05126	118.70%	1.1870	7.63035	0.15557	1.1870	15.02194	0.07902	0.07655	78.1544
40	0.05197	122.37%	1.2237	8.03848	0.15223	1.2237	15.02194	0.08146	0.07077	76.9307
41	0.05260	122.37%	1.2237	8.46844	0.14450	1.2237	15.02194	0.08146	0.06304	75.7070
42	0.05322	135.19%	1.3519	8.92139	0.15153	1.3519	15.02194	0.08999	0.06154	74.3551
43	0.05375	135.19%	1.3519	9.39857	0.14384	1.3519	15.02194	0.08999	0.05384	73.0033
44	0.05423	139.11%	1.3911	9.90128	0.14049	1.3911	15.02194	0.09260	0.04789	71.6122
45	0.05467	148.26%	1.4826	10.43087	0.14214	1.4826	15.02194	0.09870	0.04344	70.1296
46	0.05503	148.26%	1.4826	10.98879	0.13492	1.4826	15.02194	0.09870	0.03622	68.6470
47	0.05534	156.06%	1.5606	11.57656	0.13481	1.5606	15.02194	0.10389	0.03092	67.0864
48	0.05559	161.26%	1.6126	12.19576	0.13223	1.6126	15.02194	0.10735	0.02488	65.4739
49	0.05577	161.26%	1.6126	12.84807	0.12551	1.6126	15.02194	0.10735	0.01816	63.8613
50	0.05590	172.39%	1.7239	13.53529	0.12737	1.7239	15.02194	0.11476	0.01260	62.1373
51	0.05596	173.63%	1.7363	14.25925	0.12177	1.7363	15.02194	0.11558	0.00618	60.4010

52	0.05596	175.84%	1.7584	15.02194	0.11706	1.7584	15.02194	0.11706	-	58.6426
53	0.05589	184.70%	1.8470	15.82543	0.11671	1.8470	15.02194	0.12296	(0.00624)	56.7956
54	0.05577	184.70%	1.8470	16.67189	0.11079	1.8470	15.02194	0.12296	(0.01217)	54.9485
55	0.05559	189.22%	1.8922	17.56362	0.10774	1.8922	15.02194	0.12596	(0.01823)	53.0563
56	0.05535	193.74%	1.9374	18.50306	0.10471	1.9374	15.02194	0.12897	(0.02426)	51.1189
57	0.05505	193.74%	1.9374	19.49274	0.09939	1.9374	15.02194	0.12897	(0.02958)	49.1815
58	0.05470	198.69%	1.9869	20.53535	0.09675	1.9869	15.02194	0.13227	(0.03551)	47.1946
59	0.05429	199.93%	1.9993	21.63374	0.09241	1.9993	15.02194	0.13309	(0.04068)	45.1953
60	0.05384	200.18%	2.0018	22.79087	0.08783	2.0018	15.02194	0.13326	(0.04542)	43.1936
61	0.05333	202.44%	2.0244	24.00989	0.08432	2.0244	15.02194	0.13477	(0.05045)	41.1691
62	0.05278	202.44%	2.0244	25.29412	0.08004	2.0244	15.02194	0.13477	(0.05473)	39.1447
63	0.05220	201.75%	2.0175	26.64704	0.07571	2.0175	15.02194	0.13430	(0.05859)	37.1272
64	0.05158	200.70%	2.0070	28.07232	0.07150	2.0070	15.02194	0.13361	(0.06211)	35.1201
65	0.05092	200.70%	2.0070	29.57383	0.06787	2.0070	15.02194	0.13361	(0.06574)	33.1131
66	0.05024	196.19%	1.9619	31.15566	0.06297	1.9619	15.02194	0.13060	(0.06763)	31.1512
67	0.04954	194.26%	1.9426	32.82210	0.05919	1.9426	15.02194	0.12932	(0.07013)	29.2086
68	0.04881	194.26%	1.9426	34.57767	0.05618	1.9426	15.02194	0.12932	(0.07314)	27.2660
69	0.04809	183.22%	1.8322	36.42714	0.05030	1.8322	15.02194	0.12197	(0.07167)	25.4338
70	0.04735	183.22%	1.8322	38.37553	0.04774	1.8322	15.02194	0.12197	(0.07423)	23.6016
71	0.04660	178.67%	1.7867	40.42814	0.04419	1.7867	15.02194	0.11894	(0.07474)	21.8149
72	0.04588	168.04%	1.6804	42.59053	0.03945	1.6804	15.02194	0.11186	(0.07241)	20.1345
73	0.04514	168.04%	1.6804	44.86859	0.03745	1.6804	15.02194	0.11186	(0.07441)	18.4541
74	0.04442	156.99%	1.5699	47.26849	0.03321	1.5699	15.02194	0.10451	(0.07130)	16.8842
75	0.04373	149.63%	1.4963	49.79676	0.03005	1.4963	15.02194	0.09961	(0.06956)	15.3879
76	0.04302	149.63%	1.4963	52.46026	0.02852	1.4963	15.02194	0.09961	(0.07108)	13.8916
77	0.04238	131.30%	1.3130	55.26623	0.02376	1.3130	15.02194	0.08740	(0.06365)	12.5787
78	0.04174	129.26%	1.2926	58.22227	0.02220	1.2926	15.02194	0.08605	(0.06385)	11.2861
79	0.04111	125.06%	1.2506	61.33643	0.02039	1.2506	15.02194	0.08325	(0.06286)	10.0355
80	0.04056	108.26%	1.0826	64.61716	0.01675	1.0826	15.02194	0.07207	(0.05531)	8.9529
81	0.04000	108.26%	1.0826	68.07336	0.01590	1.0826	15.02194	0.07207	(0.05616)	7.8703
82	0.03948	97.98%	0.9798	71.71443	0.01366	0.9798	15.02194	0.06523	(0.05156)	6.8905
83	0.03902	87.70%	0.8770	75.55025	0.01161	0.8770	15.02194	0.05838	(0.04678)	6.0134
84	0.03854	87.70%	0.8770	79.59123	0.01102	0.8770	15.02194	0.05838	(0.04736)	5.1364
85	0.03815	72.27%	0.7227	83.84836	0.00862	0.7227	15.02194	0.04811	(0.03949)	4.4137
86	0.03777	68.41%	0.6841	88.33319	0.00774	0.6841	15.02194	0.04554	(0.03779)	3.7297
87	0.03740	66.62%	0.6662	93.05791	0.00716	0.6662	15.02194	0.04435	(0.03719)	3.0634
88	0.03711	50.56%	0.5056	98.03533	0.00516	0.5056	15.02194	0.03365	(0.02850)	2.5579
89	0.03682	50.56%	0.5056	103.27899	0.00490	0.5056	15.02194	0.03365	(0.02876)	2.0523
90	0.03657	44.07%	0.4407	108.80312	0.00405	0.4407	15.02194	0.02933	(0.02528)	1.6117
91	0.03637	34.33%	0.3433	114.62271	0.00300	0.3433	15.02194	0.02286	(0.01986)	1.2683
92	0.03617	34.33%	0.3433	120.75358	0.00284	0.3433	15.02194	0.02286	(0.02001)	0.9250
93	0.03603	24.35%	0.2435	127.21238	0.00191	0.2435	15.02194	0.01621	(0.01430)	0.6815
94	0.03591	20.07%	0.2007	134.01664	0.00150	0.2007	15.02194	0.01336	(0.01187)	0.4807
95	0.03579	20.07%	0.2007	141.18484	0.00142	0.2007	15.02194	0.01336	(0.01194)	0.2800
96	0.03574	8.67%	0.0867	148.73645	0.00058	0.0867	15.02194	0.00577	(0.00519)	0.1933
97	0.03569	8.67%	0.0867	156.69198	0.00055	0.0867	15.02194	0.00577	(0.00522)	0.1067
			99.8933	54.8956						

Depreciation

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 6/30/2023 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	TRANSMISSION PLANT						
350.20	Land Rights	282,573,177	R4	90.00	0.00%	-	
352.00	Structures & Improvements	386,384,736	R2.5	75.00	-5.00%	(19,319,237)	
353.00	Station Equipment	2,727,416,573	S0	60.00	-10.00%	(272,741,657)	
353.70	Supervisory Equipment	-				-	
354.00	Towers & Fixtures	1,526,005,036	R4	72.00	-8.00%	(122,080,403)	
355.00	Poles & Fixtures	1,278,838,555	R2.5	62.00	-40.00%	(511,535,422)	
356.00	OH Conductors & Devices	1,676,119,586	R2.5	68.00	-30.00%	(502,835,876)	
356.20	Clearing	-				-	
357.00	UG Conduit	3,872,987	S2.5	60.00	0.00%	-	
358.00	UG Conductors & Devices	9,080,617	S2.5	60.00	-5.00%	(454,031)	
359.00	Roads & Trails	12,141,468	R5	75.00	0.00%	-	
	Total Transmission Plant	7,902,432,736		65.40	-18.08%	(1,428,966,626)	
				Use 65 Years			65

	TRANSMISSION PLANT excludes land accounts					
352.00	Structures & Improvements	386,384,736	2.50	5.07%	0.13	
353.00	Station Equipment	2,727,416,573	-	35.79%	-	
353.70	Supervisory Equipment	-		0.00%	-	
354.00	Towers & Fixtures	1,526,005,036	4.00	20.03%	0.80	
355.00	Poles & Fixtures	1,278,838,555	2.50	16.78%	0.42	
356.00	OH Conductors & Devices	1,676,119,586	2.50	22.00%	0.55	
356.20	Clearing	-	-	0.00%	-	
357.00	UG Conduit	3,872,987	2.50	0.05%	0.00	
358.00	UG Conductors & Devices	9,080,617	2.50	0.12%	0.00	
359.00	Roads & Trails	12,141,468	5.00	0.16%	0.01	
	Total Transmission Plant	7,619,859,559		100.00%	1.91	**Use R 2**

[1] Account Number	[2] Description	[3] 6/30/2021 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	DISTRIBUTION PLANT (OREGON)						
360.20	Land Rights	6,441,896	S1.5	70.00	0.00%	-	
361.00	Structures & Improvements	35,033,648	R2	67.00	-10.00%	(3,503,365)	
362.00	Station Equipment	306,033,063	R1	53.00	-20.00%	(61,206,613)	
362.70	Supervisory & Alarm Equipment					-	
364.00	Poles, Towers & Fixtures	516,891,491	R1	58.00	-100.00%	(516,891,491)	
365.00	OH Conductors & Devices	325,012,527	R1	65.00	-50.00%	(162,506,263)	
366.00	UG Conduit	120,810,576	R3	75.00	-45.00%	(54,364,759)	
367.00	UG Conductors & Devices	235,065,979	R2.5	60.00	-35.00%	(82,273,093)	
368.00	Line Transformers	532,450,677	R1.5	46.00	-25.00%	(133,112,669)	
369.10	Overhead Services	117,296,138	R2	60.00	-35.00%	(41,053,648)	
369.20	Underground Services	242,221,216	R4	60.00	-40.00%	(96,888,486)	
370.00	Meters	105,898,473	S3	20.00	-3.00%	(3,176,954)	
371.00	I.O.C.P.	2,685,798	L0	27.00	-50.00%	(1,342,899)	
373.00	Street Lighting & Signal Systems	25,130,359	R1	45.00	-30.00%	(7,539,108)	
	Total OREGON Distribution Plant	2,570,971,841		53.60	-45.27%	(1,163,859,348)	
				Use 54 years			54

	DISTRIBUTION PLANT excludes land accounts (OREGON)					
361.00	Structures & Improvements	35,033,648	2.00	1.37%	0.03	
362.00	Station Equipment	306,033,063	1.00	11.93%	0.12	
362.70	Supervisory & Alarm Equipment	-		0.00%	-	
364.00	Poles, Towers & Fixtures	516,891,491	1.00	20.16%	0.20	
365.00	OH Conductors & Devices	325,012,527	1.00	12.67%	0.13	
366.00	UG Conduit	120,810,576	3.00	4.71%	0.14	
367.00	UG Conductors & Devices	235,065,979	2.50	9.17%	0.23	
368.00	Line Transformers	532,450,677	1.50	20.76%	0.31	
369.10	Overhead Services	117,296,138	2.00	4.57%	0.09	
369.20	Underground Services	242,221,216	4.00	9.45%	0.38	
370.00	Meters	105,898,473	3.00	4.13%	0.12	
371.00	I.O.C.P.	2,685,798	-	0.10%	-	
373.00	Street Lighting & Signal Systems	25,130,359	1.00	0.98%	0.01	
	Total OREGON Distribution Plant	2,564,529,945		100.00%	1.76	**Use R 2**

Curves:
R=positive
L=negative
S=0

R means right of the standard
L means left of the standard
S is at the standard

Cust

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh @ Sales

			12 Months Ended June 30, 2023 - Actual									12 Months Ended December 2025 - Normalized	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)				(H)	(I)
Line	Description	Del. Volt	Average Customers	% Total Class	Annual MWh's	% Total Class	Average Billing kW	% Total Class	Three Phase Customers	Three Phase % of Customers	Single Phase % of Customers	Average Customers	Annual MWh's
1	Res - Schedule 4	(sec)	533,013	100.00%	5,814,272	100.00%	5,042,753	100.00%	-	0.00%	100.00%	513,581	5,787,620
2													
3	GS - Schedule 23												
4	0-15 kW	(sec)	71,109	82.43%	586,948	47.87%	947,994	63.89%	13,677	19.23%	80.77%	70,880	555,432
5	15+ kW	(sec)	15,152	17.57%	639,141	52.13%	535,908	36.11%	6,937	45.78%	54.22%	15,103	604,823
6	Sec Subtotal		86,261	100.00%	1,226,089	100.00%	1,483,903	100.00%	20,614	23.90%	76.10%	85,983	1,160,255
7	Primary	(pri)	50		1,955		11,400		50	99.38%	0.62%	50	1,877
8	Total		86,312		1,228,044		1,495,302		20,664	23.94%	76.06%	86,033	1,162,132
9													
10	GS - Schedule 28												
11	0-50 kW	(sec)	4,543	43.68%	434,116	20.82%	191,574	17.93%	3,213	70.73%	29.27%	4,630	425,310
12	51-100 kW	(sec)	3,614	34.75%	669,847	32.12%	390,191	36.52%	3,086	85.40%	14.60%	3,683	656,260
13	100 + kW	(sec)	2,243	21.57%	981,603	47.07%	486,664	45.55%	2,187	97.52%	2.48%	2,286	961,692
14	Sec Subtotal		10,399	100.00%	2,085,566	100.00%	1,068,429	100.00%	8,486	81.60%	18.40%	10,599	2,043,261
15	Primary	(pri)	59		21,809		39,149		59	100.79%	-0.79%	59	21,451
16	Total		10,458		2,107,374		1,107,578		8,545	81.71%	18.29%	10,658	2,064,712
17													
18	GS - Schedule 30												
19	0-300 kW	(sec)	198	24.84%	170,220	13.63%	55,540	14.73%	198	99.58%	0.42%	200	170,668
20	300+ kW	(sec)	600	75.16%	1,078,967	86.37%	321,463	85.27%	600	99.94%	0.06%	606	1,081,806
21	Sec Subtotal		799	100.00%	1,249,187	100.00%	377,003	100.00%	798	99.85%	0.15%	806	1,252,474
22	Primary	(pri)	40		76,532		53,025		40	98.94%	1.06%	41	77,805
23	Total		839		1,325,719		430,028		838	99.81%	0.19%	847	1,330,279
24													
25	LPS - Schedule 48												
26	1 - 4 MW	(sec)	81	95.25%	456,583	79.89%	105,438	80.15%	81	100.60%	-0.60%	82	456,088
27	> 4 MW	(sec)	4	4.75%	114,945	20.11%	26,117	19.85%	4	99.59%	0.41%	4	114,820
28	Sec Subtotal		85	100.00%	571,528	100.00%	131,555	100.00%	85	100.56%	-0.56%	86	570,908
29	1 - 4 MW	(pri)	58	70.69%	509,238	37.74%	114,319	42.43%	58	99.85%	0.15%	59	819,472
30	> 4 MW	(pri)	24	29.31%	840,070	62.26%	155,107	57.57%	24	99.63%	0.37%	25	1,351,851
31	Pri Subtotal		82	100.00%	1,349,307	100.00%	269,427	100.00%	82	99.78%	0.22%	84	2,171,323
32	Trans	(trn)	7		1,156,897		317,201		7	101.08%	-1.08%	8	1,934,880
33	Total		174		3,077,732		718,183		174	100.21%	-0.21%	178	4,677,111
34													
35	Irrigation - Schedule 41 (Average)	(sec)	3,353	100.00%	196,326	100.00%	186,770	100.00%		0.00%	100.00%	3,311	234,910
36													
37	Irrigation - Schedule 41 (Annual)	(sec)	6,149						5,184	84.30%	15.70%	7,887	234,910
38													
39	PS&H - Schedule 15	(sec)	5,991	79.08%	2,159	10.47%	-	0.00%	-			5,833	2,128
40	PS&H - Schedule 51	(sec)	1,194	15.76%	8,930	43.32%	-	0.00%	-			1,210	7,898
41	PS&H - Schedule 53	(sec)	294	3.88%	8,075	39.17%	2,050	23.08%	-			296	8,821
42	PS&H - Schedule 54	(sec)	98	1.29%	1,450	7.03%	6,832	76.92%	-			98	1,374
43	Total		7,577	100.00%	20,614	100.00%	8,881	100.00%				7,437	20,221

MW

PacifiCorp
Oregon Marginal Cost Study
Cutomer Loads at Sales - MW
12 Months Ended December 2025

Line	Description	Del. Volt	(A) (B) (C) (D) System Peak	Distribution Peak	(E) Non-Coincident Peak	(F) Cust per Transformer	(G) Coincidence Factor for Winter Loads	(H) Weighted Transformer Peak
1	Res - Schedule 4	(sec)	1,021	1,213	5,043	4	0.67	3,379
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	85	90	948	2	0.77	730
5	15+ kW	(sec)	91	98	536	2	0.77	413
6	Primary	(pri)	0	0	11	1	1.00	11
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	65	70	192	1	1.00	192
10	51-100 kW	(sec)	99	104	390	1	1.00	390
11	100 + kW	(sec)	141	147	487	1	1.00	487
12	Primary	(pri)	3	3	39	1	1.00	39
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	25	26	56	2	0.77	43
16	300+ kW	(sec)	153	158	321	2	0.77	248
17	Primary	(pri)	11	11	53	1	1.00	53
18								
19	LPS - Schedule 48							
20	1 - 4 MW	(sec)	63	64	105	1	1.00	105
21	1 - 4 MW	(pri)	70	72	114	1	1.00	114
22	> 4 MW	(sec)	14	14	26	1	1.00	26
23	> 4 MW	(pri)	204	208	155	1	1.00	155
24	Trans	(trn)	222	228	317	1	1.00	317
25								
26	Irrigation - Sch 41	(sec)	31	47	187	1	1.00	187
27								
28	Sch 15	(sec)	0	0	0	1	1.00	0
29	Sch 51	(sec)	0	0	2	1	1.00	2
30	Customer-Owned Lighting - Sch 53	(sec)	0	0	2	1	1.00	2
31	Rec Field Lighting - Sch 54	(sec)	0	0	7	1	1.00	7

DistPeak

PacifiCorp
Oregon Marginal Cost Study
Weighted Distribution Peaks
Tied to December 2023 Forecast

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		Jul-22 29 17:00	Aug-22 25 17:00	Sep-22 1 17:00	Oct-22 27 08:00	Nov-22 17 09:00	Dec-22 16 09:00	Jan-23 30 08:00	Feb-23 1 08:00	Mar-23 16 07:00	Apr-23 4 07:00	May-23 17 18:00	Jun-23 29 16:00	Sum of 12 Wgt Dist peaks
	Del. Volt													
Res - Schedule 4	(sec)	289.4	176.0	15.2	2.3	16.1	91.4	151.5	133.6	26.3	16.2	12.4	282.5	1,213.0
GS - Schedule 23														
0-15 kW	(sec)	20.7	13.9	1.3	0.2	1.2	6.7	9.4	9.3	2.0	1.2	0.9	23.6	90.4
15+ kW	(sec)	23.1	15.0	1.3	0.3	1.5	8.3	10.4	10.1	2.2	1.3	1.0	23.1	97.6
Primary	(pri)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
GS - Schedule 28														
0-50 kW	(sec)	16.7	10.6	1.0	0.2	1.0	4.9	7.2	7.1	1.5	0.9	0.7	17.8	69.6
51-100 kW	(sec)	25.5	16.7	1.5	0.2	1.5	7.6	10.7	10.8	2.4	1.3	1.1	24.9	104.3
100+ kW	(sec)	32.7	22.6	1.9	0.4	2.3	11.9	16.6	16.7	3.7	2.1	1.5	34.0	146.5
Primary	(pri)	0.7	0.5	0.0	0.0	0.1	0.3	0.4	0.3	0.1	0.1	0.0	0.7	3.1
GS - Schedule 30														
0-300 kW	(sec)	5.6	4.1	0.3	0.1	0.4	2.0	2.9	2.9	0.7	0.4	0.3	6.4	26.1
300+ kW	(sec)	33.2	24.4	2.1	0.5	2.8	13.1	17.5	17.6	4.3	2.5	1.6	38.1	157.8
Primary	(pri)	2.5	1.7	0.1	0.0	0.2	0.9	1.3	1.2	0.3	0.2	0.1	2.5	11.0
LPS - Schedule 48														
1 - 4 MW	(sec)	14.3	10.2	0.9	0.2	1.2	5.9	6.5	7.4	1.8	1.1	0.6	13.4	63.7
1 - 4 MW	(pri)	16.2	11.7	1.1	0.2	1.3	6.2	7.1	7.3	1.9	1.1	0.8	16.7	71.8
> 4 MW	(sec)	2.9	2.5	0.2	0.0	0.3	1.4	1.4	1.5	0.4	0.2	0.2	3.5	14.4
> 4 MW	(pri)	42.3	36.4	3.0	0.6	3.7	19.7	19.7	21.9	5.1	3.0	2.6	49.9	207.9
Trans	(trn)	49.9	38.2	3.3	0.7	3.9	19.0	21.9	26.3	5.7	3.3	2.5	53.3	227.9
Irrigation - Sch 41	(sec)	15.9	10.4	0.8	0.0	0.0	0.1	0.2	0.2	0.1	0.3	0.6	18.2	47.0
Customer-Owned Lighting - Sch 53		-	-	-	-	-	-	-	-	-	-	-	-	-
Rec Field Lighting - Sch 54		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

PacifiCorp
Oregon Marginal Cost Study
Distribution Peaks @ Sales - MW
Tied to December 2023 Forecast

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23
		29	25	1	27	17	16	30	1	16	4	17	29
		17:00	17:00	17:00	08:00	09:00	09:00	08:00	08:00	07:00	07:00	18:00	16:00
	Del. Volt												
Res - Schedule 4	(sec)	1,366.2	1,113.0	1,122.3	827.0	997.8	1,131.4	1,390.7	1,159.8	969.3	1,039.9	1,037.3	1,187.7
GS - Schedule 23													
0-15 kW	(sec)	97.8	88.2	92.4	70.3	74.8	82.3	86.1	81.0	73.6	73.9	78.2	99.2
15+ kW	(sec)	109.1	95.1	94.0	99.3	90.7	103.3	95.3	87.6	81.4	83.3	84.8	97.1
Primary	(pri)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
GS - Schedule 28													
0-50 kW	(sec)	79.0	66.9	72.1	55.4	59.1	60.8	66.2	61.4	56.7	55.1	60.5	75.0
51-100 kW	(sec)	120.5	105.7	108.3	84.1	89.7	94.4	98.6	93.4	86.8	84.9	93.8	104.9
100+ kW	(sec)	154.6	142.8	141.9	131.3	141.5	147.2	152.7	145.1	136.9	135.0	125.1	143.1
Primary	(pri)	3.5	3.2	2.9	3.0	3.1	3.1	3.4	3.0	3.0	3.2	2.4	2.8
GS - Schedule 30													
0-300 kW	(sec)	26.5	26.0	25.2	25.4	26.3	24.7	27.0	25.0	25.1	24.8	22.9	27.0
300+ kW	(sec)	156.6	154.4	154.8	168.9	174.4	162.4	160.8	153.1	157.5	162.7	135.7	160.2
Primary	(pri)	12.0	11.0	10.1	12.7	11.5	10.8	11.6	10.4	10.9	11.9	11.4	10.4
LPS - Schedule 48													
1 - 4 MW	(sec)	67.7	64.7	68.1	76.7	76.2	72.7	59.7	64.4	66.0	72.7	53.0	56.3
1 - 4 MW	(pri)	76.6	74.3	80.7	79.4	80.5	76.3	65.3	63.5	71.0	73.6	69.3	70.2
> 4 MW	(sec)	13.8	16.0	15.3	15.3	15.8	16.9	12.5	13.2	13.1	13.5	14.9	14.6
> 4 MW	(pri)	199.6	230.4	220.4	220.5	227.8	243.5	180.5	190.5	188.5	194.1	214.2	209.8
Trans	(trn)	235.5	241.7	239.8	248.7	239.7	235.4	201.4	228.4	208.8	210.3	209.9	224.0
Irrigation - Sch 41	(sec)	75.0	65.9	60.3	12.3	1.3	1.8	1.9	1.9	3.9	17.2	51.0	76.6
Customer-Owned Lighting - Sch 53		-	-	-	-	-	-	-	-	-	-	-	-
Rec Field Lighting - Sch 54		0.0	0.0	0.1	0.0	0.0	0.1	0.2	0.1	0.0	0.0	0.0	0.0

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2021

A	B	C	D	E	F	G	H	I	J	K	L	M	N		
Substation		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Peak Month	Peak Load
Agness Avenue		18,730	17,702	17,782	14,474	15,790	16,098	16,165	15,579	16,119	14,036	13,946	20,002	Jun-21	20,002
Albina		21,282	21,405	21,346	19,076	23,551	19,109	19,045	18,950	18,043	17,427	17,422	23,099	Nov-20	23,551
Alderwood		22,900	23,067	23,162	19,715	17,045	17,654	17,762	18,121	17,295	18,930	19,315	26,041	Jun-21	26,041
Applegate		10,900	10,470	10,266	10,255	12,312	12,825	11,914	11,678	11,350	9,900	8,234	11,408	Dec-20	12,825
Ashland		16,220	16,296	15,674	12,122	14,871	15,139	15,520	15,243	13,927	11,401	12,178	18,448	Jun-21	18,448
Bandon		1,690	1,736	1,816	1,882	2,111	1,932	2,331	2,603	3,108	3,215	2,154	1,785	Apr-21	3,215
Beall Lane		19,563	19,148	19,289	14,464	15,861	15,529	16,158	15,731	14,691	13,261	14,400	20,457	Jun-21	20,457
Belknap		29,469	29,666	30,457	22,319	23,748	24,265	22,529	25,572	24,398	20,554	22,878	32,660	Jun-21	32,660
Bend Plant		19,088	16,941	18,159	14,043	14,410	15,675	15,946	16,759	12,161	10,786	11,937	22,252	Jun-21	22,252
Bloss		10,495	10,809	11,249	10,883	11,757	11,748	10,961	11,643	11,843	10,348	11,520	10,166	Mar-21	11,843
REDACTED		909	893	864	889	895	951	955	963	909	934	881	917	Feb-21	963
Bond Street		15,715	14,197	14,817	13,883	13,082	14,410	14,436	14,676	12,868	11,456	10,896	21,809	Jun-21	21,809
Brookhurst		37,627	38,057	37,161	24,292	26,085	28,163	25,827	28,770	28,093	23,991	30,550	41,875	Jun-21	41,875
Bryant		24,090	23,242	23,674	17,912	19,387	20,624	23,093	21,162	26,013	16,098	18,520	28,149	Jun-21	28,149
Buchanan		22,991	21,402	22,894	22,535	22,997	23,321	25,550	24,844	21,769	20,507	17,384	27,920	Jun-21	27,920
Buckaroo		24,425	23,070	20,376	20,859	17,284	18,639	18,210	19,455	16,798	15,532	16,967	26,368	Jun-21	26,368
Calapooya		5,543	5,533	5,531	5,289	5,460	5,755	5,612	5,539	5,283	4,999	4,504	6,001	Jun-21	6,001
Campbell		24,446	24,035	24,701	22,343	23,055	16,416	16,446	15,361	14,501	12,852	16,618	23,289	Sep-20	24,701
Cannon Beach		4,867	4,462	4,700	6,926	6,957	6,988	7,146	7,010	6,733	6,503	4,860	4,455	Jan-21	7,146
Canyonville		7,502	7,628	7,135	7,217	7,385	7,933	8,117	7,588	7,976	7,858	6,552	8,218	Jun-21	8,218
Casebeer		7,686	7,295	5,609	3,682	2,903	3,115	3,219	2,989	2,946	5,731	7,834	8,662	Jun-21	8,662
Cave Junction		13,336	12,650	13,309	15,296	16,778	17,359	17,939	17,316	18,383	15,749	12,370	14,339	Mar-21	18,383
Caveman		20,812	18,927	19,818	13,966	14,715	15,328	15,173	14,022	14,739	14,490	14,059	21,698	Jun-21	21,698
Cherry Lane		7,551	7,536	7,387	7,616	7,315	7,379	7,419	7,322	7,406	7,539	7,309	7,279	Oct-20	7,616
Chiloquin		7,367	7,303	8,134	7,380	7,453	6,707	7,313	7,568	7,654	7,944	7,913	7,640	Sep-20	8,134
China Hat		19,383	17,479	17,722	20,198	19,688	20,417	21,448	21,612	19,636	18,433	15,643	22,708	Jun-21	22,708
Circle Blvd		18,197	15,621	15,477	15,033	14,308	13,678	14,351	14,139	14,423	14,919	14,997	17,387	Jul-20	18,197
Cleveland Ave.		23,797	17,871	31,685	29,342	28,728	29,114	30,657	29,078	19,266	28,592	26,808	37,967	Jun-21	37,967
Cloake		15,790	15,891	15,315	10,331	10,961	11,405	11,494	10,295	10,943	9,311	11,626	17,983	Jun-21	17,983
Coburg		2,421	2,337	2,287	1,808	1,868	2,064	1,978	1,957	1,785	1,646	1,613	2,669	Jun-21	2,669
Columbia		32,170	31,717	29,073	27,566	27,966	29,638	30,187	30,301	28,585	27,152	25,723	33,519	Jun-21	33,519
Coquille		10,738	11,026	11,070	15,003	15,983	16,600	16,114	15,832	15,843	15,378	12,258	13,734	Dec-20	16,600
Cully		16,959	15,050	15,493	11,608	12,696	13,956	16,748	14,955	11,948	8,514	8,849	14,783	Jul-20	16,959
Culver		7,937	6,797	6,359	7,362	8,989	8,286	8,733	8,676	7,561	6,677	6,258	8,642	Nov-20	8,989
Dairy		10,746	8,546	6,609	4,092	2,778	2,863	2,715	2,599	2,667	6,904	8,937	10,113	Jul-20	10,746
Dallas		33,210	32,488	32,656	29,034	32,177	34,353	32,569	34,426	32,147	29,580	26,016	39,591	Jun-21	39,591
Dalreed		53,302	56,191	46,640	21,494	8,287	7,941	8,926	8,091	21,448	28,174	44,570	52,844	Aug-20	56,191
Deschutes		8,265	7,343	7,406	10,982	9,998	11,562	12,035	12,116	10,548	8,916	6,886	9,433	Feb-21	12,116
Devils Lake		20,257	19,422	20,008	28,083	29,641	31,539	32,217	32,116	30,833	28,233	22,730	20,932	Jan-21	32,217

Dixon	3,383	3,117	3,375	2,490	2,304	2,436	2,458	2,509	2,166	2,327	2,468	3,575	Jun-21	3,575
Dodge Bridge	11,371	11,622	11,046	10,055	11,199	13,422	10,668	16,425	10,813	9,246	9,015	12,466	Feb-21	16,425
Dowell	16,290	16,092	15,468	10,518	12,173	12,729	12,185	11,480	11,890	9,861	12,452	17,655	Jun-21	17,655
Easy Valley	19,935	20,730	18,603	14,098	16,809	17,194	16,738	15,759	16,084	13,081	14,942	22,436	Jun-21	22,436
Empire	9,962	8,833	10,420	15,387	17,404	18,610	18,370	18,710	17,895	16,370	12,185	10,479	Feb-21	18,710
Fern Hill	1,812	1,847	2,068	2,794	3,293	3,309	3,362	3,889	2,539	2,400	1,544	1,417	Feb-21	3,889
Fielder Creek	11,024	10,498	10,417	11,372	11,527	11,794	12,164	11,416	12,085	10,819	8,260	12,117	Jan-21	12,164
Foothills Rd	13,928	13,810	13,848	10,034	8,855	11,263	11,122	10,875	9,746	8,989	11,674	15,529	Jun-21	15,529
Garden Valley	14,841	12,336	14,480	10,888	10,633	10,592	10,310	9,553	10,165	9,181	11,120	16,317	Jun-21	16,317
Glendale	9,818	9,816	9,275	12,291	11,926	12,249	11,734	11,736	11,684	11,373	10,549	11,703	Oct-20	12,291
Gold Hill	8,164	8,088	7,907	7,008	8,035	8,496	7,882	7,675	7,629	6,715	6,547	8,668	Jun-21	8,668
Gordon Hollow	4,585	4,032	3,799	3,755	3,533	3,956	3,848	4,690	3,536	3,259	3,250	4,489	Feb-21	4,690
Goshen	5,613	5,600	5,347	5,848	5,672	6,356	6,309	6,143	5,768	5,463	4,155	6,258	Dec-20	6,356
Grant Street	24,072	24,817	24,947	22,661	25,315	26,565	29,174	28,523	23,985	21,096	21,475	28,826	Jan-21	29,174
Green	14,435	14,243	14,093	12,789	13,179	13,682	13,922	12,465	13,470	11,947	11,092	15,604	Jun-21	15,604
Harrisburg	8,308	7,305	7,374	7,680	8,051	8,741	8,538	8,432	8,423	7,104	5,710	8,485	Dec-20	8,741
Hazelwood	7,296	7,303	7,129	6,509	6,530	6,686	6,747	6,581	6,412	5,583	4,804	7,681	Jun-21	7,681
Hillview	28,199	24,717	29,902	23,168	24,427	25,185	23,912	24,989	24,936	20,954	20,670	31,463	Jun-21	31,463
Holladay	22,638	21,269	21,060	18,559	17,270	18,078	18,619	18,787	16,240	16,627	15,606	21,230	Jul-20	22,638
Hollywood	31,334	30,111	30,065	22,562	24,372	25,857	24,136	29,650	24,040	23,818	22,364	35,974	Jun-21	35,974
Hood River	29,865	28,567	28,247	25,171	24,399	31,263	26,571	30,603	24,427	21,559	22,183	35,540	Jun-21	35,540
Hornet	15,063	15,749	15,327	11,174	11,274	11,874	10,749	11,078	11,302	9,782	12,038	17,381	Jun-21	17,381
Independence	21,249	20,788	20,746	16,646	16,983	17,870	18,428	18,988	17,258	15,311	16,531	23,969	Jun-21	23,969

Jacksonville	17,658	18,271	17,233	12,144	14,496	15,086	15,130	14,651	14,060	11,879	13,446	20,264	Jun-21	20,264
Jefferson	8,957	8,992	9,194	9,866	10,418	10,763	10,812	11,209	11,031	10,119	9,887	11,758	Jun-21	11,758
Jerome Prairie	13,395	13,402	12,613	13,363	15,930	15,742	14,381	14,854	15,015	12,636	10,978	15,843	Nov-20	15,930
Junction City	8,095	8,288	8,096	8,179	8,647	9,228	8,821	8,988	8,615	7,580	6,394	8,346	Dec-20	9,228
Killingsworth	23,499	22,569	20,594	23,354	23,812	23,557	24,256	25,179	22,303	12,947	11,630	20,470	Feb-21	25,179
Knappa Svensen	2,828	2,943	2,847	3,971	4,381	4,500	5,097	4,934	4,703	4,397	3,074	3,471	Jan-21	5,097
Knott	19,580	19,552	19,282	21,210	22,420	23,845	28,965	28,967	24,193	21,484	19,631	31,719	Jun-21	31,719
Lakeport	17,545	17,584	18,155	17,502	18,414	18,695	19,825	19,264	19,102	17,296	16,407	18,452	Jan-21	19,825
Lancaster	8,022	7,850	7,845	6,892	7,556	6,861	9,051	8,785	8,555	7,510	6,140	7,015	Jan-21	9,051
Lebanon	30,414	30,909	29,185	27,620	27,547	29,718	28,491	29,369	26,880	25,003	23,760	35,795	Jun-21	35,795
Lincoln	19,472	19,650	18,878	19,108	18,901	19,048	18,885	21,055	18,625	17,424	16,173	22,534	Jun-21	22,534
Lockhart	11,476	14,458	11,512	17,954	20,180	21,837	21,351	21,406	21,756	20,086	14,491	12,029	Dec-20	21,837
Lyons	18,342	18,142	16,978	18,222	19,639	19,794	20,354	19,864	19,953	19,209	17,797	18,398	Jan-21	20,354
Madras	18,690	16,568	16,737	17,805	17,372	18,453	19,533	20,259	16,828	16,462	14,419	21,583	Jun-21	21,583
Mallory	13,639	12,923	12,581	10,176	11,245	11,806	12,392	13,812	10,625	9,363	8,811	15,226	Jun-21	15,226
Marys River	14,668	13,583	14,294	14,584	14,753	15,119	15,080	15,022	14,225	13,120	12,231	14,792	Dec-20	15,119
Medford	24,526	24,011	24,566	18,541	17,154	18,434	18,304	17,677	16,034	16,395	19,167	27,686	Jun-21	27,686
Merlin	23,152	22,909	22,847	25,141	27,216	28,403	29,137	25,571	29,699	21,676	19,455	25,716	Mar-21	29,699
Merrill	8,824	8,612	8,147	4,375	4,773	4,854	5,112	4,867	4,796	6,308	7,109	9,355	Jun-21	9,355
Mile High	10,108	9,485	10,286	11,120	11,763	12,708	12,593	12,648	12,555	11,190	10,229	10,563	Dec-20	12,708
Murder Creek	41,616	58,603	51,206	46,686	47,405	51,125	50,902	48,828	45,494	44,449	42,305	55,784	Aug-20	58,603
Oak Knoll	19,300	19,169	18,208	14,870	18,395	19,241	19,892	19,749	18,818	14,449	14,256	22,700	Jun-21	22,700
O'Brien	1,384	1,257	1,243	1,417	1,518	1,646	1,630	1,554	1,661	1,428	1,188	1,395	Mar-21	1,661
REDACTED	23,526	27,074	27,562	22,689	22,040	21,948	19,207	18,655	18,344	15,939	14,935	19,730	Sep-20	27,562
Overpass	36,882	36,533	34,648	34,570	33,884	36,105	36,946	37,699	34,284	26,986	29,935	38,263	Jun-21	38,263
Pallette	353	349	295	417	477	465	465	486	407	416	292	453	Feb-21	486
Park Street	33,117	31,630	31,935	22,481	25,656	27,997	26,418	25,256	25,788	21,343	22,736	34,659	Jun-21	34,659
Parkrose	27,509	28,524	27,154	23,633	25,161	26,563	27,978	31,467	24,964	22,422	21,327	33,225	Jun-21	33,225
Pendleton	30,942	28,440	25,080	18,690	19,712	21,383	21,170	23,806	21,160	21,770	19,154	33,400	Jun-21	33,400
Pilot Butte	18,542	16,398	17,002	13,898	13,585	15,086	14,639	15,193	12,602	11,359	12,370	20,739	Jun-21	20,739
Prineville	35,527	35,207	32,901	23,824	32,702	36,450	40,005	35,670	32,138	31,935	29,234	40,843	Jun-21	40,843
Prospect Central	2,189	2,408	3,144	1,868	4,311	5,147	5,304	5,530	3,134	4,523	3,695	2,194	Feb-21	5,530
Queen Ave	36,131	35,932	36,236	26,041	28,377	31,084	32,023	31,063	27,641	25,452	28,156	42,219	Jun-21	42,219
Redmond 115	37,865	36,811	35,176	35,879	33,204	37,260	38,675	36,886	33,347	31,827	26,933	41,483	Jun-21	41,483
Riddle	17,437	15,808	15,011	17,230	17,790	16,244	17,612	17,380	17,711	15,911	13,479	17,507	Nov-20	17,790
REDACTED	11,366	11,091	11,159	11,563	11,213	11,862	11,683	11,665	12,016	12,137	11,670	11,478	Apr-21	12,137
Roseburg	22,614	21,815	21,701	19,499	20,560	20,820	21,252	20,133	20,499	17,668	15,119	24,846	Jun-21	24,846
Ross Ave	7,199	6,993	7,159	5,379	5,623	6,080	6,528	6,028	6,041	5,010	5,390	7,995	Jun-21	7,995
Roxy Ann	15,252	15,494	16,024	9,377	7,867	7,982	8,175	7,207	6,849	6,306	11,396	16,977	Jun-21	16,977
Russelville	28,472	28,202	27,605	24,581	26,687	28,242	29,765	33,495	25,502	23,010	22,229	33,803	Jun-21	33,803
Sage Road	31,627	31,030	31,720	24,004	23,852	28,937	29,179	24,214	22,422	21,262	22,690	34,005	Jun-21	34,005
Scenic	28,959	29,133	28,859	19,245	19,577	21,459	20,016	19,793	18,625	15,803	23,723	32,058	Jun-21	32,058
Scio	5,137	5,332	5,171	5,118	5,339	5,576	5,326	5,361	5,235	4,891	4,263	5,833	Jun-21	5,833
Seaside	15,101	15,040	15,752	18,082	19,829	21,204	21,638	21,131	19,452	18,506	14,816	14,955	Jan-21	21,638
Shevlin Park	23,274	20,265	22,070	16,466	16,973	18,659	18,814	19,343	15,501	13,989	14,751	28,007	Jun-21	28,007
Southgate	13,786	14,482	14,313	12,871	13,367	12,998	14,371	12,762	13,554	12,122	10,919	17,030	Jun-21	17,030
State Street	18,366	18,603	19,309	27,295	31,675	33,886	33,119	32,046	32,628	29,156	23,766	19,005	Dec-20	33,886
Stayton	33,538	33,866	32,063	31,038	31,469	33,886	32,756	32,307	31,694	29,172	25,167	40,815	Jun-21	40,815

Stevens Road	22,961	23,777	22,361	13,961	16,268	17,769	18,383	18,097	15,502	12,876	18,932	26,945	Jun-21	26,945
Sutherlin	11,549	11,616	11,257	11,421	11,730	11,288	11,675	11,207	11,075	10,317	8,283	13,088	Jun-21	13,088
Sweet Home	22,385	22,268	21,916	25,370	25,583	25,283	24,438	24,361	24,388	22,327	17,081	26,191	Jun-21	26,191
Takelma	8,921	9,235	8,463	8,727	9,950	10,876	10,090	10,544	9,510	8,490	6,929	10,272	Dec-20	10,876
Talent	22,760	22,288	22,651	14,851	18,005	19,046	18,624	18,066	16,736	13,997	14,539	20,947	Jul-20	22,760
Texum	12,305	11,181	12,033	11,379	11,348	12,628	15,313	15,053	11,806	10,042	8,891	12,405	Jan-21	15,313
Umatilla	14,925	14,016	13,252	10,117	9,466	10,410	14,100	14,390	9,464	9,193	12,289	16,055	Jun-21	16,055
Vernon	36,464	34,454	33,321	25,939	28,449	30,609	32,992	33,277	27,071	21,090	21,628	38,048	Jun-21	38,048
Vilas Road	20,441	19,906	20,166	14,944	14,568	15,228	14,935	15,441	15,994	18,883	14,893	23,455	Jun-21	23,455
Village Green	13,122	13,069	12,499	13,076	13,041	14,092	13,901	13,833	13,053	12,294	10,044	14,979	Jun-21	14,979
Vine Street	27,967	23,103	22,171	14,241	15,470	16,930	16,437	20,532	16,935	16,477	21,039	27,204	Jul-20	27,967
Warrenton	16,751	17,642	16,931	16,787	18,235	18,655	19,792	19,722	18,420	17,721	15,639	16,341	Jan-21	19,792
Weston	9,336	10,982	9,944	9,540	8,887	6,245	6,370	6,356	5,928	6,024	4,983	10,058	Aug-20	10,982
Westside	13,076	12,755	12,474	11,827	13,076	13,697	14,399	13,857	13,241	11,760	11,460	15,237	Jun-21	15,237
White City	42,105	41,170	40,151	36,004	36,552	38,317	37,949	38,055	37,150	38,113	33,796	43,384	Jun-21	43,384
Winchester	23,810	25,277	23,089	19,401	20,231	19,529	20,666	19,138	20,129	17,567	16,937	26,217	Jun-21	26,217
Yew Ave	17,572	16,325	16,409	15,058	14,114	16,524	17,140	17,413	14,554	13,635	13,382	21,806	Jun-21	21,806
													Total	
Substation Peaks	119,268	125,776	60,398	19,907	66,261	148,176	191,772	87,988	61,586	15,352	-	1,747,014	2,643,497	
Weighting Factor	4.51%	4.76%	2.28%	0.75%	2.51%	5.61%	7.25%	3.33%	2.33%	0.58%	0.00%	66.09%	100.00%	

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2022

A	B	C	D	E	F	G	H	I	J	K	L	M	N		
Substation		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Peak Month	Peak Load
Agness Avenue		18,360	17,810	15,536	13,999	15,376	17,577	16,511	16,458	15,327	14,251	13,431	16,037	Jul-21	18,360
Albina		23,488	24,578	20,749	23,309	20,040	20,568	20,667	20,834	18,955	19,793	18,977	21,946	Aug-21	24,578
Alderwood		22,657	24,228	21,423	18,032	18,147	18,855	18,786	19,076	24,400	17,885	18,670	23,954	Mar-22	24,400
Applegate		10,467	10,419	8,497	10,153	11,317	11,032	12,847	13,213	11,444	10,887	9,114	9,502	Feb-22	13,213
Ashland		16,012	15,921	12,458	12,440	14,173	15,415	15,270	16,351	13,736	13,493	12,248	15,069	Feb-22	16,351
Bandon		1,791	2,003	1,987	2,370	2,257	2,520	2,482	3,164	3,023	3,236	2,795	2,416	Apr-22	3,236
Beall Lane		19,708	18,977	15,442	13,931	14,690	15,076	16,683	16,757	14,978	14,136	13,921	17,888	Jul-21	19,708
Belknap		28,978	29,637	24,326	19,915	21,479	22,387	23,188	23,781	21,177	19,778	21,529	26,814	Aug-21	29,637
Bend Plant		18,300	19,387	14,487	11,210	12,370	16,662	14,738	15,886	13,814	11,982	10,629	16,097	Aug-21	19,387
Bloss		10,171	11,626	11,974	10,170	10,025	9,668	9,634	11,212	9,752	10,912	8,954	9,580	Sep-21	11,974
Bly		1,910	1,699	1,422	1,146	1,002	1,040	1,211	1,177	1,083	1,067	1,447	2,088	Jun-22	2,088
REDACTED		928	895	875	930	968	957	921	926	893	893	922	917	Nov-21	968
Bond Street		18,359	18,900	14,099	13,523	14,500	18,381	16,762	18,881	16,531	14,001	13,055	16,649	Aug-21	18,900
Brookhurst		36,233	36,749	28,258	22,160	23,488	25,742	26,517	28,379	23,802	21,297	23,212	35,842	Aug-21	36,749
Bryant		25,767	25,441	21,884	16,959	18,862	22,680	22,318	22,485	19,260	18,992	17,443	21,935	Jul-21	25,767
Buchanan		24,031	27,782	22,903	20,813	24,046	24,260	26,715	25,479	22,647	22,246	19,861	21,390	Aug-21	27,782
Buckaroo		23,488	24,700	18,962	16,493	18,115	19,804	20,060	19,001	16,417	12,331	11,740	14,701	Aug-21	24,700
Calapooya		5,551	5,785	5,054	4,589	5,402	5,455	5,031	5,437	5,429	4,988	4,692	4,867	Aug-21	5,785
Campbell		20,546	20,428	16,221	14,069	15,347	15,844	16,130	16,141	13,068	12,089	12,244	16,291	Jul-21	20,546
Cannon Beach		4,897	4,373	4,499	5,470	6,458	7,949	9,023	8,068	6,292	6,578	5,787	4,414	Jan-22	9,023
Canyonville		7,238	7,691	7,434	6,965	7,659	8,020	8,048	8,290	7,737	7,867	6,702	7,419	Feb-22	8,290
Casebeer		8,799	6,785	5,930	2,646	2,771	3,062	5,880	3,347	2,967	4,114	6,905	6,849	Jul-21	8,799
Cave Junction		14,263	14,145	11,556	15,100	16,133	15,977	17,542	18,478	16,282	16,662	14,879	11,395	Feb-22	18,478
Caveman		20,547	20,116	17,007	12,151	13,749	18,232	15,650	15,535	13,603	12,726	13,226	17,383	Jul-21	20,547
Cherry Lane		7,333	7,294	7,174	7,321	7,410	7,317	7,480	7,510	7,285	9,686	9,661	7,093	Apr-22	9,686
Chiloquin		7,415	7,623	7,661	7,605	7,137	6,988	7,167	7,285	7,597	7,504	7,247	7,918	Jun-22	7,918
China Hat		19,124	20,869	15,318	18,955	20,164	22,467	23,518	25,672	22,931	18,489	17,870	17,699	Feb-22	25,672
Circle Blvd		15,760	17,017	15,190	14,716	14,301	13,979	13,677	14,084	14,511	14,611	15,527	15,965	Aug-21	17,017
Cleveland Ave.		33,272	34,937	28,196	25,986	28,432	32,367	30,609	33,674	32,082	32,913	25,593	31,229	Aug-21	34,937
Cloake		15,994	16,327	13,130	8,880	10,616	12,023	11,374	12,901	10,751	10,455	8,731	15,297	Aug-21	16,327
Coburg		2,477	2,654	2,096	1,584	1,831	2,155	2,159	2,257	1,946	1,830	1,617	2,245	Aug-21	2,654
Columbia		32,808	33,566	28,103	25,154	27,217	28,391	29,359	28,865	26,578	24,306	23,104	28,272	Aug-21	33,566
Coquille		10,402	13,380	11,039	13,319	15,152	16,527	16,285	17,608	15,324	15,521	13,554	11,046	Feb-22	17,608
Cully		12,152	13,652	10,055	8,756	9,707	11,241	11,207	10,632	9,551	7,711	7,002	9,814	Aug-21	13,652
Culver		9,544	7,052	6,430	6,573	7,050	8,402	8,547	10,040	8,439	6,824	5,623	5,905	Feb-22	10,040
Dairy		10,144	8,483	7,094	2,569	3,909	2,904	3,034	2,607	2,992	4,605	8,516	8,335	Jul-21	10,144
Dallas		35,885	39,087	29,229	27,599	30,710	35,004	35,635	38,644	33,378	32,094	26,849	32,328	Aug-21	39,087
Dalreed		53,434	49,732	36,996	17,533	8,146	8,107	10,165	7,926	22,084	25,749	33,617	47,030	Jul-21	53,434
Deschutes		8,473	8,562	6,901	9,314	10,257	11,432	13,537	14,701	12,638	9,681	8,708	7,266	Feb-22	14,701

Devils Lake	19,818	18,962	20,057	24,170	28,641	35,306	34,722	34,824	28,525	28,387	25,849	20,739	Dec-21	35,306
Dixon	3,577	3,837	3,024	2,165	2,395	2,605	2,723	2,686	2,299	2,366	2,489	3,007	Aug-21	3,837
Dodge Bridge	11,274	15,619	13,930	15,412	15,191	10,871	11,849	12,955	10,957	10,272	8,717	10,175	Aug-21	15,619
Dowell	16,102	16,070	13,398	10,843	11,993	12,605	13,359	13,900	12,110	11,375	10,489	15,047	Jul-21	16,102
Easy Valley	19,981	19,758	16,152	13,556	15,775	16,881	17,570	18,299	15,373	15,156	11,634	18,352	Jul-21	19,981
Empire	9,939	11,539	11,178	14,466	16,900	19,688	18,946	20,681	17,756	16,841	14,257	10,426	Feb-22	20,681
Fern Hill	1,154	1,622	2,129	2,597	2,976	3,168	2,779	2,670	2,646	2,097	1,762	1,462	Dec-21	3,168
Fielder Creek	11,693	11,522	9,557	10,514	10,771	11,256	12,274	13,147	11,785	11,169	9,013	9,566	Feb-22	13,147
Foothills Rd	13,944	13,690	11,008	9,526	10,014	10,360	10,641	11,057	10,093	9,507	9,957	13,398	Jul-21	13,944
Garden Valley	15,086	15,396	12,601	8,706	10,851	10,322	10,538	11,139	9,694	9,560	9,468	13,486	Aug-21	15,396
Glendale	10,247	9,902	8,863	11,307	11,567	12,275	13,390	13,965	12,774	12,201	11,161	9,404	Feb-22	13,965
Gold Hill	8,332	8,009	6,388	6,885	7,422	7,350	8,326	9,076	7,683	7,447	6,021	7,396	Feb-22	9,076
Gordon Hollow	4,345	4,641	3,304	3,253	3,704	4,999	5,076	5,376	4,168	3,653	3,070	3,739	Feb-22	5,376
Goshen	5,653	6,368	5,149	5,032	5,709	6,636	6,517	7,142	6,205	5,866	4,994	5,515	Feb-22	7,142
Grant Street	25,993	28,697	21,885	21,890	27,043	26,731	28,665	28,335	24,238	23,433	20,707	23,580	Aug-21	28,697
Green	14,471	14,686	12,564	10,044	12,576	13,624	13,496	15,740	12,997	12,581	10,581	13,699	Feb-22	15,740
Harrisburg	7,989	8,426	6,816	6,798	7,716	8,529	8,793	9,290	8,053	7,232	6,531	7,040	Feb-22	9,290
Hazelwood	6,869	7,343	5,490	6,052	6,272	6,866	7,332	7,226	6,461	5,960	5,406	5,821	Aug-21	7,343
Hillview	26,312	33,010	26,248	20,463	24,276	24,976	30,881	25,849	24,648	20,879	20,548	29,411	Aug-21	33,010
Holladay	19,870	21,863	20,823	17,386	17,109	19,584	18,376	18,755	16,105	16,590	15,734	20,056	Aug-21	21,863
Hollywood	30,476	34,728	26,509	19,930	22,168	26,706	26,053	25,532	22,255	23,022	19,626	30,942	Aug-21	34,728
Hood River	30,542	33,059	24,641	21,137	24,366	31,061	32,061	31,219	26,103	24,120	21,360	27,153	Aug-21	33,059
Hornet	15,832	15,608	12,948	10,205	11,389	12,930	12,689	13,423	11,505	11,176	10,404	13,615	Jul-21	15,832

Independence	22,197	23,683	18,846	15,057	16,750	18,513	18,928	19,358	16,862	16,168	13,572	16,468	Aug-21	23,683
Jacksonville	17,629	17,367	12,312	12,250	13,728	14,537	15,365	16,271	14,068	13,207	11,344	15,864	Jul-21	17,629
Jefferson	10,393	11,559	11,162	8,639	9,521	11,556	16,304	17,200	14,573	14,392	10,600	12,526	Feb-22	17,200
Jerome Prairie	14,427	14,604	11,014	13,049	14,491	14,311	9,309	9,565	8,472	8,061	7,026	7,455	Aug-21	14,604
Junction City	8,014	8,835	7,409	7,003	8,270	9,166	17,143	17,465	15,881	16,289	14,366	17,631	Jun-22	17,631
Killingsworth	18,649	20,251	16,214	15,309	16,709	18,770	18,863	19,400	17,628	20,597	14,658	19,740	Apr-22	20,597
Knappa Svensen	2,806	3,167	2,827	3,796	5,044	5,363	4,934	5,252	4,676	4,486	3,768	3,179	Dec-21	5,363
Knott	26,984	30,684	23,720	20,636	24,209	28,683	27,006	26,796	24,522	23,955	20,267	26,468	Aug-21	30,684
Lakeport	18,043	17,594	15,960	16,092	17,810	19,073	19,057	19,418	17,939	17,835	17,544	15,882	Feb-22	19,418
Lancaster	6,586	6,773	7,950	8,524	10,275	10,713	10,607	10,196	10,814	9,261	8,949	6,773	Mar-22	10,814
Lebanon	32,496	33,700	28,050	25,052	27,437	31,747	31,456	32,346	28,146	26,468	23,581	27,220	Aug-21	33,700
Lincoln	19,919	21,999	19,325	17,230	19,761	21,489	32,591	33,821	29,903	31,811	28,810	33,640	Feb-22	33,821
Lockhart	11,148	11,467	12,870	17,234	19,817	22,608	21,804	24,261	21,131	20,041	17,947	13,233	Feb-22	24,261
Lyons	17,342	18,189	17,645	18,602	20,462	20,284	20,886	20,990	21,022	19,645	17,632	17,422	Mar-22	21,022
Madras	18,790	19,133	15,032	16,816	17,408	20,689	20,994	24,394	19,728	16,907	13,067	17,264	Feb-22	24,394
Mallory	12,719	14,292	10,680	9,486	11,011	13,281	13,041	12,874	10,975	13,661	11,215	15,337	Jun-22	15,337
Marys River	14,419	15,116	13,401	14,660	14,993	15,719	16,825	17,711	15,908	15,683	14,340	12,593	Feb-22	17,711
Medford	25,056	24,762	20,349	15,402	17,071	18,076	2,153	10,225	8,446	7,497	7,404	12,386	Jul-21	25,056
Merlin	22,950	23,280	18,845	22,016	25,346	25,475	16,284	16,584	16,173	15,924	16,037	16,177	Dec-21	25,475
Merrill	9,336	7,772	7,269	4,831	4,603	5,585	26,279	26,554	25,793	21,617	24,550	31,570	Jun-22	31,570
Mile High	10,581	9,794	8,931	10,775	11,586	12,262	30,201	31,577	27,090	26,417	19,987	19,310	Feb-22	31,577
Murder Creek	50,524	54,318	50,109	46,199	45,780	49,460	8,749	5,878	5,008	8,652	10,721	9,097	Aug-21	54,318
Oak Knoll	18,868	18,537	14,008	15,594	17,109	19,408	12,143	13,039	12,155	11,993	11,648	9,753	Dec-21	19,408
O'Brien	1,413	1,331	1,099	1,483	1,584	1,641	49,504	47,673	46,617	46,805	65,816	63,946	May-22	65,816
REDACTED	21,334	24,422	21,543	18,706	16,323	16,967	23,426	21,527	17,080	17,115	15,454	17,441	Aug-21	24,422
Overpass	33,116	35,097	26,856	27,270	29,416	32,578	1,698	1,685	1,681	1,717	1,499	1,073	Aug-21	35,097
Pallette	456	379	328	329	397	467	17,704	17,952	17,599	16,139	16,301	17,420	Feb-22	17,952
Park Street	32,569	31,946	27,184	21,829	25,089	24,979	32,125	35,430	31,864	28,625	26,288	30,205	Feb-22	35,430
Parkrose	27,150	30,026	23,442	20,511	23,062	27,343	581	490	448	389	298	269	Aug-21	30,026
Pendleton	30,482	30,673	22,874	17,901	20,246	25,178	13,851	14,050	12,150	11,136	10,819	29,342	Aug-21	30,673
Pilot Butte	17,907	19,051	14,598	11,731	12,971	16,529	25,634	26,176	22,561	23,926	22,151	26,806	Jun-22	26,806
Pilot Rock	7,695	7,589	-	-	4,743	6,430	24,187	21,811	18,672	15,698	13,347	20,633	Jan-22	24,187
Prineville	36,706	37,307	30,339	30,645	33,450	36,343	14,787	16,745	14,178	12,215	11,048	16,954	Aug-21	37,307
Prospect Central	1,992	1,549	1,713	1,546	1,900	2,083	35,829	43,287	37,932	33,034	32,508	30,517	Feb-22	43,287
Queen Ave	37,075	40,484	32,421	23,775	28,039	33,445	31,291	31,246	28,088	26,607	23,527	34,464	Aug-21	40,484
Redmond 115	37,848	39,811	31,386	31,285	38,334	39,600	36,831	44,159	38,372	33,310	29,932	35,430	Feb-22	44,159
Riddle	16,485	16,162	13,979	14,523	16,446	17,070	19,115	21,412	16,988	16,471	14,125	15,337	Feb-22	21,412
REDACTED	11,880	12,162	12,489	12,505	12,657	12,737	12,183	11,985	11,389	11,783	11,556	11,026	Dec-21	12,737
Roseburg	22,343	23,596	19,756	15,868	19,284	19,605	21,357	23,365	19,823	19,560	16,235	21,780	Aug-21	23,596
Ross Ave	7,529	7,547	6,551	5,105	5,542	6,604	6,462	6,680	5,846	5,552	5,137	6,078	Aug-21	7,547
Roxy Ann	14,402	14,589	10,309	6,716	6,875	8,436	7,756	8,289	6,977	6,584	7,908	14,367	Aug-21	14,589
Russelville	29,372	32,422	25,378	22,402	25,379	30,881	30,404	29,695	25,184	25,733	21,837	28,064	Aug-21	32,422
Sage Road	30,866	30,196	25,865	20,722	23,491	25,041	24,194	24,970	24,426	21,542	22,755	28,151	Jul-21	30,866
Scenic	29,184	27,959	22,479	17,727	20,272	21,119	22,514	22,689	19,945	18,490	17,647	25,915	Jul-21	29,184
Scio	5,604	5,804	4,536	4,569	4,993	5,687	5,862	6,289	5,473	5,048	4,492	4,420	Feb-22	6,289
Seaside	16,787	13,785	18,121	15,896	18,707	23,736	21,713	20,920	18,739	18,423	16,242	14,382	Dec-21	23,736
Shevlin Park	22,189	22,985	16,096	13,807	14,721	20,205	17,983	18,813	17,564	23,366	13,670	20,564	Apr-22	23,366
Southgate	14,378	14,153	13,083	11,508	13,110	15,319	14,368	14,958	13,479	13,773	11,619	14,560	Dec-21	15,319

State Street	18,486	20,510	19,081	24,259	29,255	35,572	32,843	36,759	31,692	29,971	26,219	19,832	Feb-22	36,759
Stayton	35,054	38,167	30,054	26,643	31,206	35,029	36,836	39,282	33,021	36,354	26,728	31,714	Feb-22	39,282
Stevens Road	23,133	24,180	17,761	14,094	16,276	17,019	17,929	19,544	17,610	15,624	13,681	22,877	Aug-21	24,180
Sutherlin	12,176	12,426	10,418	9,530	10,936	11,508	11,781	13,496	11,207	10,667	9,096	11,158	Feb-22	13,496
Sweet Home	23,059	24,660	20,059	22,396	22,018	24,553	24,756	28,375	24,942	22,212	20,752	20,360	Feb-22	28,375
Takelma	9,211	9,239	6,813	8,641	9,865	9,666	10,658	11,871	9,771	9,310	7,093	8,696	Feb-22	11,871
Talent	18,577	18,623	14,091	14,997	17,452	18,119	19,294	20,861	17,329	15,973	13,790	17,791	Feb-22	20,861
Texum	12,522	12,495	9,896	10,761	12,129	12,898	12,688	13,172	14,898	11,749	10,623	9,620	Mar-22	14,898
Umatilla	15,286	14,457	12,568	12,990	9,862	12,061	13,104	11,883	9,821	8,930	9,403	13,604	Jul-21	15,286
Vernon	30,176	34,718	23,861	21,161	23,670	27,899	28,389	27,496	23,287	23,315	20,747	30,527	Aug-21	34,718
Vilas Road	20,867	20,391	18,118	13,380	14,603	15,624	16,129	16,429	14,761	14,054	16,091	20,746	Jul-21	20,867
Village Green	13,306	14,752	11,265	11,528	12,715	13,795	13,935	15,158	13,241	12,830	11,325	13,082	Feb-22	15,158
Vine Street	24,011	24,056	18,450	12,353	14,875	17,015	15,944	15,837	14,017	13,622	12,135	22,356	Aug-21	24,056
Warrenton	15,946	17,755	16,158	17,162	18,131	19,041	18,895	19,915	18,615	18,025	16,525	16,471	Feb-22	19,915
Weston	10,016	10,427	10,047	9,552	9,251	6,132	4,112	6,255	7,134	7,223	5,735	9,942	Aug-21	10,427
Westside	13,639	13,701	11,281	11,516	12,383	13,269	13,344	14,785	12,102	15,371	12,917	13,040	Apr-22	15,371
White City	42,946	41,313	38,196	35,992	35,932	38,487	37,844	39,982	36,050	35,087	34,157	38,632	Jul-21	42,946
Winchester	24,879	25,043	20,020	17,214	18,869	19,831	21,071	22,922	19,773	19,166	16,169	24,155	Aug-21	25,043
Yew Ave	18,447	20,556	15,152	13,923	15,257	18,813	17,293	19,442	17,347	14,217	12,878	16,939		
													Total	
Substation Peaks	424,997	1,089,883	11,974	-	968	140,512	33,210	741,399	71,134	72,256	65,816	101,349	2,753,497	
Weighting Factor	15.43%	39.58%	0.43%	0.00%	0.04%	5.10%	1.21%	26.93%	2.58%	2.62%	2.39%	3.68%	100.00%	

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2023

A	B	C	D	E	F	G	H	I	J	K	L	M	N	Peak	Peak
Substation		Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Month	Load
Agness Avenue		18,785	18,462	17,408	16,998	16,045	15,944	16,763	17,324	15,859	14,975	14,426	15,662	Jul-22	18,785
Albina		24,040	24,888	23,075	21,291	21,444	21,805	20,306	20,104	23,215	22,032	22,053	21,687	Aug-22	24,888
Alderwood		24,996	24,982	22,062	20,659	19,851	24,665	19,653	19,684	19,287	19,509	23,516	22,303	Jul-22	24,996
Applegate		11,277	10,563	9,724	9,233	11,506	12,097	13,503	13,051	11,444	11,015	7,928	9,113	Jan-23	13,503
Ashland		18,576	16,190	15,888	12,113	14,122	16,151	16,089	16,021	14,700	14,051	11,874	14,518	Jul-22	18,576
Bandon		2,018	1,792	1,975	2,133	2,359	2,761	2,674	2,848	2,933	3,187	2,004	2,107	Apr-23	3,187
Beall Lane		21,179	18,635	25,016	17,994	15,427	15,939	16,793	16,444	15,351	14,872	15,989	17,670	Sep-22	25,016
Belknap		31,678	29,123	28,805	21,738	21,411	23,094	23,130	23,082	25,150	23,960	27,570	26,791	Jul-22	31,678
Bend Plant		20,587	17,689	17,881	15,558	15,312	15,483	16,783	16,351	13,799	12,658	10,853	15,358	Jul-22	20,587
Bloss		11,376	9,650	11,707	10,175	2,653	1,242	840	597	628	543	444	335	Sep-22	11,707
Bly		2,011	2,216	1,862	2,523	1,193	1,518	1,371	1,263	1,638	1,566	1,188	2,035	Oct-22	2,523
REDACTED		890	1,032	1,062	913	1,013	961	907	940	915	935	969	897	Sep-22	1,062
Bond Street		20,857	17,833	17,137	13,196	16,789	20,062	20,373	17,517	15,098	13,679	11,551	15,567	Jul-22	20,857
Brookhurst		41,502	36,525	37,254	23,485	24,579	27,497	29,514	27,543	29,220	28,260	33,034	33,973	Jul-22	41,502
Bryant		27,601	24,708	25,566	16,935	20,753	23,694	22,835	21,087	21,167	19,400	18,371	22,085	Jul-22	27,601
Buchanan		28,363	26,954	21,947	19,334	27,454	27,170	26,262	26,091	23,953	21,804	16,828	20,345	Jul-22	28,363
Buckaroo		16,783	16,819	15,498	11,866	13,243	13,824	13,359	13,731	12,904	12,722	17,000	15,014	May-23	17,000
Calapooya		6,320	5,764	5,391	4,697	5,329	5,877	5,731	5,835	5,466	5,131	4,977	5,156	Jul-22	6,320
Campbell		19,320	19,012	17,985	13,259	12,827	16,829	16,974	16,313	15,438	14,768	17,202	20,447	Jun-23	20,447
Cannon Beach		4,736	4,147	4,395	4,847	6,517	7,890	7,437	8,454	9,701	6,677	4,727	4,207	Mar-23	9,701
Canyonville		7,828	7,280	7,180	6,168	8,129	8,094	8,555	8,259	6,313	5,951	5,557	6,066	Jan-23	8,555
Casebeer		8,157	7,039	7,316	3,338	3,038	3,771	3,690	3,258	3,355	3,152	7,053	6,890	Jul-22	8,157
Cave Junction		14,233	13,151	12,681	13,795	16,011	16,843	17,598	17,941	18,845	16,093	12,187	11,954	Mar-23	18,845
Caveman		22,149	20,291	18,779	13,931	14,607	15,919	16,398	16,310	14,431	13,129	15,154	17,622	Jul-22	22,149
Cherry Lane		7,364	8,300	7,335	7,167	7,630	7,368	7,438	7,724	7,511	7,497	7,227	7,328	Aug-22	8,300
Chiloquin		7,671	7,746	7,840	7,776	7,267	6,138	7,566	7,158	7,063	6,854	7,236	7,894	Jun-23	7,894
China Hat		22,331	19,414	18,557	16,405	22,372	26,276	29,231	25,346	22,555	20,131	15,631	16,687	Jan-23	29,231
Circle Blvd		17,178	17,348	15,451	15,105	14,290	14,279	14,306	13,891	14,929	14,529	15,406	15,661	Aug-22	17,348
Cleveland Ave.		36,641	33,636	32,822	25,750	32,884	36,251	47,582	34,434	30,204	28,882	24,975	29,716	Jan-23	47,582
Cloake		16,934	16,380	13,536	9,463	11,556	11,149	13,267	12,534	11,232	10,329	12,475	13,860	Jul-22	16,934
Coburg		2,721	2,380	2,158	1,604	2,135	2,360	2,320	2,234	2,037	1,840	2,285	2,283	Jul-22	2,721
Columbia		33,275	32,405	29,549	24,564	27,789	31,906	29,890	28,636	28,910	26,764	29,128	29,471	Jul-22	33,275
Coquille		10,110	11,561	10,885	12,511	16,280	16,403	18,115	17,743	16,404	15,953	12,650	11,258	Jan-23	18,115
Crowfoot		16,172	15,051	849	8,725	15,112	16,061	4	12	14,428	13,206	13,709	14,086	Jul-22	16,172
Cully		10,789	10,550	8,562	7,593	8,415	10,706	9,465	9,726	8,381	9,565	8,869	10,078	Jul-22	10,789
Culver		7,124	6,806	6,286	5,584	7,827	9,043	10,218	9,020	7,805	6,991	5,000	6,297	Jan-23	10,218
Dairy		9,654	8,504	8,167	3,441	2,475	3,000	2,678	2,403	2,643	3,134	8,017	7,074	Jul-22	9,654
Dallas		38,003	35,121	30,209	25,844	32,029	39,422	37,129	37,679	35,364	30,789	29,918	29,492	Dec-22	39,422
Dalreed		51,656	48,796	42,829	21,993	7,905	8,069	7,685	7,882	17,789	25,026	36,279	49,283	Jul-22	51,656
Deschutes		8,571	7,880	7,976	7,923	12,591	13,902	16,472	14,095	10,875	10,330	6,634	7,307	Jan-23	16,472

Devils Lake	19,596	18,941	19,345	23,842	30,496	36,731	34,978	35,247	32,075	30,060	21,348	19,325	Dec-22	36,731
Dixon	3,642	3,506	3,156	2,519	2,500	2,823	2,625	2,777	2,543	2,726	3,034	3,238	Jul-22	3,642
Dodge Bridge	12,416	11,080	11,199	9,058	11,142	12,939	13,686	12,755	11,532	10,533	7,930	16,080	Jun-23	16,080
Dowell	17,743	16,457	14,884	10,337	12,487	12,894	14,219	14,030	12,028	11,285	12,747	14,740	Jul-22	17,743
Easy Valley	21,810	19,990	17,872	11,505	16,185	16,836	19,079	18,712	16,042	14,920	14,329	17,439	Jul-22	21,810
Empire	9,145	8,669	9,902	13,485	17,722	19,340	21,664	20,529	20,618	18,165	12,780	10,648	Jan-23	21,664
Fern Hill	1,221	1,160	2,644	1,845	2,609	3,477	4,085	4,255	3,724	3,257	2,451	1,929	Feb-23	4,255
Fielder Creek	12,037	11,317	10,625	9,499	11,415	12,279	13,037	12,404	11,066	11,034	7,878	9,315	Jan-23	13,037
Foothills Rd	15,511	14,090	14,061	10,146	10,275	11,062	11,275	10,906	10,498	10,375	11,590	13,472	Jul-22	15,511
Garden Valley	15,399	14,822	12,666	9,765	10,262	10,335	11,351	10,862	10,147	10,937	11,750	12,676	Jul-22	15,399
Glendale	10,567	10,241	9,296	10,256	12,563	12,927	13,887	13,276	12,703	38,302	34,196	16,884	Apr-23	38,302
Gold Hill	8,809	8,100	7,928	5,885	7,937	8,647	9,192	8,786	7,978	7,647	5,912	7,130	Jan-23	9,192
Gordon Hollow	4,960	4,509	4,025	3,063	4,991	6,264	5,586	5,404	4,344	3,699	3,264	3,613	Dec-22	6,264
Goshen	6,205	6,056	5,291	4,707	6,815	6,661	7,444	7,027	6,233	5,742	5,360	5,497	Jan-23	7,444
Grant Street	27,857	25,798	22,295	21,147	30,354	29,174	29,102	29,578	26,646	25,787	26,742	26,317	Nov-22	30,354
Green	15,267	14,903	13,194	10,088	12,880	13,795	16,430	15,272	13,754	12,471	12,028	12,282	Jan-23	16,430
Harrisburg	8,341	7,802	6,944	6,644	8,549	8,449	8,871	9,266	8,371	7,629	6,744	6,796	Feb-23	9,266
Hazelwood	7,088	6,449	5,646	5,601	6,591	7,439	6,886	7,298	6,288	6,114	6,113	6,281	Dec-22	7,439
Hillview	30,695	27,283	25,916	19,542	29,205	30,433	25,856	25,390	25,697	27,619	24,861	24,589	Jul-22	30,695
Holladay	22,204	22,702	18,844	18,287	19,358	20,104	18,412	17,641	22,908	16,634	18,769	18,236	Mar-23	22,908
Hollywood	34,318	33,094	27,468	22,625	24,065	31,979	25,969	26,838	24,708	23,064	27,994	26,534	Jul-22	34,318
Hood River	32,591	31,720	27,652	18,819	27,677	36,282	33,046	31,055	26,377	23,791	24,328	25,351	Dec-22	36,282
Hornet	16,610	15,353	14,978	10,672	12,187	14,458	14,290	13,204	13,108	11,948	11,561	13,284	Jul-22	16,610
Independence	21,493	20,168	17,477	13,158	16,925	20,364	19,093	20,077	17,485	15,672	16,171	17,618	Jul-22	21,493

Jacksonville	19,725	16,724	16,433	9,959	13,667	15,871	16,660	15,291	15,149	13,533	12,165	15,347	Jul-22	19,725
Jefferson	15,508	13,702	12,205	10,387	16,122	16,245	17,836	18,794	19,182	14,407	10,584	12,390	Mar-23	19,182
Jerome Prairie	8,635	8,208	7,493	6,751	8,656	9,241	9,625	9,629	8,644	7,625	7,117	7,312	Feb-23	9,629
Junction City	18,869	18,396	15,553	13,657	15,822	18,517	17,176	16,814	15,898	14,508	12,011	8,895	Jul-22	18,869
Killingsworth	21,233	21,183	18,472	19,941	24,599	31,125	26,406	22,371	20,966	19,227	20,723	22,399	Dec-22	31,125
Knappa Svensen	3,032	3,262	2,823	3,519	4,723	6,073	5,500	5,423	5,228	4,467	3,297	2,879	Dec-22	6,073
Knott	30,237	29,181	26,022	21,193	25,881	33,498	28,024	28,334	24,974	23,416	26,373	24,914	Dec-22	33,498
Lakeport	17,718	17,217	16,916	16,405	18,266	18,905	18,942	18,808	18,769	18,246	17,261	16,042	Jan-23	18,942
Lancaster	7,867	8,071	7,742	7,613	9,102	9,703	11,629	12,543	11,620	9,385	7,806	7,915	Feb-23	12,543
Lebanon	33,372	31,750	29,487	24,072	30,502	32,276	33,026	31,804	28,244	27,408	27,193	28,569	Jul-22	33,372
Lincoln	36,562	34,488	32,745	29,677	32,070	37,609	35,015	35,193	32,443	30,947	33,276	31,490	Dec-22	37,609
Lockhart	11,710	12,541	12,215	17,226	20,592	22,990	23,690	23,241	22,636	20,974	14,874	12,323	Jan-23	23,690
Lyons	18,373	17,369	15,720	16,344	20,080	20,992	21,704	20,911	21,578	20,003	16,855	16,906	Jan-23	21,704
Madras	19,892	21,721	17,335	14,343	19,277	24,248	24,647	22,649	18,946	17,693	15,079	17,256	Jan-23	24,647
Mallory	16,550	13,392	11,509	9,531	11,317	15,502	12,570	13,589	18,001	10,148	12,040	11,099	Mar-23	18,001
Marys River	16,446	16,661	15,018	14,589	16,844	17,319	17,193	17,155	16,012	15,302	13,920	14,207	Dec-22	17,319
Medford	14,530	13,502	12,415	8,077	8,793	11,520	10,291	9,442	8,110	7,703	11,240	11,586	Jul-22	14,530
Merlin	15,258	15,731	16,407	15,759	15,668	16,017	16,374	16,655	16,468	16,700	16,880	16,340	May-23	16,880
Merrill	42,742	35,754	35,470	26,309	24,706	27,552	28,480	36,310	25,400	15,761	34,776	34,495	Jul-22	42,742
Mile High	25,077	22,360	19,123	18,192	27,259	29,617	31,397	32,594	25,963	24,615	17,065	18,896	Feb-23	32,594
Murder Creek	16,228	13,931	7,488	4,265	5,191	5,931	5,896	5,457	12,100	4,960	7,927	7,669	Jul-22	16,228
Oak Knoll	10,482	10,398	10,056	16,472	22,210	13,554	13,920	12,980	12,407	11,904	11,060	9,719	Nov-22	22,210
O'Brien	54,674	49,646	48,572	40,225	45,618	53,030	50,009	52,768	49,438	47,776	54,121	51,583	Jul-22	54,674
REDACTED	22,277	18,861	18,285	14,549	17,295	19,828	19,766	19,939	18,307	17,904	13,245	16,758	Jul-22	22,277
Overpass	1,368	1,274	1,183	1,326	1,450	1,509	1,616	1,550	1,939	1,432	1,192	1,083	Mar-23	1,939
Pallette	22,738	24,994	23,116	18,303	18,028	19,408	20,024	21,739	20,611	20,768	21,974	23,555	Aug-22	24,994
Park Street	34,430	32,681	30,947	27,012	32,308	37,148	37,616	35,810	31,797	30,885	25,438	27,908	Jan-23	37,616
Parkrose	445	395	359	314	467	523	566	441	401	375	249	266	Jan-23	566
Pendleton	36,454	34,126	30,999	24,178	26,003	27,990	28,856	29,566	25,520	23,233	26,702	30,543	Jul-22	36,454
Pilot Butte	29,372	28,588	24,303	19,322	23,863	31,012	25,501	26,646	23,312	23,776	26,637	24,830	Dec-22	31,012
Pilot Rock	25,680	23,200	20,487	12,804	17,716	22,469	19,814	18,978	16,144	15,545	17,759	18,931	Jul-22	25,680
Prineville	20,304	17,656	17,884	11,188	15,559	18,602	18,418	17,362	14,030	12,980	12,756	16,309	Jul-22	20,304
Prospect Central	40,072	36,793	33,644	29,534	36,887	42,643	46,154	40,587	37,951	36,131	26,752	32,894	Jan-23	46,154
Queen Ave	40,648	39,467	34,302	26,809	30,302	36,555	30,569	37,061	29,138	27,295	33,061	34,905	Jul-22	40,648
Redmond 115	40,947	38,889	36,451	30,461	37,438	45,869	47,432	42,045	36,988	34,694	29,230	33,678	Jan-23	47,432
Riddle	16,887	16,585	14,357	14,195	18,534	19,404	20,780	19,746	17,795	16,940	13,467	13,221	Jan-23	20,780
REDACTED	10,020	10,445	10,708	11,414	12,182	10,984	11,023	11,268	11,812	11,437	10,942	10,985	Nov-22	12,182
Roseburg	23,381	23,259	19,737	15,900	23,519	21,820	23,635	22,172	23,145	19,855	18,550	19,516	Jan-23	23,635
Ross Ave	7,667	6,860	7,366	4,780	6,018	6,622	6,539	6,214	5,935	5,497	4,738	5,503	Jul-22	7,667
Roxy Ann	17,350	14,684	14,792	8,654	7,159	8,036	8,383	8,016	7,427	9,037	10,854	13,617	Jul-22	17,350
Russelville	31,401	30,606	26,167	17,926	21,969	30,494	29,518	32,272	27,618	24,467	25,835	24,800	Feb-23	32,272
Sage Road	32,880	30,877	29,664	24,221	23,328	25,485	25,077	25,369	25,593	30,973	24,950	28,514	Jul-22	32,880
Scenic	31,922	28,345	29,249	19,187	20,509	22,699	23,241	22,730	20,990	19,743	23,324	27,221	Jul-22	31,922
Scio	5,381	5,179	4,597	4,251	5,855	6,175	6,349	6,207	5,322	4,808	4,114	4,720	Jan-23	6,349
Seaside	14,450	13,804	13,599	15,392	19,789	23,199	26,205	22,546	20,333	19,620	14,798	13,328	Jan-23	26,205
Shevlin Park	26,337	21,068	21,501	13,972	18,156	21,639	20,319	22,307	18,623	16,809	19,538	20,940	Jul-22	26,337
Southgate	17,007	15,397	12,417	11,318	14,747	14,493	16,784	16,323	14,313	14,073	13,269	13,184	Jul-22	17,007
State Street	17,724	18,092	18,404	23,216	30,983	33,736	38,294	36,058	35,908	33,375	23,596	19,142	Jan-23	38,294

Stayton	37,459	34,909	30,806	24,694	35,037	36,960	38,340	38,123	32,015	29,573	29,021	30,981	Jan-23	38,340
Stevens Road	25,904	24,719	23,399	14,597	18,720	21,108	21,197	20,729	19,209	16,779	17,128	20,409	Jul-22	25,904
Sutherlin	12,531	12,016	10,545	8,774	12,028	11,457	14,037	12,843	11,931	10,843	10,194	10,583	Jan-23	14,037
Sweet Home	25,517	23,946	21,514	20,520	26,795	27,192	30,122	28,850	25,792	21,503	16,655	21,264	Jan-23	30,122
Takelma	10,077	8,876	9,123	7,682	10,546	11,919	12,406	11,351	10,061	9,827	6,400	8,039	Jan-23	12,406
Talent	22,034	19,413	19,355	13,919	18,259	20,560	21,593	20,726	19,917	17,915	14,416	18,208	Jul-22	22,034
Texum	12,553	12,250	11,611	11,055	12,399	14,322	14,093	13,092	13,095	11,970	9,849	9,599	Dec-22	14,322
Umatilla	15,094	14,294	13,519	10,764	10,069	13,650	12,328	12,469	9,882	9,439	11,228	13,332	Jul-22	15,094
Vernon	34,749	33,229	26,014	22,071	26,307	35,015	29,697	30,782	33,544	22,202	27,694	28,167	Dec-22	35,015
Vilas Road	22,891	21,197	20,666	15,733	15,227	16,609	16,623	16,320	15,528	15,144	17,128	19,478	Jul-22	22,891
Village Green	14,244	13,463	11,731	10,849	13,961	14,877	15,470	14,797	13,143	9,657	10,845	11,175	Jan-23	15,470
Vine Street	25,841	23,693	19,528	15,497	16,074	19,056	16,315	16,716	15,208	18,406	19,817	18,521	Jul-22	25,841
Warrenton	16,358	17,397	16,428	16,365	19,101	19,936	20,331	20,461	19,683	19,301	17,038	16,453	Feb-23	20,461
Weston	10,649	11,102	10,321	9,044	6,218	4,209	6,604	6,202	6,064	5,643	5,032	8,757	Aug-22	11,102
Westside	19,081	13,817	14,007	12,464	13,805	14,684	14,785	14,092	14,109	13,746	10,554	10,798	Jul-22	19,081
White City	43,236	43,331	40,176	35,398	40,019	47,348	36,286	38,090	36,821	34,881	36,907	37,061	Dec-22	47,348
Winchester	26,087	25,183	21,263	15,345	20,208	20,658	23,776	22,361	20,652	18,885	19,793	21,199	Jul-22	26,087
Yew Ave	20,688	19,061	17,621	13,067	17,082	21,178	21,620	19,589	15,886	15,372	13,847	16,861	Jan-23	21,620
													Total	
Substation Peaks	1,223,592	86,632	37,785	2,523	64,746	379,458	679,454	121,021	90,575	41,489	33,880	44,420	2,805,575	
Weighting Factor	43.61%	3.09%	1.35%	0.09%	2.31%	13.53%	24.22%	4.31%	3.23%	1.48%	1.21%	1.58%	100.00%	
Three-Year Average Weighting Factor	21.19%	15.81%	1.36%	0.28%	1.62%	8.08%	10.89%	11.52%	2.71%	1.56%	1.20%	23.78%	100.00%	

Uncollectables

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2025

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
			Percent of Total Revenues				Allocated Net Uncollectible				
Line	Description	Del. Volt	Residential	Commercial	Industrial	Irrigation	Residential	Commercial	Industrial	Irrigation	Total
1	Res - Sch 4	(sec)	100.00%	0.00%	0.00%	0.00%	3,547,018	-	-	-	3,547,018
2											
3	GS - Sch 23	(sec)	0.00%	21.78%	1.86%	0.00%	-	81,256	257	-	81,513
4	GS - Sch 23	(pri)	0.00%	0.03%	0.03%	0.00%	-	101	4	-	105
5	GS - Sch 23	Total	0.00%	21.81%	1.89%	0.00%	-	81,356	261	-	81,618
6											
7	GS - Sch 28	(sec)	0.00%	27.99%	5.81%	0.00%	-	104,424	802	-	105,226
8	GS - Sch 28	(pri)	0.00%	0.19%	0.39%	0.00%	-	713	54	-	767
9	GS - Sch 28	Total	0.00%	28.18%	6.20%	0.00%	-	105,137	856	-	105,993
10											
11	GS - Sch 30	(sec)	0.00%	13.34%	12.52%	0.00%	-	49,769	1,728	-	51,497
12	GS - Sch 30	(pri)	0.00%	0.77%	1.08%	0.00%	-	2,878	148	-	3,026
13	GS - Sch 30	Total	0.00%	14.11%	13.59%	0.00%	-	52,647	1,876	-	54,523
14											
15	LPS - Sch 48	(sec)	0.00%	4.03%	18.19%	0.00%	-	15,053	2,512	-	17,565
16	LPS - Sch 48	(pri)	0.00%	13.25%	58.61%	0.00%	-	49,446	8,092	-	57,539
17	LPS - Sch 48	(trn)	0.00%	18.62%	1.51%	0.00%	-	69,456	208	-	69,664
18	LPS - Sch 48	Total	0.00%	35.90%	78.32%	0.00%	-	133,955	10,813	-	144,768
19											
20	Irg - Sch 41	(sec)	0.00%	0.00%	0.00%	100.00%	-	-	-	41,210	41,210
21											
22	Total						3,547,018	373,095	13,806	41,210	3,975,129

12 Months Ended June 2023 Net Write-offs	
Residential	$3,547,018
Commercial	$373,095
Industrial	$13,806
Irrigation	$41,210
Total	3,975,129

Revenues

PacifiCorp
Oregon Marginal Cost Study
Revenues
12 Months Ended December 2025

Line	Description	(A) Del. Volt	(B) Residential	(C) Commercial	(D) Industrial	(E) Irrigation	(F) PS&H	(G) Total
1	Res - Sch 4	(sec)	786,075,316	-	-	-	-	786,075,316
2								
3	GS - Sch 23	(sec)	-	157,321,246	2,335,114	-	-	159,656,360
4	GS - Sch 23	(pri)	-	194,939	35,504	-	-	230,443
5	GS - Sch 23	Total	-	157,516,185	2,370,618	-	-	159,886,803
6								
7	GS - Sch 28	(sec)	-	202,177,015	7,283,467	-	-	209,460,482
8	GS - Sch 28	(pri)	-	1,380,206	493,630	-	-	1,873,836
9	GS - Sch 28	Total	-	203,557,221	7,777,097	-	-	211,334,318
10								
11	GS - Sch 30	(sec)	-	96,359,540	15,693,758	-	-	112,053,298
12	GS - Sch 30	(pri)	-	5,571,208	1,348,365	-	-	6,919,573
13	GS - Sch 30	Total	-	101,930,748	17,042,123	-	-	118,972,871
14								
15	LPS - Sch 48	(sec)	-	29,145,254	22,814,294	-	-	51,959,548
16	LPS - Sch 48	(pri)	-	95,734,013	73,496,480	-	-	169,230,493
17	LPS - Sch 48	(trn)	-	134,474,636	1,891,067	-	-	136,365,703
18	LPS - Sch 48	Total	-	259,353,903	98,201,841	-	-	357,555,744
19								
20	Irg - Sch 41	(sec)	-	-	-	32,686,893	-	32,686,893
21								
22	Lgt - Sch 15	(sec)	-	-	-	-	839,381	839,381
23	Lgt - Sch 51	(sec)	-	-	-	-	2,902,697	2,902,697
24	Lgt - Sch 53	(sec)	-	-	-	-	486,692	486,692
25	Lgt - Sch 54	(sec)	-	-	-	-	90,540	90,540
26	Lgt - Total	(sec)	-	-	-	-	4,319,310	4,319,310
27								
28	Total		786,075,316	722,358,057	125,391,679	32,686,893	4,319,310	1,670,831,255

Docket No. UE 433
Exhibit PAC/1909
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Target Functionalized Revenues and Billing Determinants

February 2024

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2025

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 4, Residential					
	Transmission & Ancillary Services[1]	$53,188	$48,830	$48,830	$48,848
	System Usage- Schedule 200 Related	$4,456	$4,048	$4,048	$4,051
	System Usage- T&A and Schedule 201 Related	$6,656	$7,662	$7,662	$7,640
	Distribution	$313,400	$404,421	$404,421	$404,433
	Other Adjustments	$1,100	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$162,632	$151,248	$151,248	$151,231
	Generation Energy - Net Power Costs (Sch 201)	$244,643	$237,471	$244,643	$244,643
	Total	$786,075	$853,679	$860,851	$860,844
Schedule 23, Small General Service					
	Transmission & Ancillary Services[1]	$9,064	$12,108	$12,108	$12,109
	System Usage- Schedule 200 Related	$848	$744	$744	$744
	System Usage- T&A and Schedule 201 Related	$1,232	$1,482	$1,482	$1,487
	Distribution	$71,495	$91,009	$91,009	$91,003
	Other Adjustments	$209	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$30,768	$28,642	$28,642	$28,639
	Generation Energy - Net Power Costs (Sch 201)	$46,270	$44,971	$46,270	$46,270
	Total	$159,887	$178,956	$180,255	$180,252
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$18,256	$14,874	$14,874	$14,913
	System Usage- Schedule 200 Related	$1,471	$1,379	$1,379	$1,369
	System Usage- T&A and Schedule 201 Related	$2,125	$2,576	$2,576	$2,575
	Distribution	$53,469	$73,326	$73,326	$73,292
	Other Adjustments	$368	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$53,431	$49,960	$49,960	$49,958
	Generation Energy - Net Power Costs (Sch 201)	$80,341	$78,441	$80,341	$80,341
	Total	$209,460	$220,556	$222,456	$222,448
Primary Voltage					
	Transmission & Ancillary Services[1]	$116	$148	$148	$148
	System Usage- Schedule 200 Related	$15	$13	$13	$13
	System Usage- T&A and Schedule 201 Related	$22	$24	$24	$24
	Distribution	$345	$672	$672	$672
	Other Adjustments	$4	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$548	$509	$509	$509
	Generation Energy - Net Power Costs (Sch 201)	$824	$798	$824	$824
	Total	$1,874	$2,164	$2,190	$2,190
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$9,028	$8,773	$8,773	$8,778
	System Usage- Schedule 200 Related	$877	$812	$812	$814
	System Usage- T&A and Schedule 201 Related	$1,265	$1,512	$1,512	$1,515
	Distribution	$19,935	$32,266	$32,266	$31,960
	Other Adjustments	$225	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$32,428	$30,124	$30,124	$30,433
	Generation Energy - Net Power Costs (Sch 201)	$48,295	$47,297	$48,295	$48,295
	Total	$112,053	$120,784	$121,782	$121,795
Primary Voltage					
	Transmission & Ancillary Services[1]	$579	$521	$521	$520
	System Usage- Schedule 200 Related	$54	$51	$51	$51
	System Usage- T&A and Schedule 201 Related	$79	$94	$94	$94
	Distribution	$1,187	$1,857	$1,857	$1,847
	Other Adjustments	$14	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$2,016	$1,820	$1,820	$1,833
	Generation Energy - Net Power Costs (Sch 201)	$2,990	$2,857	$2,990	$2,990
	Total	$6,920	$7,201	$7,334	$7,334
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services[1]	$1,590	$1,550	$1,550	$1,550
	System Usage- Schedule 200 Related	$162	$136	$136	$136
	System Usage- T&A and Schedule 201 Related	$233	$252	$252	$251
	Distribution	$15,804	$22,410	$22,410	$22,410
	Other Adjustments	$40	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$5,934	$5,511	$5,511	$5,511
	Generation Energy - Net Power Costs (Sch 201)	$8,924	$8,653	$8,924	$8,924
	Total	$32,687	$38,512	$38,783	$38,783

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2025

Rate Schedule		Present Revenues ($000)	Cost of Service Revenues ($000)	Target with Unadjusted NPC Revenues ($000)	Summary of Proposed Functionalized Revenues ($000)
(1)	(2)	(3)	(4)	(5)	(6)
Schedule 48, Large General Service, 1,000kW and over					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$4,048	$3,805	$3,805	$3,800
	System Usage- Schedule 200 Related	$400	$375	$375	$377
	System Usage- T&A and Schedule 201 Related	$571	$695	$695	$697
	Distribution	$10,414	$14,726	$14,726	$14,684
	Other Adjustments	$97	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$14,583	$13,425	$13,425	$13,467
	Generation Energy - Net Power Costs (Sch 201)	$21,846	$21,078	$21,846	$21,846
	Total	$51,960	$54,104	$54,871	$54,871
Primary Voltage					
	Transmission & Ancillary Services[1]	$12,390	$13,557	$13,557	$13,550
	System Usage- Schedule 200 Related	$1,455	$1,327	$1,327	$1,325
	System Usage- T&A and Schedule 201 Related	$2,084	$2,446	$2,446	$2,454
	Distribution	$19,170	$38,991	$38,991	$39,002
	Other Adjustments	$369	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$53,651	$49,534	$49,534	$49,530
	Generation Energy - Net Power Costs (Sch 201)	$80,111	$77,772	$80,111	$80,111
	Total	$169,230	$183,627	$185,966	$185,971
Transmission Voltage					
	Transmission & Ancillary Services[1]	$10,739	$10,808	$10,808	$10,797
	System Usage- Schedule 200 Related	$1,258	$1,150	$1,150	$1,142
	System Usage- T&A and Schedule 201 Related	$1,761	$2,106	$2,106	$2,109
	Distribution	$8,883	$22,205	$22,205	$22,211
	Other Adjustments	$329	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$45,130	$41,441	$41,441	$41,448
	Generation Energy - Net Power Costs (Sch 201)	$68,267	$65,065	$68,267	$68,267
	Total	$136,366	$142,775	$145,977	$145,975
Schedules 15, 51, 53, 54 Lighting					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$26	$20	$20	$20
	System Usage- Schedule 200 Related	$10	$9	$9	$9
	System Usage- T&A and Schedule 201 Related	$14	$14	$14	$14
	Distribution	$3,256	$3,732	$3,732	$3,732
	Other Adjustments	$5	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$408	$310	$310	$310
	Generation Energy - Net Power Costs (Sch 201)	$600	$486	$600	$600
	Total	$4,319	$4,570	$4,684	$4,685
TOTAL		**$1,670,831**	**$1,806,926**	**$1,825,149**	**$1,825,149**
	Employee Discount	-$445		-$486	-$486
Additional Rate Schedules					
	Schedule 47	$5,048		$6,123	$6,123
	Schedule 848	$1,517		$3,829	$3,829
Total Oregon		**$1,676,952**		**$1,834,616**	**$1,834,615**
	Base Revenue Increase (excluding base Insurance Cost Adjustment)			**$157,664**	**$157,664**

[1]Includes only FERC transmission plus ancillary services revenues. Non-FERC transmission revenues are recovered through distribution charges.

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.919 ¢	$53,188,228	0.844 ¢	$48,847,513
System Usage Charge								
Sch 200 related, per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.077 ¢	$4,456,467	0.070 ¢	$4,051,334
T&A and Sch 201 related, per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.115 ¢	$6,655,763	0.132 ¢	$7,639,658
Distribution Charge								
Basic Charge Single Family, per month	5,114,835	5,114,835	4,928,360	bill	$11.00	$54,211,960	$16.00	$78,853,760
Basic Charge Multi Family, per month	1,281,323	1,281,323	1,234,609	bill	$8.00	$9,876,872	$9.00	$11,111,481
Total Bills	6,396,158	6,396,158	6,162,969	bill				
Add'l Basic Charge 3 phase, per month	2,881	2,881	2,881	bill	$0.00	$0	$9.00	$25,929
Three Phase Demand Charge, per kW demand	15,207	15,207	15,137	kW	$2.20	$33,301	$0.00	$0
Three Phase Minimum Demand Charge, per month	1,490	1,490	1,436	bill	$3.80	$5,457	$0.00	$0
Distribution Energy Charge, per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	4.307 ¢	$249,272,796	5.433 ¢	$314,441,398
Energy Charge - Schedule 200								
per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	2.810 ¢	$162,632,124	2.613 ¢	$151,230,512
Subtotal	6,110,468,412	5,814,272,066	5,787,620,059	kWh		$540,332,968		$616,201,585
Renewable Adjustment Clause (202), per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.019 ¢	$1,099,648	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.000 ¢	$0	0.404 ¢	$23,381,985
Subtotal						$541,432,616		$639,583,570
Schedule 201								
per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	4.227 ¢	$244,642,700	4.227 ¢	$244,642,700
Total	6,110,468,412	5,814,272,066	5,787,620,059	kWh		$786,075,316		$884,226,270
							Change	$98,150,954
Schedule No. 4 (Employee Discount)								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	13,425,928	13,425,928	13,364,385	kWh	0.919 ¢	$122,819	0.844 ¢	$112,795
System Usage Charge								
Sch 200 related, per kWh	13,425,928	13,425,928	13,364,385	kWh	0.077 ¢	$10,291	0.070 ¢	$9,355
T&A and Sch 201 related, per kWh	13,425,928	13,425,928	13,364,385	kWh	0.115 ¢	$15,369	0.132 ¢	$17,641
Distribution Charge								
Basic Charge Single Family, per month	10,403	10,403	10,024	bill	$11.00	$110,264	$16.00	$160,384
Basic Charge Multi Family, per month	388	388	374	bill	$8.00	$2,992	$9.00	$3,366
Total Bills	10,791	10,791	10,398	bill				
Three Phase Demand Charge, per kW demand	0	0	0	kW	$2.20	$0	$0.00	$0
Three Phase Minimum Demand Charge, per month	0	0	0	bill	$3.80	$0	$0.00	$0
Distribution Energy Charge, per kWh	13,425,928	13,425,928	13,364,385	kWh	4.307 ¢	$575,604	5.433 ¢	$726,087
Energy Charge - Schedule 200								
per kWh	13,425,928	13,425,928	13,364,385	kWh	2.810 ¢	$375,539	2.613 ¢	$349,211
Subtotal	13,425,928	13,425,928	13,364,385	kWh		$1,212,878		$1,378,839
Renewable Adjustment Clause (202), per kWh	13,425,928	13,425,928	13,364,385	kWh	0.019 ¢	$2,539	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	13,425,928	13,425,928	13,364,385	kWh	0.000 ¢	$0	0.404 ¢	$53,992
Subtotal						$1,215,417		$1,432,831
Schedule 201								
per kWh	13,425,928	13,425,928	13,364,385	kWh	4.227 ¢	$564,913	4.227 ¢	$564,913
Total	13,425,928	13,425,928	13,364,385	kWh		$1,780,330		$1,997,744
Schedule 80 Employee Discount						$0		($13,498)
Schedule 201 Employee Discount						($141,228)		($141,228)
Total Employee Discount						($445,083)		($499,436)
							Change	($54,353)

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Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.780 ¢	$9,049,990	1.042 ¢	$12,089,859
System Usage Charge								
Sch 200 related, per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.073 ¢	$846,986	0.064 ¢	$742,563
T&A and Sch 201 related, per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.106 ¢	$1,229,870	0.128 ¢	$1,485,127
Distribution Charge								
Basic Charge								
Single Phase, per month	787,771	787,771	789,568	bill	$17.35	$13,699,005	$22.10	$17,449,453
Three Phase, per month	247,366	247,366	247,001	bill	$25.90	$6,397,326	$32.95	$8,138,683
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	1,174,160	1,174,160	1,136,126	kW	$1.65	$1,874,608	$2.10	$2,385,865
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	575,803	575,803	557,113	kW	$5.40	$3,008,410	$6.87	$3,827,366
Reactive Power Charge, per kvar	214,425	214,425	206,864	kvar	65.00 ¢	$134,462	65.00 ¢	$134,462
Distribution Energy Charge, per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	3.989 ¢	$46,282,579	5.080 ¢	$58,940,963
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	960,906,746	938,853,746	909,353,739	kWh	2.804 ¢	$25,498,279	2.610 ¢	$23,734,133
All additional kWh, per kWh	265,181,862	259,545,643	250,901,447	kWh	2.082 ¢	$5,223,768	1.938 ¢	$4,862,470
Subtotal	1,226,088,608	1,198,399,389	1,160,255,186	kWh		$113,245,283		$133,790,944
Renewable Adjustment Clause (202), per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.018 ¢	$208,846	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.000 ¢	$0	0.421 ¢	$4,884,674
Subtotal						$113,454,129		$138,675,618
Schedule 201								
1st 3,000 kWh, per kWh	960,906,746	938,853,746	909,353,739	kWh	4.218 ¢	$38,356,541	4.218 ¢	$38,356,541
All additional kWh, per kWh	265,181,862	259,545,643	250,901,447	kWh	3.127 ¢	$7,845,688	3.127 ¢	$7,845,688
Total	1,226,088,608	1,198,399,389	1,160,255,186	kWh		$159,656,358		$184,877,847
							Change	$25,221,489

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	1,955,057	1,955,057	1,877,049	kWh	0.768 ¢	$14,416	1.026 ¢	$19,259
System Usage Charge								
Sch 200 related, per kWh	1,955,057	1,955,057	1,877,049	kWh	0.072 ¢	$1,351	0.063 ¢	$1,183
T&A and Sch 201 related, per kWh	1,955,057	1,955,057	1,877,049	kWh	0.104 ¢	$1,952	0.126 ¢	$2,365
Distribution Charge								
Basic Charge								
Single Phase, per month	211	211	211	bill	$17.35	$3,661	$22.10	$4,663
Three Phase, per month	393	393	392	bill	$25.90	$10,153	$32.95	$12,916
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	2,381	2,381	2,278	kW	$1.65	$3,759	$2.10	$4,784
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	1,316	1,316	1,255	kW	$5.33	$6,689	$6.78	$8,509
Reactive Power Charge, per kvar	1,721	1,721	1,654	kvar	60.00 ¢	$992	60.00 ¢	$992
Distribution Energy Charge, per kWh	1,955,057	1,955,057	1,877,049	kWh	3.927 ¢	$73,712	5.001 ¢	$93,871
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	1,057,095	1,057,095	1,018,579	kWh	2.761 ¢	$28,123	2.570 ¢	$26,177
All additional kWh, per kWh	897,962	897,962	858,470	kWh	2.050 ¢	$17,599	1.908 ¢	$16,380
Subtotal	1,955,057	1,955,057	1,877,049	kWh		$162,407		$191,099
Renewable Adjustment Clause (202), per kWh	1,955,057	1,955,057	1,877,049	kWh	0.018 ¢	$338	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,955,057	1,955,057	1,877,049	kWh	0.000 ¢	$0	0.421 ¢	$7,902
Subtotal						$162,745		$199,001
Schedule 201								
1st 3,000 kWh, per kWh	1,057,095	1,057,095	1,018,579	kWh	4.090 ¢	$41,660	4.090 ¢	$41,660
All additional kWh, per kWh	897,962	897,962	858,470	kWh	3.033 ¢	$26,037	3.033 ¢	$26,037
Total	1,955,057	1,955,057	1,877,049	kWh		$230,442		$266,698
							Change	$36,256

PACIFIC POWER
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Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	8,582,972	8,582,972	8,570,763	kW	$2.13	$18,255,725	$1.74	$14,913,128
System Usage Charge								
Sch 200 related, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.072 ¢	$1,471,148	0.067 ¢	$1,368,985
T&A and Sch 201 related, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.104 ¢	$2,124,992	0.126 ¢	$2,574,509
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	58,094	58,094	59,242	bill	$18.00	$1,066,356	$25.00	$1,481,050
Load Size 51-100 kW, per month	42,437	42,437	43,244	bill	$34.00	$1,470,296	$47.00	$2,032,468
Load Size 101-300 kW, per month	23,536	23,536	23,972	bill	$81.00	$1,941,732	$111.00	$2,660,892
Load Size > 300 kW, per month	719	719	733	bill	$114.00	$83,562	$156.00	$114,348
Load Size Charge								
≤ 50 kW, per kW	2,240,586	2,240,586	2,240,880	kW	$1.15	$2,577,012	$1.60	$3,585,408
51-100 kW, per kW	2,980,722	2,980,722	2,975,675	kW	$0.90	$2,678,108	$1.25	$3,719,594
101-300 kW, per kW	3,587,692	3,587,692	3,579,714	kW	$0.55	$1,968,843	$0.75	$2,684,786
>300 kW, per kW	314,004	314,004	313,436	kW	$0.35	$109,703	$0.50	$156,718
Demand Charge, per kW	8,582,972	8,582,972	8,570,763	kW	$3.87	$33,168,853	$5.31	$45,510,752
Reactive Power Charge, per kvar	612,785	612,785	606,848	kvar	65.00 ¢	$394,451	65.00 ¢	$394,451
Distribution Energy Charge, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.392 ¢	$8,009,585	0.536 ¢	$10,951,882
Energy Charge - Schedule 200								
All kWh, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	2.615 ¢	$53,431,288	2.445 ¢	$49,957,743
Subtotal	2,085,565,751	2,044,568,075	2,043,261,478	kWh		$128,751,654		$142,106,714
Renewable Adjustment Clause (202), per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.018 ¢	$367,787	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.000 ¢	$0	0.296 ¢	$6,048,054
Subtotal						$129,119,441		$148,154,768
Schedule 201								
All kWh, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	3.932 ¢	$80,341,041	3.932 ¢	$80,341,041
Total	2,085,565,751	2,044,568,075	2,043,261,478	kWh		$209,460,482		$228,495,809
							Change	$19,035,327
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	70,611	70,611	69,598	kW	$1.67	$116,229	$2.13	$148,244
System Usage Charge								
Sch 200 related, per kWh	21,808,533	21,808,533	21,450,524	kWh	0.070 ¢	$15,015	0.060 ¢	$12,870
T&A and Sch 201 related, per kWh	21,808,533	21,808,533	21,450,524	kWh	0.102 ¢	$21,880	0.111 ¢	$23,810
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	122	122	124	bill	$18.00	$2,232	$35.00	$4,340
Load Size 51-100 kW, per month	193	193	194	bill	$31.00	$6,014	$60.00	$11,640
Load Size 101-300 kW, per month	339	339	344	bill	$71.00	$24,424	$138.00	$47,472
Load Size > 300 kW, per month	48	48	48	bill	$101.00	$4,848	$197.00	$9,456
Load Size Charge								
≤ 50 kW, per kW	4,691	4,691	4,657	kW	$1.00	$4,657	$1.95	$9,081
51-100 kW, per kW	14,503	14,503	14,170	kW	$0.80	$11,336	$1.55	$21,964
101-300 kW, per kW	63,140	63,140	62,442	kW	$0.50	$31,221	$0.95	$59,320
>300 kW, per kW	21,330	21,330	20,680	kW	$0.25	$5,170	$0.50	$10,340
Demand Charge, per kW	70,611	70,611	69,598	kW	$3.48	$242,201	$6.78	$471,874
Reactive Power Charge, per kvar	7,845	7,845	7,699	kvar	60.00 ¢	$4,619	60.00 ¢	$4,619
Distribution Energy Charge, per kWh	21,808,533	21,808,533	21,450,524	kWh	0.038 ¢	$8,151	0.103 ¢	$22,094
Energy Charge - Schedule 200								
All kWh, per kWh	21,808,533	21,808,533	21,450,524	kWh	2.554 ¢	$547,846	2.371 ¢	$508,592
Subtotal	21,808,533	21,808,533	21,450,524	kWh		$1,045,843		$1,365,716
Renewable Adjustment Clause (202), per kWh	21,808,533	21,808,533	21,450,524	kWh	0.018 ¢	$3,861	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	21,808,533	21,808,533	21,450,524	kWh	0.000 ¢	$0	0.296 ¢	$63,494
Subtotal						$1,049,704		$1,429,210
Schedule 201								
All kWh, per kWh	21,808,533	21,808,533	21,450,524	kWh	3.842 ¢	$824,129	3.842 ¢	$824,129
Total	21,808,533	21,808,533	21,450,524	kWh		$1,873,833		$2,253,339
							Change	$379,506

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Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,518,544	3,518,544	3,582,710	kW	$2.52	$9,028,429	$2.45	$8,777,640
System Usage Charge								
Sch 200 related, per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.070 ¢	$876,732	0.065 ¢	$814,108
T&A and Sch 201 related, per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.101 ¢	$1,264,999	0.121 ¢	$1,515,494
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	158	158	159	bill	$436.00	$69,324	$704.00	$111,936
Load Size 201-300 kW, per month	2,505	2,505	2,529	bill	$126.00	$318,654	$204.00	$515,916
Load Size > 300 kW, per month	6,922	6,922	6,990	bill	$334.00	$2,334,660	$541.00	$3,781,590
Load Size Charge								
≤ 200 Kw, per kW					No Charge	$0	No Charge	$0
201-300 kW, per kW	651,402	651,402	665,587	kW	$1.55	$1,031,660	$2.50	$1,663,968
>300 kW, per kW	3,510,622	3,510,622	3,575,964	kW	$0.75	$2,681,973	$1.20	$4,291,157
Demand Charge, per kW	3,518,544	3,518,544	3,582,710	kW	$3.66	$13,112,719	$5.92	$21,209,643
Reactive Power Charge, per kvar	593,103	593,103	593,199	kvar	65.00 ¢	$385,579	65.00 ¢	$385,579
Energy Charge - Schedule 200								
Demand Charge, per kW	3,518,544	3,518,544	3,582,710	kW	$5.80	$20,779,718	$5.39	$19,310,807
All kWh, per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.930 ¢	$11,648,008	0.888 ¢	$11,121,969
Subtotal	1,249,187,259	1,226,112,463	1,252,474,015	kWh		$63,532,455		$73,499,807
Renewable Adjustment Clause (202), per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.018 ¢	$225,445	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.000 ¢	$0	0.264 ¢	$3,306,531
Subtotal						$63,757,900		$76,806,338
Schedule 201								
All kWh, per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	3.856 ¢	$48,295,398	3.856 ¢	$48,295,398
Total	1,249,187,259	1,226,112,463	1,252,474,015	kWh		$112,053,298		$125,101,736
							Change	$13,048,438
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	224,316	224,316	227,103	kW	$2.55	$579,113	$2.29	$520,066
System Usage Charge								
Sch 200 related, per kWh	76,532,211	76,532,211	77,804,770	kWh	0.070 ¢	$54,463	0.065 ¢	$50,573
T&A and Sch 201 related, per kWh	76,532,211	76,532,211	77,804,770	kWh	0.102 ¢	$79,361	0.121 ¢	$94,144
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	0	0	0	bill	$409.00	$0	$642.00	$0.00
Load Size 201-300 kW, per month	48	48	48	bill	$129.00	$6,192	$202.00	$9,696.00
Load Size > 300 kW, per month	438	438	443	bill	$337.00	$149,291	$527.00	$233,461.00
Load Size Charge								
≤ 200 Kw, per kW					No Charge		No Charge	
201-300 kW, per kW	12,560	12,560	12,952	kW	$1.40	$18,133	$2.20	$28,494
>300 kW, per kW	254,858	254,858	258,240	kW	$0.70	$180,768	$1.10	$284,064
Demand Charge, per kW	224,316	224,316	227,103	kW	$3.57	$810,758	$5.59	$1,269,506
Reactive Power Charge, per kvar	36,888	36,888	35,946	kvar	60.00 ¢	$21,568	60.00 ¢	$21,568
Energy Charge - Schedule 200								
Demand Charge, per kW	224,316	224,316	227,103	kW	$5.80	$1,317,197	$5.24	$1,190,020
All kWh, per kWh	76,532,211	76,532,211	77,804,770	kWh	0.898 ¢	$698,687	0.826 ¢	$642,667
Subtotal	76,532,211	76,532,211	77,804,770	kWh		$3,915,531		$4,344,259
Renewable Adjustment Clause (202), per kWh	76,532,211	76,532,211	77,804,770	kWh	0.018 ¢	$14,005	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	76,532,211	76,532,211	77,804,770	kWh	0.000 ¢	$0	0.264 ¢	$205,405
Subtotal						$3,929,536		$4,549,664
Schedule 201								
All kWh, per kWh	76,532,211	76,532,211	77,804,770	kWh	3.843 ¢	$2,990,037	3.843 ¢	$2,990,037
Total	76,532,211	76,532,211	77,804,770	kWh		$6,919,573		$7,539,701
							Change	$620,128

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	196,326,232	171,439,514	234,909,530	kWh	0.677 ¢	$1,590,338	0.660 ¢	$1,550,403
System Usage Charge								
Sch 200 related, per kWh	196,326,232	171,439,514	234,909,530	kWh	0.069 ¢	$162,088	0.058 ¢	$136,248
T&A and Sch 201 related, per kWh	196,326,232	171,439,514	234,909,530	kWh	0.099 ¢	$232,560	0.107 ¢	$251,353
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	5,221	5,221	5,155	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	910	910	899	bill	$410.00	$368,590	$580.00	$521,420
Three Phase Load Size > 300 kW, per customer	19	19	19	bill	$1,620.00	$30,780	$2,300.00	$43,700
Total Annual Bills	6,150	6,150	6,073					
Average Customers	7,984	7,984	7,884					
Monthly Bills	40,234	40,234	39,729					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	85,192	85,192	116,732	kW	$17.10	$1,996,117	$24.20	$2,824,914
Three Phase Load Size 51-300 kW, per kW	81,745	81,745	112,008	kW	$11.70	$1,310,494	$16.60	$1,859,333
Three Phase Load Size > 300 kW, per kW	8,090	8,090	11,085	kW	$7.20	$79,812	$10.20	$113,067
Single Phase, Minimum Charge	408	408	403	bill	$75.00	$30,225	$105.00	$42,315
Three Phase, Minimum Charge	1,756	1,756	1,734	bill	$120.00	$208,080	$170.00	$294,780
Distribution Energy Charge, per kWh	196,326,232	171,439,514	234,909,530	kWh	4.950 ¢	$11,628,022	7.049 ¢	$16,558,773
Reactive Power Charge, per kvar	170,466	170,466	233,576	kvar	65.00 ¢	$151,824	65.00 ¢	$151,824
Energy Charge - Schedule 200								
All kWh, per kWh	196,326,232	171,439,514	234,909,530	kWh	2.526 ¢	$5,933,815	2.346 ¢	$5,510,978
Subtotal	196,326,232	171,439,514	234,909,530	kWh		$23,722,745		$29,859,108
Renewable Adjustment Clause (202), per kWh	196,326,232	171,439,514	234,909,530	kWh	0.017 ¢	$39,935	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	196,326,232	171,439,514	234,909,530	kWh	0.000 ¢	$0	0.449 ¢	$1,054,744
Subtotal						$23,762,680		$30,913,852
Schedule 201								
All kWh, per kWh	196,326,232	171,439,514	234,909,530	kWh	3.799 ¢	$8,924,213	3.799 ¢	$8,924,213
Option A Summer On Peak Adder, per On-peak kWh	0	0	11,109,862	kWh	4.989 ¢	$0	12.030 ¢	$1,336,516
Option B Summer On Peak Adder, per On-peak kWh	0	0	11,082,022	kWh	4.989 ¢	$0	12.030 ¢	$1,333,167
Summer Off Peak Adder, per Off-peak kWh	0	0	99,032,240	kWh	-0.992 ¢	$0	-2.696 ¢	($2,669,909)
Total	196,326,232	171,439,514	234,909,530	kWh		$32,686,893		$39,837,839
							Change	$7,150,946

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	0	0	0	kWh	0.667 ¢	$0	0.650 ¢	$0
System Usage Charge								
Sch 200 related, per kWh	0	0	0	kWh	0.068 ¢	$0	0.057 ¢	$0
T&A and Sch 201 related, per kWh	0	0	0	kWh	0.097 ¢	$0	0.105 ¢	$0
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	0	0	0	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	0	0	0	bill	$400.00	$0	$570.00	$0
Three Phase Load Size > 300 kW, per customer	0	0	0	bill	$1,600.00	$0	$2,270.00	$0
Total Annual Bills	0	0	0					
Average Customers	0	0	0					
Monthly Bills	0	0	0					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	0	0	0	kW	$16.90	$0	$23.90	$0
Three Phase Load Size 51-300 kW, per kW	0	0	0	kW	$11.50	$0	$16.40	$0
Three Phase Load Size > 300 kW, per kW	0	0	0	kW	$7.10	$0	$10.10	$0
Single Phase, Minimum Charge	0	0	0	bill	$75.00	$0	$105.00	$0
Three Phase, Minimum Charge	0	0	0	bill	$120.00	$0	$170.00	$0
Distribution Energy Charge, per kWh	0	0	0	kWh	4.873 ¢	$0	6.940 ¢	$0
Reactive Power Charge, per kvar	0	0	0	kvar	60.00 ¢	$0	60.00 ¢	$0
Energy Charge - Schedule 200								
All kWh, per kWh	0	0	0	kWh	2.487 ¢	$0	2.310 ¢	$0
Subtotal	0	0	0	kWh		$0		$0
Renewable Adjustment Clause (202), per kWh	0	0	0	kWh	0.017 ¢	$0	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	0	0	0	kWh	0.000 ¢	$0	0.449 ¢	$0
Subtotal						$0		$0
Schedule 201								
All kWh, per kWh	0	0	0	kWh	3.739 ¢	$0	3.739 ¢	$0
Option A Summer On Peak Adder, per On-peak kWh	0	0	0	kWh	4.989 ¢	$0	12.030 ¢	$0
Option B Summer On Peak Adder, per On-peak kWh	0	0	0	kWh	4.989 ¢	$0	12.030 ¢	$0
Summer Off Peak Adder, per Off-peak kWh	0	0	0	kWh	-0.992 ¢	$0	-2.696 ¢	$0
Total	0	0	0	kWh		$0		$0
							Change	$0

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	166,370	166,370	158,737	kW	$2.45	$388,906	$2.73	$433,352
credit per kW of on-peak demand (OATT)	0	0	0	kW	($2.45)	$0	($2.73)	$0
System Usage Charge								
Sch 200 related, per kWh	34,535,247	34,535,247	32,950,858	kWh	0.067 ¢	$22,077	0.061 ¢	$20,100
T&A and Sch 201 related, per kWh	34,535,247	34,535,247	32,950,858	kWh	0.096 ¢	$31,633	0.113 ¢	$37,234
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$570.00	$0	$1,160.00	$0
Facility Capacity > 4,000 kW, per month	24	24	24	bill	$1,570.00	$37,680	$3,190.00	$76,560
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.25	$0	$1.35	$0
Facility Capacity > 4,000 kW, per kW	238,892	238,892	227,932	kW	$0.50	$113,966	$0.55	$125,363
Demand Charge, per kW of on-peak demand	166,370	166,370	158,737	kW	$3.46	$549,230	$7.95	$1,261,959
Reactive Power Charge, per kvar	1,829	1,829	1,745	kvar	60.00 ¢	$1,047	60.00 ¢	$1,047
Reactive Hours, per kvarh	5,840,000	5,840,000	5,572,076	kvarh	0.080 ¢	$4,458	0.080 ¢	$4,458
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	238,892	238,892	227,932	kW	$0.27	$61,542	$0.27	$61,542
Supplemental Reserves, per kW of Facility Cap.	238,892	238,892	227,932	kW	$0.27	$61,542	$0.27	$61,542
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	166,370	166,370	158,737	kW	$1.65	$261,916	$1.52	$241,280
On-Peak, per on-peak kWh	13,996,483	13,996,483	13,354,360	kWh	2.156 ¢	$287,920	1.991 ¢	$265,885
Off-Peak, per off-peak kWh	20,538,764	20,538,764	19,596,498	kWh	2.156 ¢	$422,500	1.991 ¢	$390,166
Unscheduled Energy, per kWh	4,037,353	4,037,353	3,852,130	kWh		$372,143		$372,143
Subtotal	38,572,600	38,572,600	36,802,988	kWh		$2,616,560		$3,352,631
Renewable Adjustment Clause (202), per kWh	38,572,600	38,572,600	36,802,988	kWh	0.017 ¢	$6,257	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	38,572,600	38,572,600	36,802,988	kWh	0.000 ¢	$0	0.225 ¢	$82,807
Subtotal						$2,622,817		$3,435,438
Schedule 201								
On-Peak, per on-peak kWh	13,996,483	13,996,483	13,354,360	kWh	4.500 ¢	$600,946	4.500 ¢	$600,946
Off-Peak, per off-peak kWh	20,538,764	20,538,764	19,596,498	kWh	3.195 ¢	$626,108	3.195 ¢	$626,108
Total	38,572,600	38,572,600	36,802,988	kWh		$3,849,871		$4,662,492
							Change	$812,621

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	69,839	69,839	57,787	kW	$3.11	$179,718	$3.13	$180,873
credit per kW of on-peak demand (OATT)	0	0	0	kW	($3.11)	$0	($3.13)	$0
System Usage Charge								
Sch 200 related, per kWh	6,633,968	6,633,968	6,144,492	kWh	0.065 ¢	$3,994	0.059 ¢	$3,625
T&A and Sch 201 related, per kWh	6,633,968	6,633,968	6,144,492	kWh	0.091 ¢	$5,591	0.109 ¢	$6,697
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	24	24	24	bill	$710.00	$17,040	$1,770.00	$42,480
Facility Capacity > 4,000 kW, per month	24	24	24	bill	$1,820.00	$43,680	$4,550.00	$109,200
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	29,508	29,508	28,154	kW	$1.25	$35,193	$1.35	$38,008
Facility Capacity > 4,000 kW, per kW	201,492	201,492	168,755	kW	$1.05	$177,193	$1.15	$194,068
Demand Charge, per kW of on-peak demand	69,839	69,839	57,787	kW	$1.85	$106,906	$6.21	$358,857
Reactive Power Charge, per kvar	42,521	42,521	33,459	kvar	55.00 ¢	$18,402	55.00 ¢	$18,402
Reactive Hours, per kvarh	5,610,565	5,610,565	4,314,591	kvarh	0.080 ¢	$3,452	0.080 ¢	$3,452
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	231,000	231,000	196,909	kW	$0.27	$53,165	$0.27	$53,165
Supplemental Reserves, per kW of Facility Cap.	231,000	231,000	196,909	kW	$0.27	$53,165	$0.27	$53,165
Spinning Reserves Credit, per kW of Facility Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Supplemental Reserves Credit, per kW Facil. Cap.	0	0	0	kW	($0.27)	$0	($0.27)	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	69,839	69,839	57,787	kW	$1.68	$97,082	$1.54	$88,992
On-Peak, per on-peak kWh	2,353,417	2,353,417	2,171,379	kWh	2.077 ¢	$45,100	1.908 ¢	$41,430
Off-Peak, per off-peak kWh	4,280,551	4,280,551	3,973,113	kWh	2.077 ¢	$82,522	1.908 ¢	$75,807
Unscheduled Energy, per kWh	463,281	463,281	431,196	kWh		$60,119		$60,119
Subtotal	7,097,249	7,097,249	6,575,688	kWh		$982,322		$1,328,340
Renewable Adjustment Clause (202), per kWh	7,097,249	7,097,249	6,575,688	kWh	0.017 ¢	$1,118	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	7,097,249	7,097,249	6,575,688	kWh	0.000 ¢	$0	0.225 ¢	$14,795
Subtotal						$983,440		$1,343,135
Schedule 201								
On-Peak, per on-peak kWh	2,353,417	2,353,417	2,171,379	kWh	4.358 ¢	$94,629	4.358 ¢	$94,629
Off-Peak, per off-peak kWh	4,280,551	4,280,551	3,973,113	kWh	3.031 ¢	$120,425	3.031 ¢	$120,425
Total	7,097,249	7,097,249	6,575,688	kWh		$1,198,494		$1,558,189
							Change	$359,695

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 76R/776R								
Large General Service/Partial Requirements Service - Economic Replacement Power Rider								
Transmission & Ancillary Services Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.087	$0	$0.081	$0
Primary	0	0	0	kW	$0.095	$0	$0.106	$0
Transmission	0	0	0	kW	$0.121	$0	$0.122	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.128	$0	$0.250	$0
Primary	0	0	0	kW	$0.135	$0	$0.310	$0
Transmission	0	0	0	kW	$0.072	$0	$0.242	$0

PACIFIC POWER
State of Oregon
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Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,357,579	1,357,579	1,456,129	kW	$2.78	$4,048,039	$2.61	$3,800,497
System Usage Charge								
Sch 200 related, per kWh	571,527,962	534,576,675	570,907,617	kWh	0.070 ¢	$399,635	0.066 ¢	$376,799
T&A and Sch 201 related, per kWh	571,527,962	534,576,675	570,907,617	kWh	0.100 ¢	$570,908	0.122 ¢	$696,507
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	967	967	979	bill	$580.00	$567,820	$820.00	$802,780
Facility Capacity > 4,000 kW, per month	47	47	48	bill	$1,600.00	$76,800	$2,260.00	$108,480
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,366,564	1,366,564	1,474,868	kW	$2.95	$4,350,861	$2.60	$3,834,657
Facility Capacity > 4,000 kW, per kW	321,484	321,484	351,447	kW	$1.15	$404,164	$1.00	$351,447
Demand Charge, per kW of on-peak demand	1,357,579	1,357,579	1,456,129	kW	$3.28	$4,776,103	$6.42	$9,348,348
Reactive Power Charge, per kvar	357,661	357,661	367,191	kvar	65.00 ¢	$238,674	65.00 ¢	$238,674
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,357,579	1,357,579	1,456,129	kW	$1.57	$2,286,123	$1.45	$2,111,387
On-Peak, per on-peak kWh	218,180,840	203,881,840	218,085,760	kWh	2.154 ¢	$4,697,567	1.989 ¢	$4,337,726
Off-Peak, per off-peak kWh	353,347,122	330,694,835	352,821,857	kWh	2.154 ¢	$7,599,783	1.989 ¢	$7,017,627
Subtotal	571,527,962	534,576,675	570,907,617	kWh		$30,016,477		$33,024,929
Renewable Adjustment Clause (202), per kWh	571,527,962	534,576,675	570,907,617	kWh	0.017 ¢	$97,054	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	571,527,962	534,576,675	570,907,617	kWh	0.000 ¢	$0	0.225 ¢	$1,284,542
Subtotal						$30,113,531		$34,309,471
Schedule 201								
On-Peak, per on-peak kWh	218,180,840	203,881,840	218,085,760	kWh	4.625 ¢	$10,086,466	4.625 ¢	$10,086,466
Off-Peak, per off-peak kWh	353,347,122	330,694,835	352,821,857	kWh	3.333 ¢	$11,759,552	3.333 ¢	$11,759,552
Total	571,527,962	534,576,675	570,907,617	kWh		$51,959,549		$56,155,489
							Change	$4,195,940

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	2,868,329	2,868,329	4,143,758	kW	$2.99	$12,389,836	$3.27	$13,550,089
System Usage Charge								
Sch 200 related, per kWh	1,349,307,157	1,346,524,569	2,171,322,968	kWh	0.067 ¢	$1,454,786	0.061 ¢	$1,324,507
T&A and Sch 201 related, per kWh	1,349,307,157	1,346,524,569	2,171,322,968	kWh	0.096 ¢	$2,084,470	0.113 ¢	$2,453,595
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	692	692	701	bill	$570.00	$399,570	$1,160.00	$813,160
Facility Capacity > 4,000 kW, per month	294	294	305	bill	$1,570.00	$478,850	$3,190.00	$972,950
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,405,842	1,405,842	1,520,080	kW	$1.25	$1,900,100	$1.35	$2,052,108
Facility Capacity > 4,000 kW, per kW	2,137,522	2,137,522	3,334,729	kW	$0.50	$1,667,365	$0.55	$1,834,101
Demand Charge, per kW of on-peak demand	2,868,329	2,868,329	4,143,758	kW	$3.46	$14,337,403	$7.95	$32,942,876
Reactive Power Charge, per kvar	649,927	649,927	644,775	kvar	60.00 ¢	$386,865	60.00 ¢	$386,865
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	2,868,329	2,868,329	4,143,758	kW	$1.65	$6,837,201	$1.52	$6,298,512
On-Peak, per on-peak kWh	513,849,467	512,824,467	822,791,267	kWh	2.156 ¢	$17,739,380	1.991 ¢	$16,381,774
Off-Peak, per off-peak kWh	835,457,690	833,700,102	1,348,531,701	kWh	2.156 ¢	$29,074,343	1.991 ¢	$26,849,266
Subtotal	1,349,307,157	1,346,524,569	2,171,322,968	kWh		$88,750,169		$105,859,803
Renewable Adjustment Clause (202), per kWh	1,349,307,157	1,346,524,569	2,171,322,968	kWh	0.017 ¢	$369,125	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,349,307,157	1,346,524,569	2,171,322,968	kWh	0.000 ¢	$0	0.225 ¢	$4,885,477
Subtotal						$89,119,294		$110,745,280
Schedule 201								
On-Peak, per on-peak kWh	513,849,467	512,824,467	822,791,267	kWh	4.500 ¢	$37,025,607	4.500 ¢	$37,025,607
Off-Peak, per off-peak kWh	835,457,690	833,700,102	1,348,531,701	kWh	3.195 ¢	$43,085,588	3.195 ¢	$43,085,588
Total	1,349,307,157	1,346,524,569	2,171,322,968	kWh		$169,230,489		$190,856,475
							Change	$21,625,986

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,765,230	1,765,230	2,942,058	kW	$3.65	$10,738,512	$3.67	$10,797,353
System Usage Charge								
Sch 200 related, per kWh	1,156,897,000	1,156,897,000	1,934,879,950	kWh	0.065 ¢	$1,257,672	0.059 ¢	$1,141,579
T&A and Sch 201 related, per kWh	1,156,897,000	1,156,897,000	1,934,879,950	kWh	0.091 ¢	$1,760,741	0.109 ¢	$2,109,019
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	23	23	24	bill	$710.00	$17,040	$1,770.00	$42,480
Facility Capacity > 4,000 kW, per month	60	60	60	bill	$1,820.00	$109,200	$4,550.00	$273,000
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	22,357	22,357	26,522	kW	$1.25	$33,153	$1.35	$35,805
Facility Capacity > 4,000 kW, per kW	1,855,595	1,855,595	3,095,875	kW	$1.05	$3,250,669	$1.15	$3,560,256
Demand Charge, per kW of on-peak demand	1,765,230	1,765,230	2,942,058	kW	$1.85	$5,442,807	$6.21	$18,270,180
Reactive Power Charge, per kvar	45,999	45,999	54,046	kvar	55.00 ¢	$29,725	55.00 ¢	$29,725
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,765,230	1,765,230	2,942,058	kW	$1.68	$4,942,657	$1.54	$4,530,769
On-Peak, per on-peak kWh	433,489,000	433,489,000	725,013,625	kWh	2.077 ¢	$15,058,533	1.908 ¢	$13,833,260
Off-Peak, per off-peak kWh	723,408,000	723,408,000	1,209,866,325	kWh	2.077 ¢	$25,128,924	1.908 ¢	$23,084,249
Subtotal	1,156,897,000	1,156,897,000	1,934,879,950	kWh		$67,769,633		$77,707,675
Renewable Adjustment Clause (202), per kWh	1,156,897,000	1,156,897,000	1,934,879,950	kWh	0.017 ¢	$328,930	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,156,897,000	1,156,897,000	1,934,879,950	kWh	0.000 ¢	$0	0.225 ¢	$4,353,480
Subtotal						$68,098,563		$82,061,155
Schedule 201								
On-Peak, per on-peak kWh	433,489,000	433,489,000	725,013,625	kWh	4.358 ¢	$31,596,094	4.358 ¢	$31,596,094
Off-Peak, per off-peak kWh	723,408,000	723,408,000	1,209,866,325	kWh	3.031 ¢	$36,671,048	3.031 ¢	$36,671,048
Total	1,156,897,000	1,156,897,000	1,934,879,950	kWh		$136,365,705		$150,328,297
							Change	$13,962,592

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 848 - Commercial								
Distribution Only Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand				kW				
System Usage Charge								
Sch 200 related, per kWh				kWh				
T&A and Sch 201 related, per kWh				kWh				
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$710.00	$0	$1,770.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$1,820.00	$21,840	$4,550.00	$54,600
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.25	$0	$1.35	$0
Facility Capacity > 4,000 kW, per kW	396,113	396,113	524,299	kW	$1.05	$550,514	$1.15	$602,944
Demand Charge, per kW of on-peak demand	385,893	385,893	510,772	kW	$1.85	$944,928	$6.21	$3,171,894
Reactive Power Charge, per kvar	0	0	0	kvar	55.00 ¢	$0	55.00 ¢	$0
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand				kW				
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Subtotal				kWh		$1,517,282		$3,829,438
Renewable Adjustment Clause (202), per kWh								
Insurance Premium Adder- Base (80), per kWh	*269,239,000*	*269,239,000*	*335,577,000*	kWh	0.000 ¢	$0	0.225 ¢	$755,048
Subtotal						$1,517,282		$4,584,486
Schedule 201								
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Total				kWh		$1,517,282		$4,584,486
Energy Delivered	269,239,000	269,239,000	335,577,000				Change	$3,067,204
Schedule No. 15 - Composite								
Outdoor Area Lighting Service								
No. of Customers	5,991	5,991	5,833					
Transmission & Ancillary Services Charge								
per kWh	8,258,382	8,258,382	8,156,574	kWh	0.066 ¢	$5,394	0.051 ¢	$4,193
System Usage Charge								
Sch 200 related, per kWh	8,258,382	8,258,382	8,156,574	kWh	0.026 ¢	$2,143	0.024 ¢	$1,928
T&A and Sch 201 related, per kWh	8,258,382	8,258,382	8,156,574	kWh	0.029 ¢	$2,357	0.032 ¢	$2,572
Distribution Charge								
Distribution Charge, per kWh	8,258,382	8,258,382	8,156,574	kWh	7.857 ¢	$638,246	8.948 ¢	$729,845
Energy Charge - Schedule 200								
per kWh	8,258,382	8,258,382	8,156,574	kWh	0.962 ¢	$78,307	0.742 ¢	$60,540
Subtotal	8,258,382	8,258,382	8,156,574	kWh		$726,447		$799,077
Renewable Adjustment Clause (202), per kWh	8,258,382	8,258,382	8,156,574	kWh	0.014 ¢	$1,142	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	2,159,285	2,159,285	2,127,947	kWh	0.000 ¢	$0	0.630 ¢	$13,406
Subtotal						$727,589		$812,483
Schedule 201								
per kWh	8,258,382	8,258,382	8,156,574	kWh	1.374 ¢	$111,792	1.371 ¢	$111,792
Total	8,258,382	8,258,382	8,156,574	kWh		$839,381		$924,275
							Change	$84,894
Schedule No. 51/751								
Street Lighting Service, Company-Owned System								
No. of Customers	1,194	1,194	1,210					
Transmission & Ancillary Services Charge								
per kWh	23,584,283	23,584,283	20,858,198	kWh	0.084 ¢	$17,569	0.065 ¢	$13,487
System Usage Charge								
Sch 200 related, per kWh	23,584,283	23,584,283	20,858,198	kWh	0.032 ¢	$6,696	0.030 ¢	$6,355
T&A and Sch 201 related, per kWh	23,584,283	23,584,283	20,858,198	kWh	0.047 ¢	$9,836	0.047 ¢	$9,836
Distribution Charge								
Distribution Charge, per kWh	23,584,283	23,584,283	20,858,198	kWh	10.691 ¢	$2,229,901	12.262 ¢	$2,557,571
Energy Charge - Schedule 200								
per kWh	23,584,283	23,584,283	20,858,198	kWh	1.352 ¢	$281,955	1.020 ¢	$212,810
Subtotal	23,584,283	23,584,283	20,858,198	kWh		$2,545,957		$2,800,058
Renewable Adjustment Clause (202), per kWh	23,584,283	23,584,283	20,858,198	kWh	0.014 ¢	$2,920	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	8,930,279	8,930,279	7,898,066	kWh	0.000 ¢	$0	0.630 ¢	$49,758
Subtotal						$2,548,877		$2,849,816
Schedule 201								
per kWh	23,584,283	23,584,283	20,858,198	kWh	1.696 ¢	$353,820	1.696 ¢	$353,820
Total	0	0	20,858,198	kWh		$2,902,697		$3,203,636
							Change	$300,939

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 53/753								
Street Lighting Service, Consumer-Owned System								
No. of Customers	294	294	296					
Transmission & Ancillary Services Charge								
per kWh	8,075,045	8,075,045	8,821,260	kWh	0.029 ¢	$2,558	0.022 ¢	$1,941
System Usage Charge								
Sch 200 related, per kWh	8,075,045	8,075,045	8,821,260	kWh	0.012 ¢	$1,059	0.010 ¢	$882
T&A and Sch 201 related, per kWh	8,075,045	8,075,045	8,821,260	kWh	0.015 ¢	$1,323	0.016 ¢	$1,411
Distribution Charge								
Distribution Charge, per kWh	8,075,045	8,075,045	8,821,260	kWh	4.262 ¢	$324,469	4.212 ¢	$371,574
Energy Charge - Schedule 200								
per kWh	8,075,045	8,075,045	8,821,260	kWh	0.449 ¢	$39,607	0.349 ¢	$30,786
Subtotal	8,075,045	8,075,045	8,821,260	kWh		$369,016		$406,595
Renewable Adjustment Clause (202), per kWh	8,075,045	8,075,045	8,821,260	kWh	0.014 ¢	$1,235	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	8,075,045	8,075,045	8,821,260	kWh	0.000 ¢	$0	0.630 ¢	$55,574
Subtotal						$370,251		$462,169
Schedule 201								
per kWh	8,075,045	8,075,045	8,821,260	kWh	1.320 ¢	$116,441	1.320 ¢	$116,441
Total	8,075,045	8,075,045	8,821,260	kWh		$486,692		$578,609
							Change	$91,918
Schedule No. 54/754								
Recreational Field Lighting								
Transmission & Ancillary Services Charge								
per kWh	1,449,879	1,449,879	1,373,662	kWh	0.037 ¢	$508	0.028 ¢	$385
System Usage Charge								
Sch 200 related, per kWh	1,449,879	1,449,879	1,373,662	kWh	0.016 ¢	$220	0.012 ¢	$165
T&A and Sch 201 related, per kWh	1,449,879	1,449,879	1,373,662	kWh	0.020 ¢	$275	0.020 ¢	$275
Distribution Charge								
Basic Charge, Single Phase, per month	759	759	757	bill	$6.00	$4,542	$6.00	$4,542
Basic Charge, Three Phase, per month	420	420	419	bill	$9.00	$3,771	$9.00	$3,771
Distribution Energy Charge, per kWh	1,449,879	1,449,879	1,373,662	kWh	4.001 ¢	$54,960	4.684 ¢	$64,342
Energy Charge - Schedule 200								
per kWh	1,449,879	1,449,879	1,373,662	kWh	0.578 ¢	$7,940	0.439 ¢	$6,030
Subtotal	1,449,879	1,449,879	1,373,662	kWh		$72,216		$79,510
Renewable Adjustment Clause (202), per kWh	1,449,879	1,449,879	1,373,662	kWh	0.014 ¢	$192	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,449,879	1,449,879	1,373,662	kWh	0.000 ¢	$0	0.630 ¢	$8,654
Subtotal						$72,408		$88,164
Schedule 201								
per kWh	1,449,879	1,449,879	1,373,662	kWh	1.320 ¢	$18,132	1.320 ¢	$18,132
Total	1,449,879	1,449,879	1,373,662	kWh		$90,540		$106,296
							Change	$15,756
Subtotal Oregon	14,132,701,620	13,680,122,990	15,339,351,516			$1,677,396,895		$1,885,557,483
Employee Discount						($445,083)		($499,436)
TOTAL OREGON	**14,132,701,620**	**13,680,122,990**	**15,339,351,516**			**$1,676,951,812**		**$1,885,058,047**
Distribution Only Energy	269,239,000	269,239,000	335,577,000					
Total Energy Including Distribution Only	14,401,940,620	13,949,361,990	15,674,928,516					

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Insurance Cost Adjustment - Schedule 80

FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Sch No.	MWh*	Proposed Base Revenues** ($000)	Equal Percentage Rate Spread	Proposed Schedule 80 Base Rates (¢/kWh)	Proposed Schedule 80 Base Revenues ($000)	Proposed Schedule 80 Deferred Rates (¢/kWh)	Proposed Schedule 80 Deferred Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Residential								
1	Residential	4	5,787,620	$860,844	47.2%	0.404	$23,382	0.125	$7,235
2	**Total Residential**		5,787,620	$860,844			$23,382		$7,235
	Commercial & Industrial								
3	Gen. Svc. < 31 kW	23	1,162,132	$180,252	9.9%	0.421	$4,893	0.130	$1,511
4	Gen. Svc. 31 - 200 kW	28	2,064,712	$224,638	12.3%	0.296	$6,112	0.091	$1,879
5	Gen. Svc. 201 - 999 kW	30	1,330,279	$129,130	7.1%	0.264	$3,512	0.081	$1,078
6	Large General Service >= 1,000 kW	48	4,677,111	$386,817	21.2%	0.225	$10,523	0.069	$3,227
7	Partial Req. Svc. >= 1,000 kW	47	43,379	$6,123		0.225	$98	0.069	$30
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	335,577	$3,829		0.225	$755	0.069	$232
9	Agricultural Pumping Service	41	234,910	$38,783	2.1%	0.449	$1,055	0.138	$324
10	**Total Commercial & Industrial**		9,848,099	$969,571			$26,947		$8,280
	Lighting								
11	Outdoor Area Lighting Service	15	2,128	$911		0.630	$13	0.194	$4
12	Street Lighting Service Comp. Owned	51	7,898	$3,154		0.630	$50	0.194	$15
13	Street Lighting Service Cust. Owned	53	8,821	$523		0.630	$56	0.194	$17
14	Recreational Field Lighting	54	1,374	$98		0.630	$9	0.194	$3
15	**Total Lighting**		20,221	$4,685	0.3%	0.630	$127	0.194	$39
16	**Subtotal**		15,655,940	$1,835,101	100.0%		$50,456		$15,554
17	Emplolyee Discount			($486)			($13)		($4)
18	**Total Sales with Employee Discount**			$1,834,615			$50,443		$15,550

* Includes Distribution Only consumer MWh and lighting tariff MWh
** Proposed Base Revenues prior to inclusion of base Insurance Premium Adder

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Catastrophic Fire Fund Adjustment - Schedule 193

FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Sch No.	MWh*	Proposed Distribution Revenues ($000)	Distribution Rate Spread	Proposed Schedule 193 Rate (¢/kWh)	Proposed Schedule 193 Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	5,787,620	$404,433	56.8%	0.764	$44,217
2	**Total Residential**		5,787,620	$404,433			$44,217
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	1,162,132	$91,003	12.8%	0.856	$9,948
4	Gen. Svc. 31 - 200 kW	28	2,064,712	$73,965	10.4%	0.392	$8,094
5	Gen. Svc. 201 - 999 kW	30	1,330,279	$33,807	4.8%	0.278	$3,698
6	Large General Service >= 1,000 kW	48	4,677,111	$75,898		0.178	$8,325
7	Partial Req. Svc. >= 1,000 kW	47	43,379	$2,463	11.6%	0.178	$77
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	335,577	$3,829		0.178	$597
9	Agricultural Pumping Service	41	234,910	$22,410	3.1%	1.043	$2,450
10	**Total Commercial & Industrial**		9,848,099	$303,374			$33,190
	Lighting						
11	Outdoor Area Lighting Service	15	2,128	$730	0.1%	3.749	$80
12	Street Lighting Service Comp. Owned	51	7,898	$2,558	0.4%	3.540	$280
13	Street Lighting Service Cust. Owned	53	8,821	$372	0.1%	0.460	$41
14	Recreational Field Lighting	54	1,374	$73	0.0%	0.578	$8
15	**Total Lighting**		20,221	$3,732			$408
16	**Subtotal**		15,655,940	$711,539	100.0%		$77,815
17	Emplolyee Discount			($222)			($26)
18	**Total Sales with Employee Discount**			$711,316			$77,789

* Includes Distribution Only consumer MWh and lighting tariff MWh

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Addition to Wildfire Mitigation Plan Cost Recovery Adjustment - Schedule 190

FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Sch No.	MWh*	Proposed Distribution Revenues ($000)	Distribution Rate Spread	Proposed Schedule 190 Addition Rate (¢/kWh)	Proposed Schedule 190 Addition Revenues ($000)	Total Proposed 190 Rate (¢/kWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Residential							
1	Residential	4	5,787,620	$404,433	56.8%	0.209	$12,096	0.678
2	**Total Residential**		5,787,620	$404,433			$12,096	
	Commercial & Industrial							
3	Gen. Svc. < 31 kW	23	1,162,132	$91,003	12.8%	0.234	$2,719	0.760
4	Gen. Svc. 31 - 200 kW	28	2,064,712	$73,965	10.4%	0.107	$2,209	0.309
5	Gen. Svc. 201 - 999 kW	30	1,330,279	$33,807	4.8%	0.076	$1,011	0.211
6	Large General Service >= 1,000 kW	48	4,677,111	$75,898		0.049	$2,292	0.134
7	Partial Req. Svc. >= 1,000 kW	47	43,379	$2,463	11.6%	0.049	$21	0.134
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	335,577	$3,829		0.049	$164	0.134
9	Agricultural Pumping Service	41	234,910	$22,410	3.1%	0.285	$669	0.841
10	**Total Commercial & Industrial**		9,848,099	$303,374			$9,087	
	Lighting							
11	Outdoor Area Lighting Service	15	2,128	$730	0.1%	1.023	$22	3.612
12	Street Lighting Service Comp. Owned	51	7,898	$2,558	0.4%	0.966	$76	3.481
13	Street Lighting Service Cust. Owned	53	8,821	$372	0.1%	0.126	$11	0.443
14	Recreational Field Lighting	54	1,374	$73	0.0%	0.158	$2	0.553
15	**Total Lighting**		20,221	$3,732			$111	
16	**Subtotal**		15,655,940	$711,539	100.0%		$21,294	
17	Emplolyee Discount			($222)			($7)	
18	**Total Sales with Employee Discount**			$711,316			$21,287	

* Includes Distribution Only consumer MWh and lighting tariff MWh

Docket No. UE 433
Exhibit PAC/1910
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Estimated Effect of Proposed Rates and Proposed Adjustment Schedules

February 2024

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	513,581	5,787,620	$786,075	$45,954	$832,029	$884,226	$127,212	$1,011,438	$98,151	12.5%	$179,409	21.6%	1
2	**Total Residential**		513,581	5,787,620	$786,075	$45,954	$832,029	$884,226	$127,212	$1,011,438	$98,151	12.5%	$179,409	21.6%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	86,033	1,162,132	$159,887	$10,366	$170,253	$185,145	$23,173	$208,317	$25,258	15.8%	$38,064	22.4%	3
4	Gen. Svc. 31 - 200 kW	28	10,658	2,064,712	$211,334	$25,644	$236,978	$230,749	$30,764	$261,513	$19,415	9.2%	$24,535	10.4%	4
5	Gen. Svc. 201 - 999 kW	30	847	1,330,279	$118,973	$14,740	$133,713	$132,641	$16,217	$148,858	$13,669	11.5%	$15,145	11.3%	5
6	Large General Service >= 1,000 kW	48	177	4,677,111	$357,556	$19,276	$376,831	$397,340	$32,091	$429,431	$39,785	11.3%	$52,600	14.1%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	43,379	$5,048	$179	$5,228	$6,221	$298	$6,519	$1,172	11.3%	$1,291	14.1%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,517	$547	$2,064	$4,584	$1,540	$6,125	$3,067	202.2%	$4,061	196.7%	8
9	Agricultural Pumping Service	41	7,884	234,910	$32,687	($1,212)	$31,475	$39,838	($1,308)	$38,529	$7,151	21.9%	$7,055	22.4%	9
10	**Total Commercial & Industrial**		105,606	9,512,522	$887,002	$69,540	$956,542	$996,518	$102,774	$1,099,293	$109,516	12.3%	$142,751	14.9%	10
	Lighting														
11	Outdoor Area Lighting Service	15	5,833	8,157	$839	$315	$1,154	$924	$282	$1,206	$85	10.1%	$52	4.5%	11
12	Street Lighting Service Comp. Owned	51	1,210	20,858	$2,903	$1,229	$4,132	$3,204	$1,113	$4,317	$301	10.4%	$185	4.5%	12
13	Street Lighting Service Cust. Owned	53	296	8,821	$487	$293	$780	$579	$237	$815	$92	18.9%	$35	4.5%	13
14	Recreational Field Lighting	54	98	1,374	$91	$58	$148	$106	$49	$155	$16	17.4%	$7	4.5%	14
15	**Total Public Street Lighting**		7,437	39,210	$4,319	$1,896	$6,215	$4,813	$1,681	$6,493	$494	11.4%	$278	4.5%	15
16	**Subtotal**		626,624	15,339,352	$1,677,397	$117,389	$1,794,786	$1,885,557	$231,667	$2,117,224	$208,161	12.4%	$322,439	18.0%	16
17	Emplolyee Discount		*867*	*13,364*	($445)	($27)	($472)	($499)	($73)	($573)	($54)		($101)		17
18	Paperless Credit				($1,855)		($1,855)	($1,855)		($1,855)	$0		$0		18
19	AGA Revenue				$4,071		$4,071	$4,071		$4,071	$0		$0		19
20	COOC Amortization				$1,769		$1,769	$1,769		$1,769	$0		$0		20
21	**Total**		626,624	15,339,352	$1,680,937	$117,362	$1,798,299	$1,889,043	$231,593	$2,120,637	$208,106	12.4%	$322,337	17.9%	21

1 Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), BPA credit (Sch. 98), Public Purpose Charge (Sch. 290) and System Benefits Charge (Sch. 291).
2 Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

PACIFIC POWER
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Pre Sch No.	Def. Insur. 80 ($000)	WMVM Adj 94 ($000)	Prop Sls. Adj 96 ($000)	Intv. Fndg Adj 97 ($000)	WMP Def Adj 190 ($000)	WMP Def Adj 190 ($000)	Def Acct Adj 192 ($000)	Cat Wildf Adj 193 ($000)	Repl Mtr Def Adj 194 ($000)	Deer Cr Def Adj 198 ($000)	RAC Defer. 203 ($000)	Sol. Inctv. 204 ($000)	PCAM 206 ($000)	Comm. Sol 207 ($000)	RMA 299 ($000)	RMA 299 ($000)	Total ($000)	Total ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
			PRO				PRE	PRO		PRO							PRE	PRO	PRE	PRO
	Residential																			
1	Residential	4	$7,235	$15,684	$1,158	$1,794	$27,144	$39,240	$3,530	$44,217	$1,910	$868	$3,299	$984	$6,598	$695	($17,710)	$0	$45,954	$127,212
2	**Total Residential**		$7,235	$15,684	$1,158	$1,794	$27,144	$39,240	$3,530	$44,217	$1,910	$868	$3,299	$984	$6,598	$695	($17,710)	$0	$45,954	$127,212
	Commercial & Industrial																			
3	Gen. Svc. < 31 kW	23	$1,511	$3,533	$232	$0	$6,113	$8,832	$535	$9,948	$395	$163	$628	$186	$1,255	$139	($2,812)	($4,184)	$10,366	$23,173
4	Gen. Svc. 31 - 200 kW	28	$1,879	$2,395	$413	$0	$4,171	$6,380	$227	$8,094	$516	$289	$1,094	$330	$2,230	$227	$13,751	$6,690	$25,644	$30,764
5	Gen. Svc. 201 - 999 kW	30	$1,078	$1,038	$266	$0	$1,796	$2,807	$80	$3,698	$306	$186	$692	$200	$1,411	$146	$8,620	$4,310	$14,740	$16,217
6	Large General Service >= 1,000 kW	48	$3,227	$2,292	$935	$1,123	$3,976	$6,267	$234	$8,325	$935	$608	$2,339	$655	$4,636	$514	$1,029	$0	$19,276	$32,091
7	Partial Req. Svc. >= 1,000 kW	47	$30	$21	$9	$10	$37	$58	$2	$77	$9	$6	$22	$6	$43	$5	$10	$0	$179	$298
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	$232	$164	$0	$81	$285	$450	$17	$597	$0	$0	$0	$0	$0	$0	$0	$0	$547	$1,540
9	Agricultural Pumping Service	41	$324	$754	$47	$0	$1,306	$1,976	$42	$2,450	$82	$33	$122	$35	$242	$26	($3,902)	($7,442)	($1,212)	($1,308)
10	**Total Commercial & Industrial**		$8,280	$10,197	$1,903	$1,213	$17,683	$26,770	$1,137	$33,190	$2,244	$1,285	$4,896	$1,412	$9,817	$1,058	$16,695	($626)	$69,540	$102,774
	Lighting																			
11	Outdoor Area Lighting Service	15	$4	$32	$0	$0	$55	$77	$0	$80	$1	$0	$1	$0	$4	$0	$222	$83	$315	$282
12	Street Lighting Service Comp. Owned	51	$15	$115	$2	$0	$199	$275	$0	$280	$3	$0	$3	$1	$12	$1	$894	$407	$1,229	$1,113
13	Street Lighting Service, Cust Owned	53	$17	$16	$2	$0	$28	$39	$0	$41	$1	$1	$3	$1	$4	$1	$237	$111	$293	$237
14	Recreational Field Lighting	54	$3	$3	$0	$0	$5	$8	$0	$8	$0	$0	$1	$0	$1	$0	$47	$25	$58	$49
15	**Total Public Street Lighting**		$39	$166	$4	$0	$287	$398	$0	$408	$6	$1	$8	$2	$20	$2	$1,400	$626	$1,896	$1,681
16	**Subtotal**		$15,554	$26,047	$3,064	$3,008	$45,114	$66,408	$4,667	$77,815	$4,160	$2,154	$8,203	$2,398	$16,435	$1,754	$385	$0	$117,389	$231,667
17	Employee Discount		($4)	($9)	($1)	($1)	($16)	($23)	($2)	($26)	($1)	($1)	($2)	($1)	($4)	($0)	$10	$0	($27)	($73)
18	**Total**		$15,550	$26,038	$3,063	$3,007	$45,099	$66,386	$4,665	$77,789	$4,158	$2,153	$8,201	$2,398	$16,431	$1,754	$395	$0	$117,362	$231,593

PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Pre Sch No.	Def. Insur. 80 ¢/kWh	WMVM Adj 94 ¢/kWh	Prop Sls. Adj 96 ¢/kWh	Intv. Fndg Adj 97 ¢/kWh	WMP Def Adj 190 ¢/kWh	WMP Def Adj 190 ¢/kWh	Def Acct Adj 192 ¢/kWh	Cat Wildf Adj 193 ¢/kWh	Repl Mtr Def Adj 194 ¢/kWh	Deer Cr Def Adj 198 ¢/kWh	RAC Defer. 203 ¢/kWh	Sol. Inctv. 204 ¢/kWh	PCAM Sec 206 ¢/kWh	PCAM Pri 206 ¢/kWh	PCAM Trn 206 ¢/kWh	Comm. Sol 207 ¢/kWh	RMA 299 ¢/kWh	RMA 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
			PRO				PRE	PRO		PRO									PRE	PRO
	Residential																			
1	Residential	4	0.125	0.271	0.020	0.031	0.469	0.678	0.061	0.764	0.033	0.015	0.057	0.017	0.114			0.012	(0.306)	0.000
	Commercial & Industrial																			
2	Gen. Svc. < 31 kW	23	0.130	0.304	0.020	0.000	0.526	0.760	0.046	0.856	0.034	0.014	0.054	0.016	0.108	0.098		0.012	(0.242)	(0.360)
3	Gen. Svc. 31 - 200 kW	28	0.091	0.116	0.020	0.000	0.202	0.309	0.011	0.392	0.025	0.014	0.053	0.016	0.108	0.107		0.011	0.666	0.324
4	Gen. Svc. 201 - 999 kW	30	0.081	0.078	0.020	0.000	0.135	0.211	0.006	0.278	0.023	0.014	0.052	0.015	0.106	0.107		0.011	0.648	0.324
5	Large General Service >= 1,000 kW	48	0.069	0.049	0.020	0.024	0.085	0.134	0.005	0.178	0.020	0.013	0.050	0.014	0.106	0.101	0.095	0.011	0.022	0.000
6	Partial Req. Svc. >= 1,000 kW	47	0.069	0.049	0.020	0.024	0.085	0.134	0.005	0.178	0.020	0.013	0.050	0.014	0.106	0.101	0.095	0.011	0.022	0.000
7	Dist. Only Lg Gen Svc >= 1,000 kW	848	0.069	0.049	0.000	0.024	0.085	0.134	0.005	0.178	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
8	Agricultural Pumping Service	41	0.138	0.321	0.020	0.000	0.556	0.841	0.018	1.043	0.035	0.014	0.052	0.015	0.103	0.101		0.011	(1.661)	(3.168)
	Lighting																			
9	Outdoor Area Lighting Service	15	0.194	1.496	0.020	0.000	2.589	3.612	0.000	3.749	0.036	0.006	0.039	0.012	0.172			0.009	10.425	3.900
10	Street Lighting Service HPS	51	0.194	1.453	0.020	0.000	2.515	3.481	0.000	3.540	0.044	0.006	0.040	0.012	0.146			0.009	11.320	5.150
11	Street Lighting Service	53	0.194	0.183	0.020	0.000	0.317	0.443	0.000	0.460	0.017	0.006	0.037	0.012	0.043			0.009	2.682	1.260
12	Recreational Field Lighting	54	0.194	0.228	0.020	0.000	0.395	0.553	0.000	0.578	0.023	0.006	0.038	0.012	0.043			0.009	3.435	1.840

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Single Family

kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Difference	Percent Difference
100	$25.41	$33.17	$7.76	30.54%
200	$38.63	$49.09	$10.46	27.08%
300	$51.84	$64.99	$13.15	25.37%
400	$65.06	$80.90	$15.84	24.35%
500	$78.27	$96.81	$18.54	23.69%
600	$91.48	$112.71	$21.23	23.21%
700	$104.70	$128.62	$23.92	22.85%
800	$117.91	$144.52	$26.61	22.57%
900	$131.13	$160.44	$29.31	22.35%
950	**$137.73**	**$168.39**	**$30.66**	**22.26%**
1,000	$144.34	$176.34	$32.00	22.17%
1,100	$157.55	$192.24	$34.69	22.02%
1,200	$170.77	$208.16	$37.39	21.89%
1,300	$183.98	$224.06	$40.08	21.78%
1,400	$197.20	$239.97	$42.77	21.69%
1,500	$210.41	$255.88	$45.47	21.61%
1,600	$223.62	$271.78	$48.16	21.54%
2,000	$276.48	$335.41	$58.93	21.31%
3,000	$417.38	$503.24	$85.86	20.57%
4,000	$558.28	$671.07	$112.79	20.20%
5,000	$699.19	$838.90	$139.71	19.98%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Multi-Family

kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Difference	Percent Difference
100	$22.36	$26.07	$3.71	16.59%
200	$35.58	$41.98	$6.40	17.99%
300	$48.79	$57.88	$9.09	18.63%
400	$62.01	$73.80	$11.79	19.01%
500	$75.22	$89.70	$14.48	19.25%
600	$88.43	$105.60	$17.17	19.42%
700	$101.65	$121.52	$19.87	19.55%
800	$114.86	$137.42	$22.56	19.64%
900	$128.08	$153.33	$25.25	19.71%
950	$134.69	$161.28	$26.59	19.74%
1,000	$141.29	$169.24	$27.95	19.78%
1,100	$154.50	$185.14	$30.64	19.83%
1,200	$167.72	$201.05	$33.33	19.87%
1,300	$180.93	$216.95	$36.02	19.91%
1,400	$194.15	$232.87	$38.72	19.94%
1,500	$207.36	$248.77	$41.41	19.97%
1,600	$220.57	$264.67	$44.10	19.99%
2,000	$273.43	$328.31	$54.88	20.07%
3,000	$414.34	$496.14	$81.80	19.74%
4,000	$555.24	$663.97	$108.73	19.58%
5,000	$696.14	$831.80	$135.66	19.49%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price Single Phase	Present Price Three Phase	Proposed Price Single Phase	Proposed Price Three Phase	Percent Difference Single Phase	Percent Difference Three Phase
5	500	$87	$95	$105	$116	21.24%	21.75%
	750	$121	$130	$146	$157	20.79%	21.19%
	1,000	$156	$164	$188	$199	20.54%	20.88%
	1,500	$225	$234	$270	$281	20.27%	20.52%
10	1,000	$156	$164	$188	$199	20.54%	20.88%
	2,000	$294	$303	$353	$364	20.13%	20.32%
	3,000	$432	$441	$518	$529	19.98%	20.12%
	4,000	$552	$561	$666	$677	20.66%	20.76%
20	4,000	$588	$596	$711	$722	21.06%	21.15%
	6,000	$827	$836	$1,006	$1,017	21.66%	21.71%
	8,000	$1,067	$1,075	$1,301	$1,312	21.98%	22.02%
	10,000	$1,306	$1,315	$1,596	$1,607	22.19%	22.22%
30	9,000	$1,258	$1,267	$1,540	$1,551	22.39%	22.42%
	12,000	$1,617	$1,626	$1,982	$1,993	22.55%	22.57%
	15,000	$1,976	$1,985	$2,424	$2,435	22.65%	22.67%
	18,000	$2,336	$2,344	$2,866	$2,877	22.72%	22.74%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$85	$94	$104	$115	21.45%	21.95%
	750	$119	$128	$144	$155	21.02%	21.42%
	1,000	$153	$162	$185	$196	20.77%	21.10%
	1,500	$221	$230	$266	$277	20.51%	20.75%
10	1,000	$153	$162	$185	$196	20.77%	21.10%
	2,000	$289	$297	$347	$359	20.37%	20.56%
	3,000	$424	$433	$510	$521	20.22%	20.36%
	4,000	$542	$550	$655	$666	20.91%	21.00%
20	4,000	$577	$586	$700	$711	21.29%	21.38%
	6,000	$812	$821	$990	$1,001	21.90%	21.95%
	8,000	$1,048	$1,056	$1,280	$1,291	22.23%	22.27%
	10,000	$1,283	$1,291	$1,571	$1,582	22.44%	22.47%
30	9,000	$1,236	$1,245	$1,516	$1,527	22.62%	22.65%
	12,000	$1,589	$1,598	$1,951	$1,962	22.79%	22.81%
	15,000	$1,942	$1,950	$2,386	$2,397	22.90%	22.91%
	18,000	$2,294	$2,303	$2,821	$2,832	22.97%	22.98%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$400	$446	11.41%
	4,500	$537	$590	9.98%
	7,500	$810	$879	8.56%
31	6,200	$808	$895	10.75%
	9,300	$1,090	$1,193	9.46%
	15,500	$1,654	$1,790	8.20%
40	8,000	$1,037	$1,147	10.61%
	12,000	$1,401	$1,532	9.35%
	20,000	$2,129	$2,302	8.12%
60	12,000	$1,547	$1,709	10.43%
	18,000	$2,093	$2,286	9.22%
	30,000	$3,186	$3,442	8.03%
80	16,000	$2,051	$2,262	10.28%
	24,000	$2,780	$3,033	9.10%
	40,000	$4,236	$4,573	7.95%
100	20,000	$2,556	$2,816	10.18%
	30,000	$3,466	$3,779	9.02%
	50,000	$5,287	$5,705	7.90%
200	40,000	$5,053	$5,548	9.78%
	60,000	$6,874	$7,473	8.71%
	100,000	$10,516	$11,325	7.69%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$498	$606	21.58%
	6,000	$627	$741	18.14%
	7,500	$756	$876	15.87%
31	9,300	$1,010	$1,214	20.18%
	12,400	$1,276	$1,493	16.97%
	15,500	$1,543	$1,772	14.88%
40	12,000	$1,298	$1,556	19.88%
	16,000	$1,642	$1,916	16.72%
	20,000	$1,985	$2,276	14.66%
60	18,000	$1,939	$2,318	19.51%
	24,000	$2,455	$2,858	16.43%
	30,000	$2,970	$3,398	14.41%
80	24,000	$2,575	$3,070	19.21%
	32,000	$3,262	$3,790	16.18%
	40,000	$3,949	$4,510	14.20%
100	30,000	$3,211	$3,822	19.03%
	40,000	$4,070	$4,722	16.03%
	50,000	$4,929	$5,622	14.08%
200	60,000	$6,371	$7,541	18.37%
	80,000	$8,088	$9,341	15.49%
	100,000	$9,805	$11,141	13.62%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	20,000	$3,004	$3,524	17.30%
	30,000	$3,677	$4,230	15.05%
	50,000	$5,022	$5,642	12.35%
200	40,000	$5,565	$6,333	13.79%
	60,000	$6,911	$7,745	12.07%
	100,000	$9,601	$10,570	10.09%
300	60,000	$8,284	$9,395	13.42%
	90,000	$10,302	$11,514	11.76%
	150,000	$14,338	$15,751	9.85%
400	80,000	$10,889	$12,272	12.71%
	120,000	$13,580	$15,097	11.17%
	200,000	$18,961	$20,746	9.42%
500	100,000	$13,526	$15,203	12.40%
	150,000	$16,890	$18,734	10.92%
	250,000	$23,617	$25,796	9.23%
600	120,000	$16,164	$18,134	12.19%
	180,000	$20,200	$22,371	10.75%
	300,000	$28,272	$30,845	9.10%
800	160,000	$21,439	$23,995	11.93%
	240,000	$26,820	$29,645	10.53%
	400,000	$37,583	$40,944	8.94%
1000	200,000	$26,714	$29,857	11.77%
	300,000	$33,440	$36,919	10.40%
	500,000	$46,894	$51,042	8.85%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$3,630	$4,079	12.38%
	40,000	$4,298	$4,778	11.16%
	50,000	$4,967	$5,477	10.27%
200	60,000	$6,845	$7,507	9.67%
	80,000	$8,181	$8,904	8.84%
	100,000	$9,518	$10,302	8.23%
300	90,000	$10,202	$11,158	9.37%
	120,000	$12,207	$13,254	8.58%
	150,000	$14,212	$15,350	8.01%
400	120,000	$13,486	$14,692	8.95%
	160,000	$16,159	$17,487	8.22%
	200,000	$18,832	$20,282	7.70%
500	150,000	$16,771	$18,232	8.71%
	200,000	$20,113	$21,725	8.01%
	250,000	$23,455	$25,218	7.52%
600	180,000	$20,057	$21,771	8.54%
	240,000	$24,067	$25,963	7.88%
	300,000	$28,077	$30,155	7.40%
800	240,000	$26,629	$28,850	8.34%
	320,000	$31,976	$34,439	7.70%
	400,000	$37,322	$40,028	7.25%
1000	300,000	$33,201	$35,928	8.21%
	400,000	$39,884	$42,915	7.60%
	500,000	$46,567	$49,902	7.16%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge
Single Phase							
10	2,000	$233	$174	$280	$246	19.93%	41.52%
	3,000	$350	$174	$420	$246	19.93%	41.52%
	5,000	$583	$174	$699	$246	19.93%	41.52%
Three Phase							
20	4,000	$466	$347	$559	$491	19.93%	41.52%
	6,000	$700	$347	$839	$491	19.93%	41.52%
	10,000	$1,166	$347	$1,399	$491	19.93%	41.52%
100	20,000	$2,332	$1,604	$2,797	$2,274	19.93%	41.77%
	30,000	$3,499	$1,604	$4,196	$2,274	19.93%	41.77%
	50,000	$5,831	$1,604	$6,993	$2,274	19.93%	41.77%
300	60,000	$6,997	$3,979	$8,392	$5,643	19.93%	41.84%
	90,000	$10,496	$3,979	$12,588	$5,643	19.93%	41.84%
	150,000	$17,493	$3,979	$20,979	$5,643	19.93%	41.84%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*		Proposed Price*		Percent Difference	
kW Load Size	kWh	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge	Monthly Bill	Annual Load Size Charge
Single Phase							
10	3,000	$344	$172	$413	$243	20.01%	41.42%
	4,000	$459	$172	$551	$243	20.01%	41.42%
	5,000	$573	$172	$688	$243	20.01%	41.42%
Three Phase							
20	6,000	$688	$343	$826	$485	20.01%	41.42%
	8,000	$917	$343	$1,101	$485	20.01%	41.42%
	10,000	$1,147	$343	$1,376	$485	20.01%	41.42%
100	30,000	$3,440	$1,573	$4,129	$2,243	20.01%	42.58%
	40,000	$4,587	$1,573	$5,505	$2,243	20.01%	42.58%
	50,000	$5,734	$1,573	$6,881	$2,243	20.01%	42.58%
300	90,000	$10,321	$3,908	$12,387	$5,572	20.01%	42.60%
	120,000	$13,762	$3,908	$16,515	$5,572	20.01%	42.60%
	150,000	$17,202	$3,908	$20,644	$5,572	20.01%	42.60%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$32,764	$36,565	11.60%
	500,000	$47,055	$51,536	9.52%
	700,000	$61,346	$66,508	8.41%
2,000	600,000	$64,939	$72,298	11.33%
	1,000,000	$91,729	$100,637	9.71%
	1,400,000	$119,203	$129,500	8.64%
6,000	1,800,000	$180,421	$204,159	13.16%
	3,000,000	$262,842	$290,748	10.62%
	4,200,000	$345,263	$377,338	9.29%
12,000	3,600,000	$358,683	$405,474	13.05%
	6,000,000	$523,145	$578,273	10.54%
	8,400,000	$687,075	$750,541	9.24%

Notes:

On-Peak kWh	38.20%
Off-Peak kWh	61.80%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$31,058	$37,466	20.63%
	500,000	$45,050	$52,125	15.70%
	700,000	$59,043	$66,783	13.11%
2,000	600,000	$61,537	$73,756	19.86%
	1,000,000	$87,643	$101,487	15.80%
	1,400,000	$114,507	$129,711	13.28%
6,000	1,800,000	$176,526	$213,510	20.95%
	3,000,000	$257,117	$298,183	15.97%
	4,200,000	$337,708	$382,856	13.37%
12,000	3,600,000	$350,923	$423,212	20.60%
	6,000,000	$511,725	$592,178	15.72%
	8,400,000	$671,996	$760,612	13.19%

Notes:

On-Peak kWh	37.89%
Off-Peak kWh	62.11%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	500,000	$42,973	$50,104	16.59%
	700,000	$56,452	$64,242	13.80%
2,000	1,000,000	$83,253	$96,724	16.18%
	1,400,000	$109,067	$123,886	13.59%
6,000	3,000,000	$247,194	$287,140	16.16%
	4,200,000	$324,634	$368,624	13.55%
12,000	6,000,000	$491,621	$568,682	15.67%
	8,400,000	$645,588	$730,738	13.19%

Notes:

On-Peak kWh	37.47%
Off-Peak kWh	62.53%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Docket No. UE 433
Exhibit PAC/1911
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Residential Basic Charge Calculation

February 2024

Residential Basic Charge Calculation
20 Year Residential Marginal Unit Costs
12 Months Ended December 2025

	All Residential	Single Family	Multi-Family
Poles	$94.23	$106.31	$38.64
Conductor	$40.96	$46.20	$16.79
Transformers	$122.51	$156.22	$45.20
Service Drop	$84.10	$84.10	$84.10
Meters	$24.91	$24.91	$24.91
Meter Reading	$0.00	$0.00	$0.00
Billing & Collections	$25.10	$25.10	$25.10
Uncollectables	$11.60	$11.60	$11.60
Customer Service / Other	$10.69	$10.69	$10.69
Total per Year	$414.10	$465.14	$257.04
Total per Month	$34.51	**$38.76**	**$21.42**
Current Basic Charge		$11.00	$8.00
Proposed Basic Charge		**$16.00**	**$9.00**

Docket No. UE 433
Exhibit PAC/1912
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Residential Three-Phase Basic Charge Calculation

February 2024

PacifiCorp
State of Oregon
Calculation of Three-Phase Basic Charge Differential

Line No.	Description	Value	Source
1	Cost of 30 kVA Three-Phase Polemount Transformer	$8,519	Estimated cost of installation
2	Cost of 25 kVA Single-Phase Polemount Transformer	$4,653	Estimated cost of installation
3	Incremental Transformer Cost	$3,866	Line 1 - Line 2
4	Operations & Maintenance Cost	2.88%	PacifiCorp 2023 Use of Facilities Report
5	Incremental Operations & Maintenance Cost	$111.34	Line 3 * Line 4
6	Monthly Incremental Operations & Maintenance Cost	$9.28	Line 5 / 12
7	Proposed Monthly Three-Phase Charge	$9.00	Line 6 rounded to nearest whole number

Docket No. UE 433
Exhibit PAC/1913
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Customer-Funded Substation Credit

February 2024

PacifiCorp
State of Oregon
Calculation of Customer-Funded Substation Credit

Line No.	Description	Value	Source
1	Marginal Dist. Substation Costs - Schedule 48 Primary (> 4 MW Category)	$4,772,588	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
2	Marginal Dist. Poles Costs - Schedule 48 Primary (> 4 MW Category)	$0	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
3	Marginal Dist. Conductor Costs - Schedule 48 Primary (> 4 MW Category)	$0	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
4	Marginal Customer - Metering Costs - Schedule 48 Primary (> 4 MW Category)	$42,584	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
5	Marginal Customer - Billing Costs - Schedule 48 Primary (> 4 MW Category)	$6,880	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
6	Marginal Customer - Uncollectible Costs - Schedule 48 Primary (> 4 MW Category)	$33,638	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
7	Marginal Customer - Other Costs - Schedule 48 Primary (> 4 MW Category)	$1,774	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
8	Total Marginal Distribution Costs - Schedule 48 Primary (> 4 MW Category)	$4,857,463	Line 1 + Line 2 + Line 3 + Line 4 + Line 5 + Line 6 + Line 7
9	Annualized Distribution O & M Loading Factor	44.0%	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'DistOM' tab
10	Marginal Dist. Substation Costs Less O&M - Schedule 48 Primary (> 4 MW Category)	$3,314,067	Line 1 / (1 + Line 9)
11	Proportion of Marginal Cost for Return on/Return of Dist. Substation to Total Marginal Distribution Cost - Schedule 48 Primary (> 4 MW Category)	68.2%	Line 10 / Line 8
12	Schedule 48 Primary (> 4 MW Category) Distribution Costs in Rates	$25,700,980	Exhibit PAC/1909 - Target Functionalized Revenues, Billing Determinants and Proposed Rates
13	Proportion of Unbundled Distribution Rates that are Non-FERC Transmission for Schedule 48 Primary	71.5%	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study
14	Customer-Funded Substation Credit	$4,994,278	Line 11 * Line 12 * (1 - Line 13)
15	Schedule 48 Primary (> 4 MW Category) Load Size kW	3,334,729	Exhibit PAC/1909 - Target Functionalized Revenues, Billing Determinants and Proposed Rates
16	Customer-Funded Substation Credit Price($/Load Size kW-month)	**$1.50**	Line 14 / Line 15

Docket No. UE 433
Exhibit PAC/1914
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Residential Schedule 6 Time-of-Use Pilot Program Evaluation

February 2024

Rocky Mountain Power | Pacific Power

STATE OF OREGON RESIDENTIAL TIME-OF USE PILOT

Program Evaluation

February 2024

I. Introduction

In PacifiCorp's general rate case filed in 2020, Docket No. UE 374, the Commission approved Schedule 6, a new simplified residential time-of-use option. The ultimate design of Schedule 6 was the result of stakeholder input that was incorporated into the partial stipulation related to rate spread and rate design issues in the rate case.[1] Residential Time-of-Use Schedule 6 provides customers with pricing that is about 14¢ per kWh higher from 5p.m. to 9p.m. every evening and about 4¢ per kWh lower than standard rates during all other times. Table 1 below shows how the current prices as of January 10, 2024, compare between residential time-of-use Schedule 6 and standard residential Schedule 4:

Table 1. Comparison of Energy Prices on Schedule 6 (Time-of-Use) and Schedule 4 (Standard Residential)

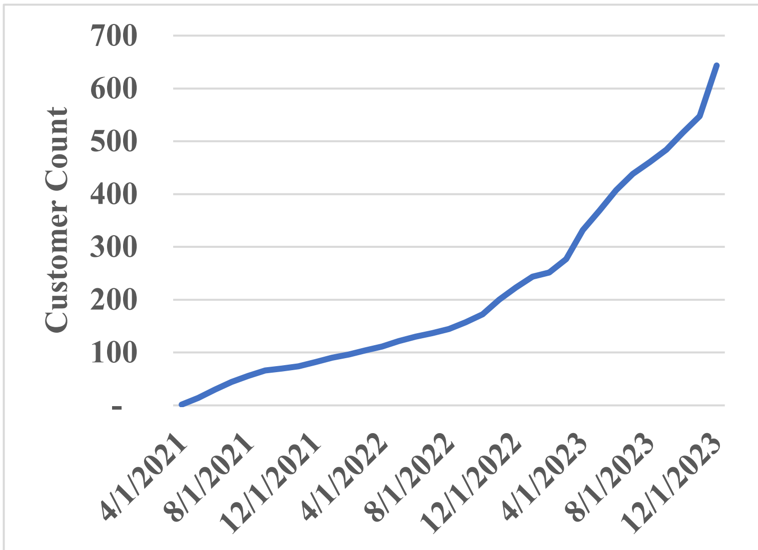
Time-of-Use Period	Time-of-Use Price	Standard Price
On-Peak	27.98¢ per kWh	13.71¢ per kWh
Off-Peak	9.92¢ per kWh	13.71¢ per kWh

To encourage customers to enroll in the program and avoid the risk of paying significantly more as they transition to time-of-use, participants are offered a first-year annual guarantee payment. If over the course of their first year on the program, they pay more than 10 percent on the time-of -use program than they would under standard rates, that customer receives a payment to limit the difference to no more than 10 percent.

[1] Partial Stipulation Related to Rate Spread and Rate Design filed on August 17, 2020, in Docket No. UE 374.

The first customer enrolled in Schedule 6 in April 2021. Since that time, the program has seen significant adoption. Continuous adoption through the present indicates that customers had an interest in the program. Figure 1 shows adoption of the program over time.

Figure 1. Schedule 6 Adoption Over time



II. Participant Bill Impact

After each Schedule 6 time-of-use participant reached its one-year anniversary on the program, the Company sent the customer a letter letting them know how much money the program saved them or cost them. The letter also informed them if they were eligible for an annual guarantee payment because they paid more than 10 percent higher for their energy cost. Through October 2023, 204 time-of-use anniversary letters were sent out. Table 2 summarizes the average savings or cost of these participants.

Table 2. Schedule 6 Participant Average Savings or Cost Summary

	Count	Annual Average Savings/(Cost)	Monthly Average Savings/(Cost)	Energy Cost Savings/(Cost)
Customers with Annual Bill Savings	163	$189.95	$15.83	13.2%
Customers with Annual Bill Cost	41	($46.78)	($3.90)	-4.9%
Total Customers Over a Year on Program as of October 2023	204	$142.38	$11.86	9.6%

Most customers saved money. The average amount they saved was about $16 per month or 13.2 percent. For a minority of customers, the program ended up costing them more. The average amount more they paid was about $4 per month or 4.9 percent higher for their energy cost.

Only a handful of customers received an annual guarantee payment. Table 3 summarizes the annual guarantee payments for these customers.

Table 3. Schedule 6 Annual Guarantee Payment Summary

	Count	Average Payment	Total Payments
Guarantee Payments	5	$52.24	$261.22

Figure 2 shows the proportions of customers who saved money, paid more money, and paid more money and received an annual guarantee payment.

Figure 2. Proportion of Schedule 6 Participants who Saved, Paid More, or Required a Guarantee Payment

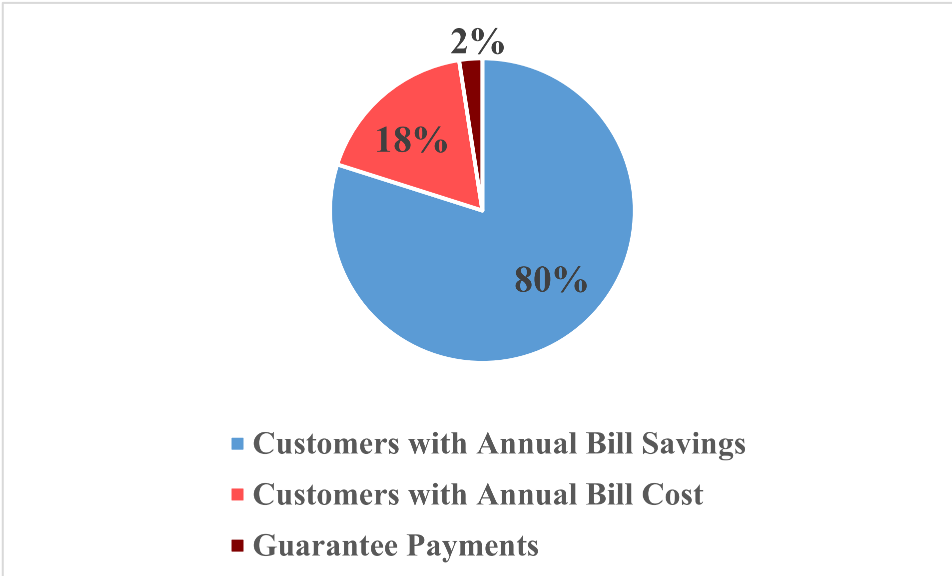


Figure 2 shows that about 80 percent of participants saved money and about 20 percent paid more under the program. Two percent paid more than 10 percent higher energy costs and required a guarantee payment.

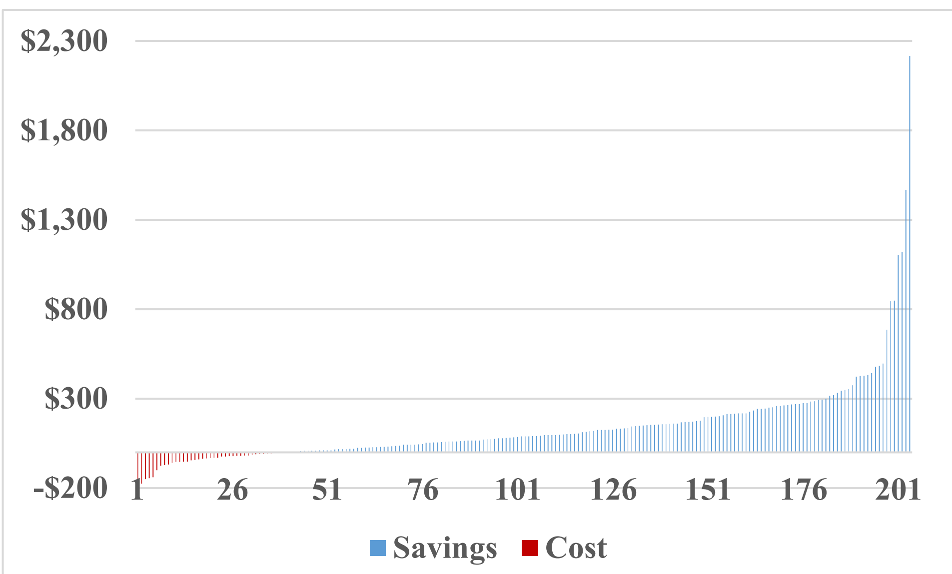
To better understand participants' bill experience, other statistics besides average were examined. Table 4 shows the median and maximum amounts that the program either saved or cost participants alongside averages.

Table 4. Average, Median, and Maximum Bill Impact for Program Participants

	Customers with Annual Bill Savings	Customers with Annual Bill Cost	Total Customers Over a Year on Program as of October 2023
Count	163	41	204
Annual Average Savings/(Cost)	$189.95	($46.78)	$142.38
Monthly Average Savings/(Cost)	$15.83	($3.90)	$11.86
Annual Median Savings/(Cost)	$125.20	($31.54)	$88.46
Monthly Median Savings/(Cost)	$10.43	($2.63)	$7.37
Maximum Annual Savings/(Cost)	$2,216.65	($189.47)	
Maximum Monthly Savings/(Cost)	$184.72	($15.79)	

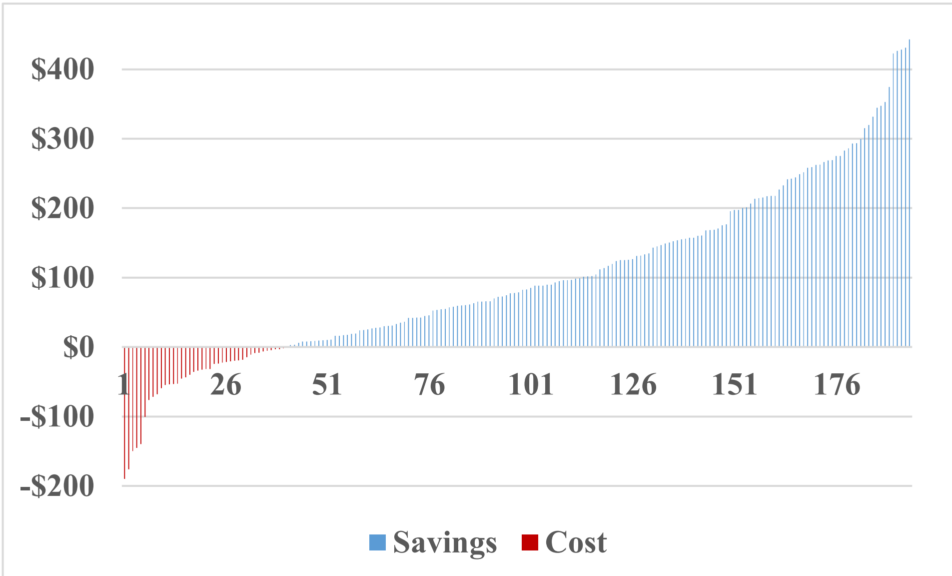
Figure 3 shows the individual bill impacts for the 204 time-of-use participants who finished one year on the program through October 2023 in ranked order.

Figure 3. Individual Participants' Annual Bill Impacts



There were a handful of very large energy users who had disproportionately high annual savings. To better show the bill impact for most participants, Figure 4 shows the same information as Figure 3, but with the top 5 percent of annual bill savings excluded.

Figure 4. Individual Participants' Annual Bill Impacts Excluding Highest 5 Percent

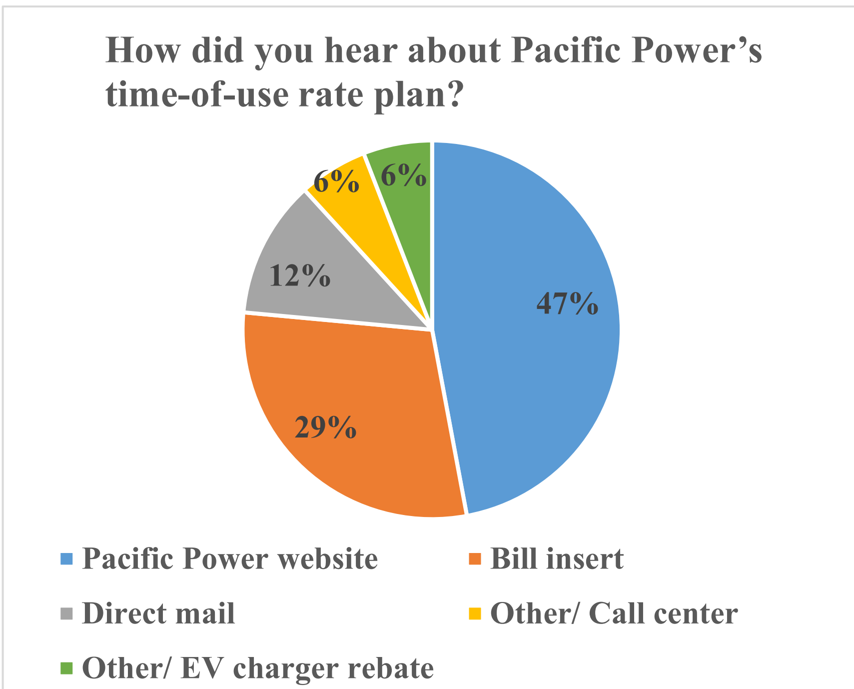


III. Survey Responses

In the 204 time-of-use anniversary letters that were sent out, an invitation to take a short online survey was included. 17 of the 204 participants completed this survey. The survey asked participants questions about how they learned about the program, what their satisfaction with the program is, their motivation for enrolling, their experience on the program, and some demographic questions about themselves.

Survey respondents were asked how they became aware of the program. Figure 5 shows the different ways that participants indicated they became aware of the program.

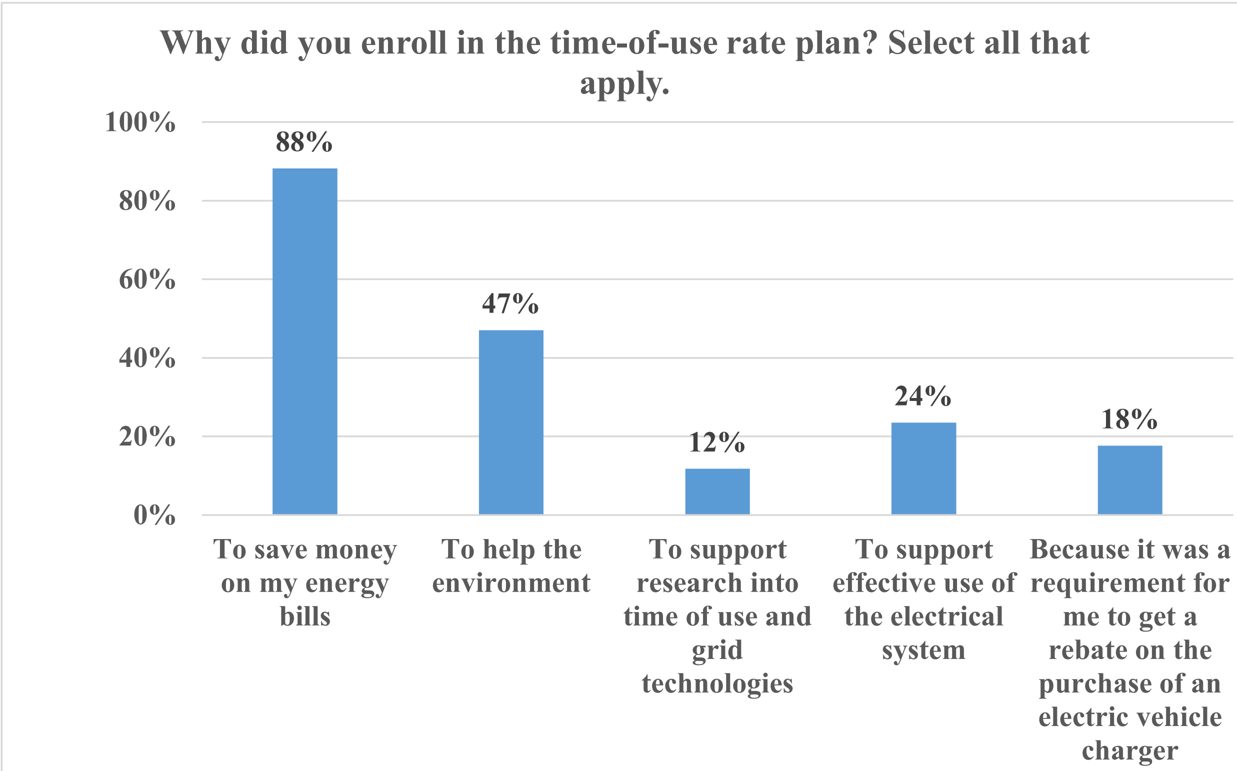
Figure 5. Program Awareness Method



The Company's website was the most prevalent way that survey respondents became aware of the program with nearly half of respondents indicating that this was how they heard about it. At about a third of responses, bill inserts were the second most prevalent way that respondents indicated they became aware of Schedule 6. Respondents also listed the direct mail, a call with one of the customer care agents, and the electric vehicle charger rebate as other ways that they learned about the program.

The survey asked respondents about why they enrolled in the program. Figure 6 shows the reasons respondents gave for enrolling.

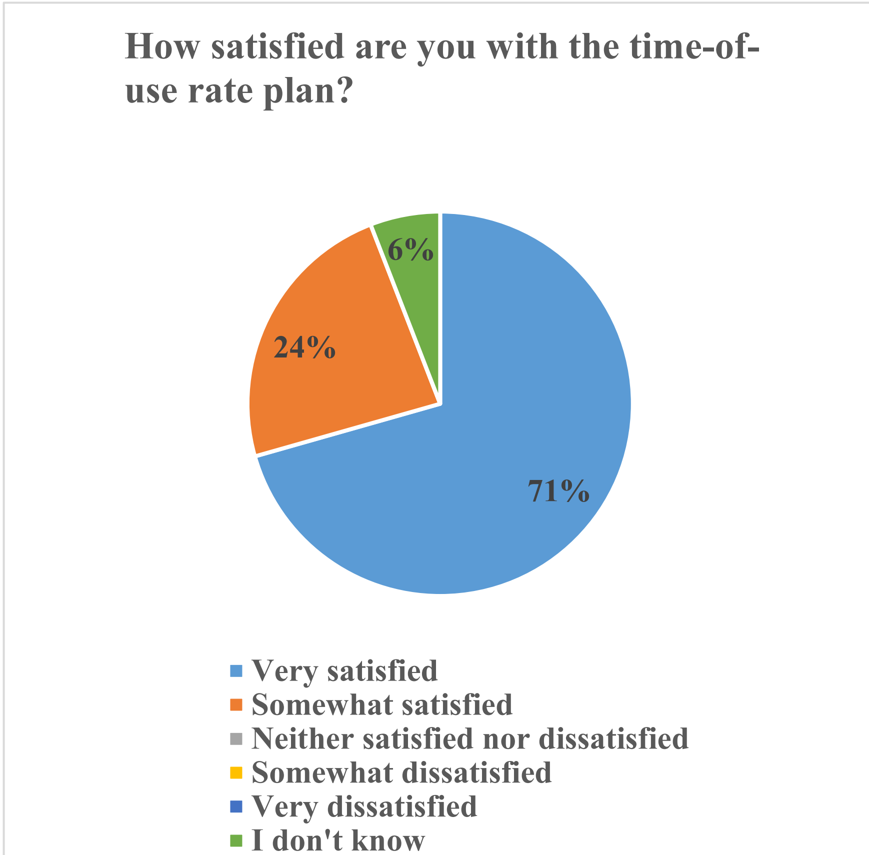
Figure 6. Program Enrollment Motivation



Almost all participants noted saving money as a reason for enrolling. A little less than half cited helping the environment. A small minority of respondents selected other reasons.

The survey asked respondents about their satisfaction with the program. Figure 7 shows their responses

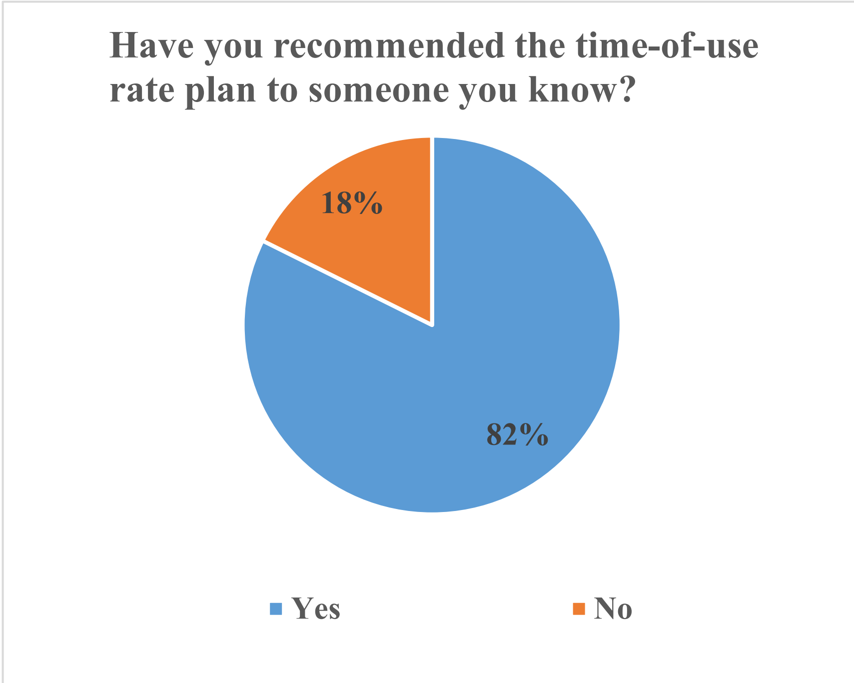
Figure 7. Program Satisfaction

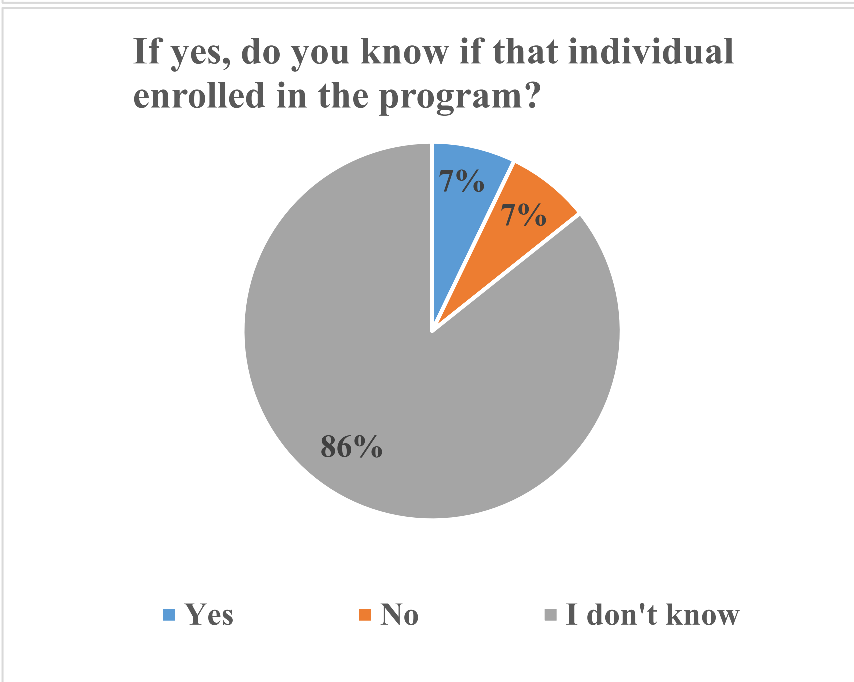


Although the sample size of 17 is relatively small, responses indicated strong satisfaction with the program. Most survey respondents indicated they were very satisfied and about a quarter indicated they were somewhat satisfied. One customer responded with "I don't know".

The survey asked participants if they recommended the program to someone else. Figure 8 summarizes their responses.

Figure 8. Program Referrals

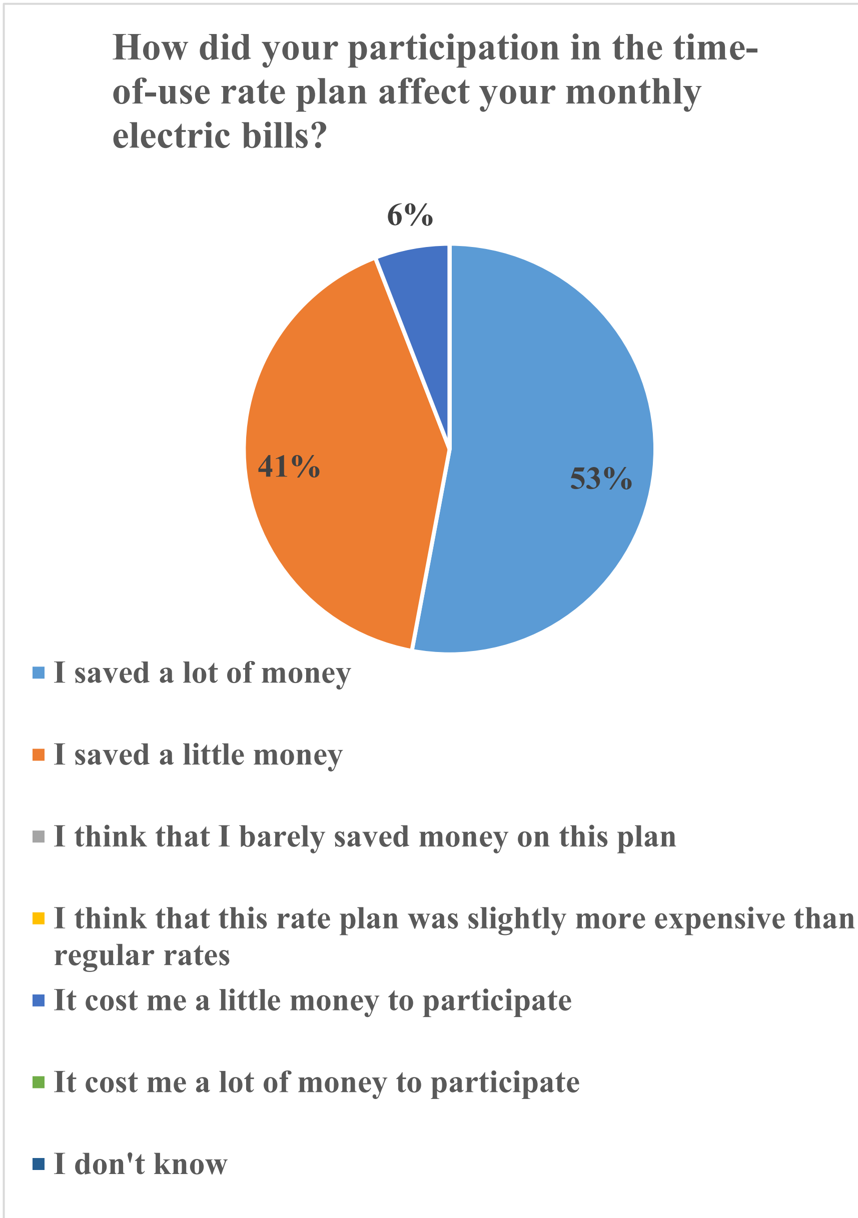




Most (82 percent) survey respondents recommended the program to someone they knew. However, most (86 percent) who answered “Yes” were unaware whether the individual they referred ultimately enrolled in the program or not.

The survey asked participants about their perceptions of how much the program saved or cost them. Figure 9 shows the responses for this question.

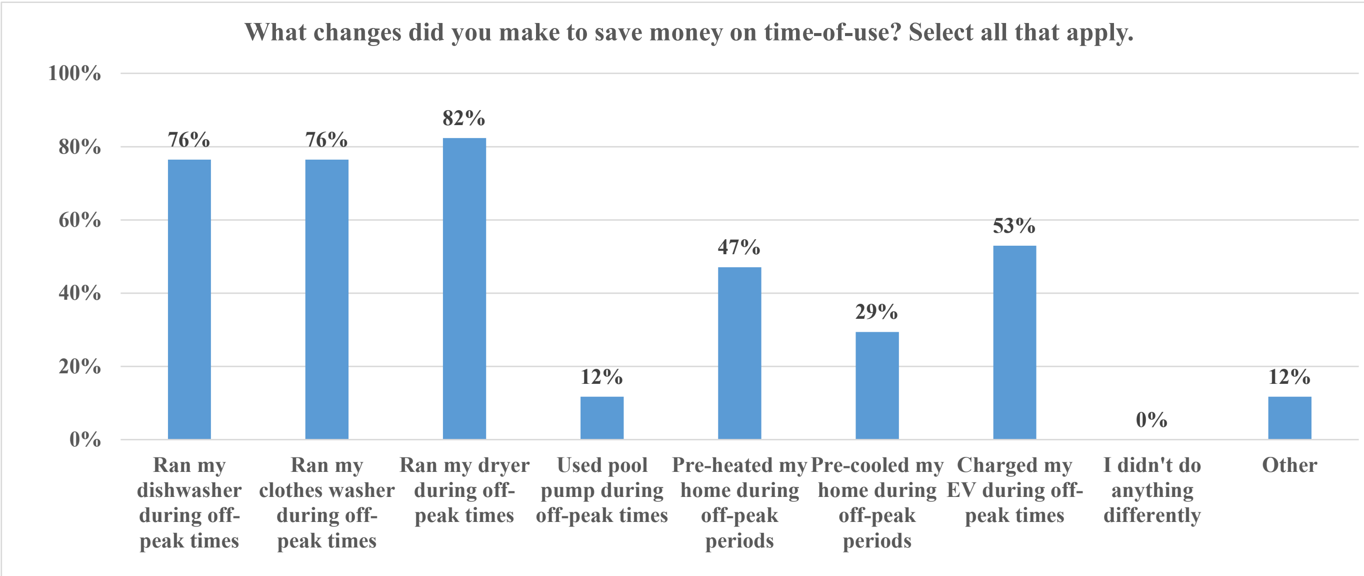
Figure 9. Bill Savings/Cost Perception



Almost all respondents indicated that they saved money. Only one respondent indicated losing money on the program.

Participants were asked what actions they took to save money on the program. Figure 10 shows their responses to this question.

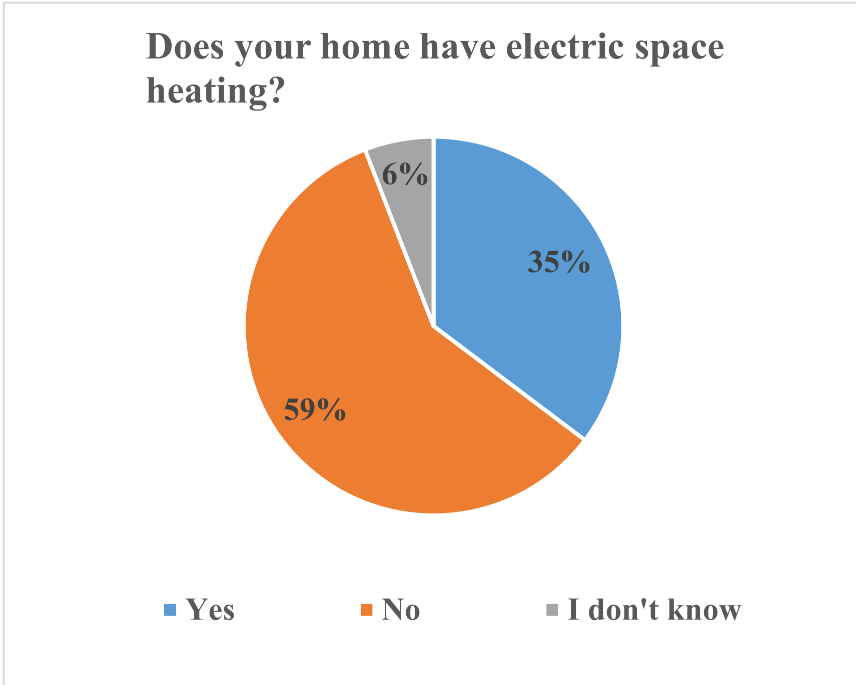
Figure 10. Actions Taken for Time-of-Use Program

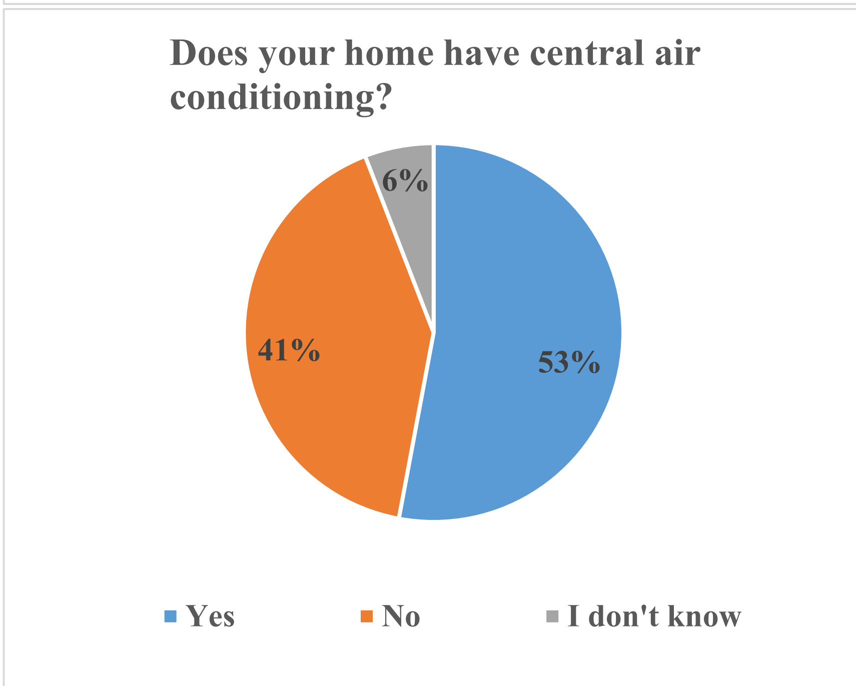


Most respondents indicated that they ran their dishwasher, clothes washer, and dryer during off-peak times. About half of respondents indicated that they pre-heated their homes or charged their electric vehicle during off-peak times. Notably, no respondent indicated that they did not do anything differently.

The survey asked participants about their heating and cooling equipment. Figure 11 shows their responses.

Figure 11. Heating and Cooling Equipment Respondents

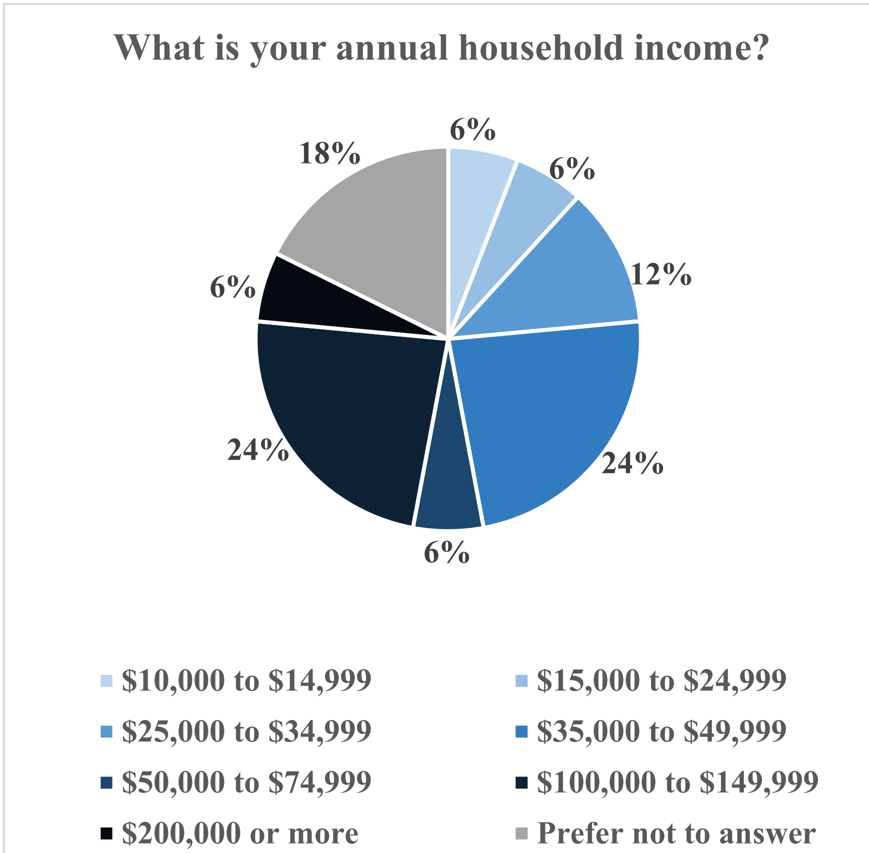


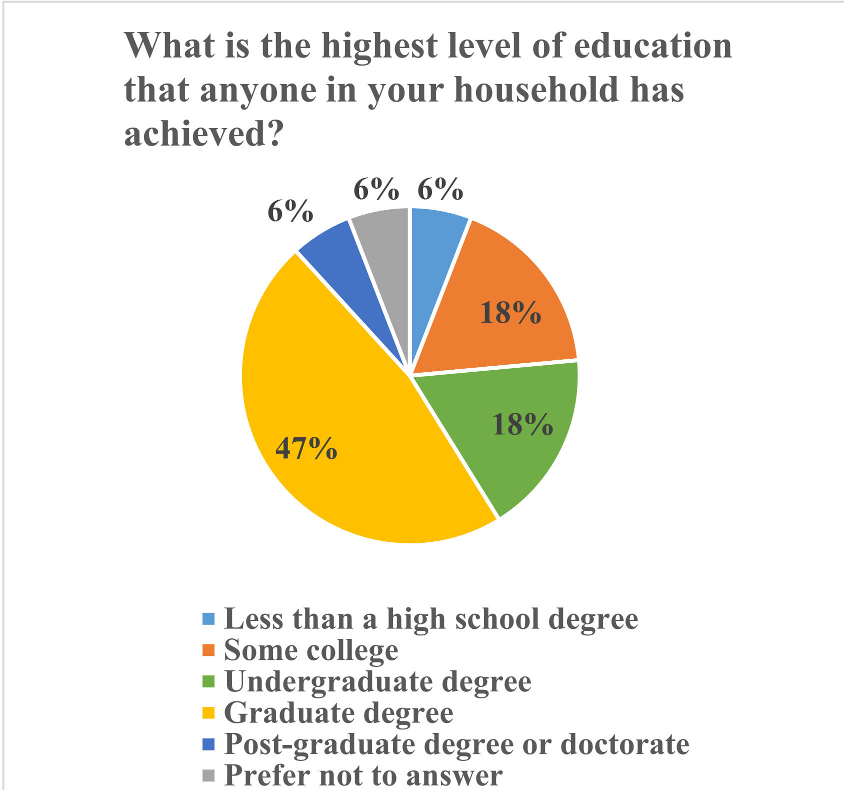


Only about a third of respondents indicated that they have electric space heating and about half indicated that they have central air conditioning.

Finally participants were asked demographic questions about their household income and the highest level of education attained in their household. Figure 12 shows their responses to these questions.

Figure 12. Demographic Information of Respondents





A fairly diverse range of incomes were indicated from survey responses with low-, moderate- and high-income all being represented. While differing levels of education were indicated from respondents, the sample of individuals who responded seemed to skew towards a higher level of educational attainment with nearly half indicating that someone in their household had a graduate degree.

IV. Usage Characteristics of Program Participants

On average, Schedule 6 time-of-use participants use more energy than standard residential Schedule 4 customers. Table 4 shows the comparison of average usage.

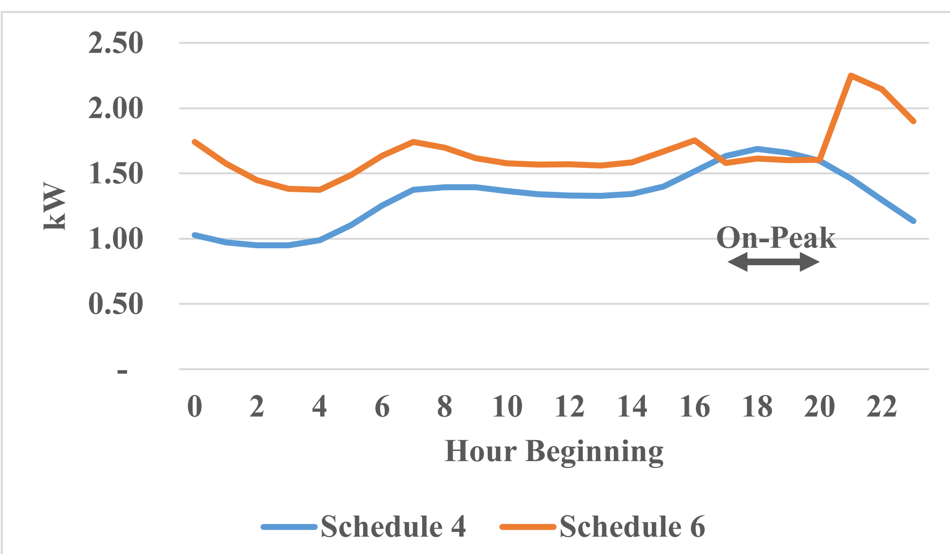
Table 4. Average Energy Usage of Schedule 6 Time-of-Use Participants Compared to Standard Schedule 4 Customers

	Schedule 4 Standard Residential	Schedule 6 Residential Time of Use	Difference	Difference (%)
kWh	958	1,207	248	25.9%

There are a number of reasons why participants may use more energy. A customer with a larger bill may be more motivated to enroll in a program like time-of-use. Also customers who have electric vehicles that they charge at home use more energy and may have greater opportunities to save by shifting the time-of charging and/or may be required to enroll in time-of-use as a condition of receiving a charger incentive.

The average hourly usage profile for Schedule 6 participants is higher than for customers on standard residential Schedule 4, but noticeably has a dip in usage during the on-peak period from 5p.m.-9p.m. Figure 13 shows the average hourly profile for Schedule 6 compared to Schedule 4.

Figure 13. Hourly Profile of Schedule 6 Time-of-Use Participants Compared to Standard Residential Schedule 4 Customers



To illustrate how the shape of Schedule 6 participants' hourly load profile compares to that of Schedule 4 customers, the hourly profile of Schedule 4 can be scaled up such that its overall usage level is the same as Schedule 6. Figure 14 shows the same information as Figure 13, but with the hourly profile of Schedule 4 scaled to the same energy level as Schedule 6.

Figure 14. Hourly Profile of Schedule 6 Time-of-Use Participants Compared to Scaled Up Standard Residential Schedule 4 Customers

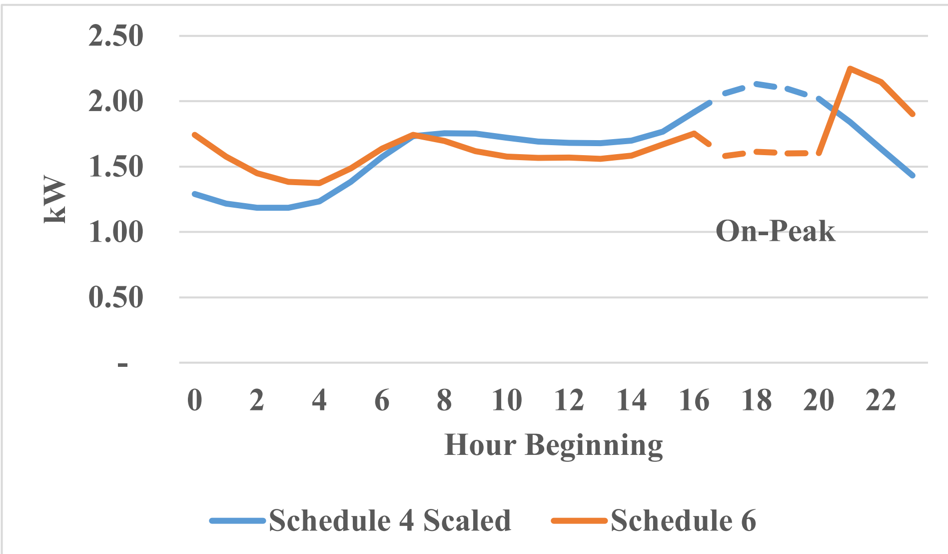


Figure 14 indicates that on average, Schedule 6 participants trim their load by about one half of a kilowatt during the on-peak period of 5p.m.-9p.m.. Usage after 9p.m. until 6am is a little higher.

V. Program Benefits

The potential benefits of the Schedule 6 time-of-use program include reduced energy costs from the shifted timing of usage, reduced generation capacity costs from lower demand during times that are significant from a capacity planning perspective, and reduced transmission cost by reducing the 12 coincident peak allocation of FERC transmission costs to PacifiCorp network customers. To examine these benefits the incremental profile of Schedule 6 time-of-use participants was compared to the profile of standard residential Schedule 4 scaled up to the same monthly usage level as Schedule 6 (net Schedule 6 profile).

The value of shifted energy was estimated by taking the net Schedule 6 profile and multiplying each hour by the average price from the Western Energy Imbalance Market (WEIM) by hour and month using the PAC-W, PAC-E, and Malin nodes for the 36 months ended June 2023. This value was then scaled by a factor of 1.61 to bring the value considered up from using historic WEIM prices to the marginal energy cost forecast for 2025 in the Company's most recently filed 2024 general rate case. Using this approach, the value of shifted energy was estimated to be an annual $26.93 per participant. Figure 15 summarizes this calculation by month and hour.

Figure 15 Estimated Value of Shifted Energy per Schedule 6 Time-of-Use Participant Using Average WEIM Prices for the 36 Months Ended June 2023 Period

	Hour Beginning																								
Month	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**Total**
7	0.6	0.4	0.3	0.3	0.2	0.2	0.1	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(1.0)	(1.3)	(1.4)	(0.9)	0.4	0.6	0.6	(2.5)
8	0.7	0.5	0.4	0.4	0.3	0.2	0.1	0.0	(0.0)	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)	(0.4)	(0.3)	(0.5)	(1.5)	(2.2)	(1.7)	(0.9)	0.7	0.8	0.7	(3.5)
9	0.6	0.5	0.4	0.3	0.2	0.2	0.1	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.2)	(0.3)	(0.3)	(0.4)	(0.6)	(1.7)	(2.3)	(1.9)	(0.9)	0.8	0.8	0.7	(4.2)
10	0.6	0.5	0.3	0.3	0.2	0.2	0.1	(0.1)	(0.2)	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.3)	(1.0)	(1.2)	(0.9)	(0.6)	0.6	0.8	0.6	(1.2)
11	0.6	0.4	0.2	0.1	0.0	0.1	0.1	(0.0)	(0.1)	(0.3)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.1)	(1.0)	(0.9)	(0.9)	(0.8)	0.7	0.9	0.7	(0.7)
12	1.1	0.7	0.4	0.2	0.1	0.1	0.1	(0.0)	(0.3)	(0.5)	(0.5)	(0.4)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	(1.9)	(1.9)	(1.8)	(1.3)	1.8	1.9	1.4	(1.4)
1	0.7	0.6	0.3	0.3	0.1	0.1	0.1	0.0	(0.1)	(0.3)	(0.3)	(0.2)	(0.2)	(0.1)	(0.0)	0.2	(0.1)	(1.1)	(1.2)	(1.2)	(1.0)	0.8	1.0	0.8	(0.7)
2	0.5	0.4	0.2	0.1	0.0	0.0	(0.0)	0.1	(0.0)	(0.2)	(0.2)	(0.1)	(0.0)	(0.0)	0.0	0.0	(0.1)	(0.8)	(1.1)	(1.1)	(0.8)	0.7	0.8	0.6	(0.9)
3	0.6	0.3	0.2	0.1	(0.1)	(0.1)	(0.1)	0.0	(0.0)	(0.2)	(0.2)	(0.1)	(0.0)	(0.0)	(0.0)	0.0	(0.1)	(0.5)	(0.7)	(0.7)	(0.6)	0.6	0.7	0.6	(0.2)
4	0.7	0.5	0.4	0.3	0.3	0.3	0.4	0.0	(0.0)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.2)	(0.2)	(0.6)	(1.0)	(1.2)	(1.0)	0.8	0.7	0.6	(0.1)
5	0.4	0.4	0.3	0.2	0.2	0.2	0.1	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.5)	(0.7)	(0.7)	(0.6)	0.5	0.6	0.5	(0.4)
6	0.4	0.3	0.2	0.1	0.1	0.1	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.3)	(0.6)	(0.5)	(0.5)	(0.4)	0.5	0.6	0.4	(0.9)
Total	7.4	5.5	3.7	2.7	1.8	1.6	1.1	0.1	(1.0)	(2.3)	(2.3)	(1.8)	(1.5)	(1.7)	(1.7)	(1.5)	(3.0)	(12.2)	(15.0)	(14.0)	(9.9)	8.8	10.2	8.1	

Estimated Value of Shifted Energy (Historic WEIM Pricing)

$\boxed{\textbf{(\$16.69)}}$

Average Historic WEIM Price

$51.42

1 Year Marginal Energy Cost (Uses Flat MidC Forecast)

$82.95

Scaling Factor

1.61

Estimated Value of Shifted Energy (Marginal Energy Cost)

$\boxed{\textbf{(\$26.93)}}$

Figure 15 shows that there were shifted energy benefits in every month, but they were strongest during the peak third quarter months of July, August, and September. The annual benefit of shifted load away from 5p.m.-9p.m. (displayed as hours beginning 17-20) was estimated to be about $82, but this amount is offset by higher load in the hours between 9p.m. and 7a.m.

Generation capacity benefit was estimated by comparing the net Schedule 6 profile against loss of load probability in 2024 from the preferred portfolio in PacifiCorp's 2021 Integrated Resource Plan. This calculation indicated that the reduction in load for each Schedule 6 participant contributed to about a 0.38 kW reduction to capacity need. In PacifiCorp's 2024 General Rate Case, its marginal cost of service study indicated that the marginal cost of generation capacity based upon the resource costs of a utility-scale 4-hour lithium ion battery is $156.28 per kW-year. Multiplying this cost by the 0.38 kW per participant estimate of capacity reduction yields an estimated benefit of $59.10. Table 5 shows this calculation.

Table 5. Calculation of Estimated Schedule 6 Generation Capacity Benefit

Marginal Generation Capacity Cost	$156.28
kW Avoided	(0.38)
Estimated Generation Capacity Benefit	**-$59.10**

PacifiCorp's FERC transmission costs are allocated to PacifiCorp and other transmission customers on the basis of PacifiCorp's 12 monthly system coincident peaks. Inasmuch as PacifiCorp's customers can reduce their loads during the 12 coincident peaks, those costs can be shifted onto other PacifiCorp transmission customers. On average, the net Schedule 6 profile is a 0.19 kW reduction, during the 12 coincident peaks hours for the 12 month period ended June 2023. Using the network service rate of $37,098 per MW-year from the 2023 Transmission Formula Rate Annual Update yields a $7.14 per participant benefit. Table 6 summarizes the calculation of this estimated benefit.

Table 6. Calculation of Estimated Schedule 6 Transmission Capacity Benefit

Month	Month	Day	Hour	Schedule 6 Net Profile (kW)
1/1/2023	1	30	8	(0.41)
2/1/2023	2	2	7	(0.01)
3/1/2023	3	6	7	0.12
4/1/2023	4	3	7	(0.13)
5/1/2023	5	19	15	(0.37)
6/1/2023	6	30	16	(0.41)
7/1/2022	7	27	15	(0.19)
8/1/2022	8	31	15	(0.05)
9/1/2022	9	6	15	(0.31)
10/1/2022	10	6	15	(0.18)
11/1/2022	11	29	17	(0.57)
12/1/2022	12	22	16	0.19
	12 Coincident Peak Reduction (kW)			(0.19)
	Network service rate ($/MW-year)			$37,098
	Avoided Transmission Cost Benefit			**-$7.14**

In total, the estimated quantifiable per participant benefit is $93.17. Table 7 summarizes the estimated benefits of the Schedule 6 program.

Table 7. Estimated Quantifiable Benefits of the Schedule 6 Program

Shifted Energy Value	-$26.93
Generation Capacity	-$59.10
Transmission Capacity	-$7.14
Total Per Participant Benefit	**-$93.17**

VI. Comparison to Legacy Time-of-Use Option

Schedule 6 was introduced as a pilot time-of-use option in 2021. However, legacy Schedule 210 time-of-use has been an option for the Company's Oregon customers since 2002. There are several key differences between pilot option Schedule 6 and legacy Schedule 210. Notably, Schedule 6 has a very simple time-of-use period of 5p.m.-9p.m. being on-peak and all other hours being off-peak. For Schedule 210, between the winter months of November through March, on-peak periods are Monday through Friday, excluding holidays, from 6am to 10am and again from 5p.m.-8p.m. Between the summer months of April through October, on-peak periods on Schedule 210 are Monday through Friday, excluding holidays, from 4p.m. to 8p.m. All other hours are considered off-peak.

Schedule 6 also has a more significant difference between on- and off-peak price compared to legacy Schedule 210. On Schedule 6, the on-peak price is 27.980¢ per kWh and the off-peak price is 9.920¢ per kWh—roughly a 2.8 to 1 differential. On Schedule 210, the on-peak price is 19.834¢ per kWh during summer months and 17.026¢ per kWh during winter months with the off-peak price being 12.585¢ per kWh—roughly a 1.6 to 1 differential in the summer and a 1.4 to 1 differential in the summer. As a result of the more tepid differential, Schedule 210 participants save on average $0.98 per month. This compares to the $11.86 per month average bill savings experienced by Schedule 6 participants discussed earlier in this report.

As shown on Figure 1 earlier in the report, adoption for Schedule 6 has been robust. Every month, new customers have steadily enrolled in the program. After being in existence about three years, the program now has over 600 participants. In contrast, legacy Schedule 210 adoption has stalled out with only about 900 participants after about 21 years. In recent years, enrollment in Schedule 210 has declined. Figure 16 shows enrollment for pilot Schedule 6 compared to legacy Schedule 210 from 2021 through 2023.

Figure 16. Comparison of Enrollment in Schedule 6 to Schedule 210 Over Time

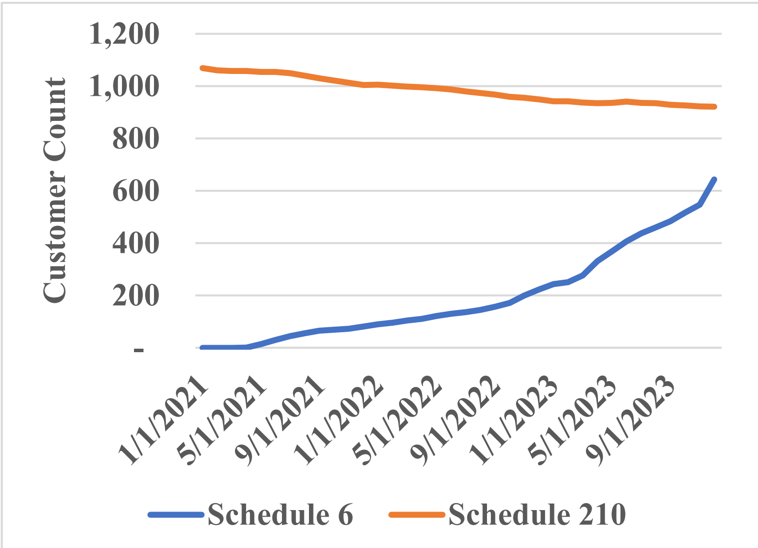


Table 8 provides a comparison of the pilot time-of-use Schedule 6 program to the legacy time-of-use Schedule 210 program.

Table 8. Comparison of Pilot Schedule 6 to Legacy Schedule 210

	Schedule 6	**Schedule 210**
Time of Use Periods	On-Peak - 5pm-9pm, all days Off-Peak - All other times	On-Peak - Nov-Mar - 6am-10am & 5pm-8pm, Mon-Fri, excluding holidays Apr-Oct - 4pm-8pm, Mon-Fri, excluding holidays Off-Peak - All other times
On- to Off-Peak Price Differential	2.8:1	Nov-Mar - 1.6:1 Apr-Oct - 1.4:1
Average Participant Bill Savings	$11.86 per month	$0.98 per month

VII. Conclusion/Recommendation

Schedule 6 has been a successful residential time-of-use program. Participants indicate a high level of satisfaction with the program, most participants save a meaningful amount of money each month, and system benefits have been demonstrated from shifted load. While the sample size of survey respondents is relatively small, the survey results indicate that customers from a wide range of incomes have participated in the program. It is recommended that the Schedule 6 program end its pilot phase and become an ongoing option for residential customers. While the system benefits of the program are less than the bill savings participants receive, participation is still relatively small. If a more significant level of participation is achieved in the future, Residential Time-of-Use Schedule 6 could be put on its own cost of service class to ensure subsidization is minimized. To reduce customer confusion, it is recommended that Schedule 210 be discontinued, since it is more difficult for customers to understand and provides minimal benefits for participants.

Docket No. UE 433
Exhibit PAC/1915
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Non-Residential Schedule 29 Time-of-Use Pilot Program Evaluation

February 2024

Rocky Mountain Power | Pacific Power

STATE OF OREGON SCHEDULE 29 - NON-RESIDENTIAL TIME OF USE PILOT

Program Evaluation

February 2024

I. Introduction

In PacifiCorp's general rate case filed in 2020, Docket No. UE 374, the Commission approved Schedule 29, a new time of use rate option pilot designed to help medium-sized non-residential customers who have very low load factors such as electric vehicle fast-charging equipment. Instead of charging traditional demand charges on a per kW basis, participants have energy charges that decline as their load factor increases with an added incentive to shift usage to off peak times through an off peak energy credit. Table 1 below shows how the current prices as of January 10, 2024 compare between optional Schedule 29 and standard non-residential Schedule 28 and Schedule 30:

Table 1. Comparison of Prices on Optional Schedule 29 and Schedule 28 and 30

Charge	Schedule 29 (Optional)	Schedule 28 (31-200 kW)	Schedule 30 (201-999 kW)
Energy Charge	**On Peak** - 28.324¢ per First Block kWh, 8.855¢ Additional kWh **Off Peak** - 27.585¢ per First Block kWh, 8.116¢ Additional kWh	8.786¢ per kWh	6.486¢ per kWh
Basic Charge	$36/Month	$18, $34, or $81 per Month (Depends on Load Size)	$126 or $334 per Month (Depends on Load Size)
Demand Charge	None	$6/kW	$11.98/kW
Load Size Charge	None	$1.15, $0.90, or $0.55 per kW (Depends on Load Size)	$1.55 or $0.75 per kW (Depends on Load Size)

Adoption for Schedule 29 has been slow. Only one customer has enrolled. This customer is a public DC fast charging station located in a remote location. The customer began taking service in May 2023 and has a very low load factor of about 0.5%. Because there is very little data on this pilot (one customer with a partial year of participation), the analysis in this report will be fairly limited.

II. Comparison to Alternative Rate Schedules

While Schedule 29 is not limited to a specific end use, one of its main purposes was to provide an new option that alleviated the very high average energy cost for electrification customers with low utilization. PacifiCorp also has a transition rate specific to electric vehicle chargers, Schedule 45, that was intended to ease the costs to these very low load factor customers until utilization increased. However, Schedule 45 is currently nearing the 8th year of the 10 year transition period to standard rates and low utilization of some charging stations still remains a barrier to electrification.

To better understand how Schedule 29 could provide savings for low load factor customers relative to standard general service rate schedules and to the current Schedule 45, a comparison of average price under different schedules for DC fast chargers was prepared. Bill estimates were calculated at 1%, 3%, and 5% load factors. Calculations were done assuming three common DC Fast Charger load size denominations of 150 kW, 250 kW, and 750 kW. Table 2 shows this average price comparison of Schedule 29 to other rate schedules alternatives.

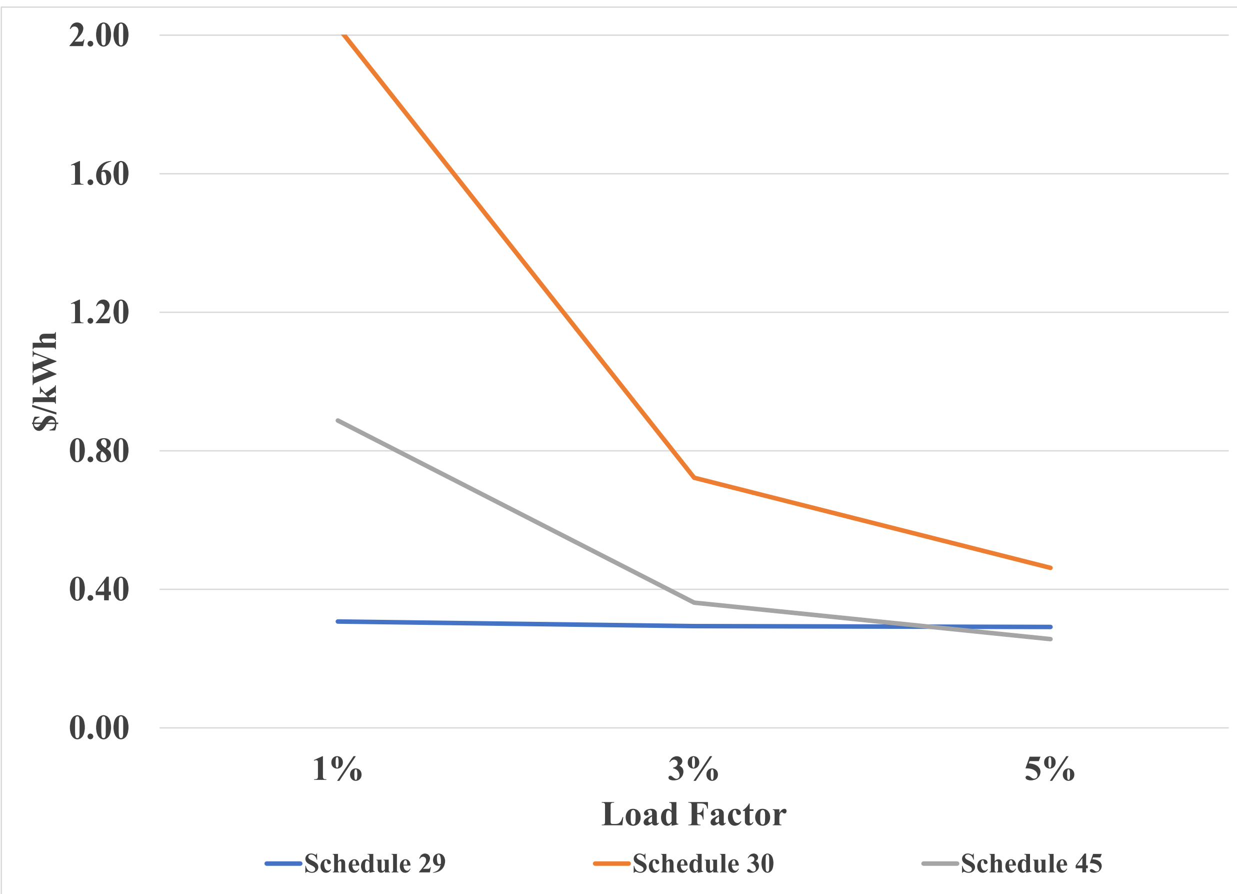
Table 2. Comparison of Average Price Across Different Load Sizes and Load Factors

Schedule 29			
Load Size	1% Load Factor ($/kWh)	3% Load Factor ($/kWh)	5% Load Factor ($/kWh)
150 kW	0.32	0.30	0.29
250 kW	0.31	0.29	0.29
750 kW	0.29	0.29	0.29
Schedule 28			
Load Size	1% Load Factor ($/kWh)	3% Load Factor ($/kWh)	5% Load Factor ($/kWh)
150 kW	1.08	0.42	0.29
250 kW			
750 kW			
Schedule 30			
Load Size	1% Load Factor ($/kWh)	3% Load Factor ($/kWh)	5% Load Factor ($/kWh)
150 kW			
250 kW	2.02	0.72	0.46
750 kW	1.90	0.68	0.44
Schedule 45			
Load Size	1% Load Factor ($/kWh)	3% Load Factor ($/kWh)	5% Load Factor ($/kWh)
150 kW	0.92	0.37	0.26
250 kW	0.89	0.36	0.26
750 kW	0.84	0.34	0.25

Table 2 shows that Schedule 29 has significantly lower average rates than other schedules at load factors below 5% and is comparable to the current Schedule 45 rates at a 5% load factor. Load factors for DC Fast Chargers are often less than 3%, with PacifiCorp's only adopter of Oregon Schedule 29 having a load factor of 0.5%. For this customer, Schedule 29 allows for a 33 cent per kWh rate as opposed to a rate that is upwards of a dollar per kWh on other rate schedules.

The lack of a demand charge means rates are relatively unaffected by very low load factors when compared to schedules that have a demand charge built in. Figure 1 below shows how significant this effect is at low load factors. These rate differences indicate that Schedule 29 operates as it was initially intended by helping to alleviate demand charges due to low load factor and keeping prices down for medium-sized non-residential customers, which can help support Oregon policy of supporting transportation electrification.

Figure 1. Comparison of Prices Across Load Factors for a 250 kW DC Fast Charger



III. Conclusion/Recommendation

Schedule 29 holds promise for helping to support transportation electrification, particularly for charging stations that experience low levels of utilization. Customer interest in program has been low, however electric vehicle fast charger customers may show greater interest in Schedule 29 as Schedule 45 nears its full transition to standard rates in May 2026. More promotion to key customers would raise awareness of this option for customers who could potentially benefit. A stronger time of use differential could also make Schedule 29 more attractive for customers who have greater control of the timing of their usage. It is recommended that Schedule 29 be converted from a pilot to an ongoing program.

Docket No. UE 433
Exhibit PAC/1916
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Calculation of Proposed Time-of-Use On-Peak Surcharges and Off-Peak Credits

February 2024

PacifiCorp
State of Oregon
12 Months Ended June 2023
Calculation of Proposed Time-of-Use On-Peak Surcharges and Off-Peak Credits

Schedule 23 Time-of-Use Option

Description	kWh	Price (¢/kWh)	Revenue
On-Peak	194,744,141	12.578	$24,494,495
Off-Peak	967,388,094	(2.532)	-$24,494,495
Total	1,162,132,235		$0

Schedule 29 Time-of-Use Option (Usages from Schedule 28 and 30 Proxies)

Description	kWh	Price (¢/kWh)	Revenue
On-Peak	552,952,067	13.014	$71,961,090
Off-Peak	2,842,038,720	(2.532)	-$71,961,090
Total	3,394,990,788		$0

Schedule 41 Time-of-Use Option

Description	kWh	Price (¢/kWh)	Revenue
On-Peak - Option A	11,109,862	12.030	$1,336,519
On-Peak - Option B	11,082,022	12.030	$1,333,170
Off-Peak	99,032,240	(2.696)	-$2,669,689
Total	121,224,125		$0

Western Energy Imbalance Market
36 Months Ended June 2023
Average of ELAP_PACE-APND, ELAP_PACW-APND, and MALIN_5_N101 Nodes

	Hour Ending PT																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
7	35.16	30.13	28.17	27.18	27.62	30.38	27.18	27.17	26.93	29.32	31.93	35.23	36.51	39.97	44.29	47.40	52.89	57.09	68.21	80.47	59.64	48.28	41.37	35.24
8	45.71	42.03	39.88	39.16	39.95	43.32	43.01	38.59	35.67	37.19	39.35	42.67	45.29	53.73	59.23	66.56	67.40	79.82	110.53	99.29	63.66	54.03	51.04	45.81
9	45.68	43.98	42.03	41.48	42.85	46.84	48.90	45.64	40.86	41.08	41.15	43.70	45.16	51.66	56.50	66.79	78.68	106.55	137.74	124.72	75.75	60.61	54.35	47.52
10	43.81	42.10	40.64	40.51	42.99	47.20	50.20	51.66	47.54	45.34	44.40	43.39	45.86	43.78	44.88	46.97	49.23	68.06	74.99	58.01	53.02	50.50	49.41	44.56
11	46.05	45.24	45.32	45.88	49.19	53.63	55.91	52.65	49.17	45.05	44.25	42.62	40.94	40.24	42.30	53.39	66.20	75.48	62.29	61.04	57.63	53.87	53.14	47.81
12	90.47	87.30	86.53	86.96	94.43	104.32	109.29	108.94	103.03	96.82	93.01	90.18	84.77	81.22	87.06	102.37	126.83	136.37	124.53	120.33	117.25	111.13	103.44	92.50
1	61.13	59.25	59.31	60.42	63.67	69.69	75.92	78.21	65.19	61.38	56.91	53.10	49.75	47.87	50.45	62.36	77.58	82.47	80.64	77.01	73.32	67.92	66.30	61.05
2	48.20	46.83	46.88	47.67	52.80	60.90	65.65	56.88	42.83	38.34	35.88	32.38	29.98	26.61	28.43	35.88	53.11	73.91	83.30	74.05	64.84	59.71	55.17	49.52
3	43.60	42.03	41.29	42.47	46.16	53.36	58.37	54.55	44.89	41.56	37.47	33.70	28.93	25.99	25.46	30.27	35.39	45.94	55.07	61.37	57.46	54.01	51.28	45.37
4	48.71	44.65	43.39	43.36	48.75	55.84	57.70	49.80	44.19	41.41	37.62	35.10	34.50	31.37	31.71	33.31	36.90	46.35	60.27	76.39	73.88	64.22	58.68	50.66
5	26.21	24.70	23.64	22.22	24.75	30.24	27.15	22.56	20.13	20.25	19.94	19.38	24.15	24.09	22.53	24.45	25.84	29.79	40.04	44.61	42.47	36.04	35.95	29.49
6	23.65	20.50	18.98	18.93	19.06	22.96	19.10	19.02	19.72	21.50	22.94	23.86	26.71	27.43	28.30	30.17	32.59	35.59	39.21	45.66	44.77	33.38	33.11	26.98

Schedule 23/ Schedule 29 Time of Use

On-Peak	72.52
Off-Peak	47.20
Difference	$\boxed{(25.32)}$

Western Energy Imbalance Market
36 Months Ended June 2023
Average of ELAP_PACE-APND, ELAP_PACW-APND, and MALIN_5_N101 Nodes

	Hour Ending PT																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
7	35.16	30.13	28.17	27.18	27.62	30.38	27.18	27.17	26.93	29.32	31.93	35.23	36.51	39.97	44.29	47.40	52.89	57.09	68.21	80.47	59.64	48.28	41.37	35.24
8	45.71	42.03	39.88	39.16	39.95	43.32	43.01	38.59	35.67	37.19	39.35	42.67	45.29	53.73	59.23	66.56	67.40	79.82	110.53	99.29	63.66	54.03	51.04	45.81
9	45.68	43.98	42.03	41.48	42.85	46.84	48.90	45.64	40.86	41.08	41.15	43.70	45.16	51.66	56.50	66.79	78.68	106.55	137.74	124.72	75.75	60.61	54.35	47.52
10	43.81	42.10	40.64	40.51	42.99	47.20	50.20	51.66	47.54	45.34	44.40	43.39	45.86	43.78	44.88	46.97	49.23	68.06	74.99	58.01	53.02	50.50	49.41	44.56
11	46.05	45.24	45.32	45.88	49.19	53.63	55.91	52.65	49.17	45.05	44.25	42.62	40.94	40.24	42.30	53.39	66.20	75.48	62.29	61.04	57.63	53.87	53.14	47.81
12	90.47	87.30	86.53	86.96	94.43	104.32	109.29	108.94	103.03	96.82	93.01	90.18	84.77	81.22	87.06	102.37	126.83	136.37	124.53	120.33	117.25	111.13	103.44	92.50
1	61.13	59.25	59.31	60.42	63.67	69.69	75.92	78.21	65.19	61.38	56.91	53.10	49.75	47.87	50.45	62.36	77.58	82.47	80.64	77.01	73.32	67.92	66.30	61.05
2	48.20	46.83	46.88	47.67	52.80	60.90	65.65	56.88	42.83	38.34	35.88	32.38	29.98	26.61	28.43	35.88	53.11	73.91	83.30	74.05	64.84	59.71	55.17	49.52
3	43.60	42.03	41.29	42.47	46.16	53.36	58.37	54.55	44.89	41.56	37.47	33.70	28.93	25.99	25.46	30.27	35.39	45.94	55.07	61.37	57.46	54.01	51.28	45.37
4	48.71	44.65	43.39	43.36	48.75	55.84	57.70	49.80	44.19	41.41	37.62	35.10	34.50	31.37	31.71	33.31	36.90	46.35	60.27	76.39	73.88	64.22	58.68	50.66
5	26.21	24.70	23.64	22.22	24.75	30.24	27.15	22.56	20.13	20.25	19.94	19.38	24.15	24.09	22.53	24.45	25.84	29.79	40.04	44.61	42.47	36.04	35.95	29.49
6	23.65	20.50	18.98	18.93	19.06	22.96	19.10	19.02	19.72	21.50	22.94	23.86	26.71	27.43	28.30	30.17	32.59	35.59	39.21	45.66	44.77	33.38	33.11	26.98

Irrigation Time of Use

On-Peak - Option A	65.27
On-Peak - Option B	81.91
Option A/B Average	73.59
Off-Peak	46.63
Difference	(26.96)

Docket No. UE 433
Exhibit PAC/1917
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Cost of Eliminating Payment Fees

February 2024

PacifiCorp
State of Oregon
Cost of Eliminating Payment Fees
12 Months Ending June 2023

Description	Fee Count	Fee	Total Annual Cost
Pay Station	69,133	$1.65	$114,069
Residential Card Payment	1,319,531	$1.99	$2,625,867
Non-Residential Card Payment	258,901	$7.99	$2,068,619
Total	1,647,565		**$4,808,555**