EXHIBIT NO. ___(JKP-1T)
DOCKET NO. UG-10___
WITNESS: JANET K. PHELPS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of **PUGET SOUND ENERGY, INC.'S** **Natural Gas Tariff Increase**	**Docket No. UG-10_____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JANET K. PHELPS ON BEHALF OF PUGET SOUND ENERGY, INC.

OCTOBER 1, 2010

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JANET K. PHELPS

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JANET K. PHELPS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Janet K. Phelps, and my business address is 10885 N.E. Fourth Street, Bellevue, Washington 98004. I am employed by Puget Sound Energy, Inc. ("PSE") as a Regulatory Consultant in Pricing and Cost of Service.

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

A. Yes, I have. It is the First Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-2).

Q. What is the purpose of your testimony?

A. I will present PSE's pro forma revenue from gas operations, the gas cost of service study, and PSE's proposed rate spread and rate design for gas service. Although the methodologies discussed in my testimony are consistent with the methodologies used in past general rate cases, I have provided a summary of these methodologies again in this case.

II. PRO FORMA REVENUE FROM NATURAL GAS OPERATIONS

Q. What is pro forma revenue?

A. Pro forma revenue is an estimate of test year revenue based on test year billing determinants (*e.g.*, volume, contract demand, number of bills) and the rates that were in place at the end of the test year. It is developed to ensure that the test year revenue used in calculating the revenue deficiency (1) reflects only those rate schedules that are being considered in the present case, (2) encompasses any rate changes that took place during the test year, and (3) is consistent with the normalized test year revenue requirement and loads. The calculation and billing determinants used to produce pro forma revenue are also used to estimate the revenue from proposed rates.

Q. Have you prepared an exhibit that demonstrates PSE's development of its pro forma revenue?

A. Yes, I have. It is the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-3).

Q. Please explain page one of the Second Exhibit to your Prefiled Direct Testimony, Exhibit No. ___(JKP-3), Adjustments to Volume (Therms) by Rate Schedule.

A. As mentioned above, pro forma revenue is based on test year billing determinants, which include gas throughput. Developing pro forma revenue involves making

adjustments to test year throughput. PSE's adjustments to test year natural gas throughput for this case are summarized on page one of the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-3). Column B of page one of Exhibit No. ___(JKP-3) shows the volume of sales and transportation for the test year ended June 2010.

The restating adjustments in column C include an out-of-period adjustment and an unbilled volume adjustment. The out-of-period adjustment corrects usage associated with billing corrections by moving the consumption from the period in which it was corrected into the period in which it should have been billed. The unbilled volume adjustment adjusts for the fact that customers' bills are issued throughout the month and do not correspond to calendar months. The volume in column B, which underlies PSE's income statement, reflects sales for a given month that were billed during that month, removes the portion of that volume that was consumed in the previous month, and adds an estimate of sales that occurred during the calendar month but were not yet billed.

In the adjustment to unbilled volume included in column C, this estimate of the unbilled portion of sales was updated to reflect sales that actually took place during each calendar month, by rate schedule, after the whole month's consumption was actually billed.

The weather normalization adjustment to volume presented in column D removes the effect of non-normal temperatures from test year loads, so that test year loads

and revenues are more reflective of normal operating conditions.

Pro forma volume that reflects all of these adjustments and is used for calculating pro forma revenue is presented in column F on page one of the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-3).

Q. Was the weather adjustment in column D of page one of Exhibit No. ___(JKP-3) developed using the same approach PSE has used in past general rate cases?

A. Yes, the same approach was used with updated information to reflect the recent time period. The approach in this case is based on PSE's weather normalization methodology presented in its 2006 general rate case, Docket Nos. UE-060266 and UG-060267 ("2006 GRC"), with minor modifications that were presented in PSE's last general rate case, Docket Nos. UE-090704 and UG-090705 ("2009 GRC"). The Commission accepted PSE's weather normalization analysis in the 2006 case, and the modifications made in 2009 were uncontested. *See* 2006 GRC, Order 08, ¶163.

Q. Please describe how PSE normalized the test year total gas system load in this case.

A. As was done in PSE's 2006, 2007 and 2009 general rate cases, PSE first compared actual daily loads for a multi-year time period to actual daily temperatures for the same multi-year period using regression analysis. This

analysis provided weather sensitivity coefficients that describe the relationship between temperature and load for three groups (Firm, Interruptible and Transport).

The adjustment required the use of a "normal" weather dataset. This was developed using data reported at Sea-Tac Airport over the 30-year period from 1980 through 2009 by calculating daily heating degree days ("HDD") using two base temperatures (45˚F and 65˚F). The actual HDDs were calculated using the average of the 24 hourly temperatures compared against the base temperature.

Then PSE used the weather sensitivity coefficients and "normal" weather data to convert the actual test year loads to normal loads in three groups (Firm, Interruptible and Transport). The amount of temperature adjustment was calculated by taking the weather sensitivity coefficients and multiplying them by the difference between the actual and normal HDDs. PSE performed this process for each base HDD (45˚F and 65˚F) that is included in the model to yield temperature adjusted load.

Q. How did PSE use temperature adjusted gas load to calculate the load adjustment for various customer groups (rate schedules) related to weather effects?

A. The following rate schedules are considered temperature sensitive and are included in the weather adjustment: Schedule 23 (Residential), Schedule 31 (Commercial, Industrial), Schedule 41 (Commercial, Industrial), Schedule 85

(Commercial), Schedule 86 (Commercial), Schedule 87 (Commercial), Schedule 87T (Commercial Transportation) and Special Contracts (Industrial). PSE next developed regression equations to characterize the relationship between temperature and load for each of the above temperature sensitive rate schedules. The system-level weather adjustment was then allocated to each of the applicable schedules by taking the percentage share of each schedule's temperature adjustment relative to the total temperature adjustment for all schedules as calculated by the rate schedule normalization equations.

Q. What were the results of PSE's gas temperature adjustment process?

A. Applying the process described above to the test year delivered load of 1,060,817,632 therms resulted in a total temperature adjustment of 27,696,526 therms. Because the test year was warmer than normal, this adjustment resulted in a pro forma delivered system load that is larger than actual load delivered during the test year. The effect of the adjustment to volume on pro forma revenue was calculated at the rates implemented in April 2010 pursuant to PSE's 2009 GRC.

Q. Please explain page two of the Second Exhibit to your Prefiled Direct Testimony, Exhibit No. ___(JKP-3), Reconciliation of Revenue by Rate Schedule.

A. Page two of the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-3), presents explanations of the differences between test year

revenue as presented in PSE's income statement and pro forma revenue as calculated based on billing determinants and rates. The revenue included in the test year income statement is presented in column B of page two, and pro forma revenue based on billing determinants and end-of-year rates is in column N. The items presented in columns C though M are explanations of the differences between the income statement and pro forma revenue. These items are related to either:

1. removal of revenue from adjusting price schedules, municipal taxes, penalty charges and new customer charges (columns C-E),

2. other restating adjustments that correspond to the restating volume adjustments, including the previously discussed billing corrections and the change in unbilled revenue adjustment (column F),

3. adjusting for price changes that took place during or after the test year, specifically the 2009 Purchased Gas Adjustment ("PGA") and implementation of rates approved in PSE's 2009 GRC (columns G and H),

4. an adjustment to volume for normal weather (column I), or

5. revising the Revenue Adjustment Factor on Schedule 101 gas rates to be consistent with the proposed revenue requirement, and removal of Everett Delta and storage rental revenues described in the Prefiled Direct Testimony of John Story, Exhibit No. ___(JHS-1T) (columns J-L).

Q. What are PSE's resulting pro forma volume and revenue?

A. The total pro forma volume for the test year is 1,090,182,856 therms, and is presented in column F of page one of Exhibit No. ___(JKP-3). The total pro

forma revenue is $1,065,818,560, and is presented in column N of page two. The gas cost associated with this revenue is $629,304,268, and is presented in column P of page two.

III. COST OF SERVICE CONSIDERATIONS

Q. What is the purpose of a cost of service study?

A. The purpose of a cost of service study is to apportion the utility's total cost of service, or revenue requirement, to the respective customer classes and to group costs so that individual rates can be properly set. This cost analysis then provides guidance for the determination of the revenue responsibility for the individual customer classes and for rate design.

Q. How is a cost of service study performed?

A. There are three broad steps to a cost of service study: (1) functionalization, (2) classification, and (3) allocation.

Q. Please describe the first step in a cost of service study, functionalization.

A. Functionalization separates plant and expenses into major categories based on the major functions of the utility, which for PSE's gas business are production, storage, transmission, and distribution of natural gas.

Q. Please describe the second step in a cost of service study, classification.

A. Classification further separates costs into categories based on the utility operation

for which the plant is constructed and expenses are incurred. PSE's distribution system is designed to perform the following three primary tasks: (1) to provide distribution services to *customers* served by the system; (2) to serve peak *demands* of all customers; and (3) to deliver the natural gas *commodity* sold to or transported for its customers. There are costs associated with each of these services, and in the cost of service study costs are categorized according to customer, demand, or commodity.

Given these three primary functions of the gas system, classification answers the question: "Why was the cost incurred – to serve the customer, to meet peak demand, or to provide the commodity?" Another way to ask this is, "Does the cost vary with the number of customers, the peak demand for which the system was designed, or the volume of gas sold or transported over the system?"

Q. Please describe customer-related costs.

A. Customer-related costs are those costs that would be needed to serve customers at minimal load conditions. These costs include, at a minimum, the costs of the service line and meter, meter reading and billing, and maintaining the customer accounting system. They may also include costs associated with minimum size distribution mains. Customer costs vary with the number of customers on the system, regardless of how much gas those customers consume.

Q. Please describe demand-related costs.

A. Demand, or capacity, costs are those costs associated with designing, installing, and operating the system to meet maximum hourly gas flow requirements. The system must be sized to meet peak requirements, even though average daily loads are below peak levels; otherwise the system would not be adequate to serve customers' demand for gas on the coldest peak load days. Demand costs vary with the size of the peak demand for which the system was designed. Demand costs are incurred whether all the capacity is used or not.

Q. Please describe commodity costs.

A. Commodity costs, such as the cost of gas itself, vary with the amount of gas transported over PSE's system, either the gas commodity sold to customers or transported for customers who purchase gas from providers other than PSE. Over a one-year period, the average daily volume of gas transported through the system is considerably less than the volume on a peak day. Gas distribution systems have very low commodity-related costs aside from purchased gas.

Q. Please describe the third step in a cost of service study, allocation.

A. Allocation is the final step in the assignment of costs to customer classes. Unless a cost is unique to a specific customer class and can be directly assigned to that customer class, it is allocated based on an allocation factor that is related to that type of cost. In general, (1) customer-related costs are allocated based on the

number of customers; (2) demand-related costs are allocated based on peak demand; and (3) commodity-related costs are allocated to customer classes based on throughput. There are many variations of these allocation factors based on the specific costs and plant items being allocated, and some costs may be allocated based on a combination of allocation factors. There may also be instances when the allocation is not entirely consistent with the classification of a cost. For instance, PSE allocates the cost of mains, a demand related cost, using a combination of demand and throughput.

IV. PSE'S NATURAL GAS COST OF SERVICE STUDY

A. Previous Cost of Service Studies

Q. Please identify all gas cost of service studies conducted by PSE in the last five years.

A. PSE filed cost of service studies in its 2006, 2007 and 2009 general rate cases. The approach used in this proceeding, which I will discuss later in my testimony, is consistent with that used in PSE's 2009 GRC. As explained below, the 2009 methodology reflects adjustments that evolved from PSE's 2006 GRC. The primary departures from the 2006 method in subsequent studies relate to the allocation of the costs of distribution mains. In 2006, mains were allocated based on data developed using SynerGEE, which is PSE's gas planning model. The portion of distribution mains less than four inches in diameter that was dedicated to serving a single customer on Schedules 85 (Interruptible), 87 (Non-exclusive

Interruptible), 57 (Transportation) and special contracts was identified using SynerGEE and directly assigned to those customer classes. The remaining main smaller than four inches was then allocated using the peak and average method to all classes except Schedules 85, 87, 57 and special contracts, and the large main was allocated using the peak and average method to all classes. In PSE's 2007 GRC, SynerGEE was again used to identify costs to directly assign to Schedules 85, 87, 57, 85T, 87T and special contracts, but in a different way than had been done in the 2006 case (85T and 87T are new transportation schedules approved in the 2007 case). In other respects the 2007 study was consistent with the 2006 study. In PSE's 2009 GRC, the allocation of mains was again changed in response to concerns raised in the 2007 case, and SynerGEE was not used.

B. Overview of PSE's Proposed Gas Cost of Service Study

Q. Why did PSE conduct its cost of service analysis both including and excluding gas commodity costs?

A. PSE conducted the analysis both including and excluding gas commodity costs to ensure that the cost of service study is consistent with the total revenue requirement including gas costs presented in the testimony of John H. Story, Exhibit No. ___(JHS-1T), and to be consistent with past cases. The study that includes gas costs is informational only, because PSE's PGA mechanism addresses changes in commodity costs. This proceeding addresses the revenue requirement deficiency that is caused by changes in costs *other than* gas costs.

Unless otherwise noted, I will refer to the cost of service analysis that excludes gas costs throughout the remainder of my testimony.

Q. Have you prepared exhibits that present PSE's cost of service study for its natural gas service in this proceeding?

A. Yes. The Third Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-4), presents the summary results proposed in this proceeding, excluding gas costs. The Fourth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-5), presents the summary results proposed in this proceeding, including gas costs. The Fifth, Sixth and Seventh Exhibits to my Prefiled Direct Testimony, Exhibit Nos. ___(JKP-6, 7 and 8), present supporting details of PSE's proposed study.

Q. What model did PSE use for its cost of service study?

A. PSE used Navigant Consulting, Inc.'s Cost of Service Model. This is the same model that PSE used in its 2006, 2007 and 2009 general rate cases.

C. Peak and Energy Allocation Factors

Q. What was the basis for allocating commodity costs?

A. PSE used weather-normalized volume for the test year, which was developed for the calculation of pro forma revenue and is discussed earlier in my testimony.

Q. How did PSE develop the peak demand allocator for demand-related costs?

A. PSE used the system design day to develop its peak demand allocator. The

system design day is based on 52 heating degree days ("HDD"), as explained in PSE's 2009 Integrated Resource Plan.[1] In broad terms, peak requirements include the loads of sales and transportation customers. To estimate the total peak demand of customers on firm sales schedules, PSE developed regression equations to characterize the relationship between firm peak loads and monthly firm volume considering the difference between peak and monthly temperatures. The total peak demand of customers on firm sales schedules was then estimated by using the estimated regression coefficients, the system design day of 52 HDD and weather normalized throughput for the test period. The transportation and interruptible sales customers' peak was equal to either those customers' contract demands (for Schedules 85, 85T, 87, 87T, and contracts), which represent the firm demand PSE is obligated to serve, or their fixed demand (for Schedule 41T), which is established annually and billed every month. The total system peak was the sum of the peak demand of customers on firm schedules and the contract or fixed demands of customers on transportation or interruptible sales schedules.

Q. How was the peak allocation factor for firm sales schedules developed at the customer class level?

A. The firm sales component mentioned above was allocated to Schedules 23, 31, 53, and 41 based on a combination of fixed demands and consumption in the peak month of the test year. Schedule 41 customers have fixed demands that are

[1] *See* 2009 Integrated Resource Plan, Appendix E: Load Forecasting Models, page E-6.

established annually, based on the customers' usage in the system peak month, and billed every month. These fixed demands were used to estimate Schedule 41 customers' contribution to the system peak. Of the total peak of firm sales schedules, the portion not assigned to Schedule 41 based on those customers' fixed demands was allocated between Schedules 23 and 53 (Residential and Propane) and Schedule 31 (Commercial and Industrial), based on those schedules' actual volume during the peak month in the test year.

Q. Why did PSE use only the contract demands of interruptible customers?

A. Contract demands represent those customers' firm load, and any use in excess of their contract demand is interruptible. The system is designed to serve firm load. Capacity projects are undertaken for the purpose of serving firm loads, not interruptible loads, so allocating peak-related costs to interruptible customers based on interruptible loads would not be consistent with the way costs are incurred by PSE. During design day weather conditions, which are the basis of the peak allocation factor, all interruptible loads of transportation and sales customers would be fully curtailed to ensure that PSE is able to serve its firm load, and the only service to interruptible customers would be their firm component. Many interruptible customers have both firm and interruptible components to their loads. Because the contract demand represents the firm portion of their loads, it is the best estimate of their contribution to the costs of meeting the system peak.

Q. Why did PSE use its design day peak demand to allocate demand-related costs instead of using a peak based on actual weather data from a recent historical period?

A. There are two primary reasons design day peak is a better choice than historical peak for cost allocation:

1. Cost causation is the primary consideration in cost of service analysis, and PSE's distribution system is designed to meet design day peak, thus costs are incurred based on the design day rather than historical observed peaks. Design day peak is a better indicator of cost causation than historical peak demands.

2. Design day provides a more stable estimate of peak than historical peaks provide, and design day provides more stable cost of service results over time.

Q. Why does design day peak better reflect the costs that are incurred than a historical peak does?

A. PSE designs its system to meet a design day peak demand, which is based on cold weather conditions. Regardless of how often those design day conditions occur, PSE incurs the capacity costs associated with being able to provide natural gas service on a design day. PSE uses the design day standard in its capacity investment decisions and builds capacity to meet that standard. As discussed in the Prefiled Direct Testimony of Susan McLain, Exhibit No. ___(SML-1T), PSE is obligated to provide reliable service, and customers expect that reliability, especially during cold weather. If PSE built the system based on a peak that occurred in a given historical period, the capacity might not be sufficient to serve

customer needs in extreme weather. The design day standard was developed in PSE's Integrated Resource Plan process and has been accepted by the Commission. An estimated peak based on historical weather conditions during a particular period would not necessarily reflect PSE's costs associated with meeting its peak demand.

Q. Why does design day peak provide a more stable estimate of peak than a peak based on historical temperatures does?

A. Weather, volumes and peak demands change from year to year, yet these changes do not represent the costs of designing and building PSE's system. If historical data were used, cost allocation would depend on weather conditions that happened to prevail during the period considered rather than the conditions for which the system was designed, which do not vary considerably from one year to the next the way weather does. The historical peak might also include some interruptible loads, which would vary over time based on both weather conditions and the amount of excess capacity in the system available to serve those loads. These factors could result in greater volatility of cost assignments from one cost study to the next. The design day standard is a more stable determinant of planned capacity.

With respect to stability over time, use of design day is consistent with the use of weather normalized volume in cost allocation. If actual volume were used, allocation among the classes would change from year to year based on the

weather because some customer classes exhibit greater weather sensitivity than other classes. Use of weather-normalized volume avoids these swings in cost allocation from one rate case to the next. Similarly, design day is a more stable basis for cost allocation because it does not depend on the weather that actually occurred during a recent period.

Q. How would the peak allocation factor be different if historical weather data were used to estimate peak loads?

A. The general method for developing the peak allocation factor would be similar, but it would use actual weather conditions that occurred during past cold periods rather than design day weather conditions. The method for estimating the contribution of firm sales schedules to system peak would be the same, but if the historical HDD were lower than the design day HDD, the total estimate of firm sales would be lower. The allocation of this firm sales load to customer classes would be done in the same manner as it is with design day.

Depending on the assumed weather conditions, interruptible sales and transportation customers might not be curtailed or might be partially curtailed, so their contributions to peak might include estimates of interruptible volumes given the weather assumptions, in addition to their contract demands. This would introduce ambiguity as to these customers' contributions to the system peak. The use of historical weather data adds ambiguity to the peak allocation factor, without justification, because those interruptible loads have no impact on PSE's

capacity planning. The design day standard is clearer as to interruptible customers' loads and is consistent with PSE's capacity planning.

D. Allocation of Plant Costs and Operating Expenses

Q. Were facilities identified that could be directly assigned to specific customer groups?

A. Yes. PSE conducted an analysis to identify the cost of services in Federal Energy Regulatory Commission ("FERC") Account 380 that are dedicated to customers on Rate Schedules 85, 85T, 87, 87T and special contracts. This portion of plant in Account 380 was directly assigned to these customer classes, and the remainder was allocated to all other customer classes based on weighting factors. Different customer classes require different sizes and types of services, which vary in cost. The number of 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.

Q. How were other customer-related 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 types of meters used to serve customers in different customer classes and the current costs of those

meters and their installation.

Q. How were distribution-related operation and maintenance ("O&M") expenses allocated?

A. Other than directly-assigned expenses, these expenses follow the cost allocation of the corresponding plant accounts.

Q. How were administrative and general ("A&G") expenses and taxes allocated to each 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 are related to the overall operation and maintenance of the utility, and were allocated based on operation and maintenance expenses.

E. Classification and Allocation of Distribution Main Costs

Q. Please describe how investment in distribution mains was classified and allocated.

A. The investment in distribution mains is classified as a demand-related cost, but it is not allocated solely on peak demand. Following a long-standing practice,

including PSE's 2009 GRC, PSE used the peak and average method for allocating this portion of its demand-related costs. This method allocates demand costs based on a combination of peak demand and average demand. Average demand is essentially another term for average throughput. PSE used an estimate of the system load factor to determine how much of these demand-related costs would be allocated based on average demand and how much would be allocated based on peak demand. A system load factor was calculated based on weather-normalized throughput and design day peak demand, which were discussed earlier in my testimony. The load factor is the ratio of average load to peak load, and when multiplied by the plant investment, provides an estimate of costs that can be attributed to average use rather than peak use. The resulting 32 percent load factor was used to divide these demand-related costs into peak demand and average demand for purposes of allocating the costs to customer classes, with the costs being allocated 32 percent on average demand and 68 percent on peak demand. The load factor provides a reasonable basis for determining what portion of these costs should be allocated based on average demand.

This peak and average approach to allocation of demand costs reflects a balance between the way the system is designed (to meet peak demand) and the way it is utilized on an annual basis (throughput based on gas usage that occurs during all conditions, not only peak conditions). It also acknowledges previous Commission guidance that some portion of demand costs should be allocated based on energy use.

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

A. A diagram of the allocation of mains is presented on page one of the Eighth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-9). The cost of mains was allocated in the following steps:

First, the total 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 system load factor described above. This resulted in $418 million (32 percent) of plant to be allocated based on average demand and $887 million (68 percent) to be allocated based on peak demand.

Second, the 68 percent to be allocated based on peak demand was allocated to all customer classes based on their estimated contributions to the system design day peak demand.

Third, the 32 percent based on average demand was split into three groups, 1) large main (greater than or equal to four inches in diameter), 2) medium main (two to three inches in diameter), and 3) small main (less than two inches in diameter). Large main was allocated to all customer classes based on annual weather normalized throughput, and small main was allocated to all classes except Schedules 85, 85T, 87, 87T and Contracts based on annual weather normalized throughput. Medium main was allocated 33 percent to all classes and

67 percent to all classes except 87, 87T and Contracts, based on annual weather normalized throughput.

Q. Why were small mains, those less than two inches, not allocated to all classes?

A. The smallest main is in isolated locations on PSE's system and is unlikely to provide benefits to the large commercial and industrial loads served on Schedules 85, 85T, 87, 87T and contracts.

Q. Why were medium mains, those two to three inches in diameter, split into two groups?

A. Parties in PSE's 2007 GRC raised different concerns regarding the allocation of mains. In general, two different ways of looking at the benefits to customers were presented in discussions about the allocation of mains costs, and these two viewpoints are diametrically opposed. One view is founded on a belief that customers only benefit from pipe through which gas molecules flow, or might flow, to reach their locations, and thus should only be allocated a share of the cost of those specific pipes, nothing more. The other view is that the gas distribution network provides an integrated system that benefits all customers, regardless of the customers' locations on that system and regardless of the actual (or modeled) flow of molecules. Giving the largest interruptible customers a full allocation of costs emphasizes system benefits, and exempting them from the cost of medium

main emphasizes customers' physical connections and the flow of gas. PSE's use of both of these approaches for medium mains balances the two perspectives.

Q. Why did PSE choose the one-third, two-thirds split, with one-third of medium main being allocated to all customers and two-thirds to all except Schedules 87, 87T and Contracts?

A. PSE considered the historical treatment of Schedules 87, 87T and Contracts customers and the benefits associated with being part of the gas distribution system. Historically, these customers had some assignment of costs related to medium main, but that assignment was small. Prior to PSE's 2004 general rate case, Docket No. UG-040640, when PSE introduced the use of SynerGEE into its cost of service study, the only assignment of medium main given to those largest customers was based on a direct assignment. The two-thirds weighting of the exemption of these customers is an acknowledgement that, in the past, the Commission approved very limited cost assignments to this group of customers. The one-third weighting of assigning the cost of medium main to all customers acknowledges the benefits to all customers of being part of a distribution system. So while their cost assignment of medium main should be small, it should not be zero. This methodology is consistent with PSE's 2009 GRC.

Q. Why did PSE choose two inches as the point for exempting large customers?

A. Large main (four inches and greater) is the backbone of the system, and medium to small main (three inches and smaller) is used to deliver gas to most customers.

Most main smaller than two inches is located in isolated locations on the system and is unlikely to provide benefits to large commercial and industrial loads, whereas medium main is ubiquitous throughout the distribution system. Three inch main is grouped with two inch main, but there is very little three inch main in the system.

Q. Please summarize the benefits of PSE's proposed approach to allocating mains.

A. There are five benefits to PSE's approach. First, this method recognizes that all customers benefit from the gas system of medium to large mains as a whole, not only from the stretch of main through which gas flows to reach the individual customer. The system is a network of pipes that provides benefits to customers in addition to providing the stretch of pipe through which molecules flow to reach the individual customer. Second, in previous general rate cases some parties have opposed using a customer's physical location on the system to determine the costs that should be assigned to that customer, and the proposed method avoids this practice. Third, by exempting large customers from the cost of the smallest diameter main (less than two inches), this approach acknowledges the fact that the smallest main is in isolated locations on the system and is unlikely to benefit large commercial and industrial customers. Fourth, PSE's approach addresses concerns regarding cost responsibility for two inch main by allocating a portion of it to all customers and excluding the largest interruptible customers from a portion of it. Fifth, PSE's approach is relatively transparent and easy to understand.

F. Results of the Cost of Service Study

Q. Please summarize the results of the cost of service study conducted by PSE.

A. The parity percentages under current rates, excluding gas costs, are summarized in Table 1 below. The parity percentage indicates what portion of the cost of service customers pay under current rates, relative to other customer classes. These results are also provided in the summary of results from the cost of service study on page one, line 36 of the Third Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-4).

Table 1: Summary of Parity Percentages

Customer Class	Parity Percentage
Total System	100%
Residential (Schedules 23, 16, 53)	98%
Commercial & Industrial (Schedules 31, 61)	94%
Large Volume (Schedules 41, 41T)	129%
Interruptible (Schedule 85, 85T)	132%
Limited Interruptible (Schedule 86)	159%
Non-exclusive Interruptible (Schedule 87, 87T)	92%
Special Contracts	79%
Rentals (Schedules 71, 72, 74)	165%

V. GAS RATE SPREAD AND RATE DESIGN

A. Rate Spread

Q. What is meant by the term rate spread?

A. Rate spread is the process of determining what portion of the total revenue requirement should be allocated to each customer class for recovery in that class's rates.

Q. Please summarize PSE's gas rate spread proposal.

A. PSE proposes to allocate the increase equally to all customer classes, with one exception. That is, each customer class except rentals will receive the same percentage increase as a percent of margin under PSE's proposal. Because the gas cost associated with rentals is included in the Residential and Commercial classes rather than the Rental class, there is no gas cost included in total rental revenue. Since total rental revenue serves as the denominator for calculating the average increase, and the denominator excludes gas costs, applying the system average increase to rentals would result in a 6.2 percent increase, compared with the total system increase of 2.3 percent. WAC 480-07-505 limits the increase to any customer class to under 3.0 percent of total revenues in a non-general rate case such as this proceeding, and giving the rental class the system average increase would violate this limit. In its proposal PSE has limited the increase to rentals to 2.9 percent in order to ensure that this customer class is not assigned an increase of 3.0 percent or greater. Therefore, the revenue to be collected by the

proposed rates is approximately $259,000 less than the deficiency presented in the Prefiled Direct Testimony of John Story, Exhibit No. ___(JHS-1T). To be clear, the $259,000 is not being spread to other customer classes, PSE is simply requesting a smaller increase than its revenue deficiency suggests. The proposed revenue allocation by rate class of the proposed $24,384,451 increase is presented on page one of the Ninth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-10), and summarized in Table 2:

Table 2: Proposed Rate Spread

Customer Class	Proposed Rate Increase[1]
Residential (Schedules 23, 16, 53)	2.5%
Commercial & Industrial (Schedules 31, 61)	2.2%
Large Volume (Schedules 41, 41T)	1.6%
Interruptible (Schedule 85, 85T)	2.6%
Limited Interruptible (Schedule 86)	1.4%
Non-exclusive Interruptible (Schedule 87, 87T)	1.3%
Rentals (Schedules 71, 72, 74)	2.9%
System Total / Average	2.3%

[1]Including gas costs. The percentage increases vary slightly between the classes because gas costs are included in the denominator. Their percentage increases to margin are equal.

B. Rate Design

Q. Please describe PSE's current rate structure for distribution service.

A. The Residential (23) and General Service Commercial/Industrial (31) schedules have only the basic charge and single-block delivery charges, whereas the Large

Volume Commercial/Industrial schedule (41, 41T) and the interruptible schedules (85, 85T, 86, 87 and 87T) have demand charges and multiple block delivery charges in addition to basic charges. Interruptible sales schedules also have a single-block, volumetric procurement charge.

Q. Please describe the proposed changes to PSE's natural gas tariff schedules.

A. PSE proposes to increase all charges related to distribution services by an equal percentage. For example, for Schedule 31, Commercial and Industrial General Service, the basic charge and delivery charge would increase by the same percentage. The exceptions to this rule are for situations where a rate component is tied to the same component on another schedule. For example, Schedules 41, 85, 86, 87, 41T, 85T, 86T and 87T all have the same demand charge. The proposed level for all schedules is based on the increase to Schedule 87. Increases to the other rate components may vary slightly to achieve the assigned revenue. The proposed rates from basic, demand and volumetric charges are provided in Exhibit No. ___(JKP-10).

Q. Please describe the residential basic charge.

A. The residential natural gas basic charge is a charge applied to each customer each month that does not vary by season or weather. The charge is meant to recover annual costs associated with providing customer service that do not vary by the amount of energy that a customer receives, the maximum amount of capacity PSE must reserve for that customer (through its gas supply capabilities and/or its

distribution capabilities), or the month service is taken. The residential basic charge for gas service of $10.00 is currently set below the $19.32 cost of providing this service.

Q. What costs are identified as customer-related in the cost of service study?

A. PSE's cost of service study includes the costs of service lines, meters and regulators and related installation, a portion of general plant, operating and maintenance costs associated with these plant items, customer accounts expenses, a portion of administrative and general costs, and related taxes.

Q. Do these customer-related costs include all fixed delivery costs?

A. No. They only include those delivery costs that have been identified as customer-related in the cost of service study. Most other delivery costs have been identified as demand-related, which means they vary with the capacity of the distribution system, although most of these costs will continue to be recovered through volumetric rates under PSE's proposal. These costs are also fixed, but they are not included in the $19.32 per month of customer-related costs. If all fixed distribution costs were included in a monthly basic charge the rate would be considerably higher.

Q. What changes does PSE propose to the residential basic charge?

A. Applying the proposed equal percentage increase to the residential class will increase the monthly basic charge to $10.62 from its current rate of $10.00.

Q. How do PSE's basic charges compare to those of other utilities?

A. The Tenth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-11), contains a comparison of basic charges and percentile rankings for residential service from 217 natural gas distribution utilities throughout the country. These data have been collected from the tariffs of the utilities. The distribution companies are members of the American Gas Association. These utilities represent all areas of the contiguous United States, and are a comprehensive group for comparison purposes. The basic charges for standard residential service range from a low of $2.50 per month at Intermountain Gas to $26.88 per month at Missouri Gas Energy. The average basic charge is $10.87 per month. By comparison, PSE's current residential basic charge of $10.00 per month is in the 49th percentile of the 217 companies. In other words, 51 percent of the other gas distribution companies in the country have residential basic charges higher than PSE's charge.

C. <u>Bill Impacts</u>

Q. What are the proposed rates for Residential Schedule 23?

A. The proposed equal percentage increase changes the basic charge from $10.00 to $10.62 per month and the delivery charge from $0.34897 per therm to $0.37043 per therm.

Q. Has PSE prepared an analysis of customer bill impacts based on the proposed rate design?

A. Yes. Page 1 of Exhibit No. ___(JKP-12) presents a comparison of a typical residential bill based on various usage levels, at existing and proposed rates. Increases to the total bill range from 2.3 percent for a customer using 180 therms to 4.1 percent for a customer using 10 therms. Increases vary by usage levels even though PSE proposes an equal percentage increase to all delivery rates, because gas costs, which are charged on a volumetric basis, are included in the bills. Page 2 presents the annual bill impacts on a customer who uses the average volume from the test year. This indicates the typical residential customer will experience a 2.6 percent increase in the total bill based on the proposed rates.

VI. CONCLUSION

Q. Has PSE prepared new natural gas tariff schedules reflecting the proposed changes to rates?

A. Yes. The revised tariffs are presented in the Twelfth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-13).

Q. Does this conclude your direct testimony?

A. Yes, it does.