BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKETS UE-240004 & UG-240005 (Consolidated)

CROSS-EXAMINATION EXHIBIT OF JOHN D. TAYLOR
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT JDT-__X

Direct Testimony of John D. Taylor

October 28, 2024

EXH. JDT-1T
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: JOHN D. TAYLOR

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

JOHN D. TAYLOR

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

PUGET SOUND ENERGY

**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
JOHN D. TAYLOR**

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I. INTRODUCTION

Q. Please state your name, affiliation, and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Puget Sound Energy ("PSE" or the "Company").

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

A. Yes; it is Exh. JDT-2.

Q. What is your assignment in this proceeding?

A. PSE requested Atrium Economics to conduct a fully allocated cost of service study to determine the embedded costs of serving its gas distribution customers and support its rate design efforts. In this regard, I am sponsoring the Gas Cost of Service Study ("COSS") that allocates PSE's gas distribution costs to the gas distribution customer rate classes. Related to rate design I am supporting the class revenue increase apportionment and proposed rate design for gas service. I am also sponsoring the normalized and forecasted revenues from gas operations and the updated allowed revenue for PSE's gas decoupling mechanism. Lastly, I am also supporting the revenue impacts of the proposed rates.

Q. Please summarize your testimony.

A. My testimony consists of this introduction and summary section and the following additional sections:

- Development of Normalized Test Year Revenues;
- Development of Projected Rate Year Revenues;
- Purpose and Principles of Cost of Service Studies;
- PSE's Cost of Service Study;
- Principles of PSE's Rate Design;
- Revenue Apportionment among Customer Classes;
- PSE's Rate Design Proposals; and
- Updated Allowed Revenue and Revenue Per Unit for PSE's Gas Decoupling Mechanism.

II. NORMALIZED TEST YEAR REVENUE FROM GAS OPERATIONS

Q. Are you presenting both the development of the normalized test year revenues from gas operations and the projected rate year revenues from gas operations?

A. Yes. I first describe the process used to develop the normalized revenue for the test year and then provide a description of the development of the projected revenue for each rate year based on forecasted rate year billing determinants. Exh. JDT-3 demonstrates PSE's development of its normalized test year revenue from natural gas operations and the projected revenue for each rate year.

Q. What is normalized test year revenue?

A. Normalized test year revenue is an estimate of test year revenue based on normalized and proformed test year billing determinants (e.g., energy sales, billed demand, number of bills) and the rates in place when filing for a rate change. It is developed to make the test year revenue used in calculating the revenue deficiency: (1) reflect only those rate schedules that are being considered in the present case; (2) encompass any rate changes that have taken place during or since the test year; and (3) align with the normalized test year revenue requirement and loads.

Q. Please explain the first worksheet within Exh. JDT-3, which shows the development of pro forma revenue by rate schedule.

A. The first worksheet ('Exh. JDT-3 (Revenue)') within Exh. JDT-3 presents calculations of the differences between test year revenue, as presented in PSE's income statement, and normalized test year revenue, as calculated based on billing determinants and rates. The revenue included in the test year income statement is presented in column B, and normalized test year revenue based on billing determinants and current rates is in column N. The items presented in columns C through M are explanations of the differences between the income statement and normalized test year revenue. These items are related to:

1. removal of revenue from municipal taxes and adjusting price schedules (columns C-G);
2. other restating adjustments that primarily correspond to non-consumption, miscellaneous accounts receivable and billing corrections (column H);
3. adjusting for price changes that took place during or after the test year, specifically the 2022 general rate case rates that were effective on January 7, 2023 (column I);
4. adjusting for a large schedule 87T customer that shut down operations in 2023 (column J);
5. adjusting to move revenues from Puget LNG service from schedule 87T to schedule 88T. PSE proposed schedule 88T in docket UG-230393, which is pending before the Commission (column K); and
6. adjusting to reflect the weather adjustment to volume (column L).

The remaining columns of the worksheet 'Exh. JDT-3 (Revenue)' within Exh. JDT-3 are discussed in Section III of this testimony.

Q. Will rates in any of the adjusting gas price schedules in Columns D through G of the worksheet 'Exh. JDT-3 (Revenue)' within Exh. JDT-3 change as a result of this filing?

A. Yes. Rates within Schedule 141N (Rates Not Subject to Refund Rate Adjustment) and Schedule 141R (Rates Subject to Refund Rate Adjustment) will be set to zero as discussed in the Prefiled Direct Testimony of Christopher T. Mickelson, Exh. CTM-1T.

Q. Please explain the second worksheet 'Exh. JDT-3 (Volume)' of Exh. JDT-3, which shows the development of volumes (therms) by rate schedule.

A. As mentioned above, normalized test year revenue is based on test year billing determinants, which are largely based on normalized energy sales. PSE's adjustments to test year natural gas throughput for this case are summarized in the worksheet 'Exh. JDT-3 (Volume)' within Exh. JDT-3. Column B on worksheet Exh. JDT-3 (Volume)' shows the actual volume of sales and transportation therms for the twelve months ending June 30, 2023. The removal of the annual therms of the large schedule 87T customer that shut down operations in 2023 is shown in column C. The adjustment to move the annual therms for Puget LNG from schedule 87T to proposed schedule 88T is shown in Column D. The weather normalization adjustment to gas volume presented in column E removes the effect of non-normal temperatures from test year loads, so the test year loads and revenues are more reflective of normal weather conditions. Normalized test year volume that reflects these adjustments is totaled in column F and is used for calculating normalized test year revenues as presented in the worksheet 'Exh. JDT-3 (Revenue)' of Exh. JDT-3, as described above.

III. PROJECTED RATE YEAR REVENUES FROM GAS OPERATIONS

Q. What are projected rate year revenues?

A. Projected revenues for each rate year are an estimate of rate year revenue based on forecasted rate year billing determinants and the rates that are in place at the time of filing for a rate change.

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

A. Rate year revenues are developed for each of the multiyear rate periods (year one and year two) by multiplying the forecasted billing determinants for each year by current rates, resulting in projected rate year revenues.

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

A. PSE's F2023 forecast approved by its Energy Management Committee in spring 2023 was used for developing the projected rate year revenues. This forecast was adjusted to remove the schedule 87T billing determinants for the large customer that shut down operations during 2023.

Q. What portions of Exh. JDT-3 present the calculation of the projected rate year revenues?

A. The first worksheet 'Exh. JDT-3 (Revenue)' of Exh. JDT-3, described above, presents the calculation of forecasted revenues. This worksheet illustrates the development of pro forma revenue by rate schedule in columns O-T, which provide the resulting revenue adjustments and total adjusted revenue for each of the rate years. The total adjusted revenues are the result of the forecasted billing determinants multiplied by current rates. Similarly, the second worksheet 'Exh. JDT-3 (Volume)' of Exh. JDT-3, described above, contains additional columns I-N which provide the forecasted volumes by rate schedule for each rate year.

Q. Please explain the third worksheet 'Exh. JDT-3 (Load Analysis)' in Exh. JDT-3 which shows the estimated effect of the F2023 forecast on the proposed rate increase compared to PSE's 2022 general rate case.

A. The change in forecasted load influences the proposed revenue requirement. By using the F2023 forecast, the revenue forecast remains accurate and responsive to forecasted changes in energy consumption patterns, thereby informing decisions on rate structures. Utilizing the load from the F2023 forecast resulted in a $64.6 million increase in required revenue due to decreased energy demands as compared to PSE's 2022 general rate case.

IV. PURPOSE AND PRINCIPLES OF COST ALLOCATION

Q. Please describe the general purpose and approach used to develop a COSS.

A. The purpose of a COSS is to allocate a utility's overall adjusted test year costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished through analyzing costs and assigning each customer or rate class its proportionate share of the utility's total costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility. In order to allocate costs to the various classes, a cost analyst reviews expense and plant accounts and develops studies of the relative costs of providing facilities and services for each rate class and analyzes the key factors that cause the costs to vary. As further detailed within this testimony, another primary consideration in developing the studies and analyses for this multiyear rate proceeding is a recent update to the rules for general rate case proceedings that requires an electric or natural gas utility to include in its rate case filing a COSS that complies with WAC 480-85.

Q. Is there a guiding principle that can support the appropriate allocation of costs?

A. Although there may not be a perfect methodology for allocating costs, there is a fundamental foundational principle—cost causation—which should be followed to produce more accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs so the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. In other words, the costs assigned or allocated to particular customers should be the costs that those particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. How does one establish the cost and utility service relationships?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records, and its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocations are determined and utilized for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term "direct assignment" means assigning costs to a specific customer or class of customers based on that customer's or class's exclusive identification with the particular plant or expense at issue. Usually, costs that are directly assigned relate to costs incurred exclusively to serve a specific customer or class of customers. For example, the mains associated with the special contracts class are directly assigned to that class based on a special study. An alternative to direct assignment is an allocation methodology based on analyzing factors that affect the relative costs of serving particular customer classes. For example, in this proceeding, I developed a relative cost study for meter and service investment costs.

Q. What are the steps in performing a COSS?

A. In order to establish the cost responsibility of each customer class, initially a three-step analysis of the utility's total operating costs must be undertaken. The three steps that are the predicate for a COSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. PSE's primary functional cost categories associated with gas service include, production, storage, transmission, distribution, and sales-specific and customer-specific costs. Indirect costs that support these functions, such as general plant and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios.

Q. Please describe cost classification.

A. The second step, classification of costs, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the system; and (3) the amount of gas consumed by customers. These classification categories have been identified for purposes of the COSS as (a) customer costs, (b) demand costs, and (c) commodity costs, respectively.

Q. Please describe the types of costs contained in the customer costs, demand costs and commodity costs categories.

A. Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand related costs (sometimes referred to as capacity costs) are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related cost component relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company to serve its sales customers.

Q. Please describe the cost allocation process.

A. The final step is the allocation of each functionalized and classified cost element to the individual customer classes. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors. For example, each customer requires a meter, yet meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service.

V. PSE'S COST OF SERVICE STUDY

A. Process Steps and Structure of the COSS

Q. What are the factors that can influence the overall cost allocation framework utilized by a gas utility when performing a COSS?

A. The factors that can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting PSE's COSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the State of Washington as it pertains to cost of service studies and gas ratemaking issues, and in particular Ch. 480-85 WAC, which was adopted by the Washington Utilities and Transportation Commission ("Commission") in Docket UG-170003.

Q. How do state regulatory policies bear upon a utility's COSS?

A. State regulatory policies and requirements prescribe whether there is a particular approach used to establish utility rates in the state. Specifically, state regulations set forth the methodological preferences or guidelines for performing cost studies or designing rates that can influence the particular cost allocation method utilized by the utility. Of particular consideration for the cost of service analyses prepared for this case is a recent amendment to the Commission's procedural rules for general rate case proceedings that requires an electric or natural gas utility to include in its rate case filing a COSS that complies with WAC 480-85.

Q. What requirements are set by the cost of service rules embodied in WAC 480-85?

A. In its Final Order in Avista Corporation's 2016 general rate case, the Commission instructed its staff to initiate a collaborative effort with the investor-owned utilities in Washington and interested stakeholders to more clearly define the scope and expected outcomes for generic cost of service proceedings in an effort to establish greater clarity and uniformity in future cost of service studies.[1] PSE participated in Commission Staff's information gathering efforts and multiple workshops over three years as the collaborative evolved into the rulemaking proceeding in Dockets UE-170002 and UG-170003. The result of this proceeding was a set of new cost of service rules requiring electric and gas utilities to file a cost of service model in compliance with both the presentation requirements and new data requirements associated with the allocation methods in WAC 480-85. These rules specify the functionalization, classification, and allocation methods for various accounts in the Uniform System of Accounts adopted by the Federal Energy Regulatory Commission ("FERC"). The methods required by the new rules still require analyses of data and various subsidiary studies to develop the inputs to the cost of service study. These are discussed in detail below, in Section V.

Q. Is the overall cost allocation approach utilized in PSE's COSS consistent with that utilized in PSE's most recent rate case?

A. Yes. In PSE's most recent case (Docket UE-220066, *et al.*), modifications were made to the methods historically applied by PSE to confirm the filed COSS was in conformance with the methods prescribed by the new cost of service rules in WAC 480-85. Similar to the 2022 rate case, PSE is filing two COSS methods, one that fully complies with WAC 480-85 and one that complies with all aspects of WAC 480-85 except for the functionalization of FERC Account 870; a distribution

[1] *WUTC v. Avista Corp.*, Docket UE-160228, *et al.*, Order 06, ¶116 (Dec. 15, 2016).

operations account that WAC 480-85-060 requires to be functionalized as Transmission.

Q. With respect to FERC Account 870, what are the differences between PSE's proposed COSS model and the COSS model that complies with WAC?

A. WAC 480-85-060 requires FERC Account 870 (Operation supervision and engineering) to be functionalized as Transmission. As such, the WAC rules-compliant COSS model functionalizes Account 870 as Transmission. However, Account 870 relates to the distribution system and is properly functionalized as Distribution within the proposed COSS model.

Q. What was the source of the cost data analyzed in PSE's COSS?

A. All cost of service data has been extracted from PSE's total cost of service (i.e., total revenue requirement) and subsidiary schedules contained in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from PSE's historical books and records and information provided by Company personnel.

Q. How are the PSE customer classes structured for purposes of the COSS?

A. The COSS is summarized in Exh. JDT-4. For PSE's COSS, I evaluated eight customer classes:

- Residential Service (Tariff Schedules 16, 23, and 53);
- Commercial and Industrial Service (Tariff Schedules 31 and 31T);

- Large Volume Service (Tariff Schedules 41 and 41T);
- Interruptible Service (Tariff Schedules 85 and 85T);
- Limited Interruptible Service (Tariff Schedules 86 and 86T);
- Non-Exclusive Interruptible Service (Tariff Schedules 87 and 87T);
- Exclusive Interruptible Service (Tariff Schedule 88T); and
- Special Contracts.

Q. Does the COSS include gas commodity costs or gas resource demand costs?

A. The COSS does not include gas commodity costs or gas resource demand costs because these costs are recovered through PSE's Purchased Gas Adjustment ("PGA") mechanism.

B. Allocation of Gas Plant Costs and Operating Expenses

Q. What are the similarities and differences in the cost allocation approach utilized in PSE's proposed COSS in this proceeding with that utilized in PSE's 2022 general rate case COSS?

A. The methods used in the WAC rules-compliant COSS model are similar to those used in PSE's 2022 general rate case with the addition of direct assignment of a portion of costs associated with a section of distribution mains that is directly assignable to the new Exclusive Interruptible Service (Rate 88T), an approximately one-mile section of pipe near the Golden Givens measuring and regulating station ("Golden Givens Section"). In PSE's 2022 general rate case the proposed COSS model reflected two differences from the WAC rules-compliant

COSS: (1) the treatment of Tacoma LNG Facility mains recorded as distribution mains, and (2) the functionalization and allocation of FERC Account 870. As described above the proposed PSE COSS model functionalizes FERC Account 870 as Distribution, whereas WAC 480-85 requires Account 870 to be functionalized as Transmission. As such, this is similar to the last case. However, in PSE's 2022 general rate case, the proposed PSE COSS model functionalized a portion of the Distribution Mains plant associated with the Tacoma LNG facility ("Four-Mile 16-Inch Section") as storage and allocated those costs only to sales customers using retail design day system peak demand. That is not required in this proceeding because the costs of the Distribution Mains plant associated with the Four-Mile 16-Inch Section are currently recovered in the Company's Schedule 141D Distribution Pipeline Provisional Recovery Adjustment and are not included in the revenue requirement nor the COSS models. As indicated above, a portion of the costs of the Golden Givens Section have been directly assigned to Rate 88T. As such, the direct assignment of mains relating to the Tacoma LNG facility differs from the last rate case.

Q. Were direct assignments of plant made in the PSE COSS?

A. Yes. PSE conducted an analysis to identify the costs in FERC Account 380 – Services that are dedicated to customers on gas Schedules 85/85T, 86/86T, 87/87T, 88T and Special Contracts. The dedicated portion of plant in FERC Account 380 was directly assigned to these customer classes, and the remainder was allocated to all other gas customer classes based on class average service installation cost as specified in WAC 480-85-060.

With regard to the Special Contracts customer class, a special study was performed in preparation for the 2019 general rate case to determine the specific distribution mains that are utilized to serve PSE's Special Contracts customers. The plant costs related to these facilities were directly assigned to the Special Contracts class in the COSS. The Company's geographic information system ("GIS") was queried to research the various pipeline pathways from system regulator stations to the customers' service addresses along with the related pipeline sizes and material types. Historical plant records were utilized to obtain the necessary cost information to complete the direct assignment of the mains plant costs to the Special Contracts class. The 2019 study was updated with newly derived unit costs for mains and the removal of one location no longer in service under the Special Contracts class and was relied upon in the development of the direct assignment of distribution mains for the COSS models presented in this filing.

With regard to the direct assignment of costs of the Golden Givens Section to Rate 88T, the actual costs incurred for the Golden Givens Section were gathered from the Company's plant accounting records and 54 percent[2] of those costs were directly allocated to Schedule 88T.

[2] The allocation of 54 percent of the costs of the Golden Givens Section is consistent with the cost allocation percentages for distribution upgrade costs at the Golden Givens station that were determined at the time the Tacoma LNG Facility was being constructed and were approved in Order No. 10 in PSE's

Q. Were other facilities allocated to Schedule 88T through the development and application of allocation factors in the COSS?

A. Yes. I developed a relative cost study for investment costs relating to meters (FERC Accounts 381, 382, 383, and 384), industrial measuring and regulating equipment (FERC Account 385), and services (FERC Account 380). As indicated above, PSE conducted an analysis to identify the costs in FERC Account 380 – Services that are dedicated to customers on gas Schedules 85/85T, 86/86T, 87/87T, 88T, and Special Contracts, and I directly assigned those costs to these customer classes. In addition, the metering equipment relating to Schedule 88T is recorded in FERC Account 385 and thus the relative cost study included measuring and regulating equipment that was identified as providing service to Schedule 88T. Lastly, the services study (FERC Account 380) included service costs providing service to Schedule 88T. In short, these relative cost studies follow the same methods utilized in the Company's 2022 general rate case but now include assets identified as providing service to Schedule 88T.

Q. Did you make any other refinements to the underlying studies in preparing this filing?

A. Yes. The Jackson Prairie storage facility serves both seasonal storage supply and system balancing functions. Since the Company's 2001 general rate case

prior multiyear rate case. *See* Dockets UE-220066 and UG-220067/210918 (consolidated), Final Order 24/10 ¶ 449, dated Dec. 22, 2022 ("Order 24/10"). *See also* the Second Exhibit to the Prefiled Direct Testimony of William F. Donahue, Exh. WFD-3, that was filed in Docket UG-230393, which supports the allocation percentages to the Golden Givens Section.

(UG-011571) PSE has utilized the same method in determining the portion of the Jackson Prairie storage facility that relates to the seasonal storage supply and system balancing. This method analyzes the daily movement of gas across the Company's system including Jackson Prairie's daily withdrawal and injections and the nominations and actual gas used by the Company's transportation and sales customers. In the Company's 2022 general rate case, this method determined that 21 percent of Jackson Prairie storage costs relate to providing system balancing. In the 2022 general rate case the Alliance of Western Energy Consumers filed response testimony claiming that none of Jackson Prairie's costs related to system balancing. One of their criticisms was that the analysis conducted by PSE did not exclude days when no injections or withdrawals occur at Jackson Prairie. The method used in this filing now excludes those days (20 out of 365 days during the test year) and finds that 20.8 percent of Jackson Prairie storage costs relate to providing system balancing. The 20.8 percent is based on a four-year average inclusive of the test year.

Q. How did the COSS allocate distribution-related gas operation and maintenance ("O&M") expenses?

A. In general, the distribution O&M expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of particular plant facilities necessitates the incurrence of cost, i.e., expenses incurred by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account 887, Maintenance of Mains, is allocated on the same basis as its corresponding plant accounts, Mains – Account 376. With the detailed analyses supporting the assignment or allocation of major plant in service components, where feasible, it was appropriate to rely upon those results in allocating related O&M expenses. As explained above, one difference between the proposed COSS model and the WAC rules-complaint COSS model is the functionalization of FERC account 870; where the proposed model functionalizes this cost as Distribution and WAC 480-85 requires this account to be functionalized as Transmission.

Q. How were administrative and general ("A&G") expenses and taxes allocated to each gas customer class?

A. A&G expenses were allocated on an account-by-account basis. Items related to labor costs, such as employee pensions and benefits, were allocated based on O&M labor costs. Items related to plant, such as maintenance of general plant and property taxes, were allocated based on plant. Items related to revenue, such as regulatory commission expenses, were allocated based on revenue. All other A&G costs were allocated based on O&M expenses.

Q. Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.

A. The reserve for depreciation and depreciation expenses were allocated by function in proportion to their associated plant accounts.

Q. How did the COSS allocate taxes other than income taxes?

A. The study allocated all taxes, except for income taxes, in a manner which reflected the specific cost associated with the particular tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category, i.e., payroll, property, or revenue. Typically, taxes of a utility other than income taxes can be grouped into the following categories: (1) labor; (2) plant; and (3) revenue. In the PSE COSS, all non-income taxes were assigned to labor, plant, or revenue which were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. How were income taxes allocated to each customer class?

A. Current income taxes were allocated based on each individual class's operating income. Income taxes at an equal rate of return were allocated to each class based on the allocation of rate base to each class.

Q. Have you provided an exhibit with the results of the PSE-proposed and WAC rules-compliant COSS models?

A. Yes. See Exh. JDT-4 for the results of these models. This exhibit includes the gas cost of service template that is required by the Commission and contains Schedules A-E. There are two sets of B, C, and E schedules the first set, 'B-COS Results (WAC)', 'C-COS Allocation Factors (WAC)', and 'E-Summary of Results (WAC),' that result from the COSS model that complies with WAC 480-85, and a second set, 'B-COS Results (PSE)', 'C-COS Allocation Factors (PSE)', and 'E-Summary of Results (PSE),' that aligns with PSE's proposed treatment of FERC Account 870.

C. PSE's Cost of Service Study Results

Q. Have you prepared a summary of the PSE-proposed COSS results?

A. Yes. Exh. JDT-4, worksheet 'E-Summary of Results (PSE)', summarizes the results of PSE's COSS model. This exhibit presents the resulting allocation by customer class of PSE's proposed revenue requirement based strictly on the results of the computations included in the COSS. The revenue-to-cost ratios and parity ratios under current rates, presented on this schedule, are summarized in Table 1 below. The revenue-to-cost ratios portray the ratio between the cost to serve these customers and the normalized test year revenues collected from these customers. The parity ratios portray the relative difference between the revenues currently recovered from each class and the costs to serve each class at the system average rate of return. A revenue-to-cost ratio below 1.00 means that the current rates and revenues of the particular customer class are below its indicated cost of service, while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the customer class are above its indicated cost of service. The parity ratio provides insights into the relative differences across the classes once all classes are adjusted for system-level over- or under-recovery. These results provide cost guidelines for use in evaluating a utility's class revenue levels and rate structures.

Table 1 - Results of Gas Cost of Service Studies

Customer Class	**Schedule**	**Revenue-to-Cost Ratio**	**Parity Ratio**
Residential	16/23/53	0.92	1.10
Commercial & Industrial	31/31T	0.68	0.81
Large Volume	41/41T	0.79	0.94
Interruptible	85/85T	0.71	0.85
Limited Interruptible	86/86T	1.10	1.31
Non-exclusive Interruptible	87/87T	0.48	0.57
Exclusive Interruptible	88T	0.97	1.15
Special Contracts		1.90	2.26
Total/System Average		0.84	1.00

As can be observed in the column 'Revenue-to-Cost Ratio' in the above table, all customer classes except Limited Interruptible and Special Contracts show under-recovery of the costs to serve them. From a parity perspective, Schedules 16, 23, and 53 as well as Schedules 41 and 41T are relatively close to unity with the overall system revenue-to-cost ratio, whereas the other customer schedules (31, 31T, 85, 85T, 86, 86T, 87 and 87T) show further disparity from unity with the overall system revenue-to-cost ratio.

VI. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design utilized to develop rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature, including:

1. cost of service;
2. efficiency;
3. value of service;
4. stability/gradualism;
5. non-discrimination;
6. administrative simplicity; and
7. balanced budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in *Principles of Public Utility Rates*. Each of these principles plays an important role in analyzing the rate design proposals of PSE.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, these principles can compete, and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual competition between these principles. Bonbright discusses this tension in detail and rate design recommendations must deal effectively with the tension. There are tensions between cost and value of service principles as well as efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. How are these principles translated into the design of retail gas rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity, the rate design process has to be, in part, influenced by judgmental evaluations.

VII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate PSE's proposed revenue increase for the rate years to its customer classes.

A. As just described, the apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in PSE's process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. Based on the parity ratios shown above in Table 1 and the desire to move toward full parity over time, PSE proposes to:

1. apply 90 percent of the system average increase to Schedules 16, 23, and 53;
2. apply 110 percent of the system average increase to Schedules 41 and 41T;
3. apply 125 percent of the average increase to Schedules 31, 31T, 85, and 85T;
4. apply 150 percent of the average increase to Schedules 87 and 87T;
5. apply 75 percent of the average increase to Schedule 86 and 86T; and
6. set Schedule 88T rates to full parity.

The proposed revenue allocation by rate class of the proposed increase for rate years one and two is presented in the worksheet 'Exh. JDT-5 (Rate Spread)' in Exh. JDT-5. This revenue allocation approach resulted in the reasonable movement of all classes' revenue-to-cost ratios toward unity or 1.00. From a class cost of service standpoint, this type of class movement and reduction in the existing class rate subsidies is desirable. Table 2 below shows the movement of all classes towards parity using the test year deficiency.

Table 2 - Results of Proposed Rate Spread

Customer Class	Schedule	Current Parity Ratio	Proposed Parity Ratio	Percentage Increase
Residential	16/23/53	1.10	1.08	17.04%
Commercial & Industrial	31/31T	0.81	0.85	24.34%
Large Volume	41/41T	0.94	0.96	21.06%
Interruptible	85/85T	0.85	0.88	23.90%
Limited Interruptible	86/86T	1.31	1.23	11.69%
Non-exclusive Interruptible	87/87T	0.57	0.62	29.12%
Exclusive Interruptible	88T	1.15	1.00	3.19%
Special Contracts		2.26	2.05	7.86%
Total/System Average		1.00	1.00	19.06%

Q. What changes are being proposed to the Special Contracts rates?

A. As is shown in Table 2, the Special Contracts rates will increase by 7.86 percent. This rate increase is governed by the conditions in the special contracts between these customers and PSE that specify how any base rate changes will be applied to these customers.

Q. What changes are being proposed to Schedule 88T rates?

A. PSE is proposing to set Schedule 88T rates to recover the full cost to serve Schedule 88T as indicated by the COSS model. Certain costs to serve Schedule 88T are included in Schedule 141D which is suspended per Docket UG-230393.

VIII. PSE'S RATE DESIGN PROPOSALS

Q. Please summarize the rate design changes PSE has proposed in this rate proceeding.

A. PSE is proposing to realign pricing components for existing customer classes over multiple rate years by moving towards the unit cost to serve. The proposal includes a potential for an up to 30 percent increase in monthly customer charges and an 18 percent increase in demand charges, to maintain these charges at or below the respective unit costs within the COSS results. There are a few exceptions to this:

- PSE is proposing no changes to the basic charge for Schedules 31T, 41T, and 86T. Historically the difference between the sales and transportation basic charges represented processes required to work with transportation customers; unique to the fact they are transportation customers, (e.g., gas scheduling, gas control, measuring, and metering). Over time these processes were automated and no longer require the same level of dedicated personnel. The Company is proposing to move the sales and transportation basic charges for each rate schedule closer to equivalency over the two rate years in this multiyear rate filing, with full equivalency reached for Schedule 85/8T and Schedule 87/87T.

- The procurement charges for sales Schedules 31, 41, 85, 86, and 87 were increased by the class average increase for each of the two rate years up to a maximum of the unit rates indicated in the COSS model and presented in the worksheet 'Exh. JDT-5 (Procmnt Chrg)' of Exh. JDT-5.

Q. Is PSE proposing to move each customer class's demand charge fully to its cost of service?

A. No. There is a significant variation in demand-related costs for each customer class. Certain classes have much higher demand-related costs than others, depending largely on the level of firm use by the customer class. However, given these significant variations, PSE is proposing to move demand rates incrementally closer to demand cost unit rates indicated in the COSS model.

Q. Have you provided an exhibit that depicts the proposed rates for all classes of service and corresponding revenues to show that PSE's proposed rates generate the total distribution revenue and total revenue increase it has proposed in this proceeding?

A. Yes. The worksheet 'Exh. JDT-5 (Rate Design)' shows the derivation of each rate component for each of PSE's tariff schedules and the corresponding revenues generated from those proposed rates. Worksheet 'Exh. JDT-5 (Procmnt Chrg)' provides details on the procurement charge and worksheet 'Exh. JDT-5 (141DCARB)' shows the proposed decarbonization rate adjustment rates.

Q. How were rates developed for the newly proposed Schedule 141DCARB decarbonization rate adjustment?

A. The amounts set for recovery in Schedule 141DCARB for each rate year are presented within the worksheet 'Exh. JDT-5 (141DCARB)' of Exh. JDT-5. The development of these amounts is supported by Susan E. Free in Exh. SEF-23. For the rate spread, PSE proposes to use an allocator based on 50 percent customer counts and 50 percent margin revenue from the test year to apportion the Schedule 141DCARB revenue requirement to all customer classes. For the rate design, PSE proposes to recover these costs through a volumetric charge. For additional information on the decarbonization rate adjustment, please see the Prefiled Direct Testimony of Christopher T. Mickelson, Exh. CTM-1T.

IX. PROPOSED GAS RATE IMPACTS

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

A. Several gas rider schedules will be reset concurrent with the effective date of new base gas rates resulting from this multiyear rate case. Specifically, the impacts of the base gas rate changes must be added to the impacts of gas rate changes associated with the concurrent changes to PSE's Schedule 141N (Rates Not Subject to Refund) and Schedule 141R (Rates Subject to Refund). The bill impacts also incorporate the new proposed Schedule 141DCARB (Decarbonization Rate Adjustment). The combined impact of these changes, based on rates currently in effect using forecasted billing determinants for each of the rate years, is presented in Exh. JDT-6. Residential bill impacts under different monthly usage assumptions and for a typical residential customer is also presented in Exh. JDT-6. Table 3 below summarizes the overall bill impacts by customer class for each of the multiyear rate plan years.

Table 3 - Estimated Customer Class Impacts of Proposed Rates

Customer Class	Schedule	2025 Revenue Change	2025 Overall Impact	2026 Revenue Change	2026 Overall Impact
Residential	16/23/53	$121,323,117	17.92%	$15,531,732	1.95%
Commercial & Industrial	31/31T	$59,179,442	23.11%	$7,909,449	2.51%
Large Volume	41/41T	$9,127,830	16.70%	$1,206,487	1.89%
Interruptible	85/85T	$3,769,940	15.42%	$490,860	1.75%
Limited Interruptible	86/86T	$327,497	9.54%	$31,655	0.85%
Non-exclusive Interruptible	87/87T	$2,942,070	21.20%	$341,962	2.04%
Exclusive Interruptible[3]	88T	($758,473)	-51.90%	($307,905)	-30.46%
Special Contracts		$128,968	4.30%	$146,044	4.68%
Total		$196,040,390	18.96%	$25,350,286	2.07%

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

A. The impact on the monthly bill of PSE's typical residential gas customer using 64 therms is an increase of $13.96, or 17.29 percent over current levels for rate year one and an increase of $1.51 or 1.59 percent over rate year one levels in rate year two.

[3] The total cost to serve and expected level of revenues is the subject of Docket UG-230393 which is pending a decision from the Commission. The total impact to Schedule 88T will depend on the level of revenues set for recovery from Schedule 88T as an outcome of this docket and Docket UG-230393.

X. PROPOSED UPDATES TO PSE'S GAS DECOUPLING MECHANISMS

Q. Has PSE updated its gas decoupling mechanism to reflect the rates proposed in this filing?

A. Yes. PSE has updated the Monthly Allowed Delivery Revenue per Customer and Delivery Revenue Per Unit Rates associated with PSE's gas decoupling mechanism, which are provided in Exh. JDT-7.

XI. COMPLIANCE FILING

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

A. Please see the Prefiled Direct Testimony of Christopher T. Mickelson, Exh. CTM-1T, for a list of the gas rates PSE intends to update in the compliance filing for this case.

Q. Have the proposed tariff sheets been included in this filing?

A. Yes. Please see the Eleventh Exhibit to the Prefiled Testimony of Christopher T. Mickelson, Exh. CTM-12, for the gas tariff sheets that have been included as part of this filing.

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

A. No.

XII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.