EXH. JDT-1T
DOCKETS UE-19___/UG-19___
2019 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-19____** **Docket UG-19____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

JOHN D. TAYLOR

ON BEHALF OF PUGET SOUND ENERGY

JUNE 20, 2019

PUGET SOUND ENERGY

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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 Black and Veatch Management Consulting, LLC, as a Principal Consultant. My business address is 14401 Lamar Avenue, Overland Park, KS 66211.

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

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

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

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

Q. What is your assignment in this proceeding?

A. PSE requested Black & Veatch to conduct a fully-allocated cost of service study to determine the embedded costs of serving its gas distribution customers and support rate design efforts. In this regard, I am sponsoring the Cost of Service Study ("COSS") that allocates PSE's gas distribution costs to the gas distribution

customer's rate classes. I am also supporting the class revenue increase apportionment and proposed rate design for gas service.

Q. Please summarize your testimony.

A. In my testimony I present PSE's natural gas COSS and discuss its results, present the revenue increase apportionment. and present the various rate design proposals filed by PSE in this proceeding. My testimony consists of this introduction and summary section and the following additional sections:

- Purpose and Principles of Cost of Service Studies
- PSE's COSS
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- PSE's Rate Design Proposals

II. PURPOSE AND PRINCIPLES OF COST ALLOCATION

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

A. The purpose of the COSS is to allocate PSE's gas distribution 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 revenues and 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, I reviewed PSE's expense and plant accounts and developed studies of the relative costs of providing facilities and services for each rate class and analyzed the key factors that cause the costs to vary.

Q. Mr. Taylor, is the preparation of a cost allocation study an exact science?

A. No, it is not. The fundamental purpose of a cost allocation study is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers, and then assigning or allocating those costs to individual rate classes on the basis of how those rate classes cause the costs to be incurred. This process inherently requires a substantial level of judgment and can be more accurately described as engineering/accounting art, rather than science. Although there may be not be a perfect methodology for allocating costs, there are certain fundamental and foundational principles, e.g., cost causation and consistency, which should be followed in order to produce more accurate and reasonable results. As described in further detail below, the cost allocation studies I developed follow these principles.

Q. What is the guiding principle that should be followed when performing a cost of service study?

A. The COSS analysis is intended to establish cost responsibility among the various customer classes the utility serves. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer

classes. The most important theoretical principle underlying a COSS is that cost incurrence should follow cost causation. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. What are the steps to 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: gas supply, storage, transmission, distribution, sales specific, and transport 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 1) customer costs; 2) demand costs and 3) 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 or capacity related 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 component of cost relative to PSE'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 PSE for its sales to service 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 class. Costs typically are allocated on customer, demand, commodity or revenue allocation factors. From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. 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. For some classes such as the largest customers, the meter cost may be unique for each customer.

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

A. To establish these relationships, PSE must analyze its gas system design and operations, its accounting records as well as 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 allocation methodologies can be chosen 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 relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

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

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

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

A. Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

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

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

III. PSE'S COST OF SERVICE STUDY

A. Process Steps and Structure of the Cost of Service Study

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

A. Yes. The factors which 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.

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 the historical books and records of PSE and information provided by PSE personnel.

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

A. The COSS is summarized in the Second Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-3. 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); Special Contracts; and Rentals. See the Third Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-4, for account detail by classification and rate class.

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 historically 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 which can influence the particular cost allocation method utilized by the utility. For example, in a Washington Natural Gas (now Puget Sound Energy) case, Docket UG-940814, the WUTC expressed a preference for the gas utility to utilize a costing methodology, Peak & Average, which allocates some fixed costs on the basis of annual use (or throughput) in order to reflect the proposition that a range of factors influence how gas transmission and distribution system costs are incurred and its significance in the cost study process. In its December 2016 Order in Dockets UE-160228 and UG-

160229 (*consolidated*), the WUTC instructed its staff to initiate a collaborative effort with the investor-owned Washington utilities 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]

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. The overall allocation approach is similar to that presented and used for the settlement in PSE's 2017 general rate case, Docket UG-170034 ("2017 GRC"). Because PSE's 2017 GRC is the only proceeding in the past five years to include a cost study, PSE's COSS satisfies the requirement in WAC 480-07-510(6). As described in more detail in this testimony, there were modifications made to the allocation of distribution mains; however, the general process of using the peak and average method was followed for the COSS presented in this proceeding.

Q. Does the COSS include gas commodity costs?

A. The COSS does not include gas commodity costs because these costs are recovered through PSE's Purchased Gas Adjustment mechanism.

[1] *Wash. Utils. & Transp. Comm'n v. Avista Corp., dba Avista Utils.*, DocketsUE-160228, *et al.*, Order 06, ¶116 (Dec. 15, 2016).

Q. Does the COSS include gas demand costs?

A. No. Historically the gas COSS has been used to allocate gas demand costs, but those cost are being addressed in the Prefiled Direct Testimony of Ronald J. Amen, Exh. RJA-1T, through an analysis described in his testimony.

B. Allocation of Gas Plant Costs and Operating Expenses

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

A. Yes. PSE conducted an analysis to identify the cost of services in FERC Account 380 that are dedicated to customers on gas Schedules 85, 85T, 87, 87T and Special Contracts. This 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 weighting factors. Different customer classes require different sizes and types of services, which vary in cost. The number of gas customers was weighted based on cost data for various sizes and types of services, and these weighted customer counts were used to allocate costs across customer classes. The use of weighting factors takes these cost differences into account when assigning costs to the customer classes.

Further, a special study was performed to determine the specific distribution mains that are utilized to serve PSE's Special Contract customer. The plant costs related to these facilities were directly assigned to the Special Contract class in the COSS. PSE'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.

Q. How were other customer-related gas costs allocated to classes?

A. Meters and meter installations (Accounts 381 and 382), house regulators and installations (Accounts 383 and 384), and industrial measuring and regulating station equipment (Account 385) were allocated based on the actual types of meters used to serve gas customers in different customer classes and the current costs of those meters and their installation.

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

A. In general, these expenses were allocated on the basis of the cost allocation methods used for PSE'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 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 No. 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 deemed appropriate to rely upon those

results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

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 operation and maintenance expenses.

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

A. These items 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 function. Typically, taxes of a utility other than income taxes can be grouped into the following categories: (1) labor; (2) plant; and (3) function, *e.g.*, distribution, storage, rental.

In the PSE COSS, all non-income taxes were assigned to one of the above stated categories 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' revenue requirement. Income taxes at an equal rate of return were allocated to each class based on the allocation of rate base to each class.

C. Allocation of Distribution Mains

Q. How were distribution mains classified and allocated in the COSS?

A. The peak and average methodology was used to classify and allocate gas distribution main costs. This methodology allocates gas demand costs based on a combination of peak demand and average demand (or average throughput). PSE used an estimate of the gas system load factor to determine how much of these demand-related gas costs would be allocated based on average gas demand and how much would be allocated based on peak gas demand. The gas system load factor was calculated based on weather-normalized throughput and design day peak demand, which were discussed earlier in my testimony. Multiplying this load factor by the gas plant investment provides an estimate of costs that can be attributed to average use, with the remainder being assigned to peak use.

Q. What is the resulting classification of gas distribution mains?

A. PSE's gas system design day load factor is 32.23 percent. So, based on the peak and average methodology, 32.23 percent of PSE's gas distribution mains were classified as commodity-related and allocated on average demand and 67.77 percent were classified as demand-related and allocated on design day peak demand.

Q. How was the peak and average method of cost allocation applied to gas distribution mains?

A. The cost of mains was allocated in the following steps:

First, the total gas distribution mains plant was divided into the portion to be allocated based on peak demand and the portion to be allocated based on average demand using the gas system load factor described above. This resulted in $651 million (32.23 percent) of gas plant to be allocated based on average gas demand and $1,368 million (67.77 percent) to be allocated based on peak gas demand.

Second, based on the study of mains utilized to serve Special Contracts, 0.1315 percent of mains was directly assigned to Special Contracts. The remaining mains were split into three groups 1) large distribution main (greater than or equal to four inches in diameter); 2) medium distribution main (two to three inches in diameter); and 3) small distribution main (less than two inches in diameter). These groups were developed for both the 32.23 percent to be allocated on average gas demand and the 67.77 percent to be allocated on peak gas demand.

Third, for the 67.77 percent to be allocated on peak gas demand large mains were allocated to all gas customer classes except Special Contracts; medium mains were allocated to all customer classes except Non-Exclusive Interruptible (Schedule 87 and 87T) and Special Contracts, and small mains were allocated to all customer classes except the Interruptible Classes (Schedules 85, 85T, 86, 86T, 87 and 87T) and Special Contracts. All the above allocations were based on each customer classes estimated contribution to the gas system design day peak demand.

Fourth, a similar process was followed for the 32.23 percent to be allocated on average gas demand annual weather normalized gas throughput. Large mains were allocated to all gas customer classes except Special Contracts; medium mains were allocated to all customer classes except Non-Exclusive Interruptible (Schedules 87 and 87T) and Special Contracts, and small mains were allocated to all customer classes except the Interruptible Classes (Schedules 85, 85T, 86, 86T, 87 and 87T) and Special Contracts. All the above allocations were based on each customer classes annual weather normalized throughput.

Q. Why were medium and small distribution mains not allocated to all gas customer classes?

A. Regarding the smallest mains (less than two inches), a review of the meter sizes for the Non-Exclusive Interruptible (87 and 87T) showed that it is reasonable to assume that none of these customers are served from mains that are smaller than four inches. Further, the smallest main are in isolated locations on PSE's gas

distribution system and are unlikely to provide benefits to the large gas commercial and industrial loads served on Schedules 85, 85T, 86, 86T, 87, and 87T. Further, none of the medium size mains were allocated to the Non-Exclusive Interruptible classes (Schedules 87 & 87T), given the mains serving these customers were four inch or larger.

Q. How does this method align with the one used by PSE in its 2017 GRC?

A. The method of allocating distribution mains explained above is generally in alignment with PSE's past allocation of mains with the following exceptions; (1) directly assigning mains through a special study to the Special Contract class as described above; (2) the full exclusion of Interruptible, Limited Interruptible, and the Non-Exclusive Interruptible from the allocation of mains less than two inches, and (3) the exclusion of the Non-Exclusive Interruptible class from the allocation of medium mains (two-three-inch mains). In PSE's 2017 GRC, the medium-size mains were split into two groups in which 33 percent was allocated to classes including the Non-Exclusive Interruptible class and 67 percent were allocated to classes excluding the Non-Exclusive Interruptible class. Rather than bifurcate the medium mains and allocate only a subset to the Non-Exclusive Interruptible class a review of the data indicated that it was reasonable to allocate none of the medium size mains to the Non-Exclusive Interruptible class as indicated above.

Q. Have you provided exhibits related to these inputs and allocations?

A. Yes. See the Fourth Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-5, for a list of Account Inputs and Allocation Choices. See the Fifth

Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-6, for a list of external allocation factors.

D. PSE's Cost of Service Study Results

Q. Please summarize the results of the gas cost of service study.

A. The parity percentages under current rates, excluding gas costs, are summarized in Table 1 below. 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 parity ratio of less than 1.00 means that the current rates and revenues of the particular customer class are below its indicated COSS, while a parity ratio of greater than 1.00 means that the rates and revenues of the customer class are above its indicated COSS (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 Study

Customer Class	Schedule	Parity Ratio
Residential	16/23/53	1.07
Commercial & Industrial	31/31T	0.82
Large Volume	41/41T	1.22
Interruptible	85/85T	1.08
Limited Interruptible	86/86T	1.71
Non-exclusive Interruptible	87/87T	0.83
Special Contracts		1.71
Rentals	71/72/74	1.37
Total/System Average		**1.00**

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

A. Yes. The Second Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-3, summarizes the results of PSE's COSS. 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. Further, this exhibit summarizes the costs allocated to the customer classes on a functionalized (*e.g.,* by production and distribution), and classified (*i.e.* by demand, customer and commodity) basis. Of interest are the customer related and demand related costs which support the existing and proposed levels of Basic Service Charges and Demand Charges.

Q. Have you prepared an Exhibit showing the results of the COSS using the 2017 GRC mains allocation method?

A. Yes. Pages 6-9 of the Second Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-3, provides the summary output of the COSS using the 2017 GRC mains allocation method. The method utilized in 2017 was updated to reflect the new system load factor, balance of mains plant, design day allocation factors, and annual volumes by class. Table 2, below, provides a comparison of the revenue-to-cost parity ratio for each class under the filed COSS method of allocating distribution mains and under the 2017 GRC method. As can be seen, this change predominately impacts the Special Contracts parity ratio, which is due to the lower portion of distribution mains assigned to this class based on the direct assignment study described above.

Table 2 –Parity Ratio Comparison

Customer Class	Schedule	Filed COSS	2017 Mains Method
Residential	16/23/53	1.07	1.07
Commercial & Industrial	31/31T	0.82	0.82
Large Volume	41/41T	1.22	1.24
Interruptible	85/85T	1.08	1.09
Limited Interruptible	86/86T	1.71	1.58
Non-exclusive Interruptible	87/87T	0.83	0.75
Special Contracts		1.71	0.66
Rentals	71/72/74	1.37	1.37
Total/System Average		**1.00**	**1.00**

IV. PRINCIPLES OF SOUND RATE DESIGN

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

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

1. Efficiency;
2. Cost of Service;
3. Value of Service;
4. Stability;
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 with each other 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. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such 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. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows: (1) Capital Attraction, (2) Consumer Rationing, and (3) Fairness to Ratepayers.

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing

requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

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 into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process has to be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate PSE's proposed revenue increase of $97.8 million 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 the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. Based on the parity percentages shown above in Table 1 and the desire to move toward full parity over time, PSE proposes to: 1) apply the system average increase to those classes with parity

percentages between 90 percent and 110 percent (Schedules 16, 23, 53, 85, 85T); 2) apply 50 percent of the average increase to those classes between 110 and 150 percent of parity (Schedules 41 and 41T); 3) apply no increase to those above 150 percent of parity (Schedules 86 and 86T); and 4) apply 150 percent of the average increase to those below 90 percent of parity (Schedules 31, 31T, 87 and 87T). Further, the Rentals class was set to their cost to serve which reflected a targeted margin decrease of $643,783, to reflect PSE's expectation to sell or end this program in the near future as discussed in the Prefiled Direct Testimony of William T. Einstein, Exh. WTE-1T. The proposed revenue allocation by rate class of the proposed $97.8 million increase is presented on page one of the Sixth Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-7.[2] This revenue allocation approach resulted in reasonable movement of all class's revenue-to-cost ratio 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.

[2] The requested $97.8 million in base rates in the Sixth Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-7, recovers the requested $65.4 million increase in net revenues inclusive of the $32.4 million in gas revenues that will no longer be collected in gas Schedules 141, 141X, and 149, as explained in Prefiled Direct Testimony of Jon A. Piliaris, Exh. JAP-1T.

VI. PSE'S RATE DESIGN PROPOSALS

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

A. I will present the specific rate design changes and supporting rationale for PSE's proposals. PSE has proposed the following rate design changes to its current tariff schedules:

- PSE proposes to maintain the current level of monthly basic service charges for all customer classes and incorporate the addition of the Schedule 141 (ERF) and Schedule 141X (EDIT) basic service charge adjustments to the base schedule tariffed basic service charge. For example, the Residential basic service charge will move from $11.00 to $11.52.
- PSE is proposing to increase the demand charge rate for most customer classes with a demand rate (Schedules 41, 41T, 85, 85T, 86, 86T, 87, and 87T) to better reflect the underlying unit demand costs associated with these customer classes.
- PSE is proposing to increase the balancing charge for all transportation service classes from $0.00070 to $0.00100. This amount is supported by the Third Exhibit to the Prefiled Direct Testimony of Ronald J. Amen, Exh. RJA-4, which indicates a balancing unit cost of $0.00135.
- Given the above proposals, the next step was to update the volumetric rates to ensure each class's total margin revenue equals the proposed margin revenue developed in the rate apportionment.

- PSE is proposing to change each sales classes procurement charge in proportion to the increase to the volumetric charge (e.g., the volumetric charge for Schedule 41 increased by 13.3 percent so the procurement charge also increased by 13.3 percent). These increases move each sales class closer to the amounts supported by the COSS as depicted in the Seventh Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-8.

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, with certain classes having much higher demand-related costs than others depending largely on the level of firm use present in the schedule. However, given these significant variations, PSE is proposing to move demand rates incrementally closer to demand costs. Specifically, in the interest of gradualism, PSE is proposing to move the demand charges for all customers closer to their full demand-related costs. The decision on these increases considered the current demand charges for both the sales and transport schedules and the demand unit costs resulting from the COSS.

Q. Have you prepared an exhibit depicting the demand unit costs?

A. Yes. The Seventh Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-8, provides information from the COSS model on the demand unit costs for each class as well as information on procurement and balancing costs.

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. Pages 2-12 of the Sixth Exhibit to the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-7, show the derivation of each rate component for each of PSE's tariff schedules and the corresponding revenues generated from those proposed rates.

VII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.