EXHIBIT NO. ___(JKP-1T)
DOCKET NOS. UE-09___/UG-09___
2009 PSE GENERAL RATE CASE
WITNESS: JANET K. PHELPS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-09_____** **Docket No. UG-09_____**

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

MAY 8, 2009

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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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" or "the Company") 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 Exhibit No. ___(JKP-2).

Q. What is the purpose of your testimony?

A. I will present the pro forma revenue from gas operations proposed in this filing, the gas cost of service study, and the Company's proposed rate spread and rate design for gas service. I will discuss the results of the gas cost of service collaborative that PSE conducted as a result of the settlement in the Company's last general rate case, Docket Nos. UE-072300 and UG-072301 ("2007 GRC").

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. 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. The Company'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 December 2008. Column C shows the removal of volume from Schedule 50, Compressed Natural Gas, which was discontinued during the test year. The restating adjustments in column D 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 D, 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.

In the Company's 2007 GRC, the Commission approved the elimination of Schedules 36, 51 and 57, effective November 1, 2008. The schedule migration adjustment to test year volume in column E represents the fact that test year volume includes 10 months of consumption under these schedules. The net volume adjustment is zero because this adjustment merely reflects movement between schedules as a result of schedule terminations.

In the weather normalization adjustment to volume presented in column F, actual volume is adjusted by comparing actual weather during the test period with normal weather, as defined by heating degree days. This adjustment is described in the Prefiled Direct Testimony of Lorin Molander, Exhibit No. ___(LIM-1T).

Column G contains an adjustment to test year volume as a result of the phasing in of conservation programs implemented by the Company during the test year. This adjustment is described in the Prefiled Direct Testimony of Jon Piliaris, Exhibit No. ___(JAP-1T).

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

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 the Company'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 O. The items presented in columns C though N are explanations of the differences between the income statement and pro forma revenue. These items are related to either:

1. removal of revenue from the discontinued Schedule 50, adjusting price schedules, municipal taxes, penalty charges and new customer charges (columns C-F),

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 G),

3. adjusting for price changes that took place during the test year, specifically the 2008 Purchased Gas Adjustment ("PGA") and implementation of rates approved in PSE's 2007 GRC, and the phase-in of conservation programs (columns H, I and K). The effects of customer migration between schedules due to the elimination of Schedules 36, 51 and 57 is included in the 2007 GRC;

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

5. revising the Revenue Adjustment Factor on Schedule 101 gas rates to be consistent with the proposed revenue requirement, and including the Summit buyout adjustment described in the Prefiled Direct Testimony of Mike Stranik, Exhibit No. ___(MJS-1T) (columns L-M).

Q. How have you accounted for schedules that were closed or opened during the test year?

A. The revenue adjustment for 2007 GRC rates in column I of page two includes the effects of the rate increase for all schedules approved in that docket, the closure of Schedules 36, 51 and 57, and the commencement of Schedules 31T, 41T, 85T, 86T and 87T. All customers on Schedules 36, 51 and 57 were moved to other schedules on November 1, 2008. To calculate these customers' contributions to revenue at existing rates, their consumption for January through October was also moved to their destination schedules and was re-priced at the rates that went into effect November 1, 2008. The volume adjustment is in column E of page one, and the revenue change associated with this migration is included in column I of page two. Thus, pro forma revenue at existing rates in column O calculates revenues as if the customers had been on the new schedules for the entire test year at the rates that were implemented in November 2008. These are restatements of test year revenue.

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

A. Total pro forma volume for the test year of 1,118,222,744 therms is presented in column I of page one, and pro forma revenue of $1,228,490,778 is presented in column O of page two. The gas cost of $786,226,721 associated with this revenue is presented in column Q 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. The Company'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 as related to customer, demand, or commodity.

Customer-related 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.

Demand or capacity costs are associated with the costs of 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.

Commodity costs vary with the amount of gas transported over the Company'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.

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 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, the Company allocates the cost of mains, a demand related cost, using a combination of demand and throughput.

IV. NATURAL GAS COLLABORATIVE

Q. Please describe the 2008 Natural Gas Collaborative ("Collaborative").

A. In the partial settlement regarding natural gas rate spread and rate design in PSE's 2007 GRC, the parties to the settlement agreed that "PSE will conduct a collaborative on natural gas cost of service, rate spread and rate design in advance of PSE's next general rate case."[1] This settlement was approved by the Commission. In accord with the settlement, the Company retained an outside expert to facilitate the Collaborative and provided that expert with relevant documents from the 2007 GRC. Representatives from PSE, the Commission

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[1] Docket Nos. UE-072300 and UG-072301 (consolidated), Partial Settlement Re: Natural Gas Rate Spread and Rate Design, page 7.

Staff, Northwest Industrial Gas Users, Nucor Steel Seattle, Public Counsel Section of the Washington Office of Attorney General ("Public Counsel"), and Seattle Steam Company met four times in November and December 2008 to discuss issues. The Third Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-4), contains the consultant's final report on the Collaborative.

Q. How has the Collaborative influenced the Company's proposal in this proceeding?

A. As indicated in the report presented in the Third Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-4), there were no clear agreements by the Collaborative as to the specifics of the Company's cost of service study in the present case. However, Collaborative discussions related to the allocation of mains led PSE to propose changes to its approach to this issue. This will be discussed later in my testimony.

V. 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 the Company in the last five years.

A. The Company filed cost of service studies in general rate cases in 2004, 2006 and 2007. In 2006, the following changes from the 2004 study were made:

- New composite allocation factors used to allocate Jackson Prairie storage costs and related TF-2 pipeline costs, and TF-1 pipeline capacity gas costs were developed to reflect the Company's current resources. These allocation factors were similar in concept to those used in the previous method, which had been developed in the mid-1990s.

- There were modifications to the allocation of certain administrative and general ("A&G") expenses. In the previous method, half of certain A&G accounts were allocated based on operations and maintenance ("O&M") expense and the other half of those accounts were allocated based on system throughput, rather than the entire account being allocated based on O&M.

- The peak demand allocation factor was developed based on a design day peak, consistent with the Company's Integrated Resource Plan (or Least Cost Plan). Prior to 2006, average weather conditions during five observed peak days over a three-year period were used to estimate the peak for cost allocation purposes.

- The allocation of distribution mains was modified, but it relied upon data from an analysis that PSE had performed in its 2004 GRC using data from the Company's gas planning model, SynerGEE. In 2004, the directly assigned component of all sizes of main to Schedule 85, 87, 57 and special contract customers was identified and split off prior to applying the peak and average split to the remaining plant, which was then allocated to all other customers. In 2006, the directly-assigned plant was limited to small main (less than four inches) dedicated to serve a single customer. The remaining small main was then allocated on peak and average to all classes except Schedules 85, 87, 57 and special contracts, and the large main was allocated on peak and average to all classes.

In PSE's 2007 GRC, the Company again modified the allocation of mains in an attempt to develop a method that treated all customers consistently and could be repeated in future cases. In other respects the 2007 GRC was consistent with the 2006 study. The proposed cost of service study in this proceeding is consistent with the study proposed in the 2007 GRC with the exception of the allocation of mains, which I will discuss later in my testimony.

B. <u>Overview of the Company's Proposed Gas Cost of Service Study</u>

Q. Did the Company include gas costs in its cost of service analysis?

A. Consistent with past cases, the Company conducted the analysis both including and excluding gas commodity costs. The study that includes gas costs is informational only, because the Company's PGA mechanism addresses changes in commodity costs. This means that natural gas general rate cases address 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. Is the methodology employed in the Company's cost of service study for its natural gas service in this proceeding identical to the methodology used in the cost of service study in its 2007 GRC?

A. No. As a result of discussions that took place in the Collaborative, the Company is proposing changes to one aspect of the cost of service study, the allocation of mains. Therefore, the Company has conducted four versions of its cost of service study, two of which are presented in exhibits. The Fourth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-5), presents the summary results proposed in this proceeding, excluding gas costs. The Fifth Exhibit to my Prefiled

Direct Testimony, Exhibit No. ___(JKP-6), presents the summary results proposed in this proceeding, including gas costs. The Sixth, Seventh, and Eighth Exhibits to my Prefiled Direct Testimony, Exhibit Nos.___(JKP-7, 8 and 9), present supporting details of PSE's proposed study. The Ninth and Tenth Exhibits to my Prefiled Direct Testimony, Exhibit Nos. ___(JKP-10 and 11), present summary results consistent with the method used in PSE's 2007 GRC, excluding and including gas costs, respectively. Both PSE's proposed and its previous method reflect the elimination of Schedules 36, 51 and 57 and the establishment of new transportation schedules. The other two cost of service studies, which differ from the proposed study only with respect to the allocation of mains costs, are described later in my testimony.

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

A. The Company is using Navigant Consulting, Inc.'s Cost of Service Model. This is the same model that PSE used in its 2006 and 2007 general rate cases and is using for its electric cost of service study in this proceeding.

C. <u>Peak and Energy Allocation Factors</u>

Q. What was the basis for allocating commodity costs?

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

Q. How was the peak demand developed?

A. The Company 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 the Company's 2007 Integrated Resource Plan.[2] In broad terms, peak requirements include the loads of sales and transportation customers. The total peak demand of customers on firm sales schedules was estimated using regression equations based on 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 the Company 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

[2] *See* May 2007 Integrated Resource Plan, Appendix H: Load Forecasting Models, pages H-5 and H-6.

established annually, based on the customers' usage in the system peak 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 the Company. 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 the Company 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. The Company 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, the Company incurs the 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. PSE is obligated to provide reliable service, and customers expect that reliability, especially during cold weather. If the Company 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 the Company'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 the Company'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 the Company'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 change considerably over time. 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, assuming the historical HDD is 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 the Company's capacity planning. The design day standard is clearer as to interruptible customers' loads and is consistent with the Company's capacity planning.

D. Allocation of Plant Costs

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

A. Yes. The Company 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 O&M expenses allocated?

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

E. Allocation of A&G Expenses

Q. How were A&G and income 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 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.

F. Classification and Allocation of Distribution Main Costs

Q. Why does the Company propose a change to the allocation of distribution mains?

A. Certain parties in PSE's 2007 GRC expressed concerns about PSE's approach to allocation of mains costs in that case. The parties did not agree on an allocation method in that proceeding, even though there was a settlement as to rate spread. This issue also was discussed in the subsequent Collaborative, but the parties still did not reach agreement. The current proposal presents PSE's attempt to produce an allocation method that 1) is consistent with cost of service principles, 2) acknowledges past Commission decisions, 3) is consistent with PSE's distribution system, 4) is fair, 5) is reasonable, and 6) addresses concerns raised in PSE's 2007 GRC by parties on both ends of the spectrum.

Q. What concerns by interveners related to the allocation of mains costs has the Company addressed in its proposal?

A. In broad terms, there are two major issues. The first is a concern that large customers (on Schedules 85, 85T, 87, 87T and contracts) benefit at the expense of all other customers through the use of the Company's gas planning model, SynerGEE, for making a direct assignment of costs to large customers. The specifics of this concern were articulated in the direct testimony of Glenn A. Watkins, Exhibit No. GAW-1T, on behalf of Public Counsel in PSE's 2007 GRC. Briefly, this concern is related to 1) the lack of transparency and difficulty verifying multiple assumptions in the SynerGEE analysis, 2) the fact that use of SynerGEE accounts for certain customers' physical locations on PSE's distribution system (*i.e.*, "skeletonizes" the system), which means these customers do not share proportionately in the cost of the system even though they share the benefits, and 3) the use of assumptions related to the time of day used for the SynerGEE analysis and the excess capacity on the system. In addition to the issues raised by interveners, PSE is concerned that the SynerGEE analysis can easily be interpreted out of context and misapplied.

The second concern is from the other end of the spectrum. Certain large interruptible customers and their representatives expressed concern over the Company's use of throughput to allocate the costs of small main to large customers. These parties argued that because of their load size, they "do not use" small main (sometimes defined as pipe less than four inches in diameter), and they should not receive an allocation of costs associated with small main.[3]

Q. How does PSE's proposed approach address these concerns?

A. These two concerns are diametrically opposed to one another. One view asserts that all customers derive at least some benefit from the entire system and therefore should pay a share of the entire system cost, while the other view asserts that customers should only pay for small pipe if it can be clearly demonstrated their class uses it, and be exempt from paying for any part of the rest. Therefore it is difficult to satisfy all parties.

PSE's approach addresses the concerns about the direct assignment to large customers by eliminating the use of SynerGEE to identify peak-related costs in the cost of service study and instead using the peak demand allocation factor for

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[3] *See* 2007 GRC, Prefiled Response Testimony of Kevin C. Higgins, Exhibit No. KCH-1T, at 12-13.

all classes. The methodology addresses large customers' concerns about paying for the cost of small main by exempting large customers on Schedules 85, 85T, 87, 87T and special contracts from making a contribution based on energy to a portion of small main. This is done without directly assigning costs based on customers' locations.

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, the Company 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. The Company used an estimate of the system load factor to determine how much of the 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 33 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 demand-related costs being allocated 33 percent on average demand and 67 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 Eleventh Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-12). 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 $381 million (33 percent) of plant to be allocated based on average demand and $774 million (67 percent) to be allocated based on peak demand.

Second, the 67 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 33 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, small main was allocated to all classes except Schedules 85, 85T, 87, 87T and contracts based on annual weather normalized throughput, and 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. As I mentioned above, 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 believes that the gas distribution network provides an integrated system which 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 puts greater emphasis on system benefits, and exempting them from the cost of medium main puts greater emphasis on customers' physical connections and the flow of gas. PSE's use of both of these approaches balances the two perspectives regarding medium mains.

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 87, 87T and contracts?

A. The Company considered the historical treatment of these customers and the benefits associated with being part of the gas distribution system. Historically, Schedule 87, 87T customers (all of whom currently are connected to large mains) and contract 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 the Company 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.

Q. What are the benefits of being part of PSE's gas distribution system?

A. PSE's distribution system is a network of pipes that includes parallel and interconnected lines, and different pipes could be used to move gas from one point to another. The Company generally chooses to use medium diameter pipes to serve smaller customers and larger diameter pipes to serve larger customers. However, both sizes of pipe create capacity on the system. If there were less medium sized pipe, either there would be more larger sized pipe or less capacity available to serve all customers, large or small. The existence of medium pipe makes capacity available for everyone. Capacity must be looked at as a whole, and total capacity allows service to large interruptible customers even though some of the capacity is in the form of medium size main.

An analogy might be helpful in understanding these system benefits. The gas distribution system can be compared to a network of roads that includes freeways, arterials and side streets. During times of normal or low traffic volumes, cars and trucks use the side streets to get to the arterials and the arterials to get to the freeways. When traffic is heavy, the freeways get congested and traffic slows down; drivers of some of the cars then make decisions to use more of the side streets and arterials rather than continuing to add to the congestion on the freeways. If the side streets and arterials that parallel the freeways were not available, all of that traffic would still try to crowd the freeways resulting in gridlock. During the high volume times, the trucks on the freeways may not use the side streets and arterials themselves, but they gain by having other cars select those alternatives. This benefit is very clear during times of high volume, but even during times of average use, the existence of smaller roads allows the freeway to be less congested than it would otherwise be. Having arterials and side streets benefits all vehicles, even those who are traveling long distances at high speeds on the freeway. Similarly, the gas distribution system as a whole provides capacity for all customers, including those who are connected to large main. There would be more curtailments of interruptible customers if there were less medium main.

The benefits of an interconnected parallel system are demonstrated in runs of Company's SynerGEE planning model. This model demonstrates that gas takes multiple routes to a given customer, depending on temperature, load and outage conditions. The redundancy in the system provides additional system capacity and allows service to a given customer even if parts of the system are temporarily out of service.

Q. Have Schedule 85 and 85T customers always been treated differently than Schedule 87 and 87T customers with respect to the allocation of mains costs?

A. No. Historically Schedules 85, 85T, 87, and 87T customers were treated as a group, along with the recently-eliminated Schedule 57. However, most transportation customers are now grouped with either Schedule 85 or 87. Also, there are size and service differences between the two groups, so they are being treated separately in PSE's current proposal. A number of Schedule 85 and 85T customers have service lines that are physically connected to medium main. Not only do they receive general system benefits of two inch main, their gas has to flow directly through two inch main to reach them. By comparison, there are currently no Schedule 87 and 87T customers connected to medium or small main.

Q. Why can't PSE identify the specific portion of small main that does serve the large customers?

A. PSE can identify pipe through which gas flows to serve the loads of the specific customers being studied using SynerGEE, but there are drawbacks to this approach, as I discussed above. The footage of main identified by a SynerGEE run does not incorporate the benefits to all customers of being connected to the distribution system. Also, the results of the SynerGEE run vary greatly depending on the assumptions used, such as weather. Using SynerGEE to identify costs to be assigned to a subset of customers takes into account the distance of individual customers from the city gate for that specific group of customers, but not for all customers.

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 (two inches and smaller) is used to deliver gas to most of the 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 the Company's proposed approach to allocating mains.

A. There are five benefits to the Company'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, 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 so-called skeletonization. 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 the concern 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, the Company's approach is relatively transparent and easy to understand.

Q. You mentioned earlier that PSE's proposal includes a change to the allocation of mains. How was the peak and average method of cost allocation applied to distribution mains in PSE's 2007 GRC?

A. The cost of service analysis presented in the Ninth and Tenth Exhibits to my Prefiled Direct Testimony, Exhibit Nos.___(JKP-10 and JKP-11), reflects the 2007 GRC method. A diagram of this approach is presented on page two of the Eleventh Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-12). In the cost of service study that uses PSE's 2007 method, the cost of mains was allocated in the following steps:

1. 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.

2. The amount to be allocated based on peak demand was divided into a portion to be directly assigned to the largest customers, who were served on Schedules 85, 85T, 87, 87T and special contracts, and all other customers. The directly-assigned portion to be assigned to customers on Schedules 85, 85T, 87, 87T and special contracts was identified based on a flow analysis that was conducted using the Company's planning tool, SynerGEE.

3. This directly assigned portion of main was assigned a value based on plant cost data.

4. The remaining portion of costs to be allocated on peak day demand was allocated to all other customer classes based on their estimated contributions to the system design day peak demand.

5. The amount to be allocated on average demand was allocated to all classes based on total or minimum energy requirements for the test year. For customers on Schedules 85, 85T, 87, 87T and special contracts, their minimum energy requirement was used. This was defined as gas consumption in the month in which they had the smallest use multiplied by 12 months. For all other classes, total weather normalized volume for the test year was used.

G. Results of the Cost of Service Study

Q. Please summarize the results of the cost of service study filed by the Company.

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 Fourth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-5). The results of the cost of service study using PSE's 2007 GRC method as provided in the Ninth Exhibit to my Prefiled Direct

Testimony, Exhibit No.___(JKP-10), are presented as well. The final two columns present the results of cost studies based on two different assumptions regarding the cost responsibility of large customers for that portion of medium and small main allocated based on average use, for comparison purposes. In the "100 Percent to All Classes" scenario, small and medium-sized main are allocated to all classes based on throughput, and in the "0 Percent to Large Classes" scenario, Schedules 85, 85T, 87, 87T and contracts receive no costs associated with the average portion of small and medium-sized main.

Table 1: Summary of Parity Percentages

Customer Class	Company Proposal	2007 Method	100% to All Classes	0% to Large Classes
Total System	100%	100%	100%	100%
Residential (Schedules 23, 16, 53)	99%	99%	100%	99%
Commercial & Industrial (Schedules 31, 61)	97%	97%	98%	96%
Large Volume (Schedules 41, 41T)	131%	130%	134%	129%
Interruptible (Schedule 85, 85T)	119%	137%	113%	154%
Limited Interruptible (Schedule 86)	161%	159%	166%	157%
Non-exclusive Interruptible (Schedule 87, 87T)	95%	96%	70%	108%
Special Contracts	80%	85%	62%	88%
Rentals (Schedules 71, 72, 74)	79%	79%	79%	79%

VI. GAS RATE SPREAD

Q. How do the Company's cost of service study results relate to 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. The cost of service study is the Company's best indicator of what it costs to serve each class of customer, and it provides guidance to the rate spread process.

Q. What factors did the Company consider in developing its gas rate spread proposal?

A. The Company's proposal emphasizes two factors: the customer class relationship to parity and customer impacts. The parity percentages presented on page one of the Fourth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-5), and discussed earlier in my testimony indicate that some classes currently pay less than it costs to serve them, and other classes pay more than it costs to serve them. Because this relationship between costs and revenues varies by customer class, the Company's earned return also varies by customer class. By adjusting rate spread, classes can be brought closer to paying the costs that the Company estimates it incurs to serve the class and class level rates of return can be brought closer to the system average rate of return. PSE's long-term goal is to set rates at cost of service levels for each class, and the proposed rate spread is designed to move classes toward those levels without producing unacceptably large customer impacts.

Q. Please summarize the Company's gas rate spread proposal.

A. To customer classes with parity percentages between 95 percent and 105 percent, the Company proposes to assign the average increase. Because Schedules 41 and

85 have parity percentages of 131 percent and 119 percent respectively, the Company proposes 50 percent of the average increase. Because Schedule 86 has an especially high parity ratio of 161 percent, the Company proposes no increase to this class. The Company proposes the system average increase of 2.2 percent for the rental class. The proposed revenue allocation by rate class is presented on page one of the Twelfth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-13), and is summarized in Table 2:

Table 2: Proposed Rate Spread

Customer Class	**Parity Percentages[1]**	**Proposed Rate Increase – Sales Customers[2]**	**Proposed Rate Increase – Transportation Customers**
Residential (Schedules 23, 16, 53)	99%	2.5%	n/a
Commercial & Industrial (Schedules 31, 61)	97%	2.2%	n/a
Large Volume (Schedules 41, 41T)	131%	0.7%	3.9%
Interruptible (Schedule 85, 85T)	119%	0.4%	3.7%
Limited Interruptible (Schedule 86)	161%	0.0%	n/a
Non-exclusive Interruptible (Schedule 87, 87T)	95%	0.5%	7.2%
Rentals (Schedules 71, 72, 74)	79%	2.2%	n/a
System Total / Average	100%	2.2%	n/a

[1]At existing rates excluding gas costs.
[2]Including gas costs. The percentage increases vary slightly between the residential and commercial/industrial classes because gas costs are included. Their percentage increases to margin are equal.

Because total increase percentages include gas costs for sales customers but not for transportation customers, their total percentage increases differ even though their percentage increases to margin are equal. For example, Schedules 85 and 85T have the same percentage increase to margin and the same distribution rates, but because Schedule 85T has no gas costs in the denominator, the total percentage increases differ between 85 and 85T.

VII. GAS RATE DESIGN

A. Overview of Rate Design

Q. What principles are fundamental to a sound rate design?

A. The following seven principles are fundamental to a sound rate structure. Rates should (1) provide for recovery of the total revenue requirement, (2) provide revenue stability and predictability to the utility, (3) provide rate stability and predictability to the customer, (4) reflect the cost of providing service, (5) be fair, (6) send proper price signals, and (7) be simple and understandable. These principles are consistent with those presented in "Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, (2nd Edition, 1988).

Q. How can the results of the cost of service study be used for rate design within each class?

A. The unit cost table presented on page four of the Fourth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-5), serves as a guide to the appropriate levels of the demand, commodity, and customer charges for each customer class.

Q. Please summarize the proposed changes to the Company's natural gas tariff schedules.

A. The Company proposes no major changes to rate design in this proceeding. In general, each rate component of a given schedule increases by the same percentage. The only exception to this is driven by the demand charge, which is the same for all schedules. The demand charge is increased by an equal percentage based on the proposed increase to Schedule 87. The demand charge for Schedules 41, 85 and 86 remains tied to the Schedule 87 level, and other rate components are adjusted on an equal percentage basis to produce the proposed revenue.

Q. What changes does the Company propose to Residential Schedule 23 and Propane Schedule 53?

A. PSE proposes to increase the basic charge from $10.00 per month to $10.73 per month. The delivery charge is the only other delivery rate of Schedules 23 and 53, and it is proposed to change from $0.33606 per therm to $0.36066 per therm.

B. Comparison of Basic Charges

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

A. The Thirteenth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-

14), contains a comparison of basic charges and percentile rankings for residential service from 210 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 $3.00 per month at Cascade Natural Gas to $24.62 per month at Missouri Gas Energy. The average basic charge is $10.07 per month. By comparison, PSE's current residential basic charge of $10.00 per month in the 60th percentile of the 210 companies. In other words, 40 percent of the other distribution companies in the country have residential basic charges higher than PSE's charge.

Q. Has the Company prepared new natural gas tariff schedules reflecting the proposed changes?

A. Yes. The revised tariffs are presented in the Fourteenth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(JKP-15).

C. Additional Rate Schedule Comments

Q. What changes are being proposed to the PGA rates?

A. The Company's analysis in this proceeding showed that the adjustment to the rates in Schedules 101 and 106 for revenue sensitive items should be changed from the current 1.04514 to 1.045199. The Company proposes to implement this change to the Schedule 101 and 106 tariff sheets in the compliance filing of this proceeding.

VIII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.