

**EXH. JDT-1T  
DOCKETS UE-22 \_\_\_/UG-22 \_\_\_  
2022 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-22 \_\_\_**

**Docket UG-22 \_\_\_**

**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**

**JOHN D. TAYLOR**

**ON BEHALF OF PUGET SOUND ENERGY**

**JANUARY 31, 2022**

**PUGET SOUND ENERGY**  
**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**  
**JOHN D. TAYLOR**  
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**PUGET SOUND ENERGY**  
**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**  
**JOHN D. TAYLOR**  
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Exh. JDT-3	Normalized Revenues from Gas Operations
Exh. JDT-4	PSE Gas Cost of Service Study
Exh. JDT-5	Gas Rate Spread & Rate Design
Exh. JDT-6	Proposed Revenue Impacts
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Exh. JDT-8	Gas Capacity Resource Allocation
Exh. JDT-9	Proposed Gas Tariff Schedule Revisions

1 **PUGET SOUND ENERGY**

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

4 **I. INTRODUCTION**

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

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

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

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

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

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

14 **Q. What is your assignment in this proceeding?**

15 A. PSE requested Atrium Economics to conduct a fully-allocated cost of service  
16 study to determine the embedded costs of serving its gas distribution customers  
17 and support rate design efforts. In this regard, I am sponsoring the Gas Cost of  
18 Service Study (“COSS”) that allocates PSE’s gas distribution costs to the gas  
19 distribution customer’s rate classes. Related to rate design I am supporting the  
20 class revenue increase apportionment and proposed rate design for gas service. I

1 am also sponsoring the normalized and forecasted revenues from gas operations  
2 and the updated allowed revenue for PSE's gas decoupling mechanism. Lastly, I  
3 present the allocation study of PSE's natural gas capacity resource costs,  
4 consisting of U.S. interstate and Canadian provincial pipeline capacity resources  
5 and leased gas storage capacity resources, for use in PSE's Purchased Gas  
6 Adjustment ("PGA") filings.

7 **Q. Please summarize your testimony.**

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

- 10 • Development of Normalized Test Year Revenues;
- 11 • Development of Projected Rate Year Revenues;
- 12 • Purpose and Principles of Cost of Service Studies;
- 13 • PSE's Cost of Service Study;
- 14 • Principles of PSE's Rate Design;
- 15 • Revenue Apportionment among Customer Classes;
- 16 • PSE's Rate Design Proposals;
- 17 • Updated Allowed Revenue and Revenue Per Unit for PSE's Gas
- 18 Decoupling Mechanism, and
- 19 • Allocation of Gas Resource Demand Costs.

1        **II.        NORMALIZED TEST YEAR REVENUE FROM GAS OPERATIONS**

2        **Q.        Are you presenting both the development of the normalized test year**  
3        **revenues from gas operations and the project rate year revenues from gas**  
4        **operations?**

5        A.        Yes. I first describe the process used to develop the normalized revenue for the  
6        test year and then provide a description of the development of the projected  
7        revenue for each rate year based on forecasted rate year billing determinants. The  
8        third exhibit to my testimony, Exh. JDT-3, demonstrates PSE’s development of its  
9        normalized test year revenue from natural gas operations and the projected  
10       revenue for each rate year.

11       **Q.        What is normalized test year revenue?**

12       A.        Normalized test year revenue is an estimate of test year revenue based on  
13       normalized and proformed test year billing determinants (e.g., energy sales, billed  
14       demand, number of bills) and the rates that are in place at the time of filing for a  
15       rate change. It is developed to make sure that the test year revenue used in  
16       calculating the revenue deficiency: (1) reflects only those rate schedules that are  
17       being considered in the present case, (2) encompasses any rate changes that have  
18       taken place during or since the test year, and (3) is consistent with the normalized  
19       test year revenue requirement and loads. The billing determinants used to produce  
20       normalized test year revenue are also used to estimate the revenue from proposed  
21       rates.

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

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

- 11 1. removal of revenue from municipal taxes and adjusting price schedules  
12 (columns C-H).
- 13 2. other restating adjustments that primarily correspond to billing corrections  
14 (column I).
- 15 3. adjusting for price changes that took place during or after the test year,  
16 specifically the 2019 general rate case rates that were effective on October  
17 1, 2020 (column K).
- 18 4. adjusting for price changes that took place during or after the test year,  
19 specifically the IRS Private Letter Ruling (PLR) resulting in rates effective  
20 October 1, 2021 (column L).
- 21 5. an adjustment to revenue to reflect the weather adjustment to volume  
22 (column M).

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

1 **Q. Will rates in any of the adjusting gas price schedules in Columns D through**  
2 **H of the worksheet ‘Exh. JDT-3 (Revenue)’ within Exh. JDT-3 change as a**  
3 **result of this filing?**

4 A. Yes. Rates within Schedule 149 (Cost Recovery Mechanism for Pipeline  
5 Replacement or “Gas CRM”) will be reset to reflect the transfer of Gas CRM  
6 program revenue from gas Schedule 149 to base natural gas rates, as discussed in  
7 testimony of Susan E. Free, Exh. SEF-1T.

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

10 A. As mentioned above, normalized test year revenue is based on test year billing  
11 determinants, which is largely based on normalized energy sales. PSE’s  
12 adjustments to test year natural gas throughput for this case are summarized in  
13 this worksheet ‘Exh. JDT-3 (Volume)’ within Exh. JDT-3. This begins with  
14 column B, which shows the actual volume of sales and transportation therms for  
15 the twelve months ending June 30, 2021. The weather normalization adjustment  
16 to gas volume presented in column C which removes the effect of non-normal  
17 temperatures from test year loads, so the test year loads and revenues are more  
18 reflective of normal weather conditions. This adjustment is described in the  
19 testimony of Kelly H. Xu, Exh. KHX-1T. Normalized test year volume that  
20 reflects these adjustments is totaled in column D and is used for calculating  
21 normalized test year revenues as presented in the worksheet ‘Exh. JDT-3  
22 (Revenue)’ of Exh. JDT-3, as described above.



1           **III.     PROJECTED RATE YEAR REVENUES FROM GAS OPERATIONS**

2           **Q.     What are projected rate year revenues?**

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

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

7           A.     Rate year revenues are developed for each of the multi-year rate periods (2023,  
8           2024 and 2025) by multiplying the forecasted billing determinants for each year  
9           by current rates, resulting in projected rate year revenues.

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

11          A.     PSE’s F2021 forecast approved by its Energy Management Committee in spring  
12          2021 was used for developing the projected rate year revenues. This forecast was  
13          adjusted to account for additional billing determinants expected from a new large  
14          volume customer that is expected to start taking service during 2022.

15          **Q.     What portions of Exh. JDT-3 present the calculation of these revenues?**

16          A.     The first worksheet ‘Exh. JDT-3 (Revenue)’ of Exh. JDT-3, described above,  
17          presents the calculation of forecasted revenues. This worksheet illustrates the  
18          development of pro forma revenue by rate schedule in columns P-W, which  
19          provide the resulting revenue adjustments and total adjusted revenue for each of  
20          the rate years. The total adjusted revenues are the result of the forecasted billing

1 determinants multiplied by current rates. Similarly, the second worksheet 'Exh.  
2 JDT-3 (Volume)' of Exh. JDT-3, described above, contains additional columns E-  
3 L which provide the forecast volumes by rate schedule for each of the rate years.

4 **IV. PURPOSE AND PRINCIPLES OF COST ALLOCATION**

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

6 A. The purpose of a COSS is to allocate a utility's overall adjusted test year costs to  
7 the various classes of service in a manner that reflects the relative costs of  
8 providing service to each class. This is accomplished through analyzing costs and  
9 assigning each customer or rate class its proportionate share of the utility's total  
10 revenues and costs within the test year. The results of these studies can be utilized  
11 to determine the relative cost of service for each customer class and to help  
12 determine the individual class revenue responsibility. In order to allocate costs to  
13 the various classes, a cost analyst reviews expense and plant accounts and  
14 develops studies of the relative costs of providing facilities and services for each  
15 rate class and analyzes the key factors that cause the costs to vary.

16 As further detailed within this testimony, another primary consideration in  
17 developing the studies and analyses for this proceeding is a recent update to the  
18 rules for general rate case proceedings that requires an electric or natural gas  
19 utility to include in its rate case filing a COSS that complies with WAC 480-85.

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

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

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

13 A. To establish these relationships, the Company must analyze its gas system design  
14 and operations, its accounting records as well as its system and customer load data  
15 (e.g., annual and peak period gas consumption levels). From the results of those  
16 analyses, methods of direct assignment and common cost allocation  
17 methodologies can be chosen for all of the utility's plant and expense elements.

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

19 A. The term direct assignment relates to a specific identification and isolation of  
20 plant and/or expense incurred exclusively to serve a specific customer or group of  
21 customers. Direct assignments best reflect the cost causation characteristics of

1 serving individual customers or groups of customers. Therefore, in performing a  
2 COSS, the cost analyst seeks to maximize the amount of plant and expense  
3 directly assigned to particular customer groups to avoid the need to rely upon  
4 generalized allocation methods. An alternative to direct assignment is an  
5 allocation methodology supported by a special study as is done with costs  
6 associated with meters and services.

7 **Q. What prompts the analyst to elect to perform a special study?**

8 A. When direct assignment is not readily apparent from the description of the costs  
9 recorded in the various utility plant and expense accounts, then further analysis  
10 may be conducted to derive an appropriate basis for cost allocation. For example,  
11 in evaluating the costs charged to certain operating or administrative expense  
12 accounts, it is customary to assess the underlying activities, the related services  
13 provided, and for whose benefit the services were performed.

14 **Q. How do you determine whether to directly assign costs to a particular  
15 customer or customer class?**

16 A. Direct assignments of plant and expenses to particular customers or classes of  
17 customers are made on the basis of special studies wherever the necessary data  
18 are available. These assignments are developed by detailed analyses of the  
19 utility's maps and records, work order descriptions, property records and  
20 customer accounting records. Within time and budgetary constraints, the greater  
21 the magnitude of cost responsibility based upon direct assignments, the less

1 reliance need be placed on common plant allocation methodologies associated  
2 with joint use plant.

3 **Q. Is it realistic to assume that a large portion of the plant and expenses of a**  
4 **utility can be directly assigned?**

5 A. No. The nature of utility operations is characterized by the existence of common  
6 or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a  
7 utility's plant and expense cannot be directly assigned to customer groups,  
8 common allocation methods must be derived to assign or allocate the remaining  
9 costs to the customer classes. The analyses discussed above facilitate the  
10 derivation of reasonable allocation factors for cost allocation purposes.

11 **Q. What are the steps to performing a COSS?**

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

16 **Q. Please describe cost functionalization.**

17 A. The first step, cost functionalization, identifies and separates plant and expenses  
18 into specific categories based on the various characteristics of utility operation.  
19 PSE's primary functional cost categories associated with gas service include:  
20 production, storage, transmission, distribution, and customer specific costs.

1 Indirect costs that support these functions, such as general plant and  
2 administrative and general expenses, are allocated to functions using allocation  
3 factors related to plant and/or labor ratios.

4 **Q. Please describe cost classification.**

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

12 **Q. Please describe the types of costs contained in the Customer Costs, Demand  
13 Costs and Commodity Costs categories.**

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

20 Demand or capacity related costs are associated with plant that is designed,  
21 installed and operated to meet maximum hourly or daily gas flow requirements,

1 such as the transmission and distribution mains, or more localized distribution  
2 facilities that are designed to satisfy individual customer maximum demands. Gas  
3 supply contracts also have a capacity related component of cost relative to the  
4 Company's requirements for serving daily peak demands and the winter peaking  
5 season.

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

10 **Q. Please describe the cost allocation process.**

11 A. The final step is the allocation of each functionalized and classified cost element  
12 to the individual customer class. Costs typically are allocated on customer,  
13 demand, commodity or revenue allocation factors. From a cost of service  
14 perspective, the best approach is a direct assignment of costs where costs are  
15 incurred for a customer or class of customers and can be so identified. Where  
16 costs cannot be directly assigned, the development of allocation factors by  
17 customer class uses principles of both economics and engineering. This results in  
18 appropriate allocation factors for different elements of costs based on cost  
19 causation. For example, we know from the manner in which customers are billed  
20 that each customer requires a meter. Meters differ in size and type depending on  
21 the customer's load characteristics. These meters have different costs based on  
22 size and type. Therefore, meter costs are customer-related, but differences in the

1 cost of meters are reflected by using a different meter cost for each class of  
2 service. For some classes such as the largest customers, the meter cost may be  
3 unique for each customer.

#### 4 V. PSE'S COST OF SERVICE STUDY

##### 5 **A. Process Steps and Structure of the COSS**

6 **Q. Are there factors that can influence the overall cost allocation framework**  
7 **utilized by a gas utility when performing a COSS?**

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

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

13 A. It is important to understand these considerations because they influence the  
14 overall context within which a utility's cost study was conducted. In particular,  
15 they provide an indication of where efforts should be focused for purposes of  
16 conducting a more detailed analysis of the utility's gas system design and  
17 operations and understanding the regulatory environment in the State of  
18 Washington as it pertains to cost of service studies and gas ratemaking issues; and  
19 in particular the new chapter WAC 480-85 adopted by the Washington Utilities  
20 and Transportation Commission ("WUTC" or "Commission") in Docket UG-  
21 170003.



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

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

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

13 A. In its Final Order in Avista Corporation's 2016 general rate case, the WUTC  
14 instructed its staff to initiate a collaborative effort with the investor-owned  
15 Washington utilities and interested stakeholders to more clearly define the scope  
16 and expected outcomes for generic cost of service proceedings in an effort to  
17 establish greater clarity and uniformity in future cost of service studies.<sup>1</sup> PSE  
18 participated in Commission Staff's information gathering efforts and multiple  
19 workshops over three years as the collaborative evolved into the rulemaking  
20 proceeding in Dockets UE-170002 and UG-170003. The result of this proceeding

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<sup>1</sup> *WUTC v. Avista Corp.*, Dockets UE-160228/UG-160229 Order 06 at ¶ 116 (Dec. 15, 2016).

1 was a set of new cost of service rules requiring electric and gas utilities to file a  
2 cost of service model in compliance with both the presentation requirements and  
3 new data requirements associated with the allocation methods in WAC 480-85.  
4 These rules specify the functionalization, classification, and allocation methods  
5 for various FERC Account Numbers. These required methods still require  
6 analyses of data and various subsidiary studies to develop the inputs to the cost of  
7 service study. These are discussed in detail below, in Section B: Allocation of Gas  
8 Plant Costs and Operating Expenses).

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

11 A. No. As described in more detail in this testimony, there were modifications made  
12 to the methods historically applied by PSE to ensure the filed COSS is in  
13 conformance with the methods prescribed by the new cost of service rules defined  
14 in WAC 480-85. Further, PSE is filing two COSS methods, one in compliance  
15 with WAC 480-85 and one in compliance with all aspects of WAC 480-85 except  
16 for mains associated with the PSE’s Tacoma Liquefied Natural Gas Facility  
17 (“Tacoma LNG Facility”) to comply with a previous settlement agreement in  
18 Docket UG-151663 and the functionalization of FERC Account 870; a  
19 distribution operations account WAC 480-85 requires to be functionalized as  
20 Transmission.

1 **Q. What are the settlement agreement terms in Docket UG-151663 that require**  
2 **a COSS that is not in compliance with the methods prescribed in WAC 480-**  
3 **85?**

4 A. PSE, WUTC Staff, the Public Counsel Section of the Washington Office of  
5 Attorney General (“Public Counsel”), the Northwest Industrial Gas Users, and the  
6 Industrial Customers of Northwest Utilities (both collectively now known as the  
7 Alliance of Western Energy Consumers (“AWEC”)) entered into a settlement  
8 agreement (“Agreement”) that provided a basis upon which the parties could  
9 recommend proceeding with the Tacoma LNG Facility. In the Agreement the  
10 Settling Parties acknowledged and agreed that costs of distribution system  
11 upgrades associated with the Tacoma LNG Facility should be allocated in  
12 accordance with the principle of cost causation. Specifically, PSE agreed not to  
13 allocate any costs associated with either a new 16-inch distribution line or Bonney  
14 Lake lateral improvements to transportation customers. Instead, PSE promised to  
15 allocate such costs to sales customers based on their contribution to PSE’s total  
16 retail design day system peak demand.

17 In all retail class cost of service studies used to set retail gas  
18 sales and transportation delivery tariff rates, PSE agrees to  
19 propose to allocate the costs of each of the 16-Inch Line  
20 and the Bonney Lake Lateral Improvements identified and  
21 recorded in the subaccount of FERC Account 376 in a  
22 manner consistent with the interclass allocation of the costs  
23 of the Tacoma LNG Facility. PSE will support the  
24 interclass allocation of the Tacoma LNG Facility costs to  
25 only sales customers on the basis of their contribution to

1 PSE's total retail design day system peak demand  
2 (Dth/day).<sup>2</sup>

3 The newly-adopted WAC 480-85-060, however, requires distribution mains to be  
4 functionalized as distribution and allocated on peak and average. The rules also  
5 require storage functions to be allocated on average and excess ("average winter  
6 sales that exceed average summer sales"). The rules provide no room for  
7 functionalizing mains in FERC Account 376 as storage related or allocating these  
8 mains only to sales customers using retail design day system peak demand as  
9 required by the Agreement. In short, the rules conflict with the Agreement and as  
10 such PSE is filing a proposed COSS model that functionalizes these mains as  
11 storage, classifies them on the basis of demand and allocates them to sales  
12 customers using their contribution to PSE's total retail design day system peak  
13 demand.

14 **Q. What are the differences between the proposed COSS model and the WAC**  
15 **rules compliant COSS model with respect to FERC Account 870?**

16 A. The newly-adopted WAC 480-85-060, requires FERC Account 870 - Operation  
17 supervision and engineering to be functionalized as Transmission. As such the  
18 WAC rules compliant COSS model functionalizes this account as Transmission.  
19 However, this account relates to the distribution system and is properly  
20 functionalized as Distribution within the proposed COSS model.

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<sup>2</sup> *In the Matter of Puget Sound Energy, Inc.*, Docket UG-151663, Settlement Agreement, App. A to Final Order 10 at 12 (Nov. 1, 2016).

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

2 A. All cost of service data has been extracted from PSE's total cost of service (i.e.,  
3 total revenue requirement) and subsidiary schedules contained in this filing.

4 Where more detailed information was required to perform various analyses  
5 related to certain plant and expense elements, the data were derived from PSE's  
6 historical books and records and information provided by Company personnel.

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

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

- 10 • Residential Service (Tariff Schedules 16, 23, and 53);
- 11 • Commercial and Industrial Service (Tariff Schedules 31 and 31T);
- 12 • Large Volume Service (Tariff Schedules 41 and 41T);
- 13 • Interruptible Service (Tariff Schedules 85 and 85T);
- 14 • Limited Interruptible Service (Tariff Schedules 86 and 86T);
- 15 • Non-Exclusive Interruptible Service (Tariff Schedules 87 and 87T), and
- 16 • Special Contracts.

17 **Q. Does the COSS include gas commodity costs?**

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

1 **Q. Does the COSS include gas resource demand costs?**

2 A. No. Section XI of this testimony presents the recommended allocation of pipeline  
3 capacity and storage costs for use in PSE's PGA Filings.

4 **B. Allocation of Gas Plant Costs and Operating Expenses**

5 **Q. What are the similarities and differences in the cost allocation approach**  
6 **utilized in PSE's proposed COSS in this proceeding with that utilized in**  
7 **PSE's 2019 general rate case COSS?**

8 A. Where the methods prescribed by the new cost of service rules defined in WAC  
9 480-85 are aligned with the methods in PSE's 2019 general rate case, those same  
10 methods are reflected in this proceeding.<sup>3</sup> In instances where there is a conflict  
11 between the methods in PSE's 2019 general rate case and the methods prescribed  
12 in WAC 480-85, the prescribed methods are employed in the WAC rule  
13 compliant COSS model. As described above the proposed COSS model reflects  
14 two differences (1) the treatment of Tacoma LNG Facility mains recorded as  
15 distribution mains and (2) the functionalization and allocation of FERC Account  
16 870. A summary of these similarities and differences are presented below:

17 Production and Gathering Plant – Production and Gathering plant and associated  
18 O&M relate to LP storage facilities that provide limited supplemental supply  
19 during peak periods. These were allocated on design day in PSE's 2019 general

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<sup>3</sup> *WUTC v. Puget Sound Energy*, Dockets UE-190529/UG-190530.

1 rate case COSS model. In the COSS models presented in this case, they are  
2 functionalized as storage and allocated to sales customers based on excess winter  
3 sales (i.e., to sales customers with a ratio based on average winter sales that  
4 exceed average summer sales).

5 Underground Storage – In compliance with the prescribed methods in WAC 480-  
6 85, storage costs associated with balancing are allocated to all customers based on  
7 winter sales. Other Underground Storage plant and associated O&M costs are  
8 allocated to sales customers based on excess winter sales. In the 2019 general rate  
9 case storage costs associated with balancing were allocated to all customers based  
10 on annual volumes with the remaining storage costs allocated in the same method,  
11 to sales customers based on excess winter sales.

12 Distribution Mains – A portion of Distribution Mains plant is directly assigned to  
13 the special contract class and a subset of distribution mains associated with the  
14 Tacoma LNG facility are functionalized as storage and allocated only to sales  
15 customers using retail design day system peak demand. The remaining costs of  
16 mains are classified as demand and allocated based on design day (peak) and  
17 annual throughput (average) weighted on the system load factor. There are two  
18 primary differences between the proposed COSS in this case and the 2019 general  
19 rate case. First, the peak and average method utilized in the 2019 general rate case  
20 excluded certain rate classes from the allocation of smaller distribution mains that

1 do not serve those classes.<sup>4</sup> Given the prescribed methods in WAC 480-85 do not  
2 allow for the exclusion of classes from an allocation of distribution mains these  
3 classes are now being allocated all mains that were not directly assigned to the  
4 Special Contract class. Second, the calculation of the peak component was  
5 updated in the current proceeding to utilize data from the Gas Load Study Report,  
6 presented in Curt D. Puckett’s Prefiled Direct Testimony, Exh. CDP-1T. The  
7 direct assignment of distribution mains to the special contract class is reflected in  
8 both the proposed COSS and the WAC-compliant COSS because there is a  
9 provision in WAC 480-85 for “Direct assignment of distribution mains to a single  
10 customer class where practical.”

11 Customer Related Plant – The methods employed in the COSS models are the  
12 same as employed by PSE in the 2019 general rate case. Meters and meter  
13 installations (Accounts 381 and 382), house regulators and installations (Accounts  
14 383 and 384), and industrial measuring and regulating station equipment  
15 (Account 385) were allocated based on the actual types of meters used to serve  
16 gas customers in different customer classes and the current costs of those meters  
17 and their installation.

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

19 A. Yes. PSE conducted an analysis to identify the cost of services in FERC Account  
20 380 that are dedicated to customers on gas Schedules 85, 85T, 87, 87T and

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<sup>4</sup> For details on this peak and average approach in PSE’s 2019 general rate case, please see Exh. JDT-1T at 15-19 in Docket UG-190530.



1 Special Contracts. This portion of plant in FERC Account 380 was directly  
2 assigned to these customer classes, and the remainder was allocated to all other  
3 gas customer classes based on weighting factors. Different customer classes  
4 require different sizes and types of services, which vary in cost. The number of  
5 gas customers was weighted based on cost data for various sizes and types of  
6 services, and these weighted customer counts were used to allocate costs across  
7 customer classes. The use of weighting factors takes these cost differences into  
8 account when assigning costs to the customer classes.

9 Further, a special study was performed in preparation for the 2019 general rate  
10 case to determine the specific distribution mains that are utilized to serve PSE's  
11 Special Contract customer. The plant costs related to these facilities were directly  
12 assigned to the Special Contract class in the COSS. The Company's geographic  
13 information system ("GIS") was queried to research the various pipeline pathways  
14 from system regulator stations to the customers' service addresses along with the  
15 related pipeline sizes and material types. Historical plant records were utilized to  
16 obtain the necessary cost information to complete the direct assignment of the  
17 mains plant costs to the Special Contracts class. This study was relied upon in the  
18 development of the direct assignment of distribution mains for the COSS models  
19 presented in this filing.

1 **Q. How did the COSS allocate distribution-related gas operation and**  
2 **maintenance (“O&M”) expenses?**

3 A. In general, these expenses were allocated on the basis of the cost allocation  
4 methods used for the Company’s corresponding plant accounts. A utility’s O&M  
5 expenses generally are thought to support the utility’s corresponding plant in  
6 service accounts. Put differently, the existence of particular plant facilities  
7 necessitates the incurrence of cost, i.e., expenses by the utility to operate and  
8 maintain those facilities. As a result, the allocation basis used to allocate a  
9 particular plant account will be the same basis as used to allocate the  
10 corresponding expense account. For example, Account 887, Maintenance of  
11 Mains, is allocated on the same basis as its corresponding plant accounts, Mains –  
12 Account 376. With the detailed analyses supporting the assignment or allocation  
13 of major plant in service components, where feasible, it was deemed appropriate  
14 to rely upon those results in allocating related expenses in view of the overall  
15 conceptual acceptability of such an approach. As explained above, one difference  
16 between the proposed COSS model and the WAC-compliant COSS model is the  
17 functionalization of FERC Account 870; where the proposed model functionalizes  
18 this cost as Distribution and WAC 480-85 requires this account to be  
19 functionalized as Transmission.

1 **Q. How were administrative and general (“A&G”) expenses and taxes allocated**  
2 **to each gas customer class?**

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

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

11 A. These items were allocated by function in proportion to their associated plant  
12 accounts.

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

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

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

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

5 **Q. Have you provided an exhibit with the results of the proposed and WAC rule**  
6 **compliant COSS models?**

7 A. Yes. See Exh. JDT-4, for the results of these models. This exhibit is within the  
8 required gas cost of service template provided by the WUTC and contains  
9 Schedules A-E. There are two sets of B, C, and E schedules. The first set: 'B-COS  
10 Results (WAC)', 'C-COS Allocation Factors (WAC)', and 'E-Summary of  
11 Results (WAC)', that result from the COSS model that complies with WAC 480-  
12 85, and a second set: 'B-COS Results (PSE)', 'C-COS Allocation Factors (PSE)',  
13 and 'E-Summary of Results (PSE),' that aligns with PSE's proposed treatment of  
14 LNG mains and FERC Account 870.

15 **C. PSE's Cost of Service Study Results**

16 **Q. Have you prepared a summary of PSE's COSS results?**

17 A. Yes. Exh. JDT-4, worksheet 'E-Summary of Results (PSE)', summarizes the  
18 results of PSE's COSS model. This exhibit presents the resulting allocation by  
19 customer class of PSE's proposed revenue requirement based strictly on the  
20 results of the computations included in the COSS. The revenue-to-cost ratios and

1 parity ratios at current rates, presented on this schedule, are summarized in Table  
 2 1 below. The revenue-to-cost ratios portray the ratio between the cost to serve  
 3 these customers and the normalized test year revenues collected from these  
 4 customers. The parity ratios portray the relative difference between the revenues  
 5 currently recovered from each class and the costs to serve each class at the system  
 6 average rate of return. A revenue-to-cost ratio below 1.00 means that the current  
 7 rates and revenues of the particular customer class are below its indicated cost of  
 8 service, while a parity revenue-to-cost ratio of greater than 1.00 means that the  
 9 rates and revenues of the customer class are above its indicated cost of service.  
 10 The parity ratio provides insights into the relative differences across the classes  
 11 once all classes are adjusted for system-level over or under recovery. These  
 12 results provide cost guidelines for use in evaluating a utility's class revenue levels  
 13 and rate structures.

14 **Table 1 – Results of Gas Cost of Service Studies**

<b>Customer Class</b>	<b>Schedule</b>	<b>Revenue-to-Cost Ratio</b>	<b>Parity Ratio</b>
Residential	16/23/53	0.97	1.09
Commercial & Industrial	31/31T	0.75	0.84
Large Volume	41/41T	0.83	0.93
Interruptible	85/85T	0.69	0.77
Limited Interruptible	86/86T	1.14	1.28
Non-exclusive Interruptible	87/87T	0.43	0.49
Special Contracts		1.42	1.59
<b>Total/System Average</b>		<b>0.89</b>	<b>1.00</b>

15  
 16 As can be observed from the above table, all customer classes except Residential,  
 17 Limited Interruptible, and Special Contracts show under-recovery of the costs to

1 serve them. From a parity perspective Schedules 16/23/53, 31/31T, 41/41T are  
2 relatively close to unity with the overall system revenue-to-cost ratio. Whereas,  
3 the other customer schedules 85/85T, 86/86T, 87/87T, and Special Contracts  
4 show further disparity from unity with the overall system revenue-to-cost ratio.

5 **VI. PRINCIPLES OF SOUND RATE DESIGN**

6 **Q. Please identify the principles of rate design utilized in development of rate**  
7 **design proposals.**

8 A. A number of rate design principles or objectives find broad acceptance in utility  
9 regulatory and policy literature. These include:

- 10 1. Cost of Service.
- 11 2. Efficiency.
- 12 3. Value of Service.
- 13 4. Stability/Gradualism.
- 14 5. Non-Discrimination.
- 15 6. Administrative Simplicity.
- 16 7. Balanced Budget.

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

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

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

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

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

1                   **VII. DETERMINATION OF PROPOSED CLASS REVENUES**

2       **Q. Please describe the approach generally followed to allocate PSE’s proposed**  
3       **revenue increase of \$62.5 million to its customer classes.**

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

- 11           1. Apply 125 percent of the system average increase to Schedules 31, 31T,  
12           41, and 41T.
- 13           2. Apply 150 percent of the average increase to Schedules 85, 85T, 87, and  
14           87T.
- 15           3. Apply no increase to Schedules 86 and 86T.
- 16           4. Apply the remaining increase to Schedules 16, 23, and 53, which results in  
17           an 89 percent of the system average increase.

18       The proposed revenue allocation by rate class of the proposed \$62.5 million  
19       increase is presented on the worksheet ‘Exh. JDT-5 (Rate Spread)’ of Exh. JDT-5.  
20       This revenue allocation approach resulted in reasonable movement of all class’s  
21       revenue-to-cost ratio toward unity or 1.00. From a class cost of service standpoint,  
22       this type of class movement, and reduction in the existing class rate subsidies, is  
23       desirable. Table 2 below shows the movement of all classes towards parity.



1

**Table 2 – Results of Proposed Rate Spread**

<b>Customer Class</b>	<b>Schedule</b>	<b>Current Parity Ratio</b>	<b>Proposed Parity Ratio</b>	<b>Percentage Increase</b>
Residential	16/23/53	1.09	1.08	10.67%
Commercial & Industrial	31/31T	0.84	0.86	14.93%
Large Volume	41/41T	0.93	0.96	14.93%
Interruptible	85/85T	0.77	0.81	17.91%
Limited Interruptible	86/86T	1.28	1.14	0.00%
Non-exclusive Interruptible	87/87T	0.49	0.51	17.91%
Special Contracts		1.59	1.54	8.76%
<b>Total/System Average</b>		<b>1.00</b>	<b>1.00</b>	

2

3

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

4

A. As is shown in Table 2 the Special Contracts rates will increase by 8.76 percent.

5

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.

6

7

8

**VIII. PSE’S RATE DESIGN PROPOSALS**

9

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

10

11

A. In general PSE is proposing to increase basic charges, delivery charges, demand charges, and procurement charges by the same percentage increase as the Schedules’ targeted increase presented in Table 2 above. There are a few exceptions to this:

12

13

14

- 1 • PSE is proposing no changes to the transportation classes' basic charge.  
2 Historically, the difference between the sales and transportation basic  
3 charges represented processes required to work with transportation  
4 customers, unique to the fact they are transportation customers (e.g., gas  
5 scheduling, gas control, measuring, and metering). Over time these  
6 processes were automated and no longer required the same level of  
7 dedicated personnel.
- 8 • The procurement charges for Schedule 31, 31T, 41, and 41T were only  
9 increased to the unit rates indicated in the COSS model and presented in  
10 the worksheet 'Exh. JDT-5 (Procmnt Chrg)' of Exh. JDT-5.

11 Lastly, PSE is proposing to increase the balancing charge for all transportation  
12 service classes from \$0.00100 to \$0.00118 per therm. This amount is supported  
13 by Section XI of this testimony, which indicates a balancing unit cost of \$0.00136  
14 per therm.

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

17 A. No. There is a significant variation in demand-related costs for each customer  
18 class. Certain classes have much higher demand-related costs than others,  
19 depending largely on the level of firm use present in the schedule. However,  
20 given these significant variations, PSE is proposing to move demand rates  
21 incrementally closer to demand costs.

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

5 A. Yes. The worksheets (1) 'Exh. JDT-5 (RES\_RD)', (2) 'Exh. JDT-5 (C&I-RD)',  
6 and (3) 'Exh. JDT-5 (INTRPL-RD)' of Exh. JDT-5 show the derivation of each  
7 rate component for each of PSE's tariff schedules and the corresponding revenues  
8 generated from those proposed rates. Worksheet 'Exh. JDT-5 (Procmnt Chrg)'  
9 provides details on the procurement charge and worksheet 'Exh. JDT-5  
10 (Balancing)' shows the current and proposed balancing rates.

11 **Q. How were rates developed for the newly proposed adjusting price Schedule**  
12 **141R and Schedule 141N used to change rates during the multiyear rate**  
13 **plan?**

14 A. The amounts set for recovery in Schedule 141R and 141N for each of the rate  
15 years are presented within the worksheet 'Exh. JDT-5 (Rate Spread)' of Exh.  
16 JDT-5. The development of these amounts is supported in the Prefiled Direct  
17 Testimony of Susan E. Free, Exh. SEF-1T. The Schedule 141N amounts set for  
18 recovery was first adjusted for additional base schedule revenues resulting from  
19 the change in billing determinants between the test year where the base rates were  
20 set and the rate years. These amounts including the Schedule 141N adjusted  
21 amounts are then allocated to each of the customer classes based on the allocation  
22 of rate base from the COSS model, exclusive of Special Contracts. The amounts

1 are then divided by the forecasted billing determinants (therms) for each customer  
2 class developing a unit rate unique for each rate year. The worksheet 'Exh. JDT-5  
3 (MYRP)' of Exh. JDT-5 presents the development of the rates for Schedule 141R  
4 and 141N for each of the rate years.

5 **IX. PROPOSED GAS RATE IMPACTS**

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

7 A. Several gas rider schedules will be reset concurrent with the effective date of new  
8 base gas rates resulting from this rate case. Specifically, the impacts of the base  
9 gas rate changes must be added to the impacts of gas rate changes associated with  
10 the concurrent changes to PSE's Schedule 141X (Protected-Plus Excess Deferred  
11 Income Tax (EDIT)) and Schedule 149 (Cost Recovery Mechanism). The bill  
12 impacts also incorporate the proposed Schedule 141N and Schedule 141R (non-  
13 refundable and refundable multi-year rate riders). The combined impact of these  
14 changes, based on rates currently in effect using forecasted billing determinants  
15 for each of the rate years, is presented in Exh. JDT-6. Exhibit JDT-6 also presents  
16 residential bill impacts under different monthly usage assumptions and for a  
17 typical residential customer. Table 3 below summarizes the overall bill impacts by  
18 rate schedule for each of the rate plan years.

**Table 3. Estimated Customer Impact of Proposed Rates**

Customer Class	Rate Sched.	2023				2024		2025	
		GRC Impact \$M	GRC Impact %	GRC Impact + Other Riders \$M	GRC Impact + Other Riders %	GRC \$M	GRC %	GRC \$M	GRC %
Residential Service	23,53	\$ 91.4	12.1%	\$ 89.4	11.9%	\$ 18.6	2.2%	\$ 15.1	1.7%
Residential Gas Lights	16	\$ 0.0	12.4%	\$ 0.0	12.1%	\$ 0.0	2.3%	\$ 0.0	1.8%
Commercial & Industrial	31	\$ 39.0	14.8%	\$ 38.2	14.5%	\$ 7.6	2.5%	\$ 6.3	2.0%
Large Volume	41	\$ 5.0	10.3%	\$ 4.9	10.1%	\$ 0.9	1.6%	\$ 0.7	1.3%
Interruptible	85	\$ 0.5	8.0%	\$ 0.5	7.8%	\$ 0.1	1.5%	\$ 0.1	1.2%
Limited Interruptible	86	\$ 0.2	4.1%	\$ 0.1	3.9%	\$ 0.1	1.7%	\$ 0.1	1.5%
Non-Exclusive Interruptible	87	\$ 0.4	4.7%	\$ 0.4	4.6%	\$ 0.0	0.6%	\$ 0.0	0.5%
Commercial & Industrial Transportation	31T	\$ 0.0	20.0%	\$ 0.0	19.5%	\$ 0.0	3.5%	\$ 0.0	2.8%
Large Volume Transportation	41T	\$ 1.6	32.2%	\$ 1.5	31.5%	\$ 0.3	5.4%	\$ 0.3	4.2%
Interruptible Transportation	85T	\$ 2.5	35.8%	\$ 2.4	35.0%	\$ 0.6	6.0%	\$ 0.5	4.8%
Limited Interruptible Transportation	86T	\$ 0.0	9.9%	\$ 0.0	9.5%	\$ 0.0	4.1%	\$ 0.0	3.7%
Non-Exclusive Interruptible Transportation	87T	\$ 2.3	42.8%	\$ 2.3	41.9%	\$ 0.4	4.9%	\$ 0.3	3.7%
Special Contracts		\$ 0.1	6.8%	\$ 0.1	6.4%	\$ -	0.0%	\$ -	0.0%
Total		\$ 143.0	13.0%	\$ 139.9	12.7%	\$ 28.5	2.3%	\$ 23.3	1.8%

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

2 A. The impact on the monthly bill of PSE's typical residential gas customer using 64  
3 therms is an increase of \$8.99, or 11.88 percent over current levels for rate year  
4 one; an increase of \$1.86 (2.20 percent increase) in rate year two, and \$1.51  
5 increase (1.74 percent increase) in rate year three.

6 **Q. What protections are provided to PSE's low-income customers as part of this**  
7 **multiyear rate plan?**

8 A. To help mitigate the effect of the proposed residential rate increases on its most  
9 vulnerable customers, PSE is proposing to increase the level of low-income  
10 energy assistance funding and to initiate a new Bill Discount Rate. These  
11 additions will complement PSE's existing portfolio of low-income energy  
12 assistance programs. See testimonies of Birud D. Jhaveri, Exh. BDJ-1T, and Carol  
13 L. Wallace, Exh. CLW-1T, for more information.

14 **X. PROPOSED UPDATES TO PSE'S GAS DECOUPLING MECHANISMS**

15 **Q. Is PSE offering any testimony in support of the continuation of its decoupling**  
16 **mechanism in this filing?**

17 A. Yes. Birud Jhaveri, in Exh. BDJ-1T, provides additional details on the operation  
18 of both the gas and electric decoupling mechanisms. His testimony explains that  
19 the mechanisms have performed well and PSE recommends continuation of these  
20 mechanisms.

1 **Q. Has PSE updated its electric and gas decoupling mechanisms to reflect the**  
2 **rates proposed in this filing?**

3 A. Yes. PSE has updated the Allowed Revenue and Revenue Per Unit Rates  
4 associated with PSE's gas decoupling mechanism, which are provided in Exh.  
5 JDT-7. Calculations associated with PSE's electric decoupling mechanism are  
6 provided in Exh. BDJ-9 and Exh. BDJ-10.

7 **XI. ALLOCATION OF GAS RESOURCE DEMAND COSTS**

8 **Q. What is the purpose of this section of your testimony?**

9 A. This section of my testimony describes the allocation of pipeline capacity and  
10 storage costs for use in PSE's PGA filings. The methods utilized and described  
11 below are aligned with those presented in PSE's 2019 general rate case.

12 **Q. Please identify the steps utilized to determine the use of capacity resources**  
13 **and how they can guide capacity resource cost allocation.**

14 A. The process for determining the need for pipeline capacity can be summarized in  
15 the six-step process described below. The six steps reflect a logical progression in  
16 identifying why and when capacity is needed, and thus give guidance as to how to  
17 allocate the related costs.

18 **Step 1:** One must consider the average summer demand or sales volume level.

19 This must be served by flowing gas supply using year-round pipeline capacity  
20 because, other than for load balancing, storage and peaking resources are not

1 generally available or economical as a base resource in the summer. PSE's  
2 normalized average daily sales volume in the summer months during the 12  
3 months ended June 2021 was approximately 150,623 dekatherms per day  
4 ("Dth/day"). Thus, average summer sales volumes require pipeline capacity of  
5 150,623 Dth/day. Since year-round pipeline capacity is used to serve summer and  
6 winter sales volumes (Step 2), it is reasonable to allocate the cost of this capacity  
7 to annual sales volumes.

8 **Step 2:** In order to have sufficient volumes in storage to serve the winter sales  
9 volumes, storage injections must be made using flowing gas and year-round  
10 pipeline capacity. Average summer injection requirements for Jackson Prairie and  
11 Clay Basin are 73,290 Dth/day. PSE could schedule its injection requirements  
12 around its customer requirements and operate all summer long with 73,290  
13 Dth/day of pipeline capacity. Because this capacity is needed specifically to fill  
14 storage, which is in turn used to serve winter sales volumes, it is reasonable to  
15 allocate the costs of this capacity to winter sales volumes. This capacity is also  
16 available to flow additional gas to serve winter sales volumes after the summer  
17 injection period (Step 3).

18 **Step 3:** Before determining the need for additional pipeline capacity to serve  
19 winter demand, PSE considers the average availability of storage withdrawals  
20 from Jackson Prairie that use Williams Northwest Pipeline TF-2 transportation  
21 capacity and thus do not require the use of year-round pipeline capacity. Average  
22 daily winter withdrawals from Jackson Prairie storage average approximately



1 41,566 Dth/day. The TF-2 capacity utilized by Jackson Prairie withdrawals would  
2 reasonably be allocated partially to winter sales volumes, design peak volumes  
3 and system load balancing.

4 **Step 4:** Winter average daily sales volumes are 423,790 Dth/day. These  
5 requirements are met with the capacity acquired in Steps 1, 2 and 3, thus leaving  
6 an average winter sales demand of 142,885 Dth/day (423,7902 minus 41,566  
7 minus 73,290 minus 150,623) to be fulfilled with additional year-round pipeline  
8 capacity. It is reasonable to allocate the costs of this capacity to winter sales  
9 volumes.

10 **Step 5:** PSE considers its design peak sales requirement and the deliverability of  
11 all of its storage and peaking resources that have not already been considered in  
12 use on the average winter day. PSE's estimated design peak requirement for the  
13 12 months ended June 2021 was approximately 973,131 Dth/day. PSE's storage  
14 resources provide, at maximum deliverability, a total of 447,057 Dth/day.  
15 However, PSE has already relied on 41,566 Dth/day from Jackson Prairie on an  
16 average winter day in Step 3, thus incremental storage provide a resource of  
17 405,491 Dth/day (447,057 minus 41,566). It is reasonable that the costs of the  
18 various resources that provide this incremental deliverability should be allocated  
19 based on their use to serve the design peak requirements of the system.

20 **Step 6:** The design peak demand is not yet met, and no additional gas storage or  
21 peaking resources are available in a cost-effective manner. PSE thus must use  
22 additional year-round pipeline capacity of 107,356 Dth/day to make up the

1 shortfall. Because this last increment of pipeline capacity is required only to serve  
2 the design peak day requirements of the customer demand, it is reasonable to  
3 allocate the cost of this capacity based on the contribution of various customer  
4 classes to design peak day demand. Exh. JDT-8 illustrates the six steps described  
5 above in both tabular and graphical format.

6 **Q. What is your overall recommendation as to the allocation of year-round**  
7 **pipeline capacity, storage, peaking and redelivery capacity costs?**

8 A. As summarized in the table on the worksheet 'JDT-8 (Capacity Table)' of Exh.  
9 JDT-8, I recommend that year-round pipeline capacity costs should be allocated  
10 within the PGA as 27.7 percent to annual sales volumes, 42.7 percent to winter  
11 sales volumes and 29.6 percent to design peak volumes. I recommend that the 79  
12 percent of Jackson Prairie and its related pipeline capacity that is not allocated to  
13 system balancing be allocated in the PGA as follows: 9.3 percent to winter sales  
14 and 69.7 percent to design peak day.

15 **Q. What are the resulting unit demand cost rates for the various sales service**  
16 **classes in the PGA?**

17 A. The computations to determine the class-by-class unit demand cost rates that  
18 result from the foregoing allocation of pipeline, storage and peaking capacity are  
19 shown on the worksheet 'JDT-8 (Capacity Use Summary)' of Exh. JDT-8. The  
20 capacity costs are first allocated to sales customers within each customer class

1 based on their respective annual, winter, and design day peak volumes and then  
2 converted to a unit-of-sales basis by class for use in PSE's PGA filings.

## 3 XII. COMPLIANCE FILING

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

6 A. The compliance filing in this case will include updates to all PSE base gas rate  
7 schedules, as well as a host of adjusting price schedules. These adjusting price  
8 schedules that will be included in the compliance filing are as following:

- 9 • Gas Schedule 141N (Rates Not Subject to Refund);
- 10 • Gas Schedule 141R (Rates Subject to Refund);
- 11 • Gas Schedule 142 (Revenue Decoupling Adjustment Mechanism); and
- 12 • Gas Schedule 149 (Cost Recovery Mechanism for Pipeline Replacement).

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

15 A. The proposed changes to the gas tariff sheets for the adjusting price schedules  
16 along with the base schedules are included in Exh. JDT-9.

17 **Q. Have all these tariff sheets been formally filed as part of this case?**

18 A. No. Proposed changes to gas Schedule 149 have not been filed as part of this case.  
19 Since PSE is not proposing any structural changes to gas Schedule 149 and will  
20 potentially be updating the rates on this schedule based on the outcome of its

1 normal update next November 1 and the subsequent outcome of this general rate  
2 case, this schedule is not included among the tariff sheets in Exh. JDT-9.

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

5 A. Yes. There is one gas tariff schedule that relies on the results of the most current  
6 rate case — Gas Rule 6 (Extension of Distribution Facilities).

7 **Q. When will this tariff revision be filed with the Commission?**

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

10 **XIII. CONCLUSION**

11 **Q. Does this conclude your direct testimony?**

12 A. Yes.