EXHIBIT NO. ___(JKP-1T)
DOCKET NOS. UE-07___/UG-07___
2007 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-07_____** **Docket No. UG-07_____**

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

DECEMBER 3, 2007

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 ("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 results of the Gas Rate Schedule Review, which the Company conducted in response to the Commission's order in PSE's last General Rate Case, UG-060267. I also 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. These proposals reflect the results of the Gas Rate Schedule Review.

II. GAS RATE SCHEDULE REVIEW

Q. Please describe the Gas Rate Schedule Review.

A. In its order in the Company's last general rate case, UG-060267, the Commission stated "the Company's current rate schedules should be reviewed before the next general rate case filing to consider how schedules could be combined or separated to better reflect similar types of usage and cost causation. We encourage the parties to undertake such a review prior to PSE's next general rate filing." (UG-060267 Order 08, paragraph 143). In response to this guidance, the Company assembled a team with representatives from several departments to conduct the review. In accordance with the Commission's guidance, the scope of the review was the consideration of how schedules should be separated or combined. The review process included the following activities:

- Identification of issues that would need to be addressed during the review;
- Identification of principles to guide the review process;
- Development of research on the history, purpose, customer characteristics and load characteristics of each schedule;
- Meeting with customers to get their input regarding the schedules and issues of concern;
- Development of detailed analyses of certain schedules, including examination of customer bill impacts of potential changes;
- Meeting with interested parties involved in the Company's last general rate case to present preliminary findings and get their input;
- Development of recommendations for implementation in the

present case.

Changes to the Company's schedules that are proposed in the present case as a result of the review are the following:

- Eliminate Schedule 36, Special Commercial Heating Service (Optional), and migrate customers to either Schedule 41 or Schedule 31;
- Eliminate Schedule 51, Special Multiple Unit Housing Service (Optional), and migrate customers to Schedule 31;
- Revise the rate design on Schedule 41, Large Volume High Load Factor Gas Service (Optional), to make the rates more consistent with the purpose of the schedule, which is to provide service to large, high load factor customers;
- Provide the option to purchase transportation service on the following schedules:
  - 31 Commercial & Industrial General Service
  - 41 Large Volume High Load Factor Gas Service (Optional)
  - 85 Interruptible Gas Service with Firm Option
  - 86 Limited Interruptible Gas Service with Firm Option (Optional)
  - 87 Non-exclusive Interruptible Gas Service with Firm Option (Optional)
- Close Schedule 57, Distribution System Firm and Interruptible Transportation Service (Optional), to new customers at the completion of the present case and terminate the schedule on December 31, 2012.

The results of the review are presented in more detail in the final report of the Gas Rate Schedule Review, which is presented as Exhibit No. ___(JKP-3)

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Q. Why does the Company propose to eliminate Schedule 36?

A. Schedule 36 was originally created to separate residential heating from commercial heating and to isolate space heating of living premises as a specific end use. The Company concluded that the service Schedule 36 customers receive is no different from the service provided to similar customers on Schedule 31, and that the reasons that led to the existence of Schedule 36 are no longer important. At existing rates, nearly all Schedule 36 customers could be served at lower rates on either Schedule 31 or Schedule 41. Schedule 36 has been combined with Schedule 31 in cost of service studies for a number of years, so there is no current data that indicates how costs differ between the schedules.

Q. Why does the Company propose to eliminate Schedule 51?

A. Schedule 51 provides service to apartment buildings where PSE owns a service line beyond the meter. The study examined the importance of having a separate schedule for these six customers, and concluded that Schedule 51 was unnecessary. There are currently similar customers taking service on Schedule 31, and Schedule 51 has not attracted new customers in several years. The six customers on Schedule 51 could all be served at lower rates on Schedule 31. Schedule 51 has been combined with Schedule 31 in cost of service studies for a number of years, so there is no current data that indicates how costs differ between the schedules.

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Q. Why does the Company propose to revise the rate design on Schedule 41?

A. Schedule 41 is intended to provide service to large volume, high load factor customers. These customers are less costly to serve on a per-therm basis because of their size and high load factors. Because gas rate schedules are optional and customers are allowed to choose schedules, there are customers who don't fit that description who choose to be on Schedule 41, and there are large, high load factor customers who would be best served on Schedule 41 who are served on other schedules instead. Although Schedule 41 has rate components that are appropriate for large customers, the basic charge and demand charge are far enough below the cost of service that they do not effectively encourage the proper customers to be on the schedule. The proposed changes are designed to encourage the customers for whom Schedule 41 is designed to take service on it, and to encourage customers who do not belong on Schedule 41 to take service on the appropriate schedule, which in most cases is Schedule 31. During the review, customers were asked whether it was important to have a schedule for large, high load factor customers and they indicated it was important to them, and that only the customers for whom the schedule is intended should be on it.

Q. Why does the Company propose to add transportation as an option on sales schedules, close Schedule 57, and eliminate Schedule 57 after four years?

A. When transportation service was established, a great deal of attention was given to the importance of rates for sales and transportation service providing

equivalent margin. That is, customers should choose from whom to purchase gas based on the cost of gas rather than differences in the price of delivery service over PSE's distribution system. Delivery service is the same regardless of whether or not the customer buys gas from PSE, and delivery rates should be consistent between sales and transportation service. The review revealed inconsistencies in this regard.

Q. What are the inconsistencies between sales and transportation service?

A. The Company offers three interruptible sales schedules (Schedules 85, 86 and 87) that serve distinctly different customer groups, and only one transportation schedule (Schedule 57), which serves a wide range of customers. Schedule 57 delivery charges equal those of Schedule 87, which serves the largest interruptible customers, yet most Schedule 57 customers' loads are smaller than the minimum volume on Schedule 87, so they would not qualify for Schedule 87 if they were sales customers. Because Schedule 87 has relatively high rates in the first two blocks and low rates in the later blocks, smaller transportation customers pay higher rates, on average, than interruptible sales customers of similar size.

Q. Are there other inconsistencies between sales and transportation service?

A. Yes, there are. All three interruptible sales schedules include minimum volume requirements and related minimum charges. Schedules 85 and 86 have fuel exclusivity clauses. Schedules 85, 86 and 87 all contain backup fuel requirements so that, in the event of a curtailment, customers can continue operations. This

requirement can be waived with approval of the Commission. Schedule 86 is only available to certain types of customers. The three interruptible sales schedules have different priorities in the event of a curtailment. Schedule 57 does not include any of these provisions.

Q. What is the Company trying to achieve with the proposed changes to transportation service?

A. The Company is trying to improve the consistency of service to its customers. A given customer should pay an amount for delivery service regardless of whether that customer purchases gas from PSE. The current rate structure does not allow that consistency, especially for smaller transportation customers. In addition, there are transportation customers who have firmed their entire loads. This indicates that there is a need for firm transportation service, and the Company's intention is to provide this service in a manner that is consistent with firm sales service.

Q. Why can't the existing interruptible sales schedules be combined to be consistent with the transportation schedule, Schedule 57?

A. The three interruptible sales schedules serve three distinct groups of customers, and combining them into a single class would be problematic. Schedule 87 is designed to serve large interruptible customers who have very small contract demands relative to their total loads. Their presence allows the Company to curtail large volumes relatively efficiently should curtailment be necessary. Their

tariff includes a six-block declining delivery charge. Schedule 86 customers are primarily schools, who have much smaller loads and different needs than large industrial customers. Schedule 86 has a two-block delivery charge, with the threshold at 1,000 therms per month, which is far below the second block threshold of 25,000 therms for both Schedules 85 and 87. Schedule 85 customers are in between Schedules 86 and 87 in terms of their volume, and they have a three-block delivery charge. Average annual use per customer in 2006 was 2.3 million therms for Schedule 87, 480,695 therms for Schedule 85, and 41,881 therms for Schedule 86. Having three schedules provides the Company a tool for determining how to curtail customers under certain circumstances, because they have different priorities. Schedule 87 customers are the first curtailed, Schedule 85 customers are second curtailed, and Schedule 86 customers are the last to be curtailed. Customers have indicated that curtailment priority is important to them.

Q. How would rates for transportation customers on Schedules 31T, 41T, 85T, 86T and 87T differ from rates for customers on the parallel sales schedules?

A. The proposed rates for transportation schedules are based on the parallel sales schedules, and have the following characteristics:

- The proposed basic charge is $300 greater for transportation service than for the equivalent sales service on each schedule. This is consistent with the current differential between sales and transportation service, and is based on costs that are unique to providing transportation service.
- The proposed per-therm delivery charges are equal to the delivery charges

on the equivalent sales schedules.

- The proposed demand charges are equal to the demand charges on the equivalent sales schedules.

- Transportation service would continue to include the gas-supply related balancing charge, which consists of the leased portion of Jackson Prairie that is used for balancing.

- Transportation service would no longer include the portion of the balancing charge that is related to the PSE-owned portion of Jackson Prairie used for balancing, because those costs are included in the delivery charges and are also paid by sales customers.

- Transportation service would not include the procurement charge that is included on sales schedules 85, 86 and 87. This is consistent with current practice. Firm sales Schedules 31 and 41 do not have a separate procurement charge because those costs are included in their delivery charges. Therefore Schedules 31T and 41T include a credit for procurement costs that equals the opposite of the proposed procurement charge on Schedules 85, 86 and 87.

- Transportation customers would not be subject to Schedule 120, which is the adjusting schedule that provides revenue to fund conservation programs. Transportation customers currently are not subject to this charge, and they are not eligible to participate in PSE's conservation programs. The Company proposes no change to this arrangement.

- Transportation service would continue to include charges for Schedule 129, which is the adjusting schedule that provides funds for low income programs. For example, a customer on Schedule 85T would pay the Schedule 129 rates applicable to Schedule 85 sales customers.

The proposed rates are presented on pages 2-12 of Exhibit No. ___(JKP-10).

Q. Would Schedules 31T, 41T, 85T, 86T and 87T have the same terms and conditions as the parallel sales schedules?

A. Transportation service would include the same requirements of the parallel sales schedules. These requirements include the following:

- The curtailment priorities that apply to sales Schedule 85, 86 and 87 would apply to the parallel transportation schedules.
- Schedules 85T, 86T and 87T include a requirement that the customer maintain backup equipment, consistent with the parallel sales schedules. This requirement can be waived if the customer applies to the Commission for a waiver and that application is approved by the Commission.
- Schedules 85T and 86T include a fuel-exclusivity requirement.
- The minimum annual and monthly charges on Schedules 85, 86 and 87 would apply to Schedules 85T, 86T and 87T.
- Schedule 87T includes an annual contract volume, consistent with sales Schedule 87.

Q. Would existing Schedule 57 customers who have to move to another transportation schedule when Schedule 57 is terminated be subject to all of the same terms and conditions as new transportation customers?

A. They would, with one exception. Schedule 57 does not include a requirement that customers have backup equipment that enables them to continue operations in the event of a curtailment. Transportation customers currently served on Schedule 57 would be exempt from this requirement when they migrate to the new transportation schedules, either at the initiation of the new schedules or when Schedule 57 is terminated. New customers or those who migrate from sales to transportation service would be subject to this requirement.

Q. What impact do you expect the proposed changes to have on customer bills?

A. At existing rates, 88 percent of Schedule 36 customers are expected to experience

rate decreases. The remaining 12 percent are expected to see increases of less than 1.5 percent.

All Schedule 51 customers would pay less on Schedule 31, at existing rates.

Most small-load transportation customers are currently expected to pay less on Schedule 85T or 41T than they currently pay on Schedule 57. Transportation customers with loads over one million therms, who are eligible for Schedule 87T, would be charged the same rates they have on Schedule 57, with the exception of minimum charges. Those who would be affected by the minimum charges, and thus prefer to remain on Schedule 57, would be able to do so until Schedule 57 is terminated in four years.

The summary of the migration adjustment to revenue provided on page 3 of Exhibit No. ___(JKP-4) illustrates a net reduction of $2,218,411 in revenue under existing rates. This indicates that at existing rates, customers who are expected to migrate based on the proposed schedules would pay $2,218,411 less than they pay on their current schedules.

III. PRO FORMA REVENUE FROM NATURAL GAS OPERATIONS

Q. Why is it necessary to develop pro forma revenue?

A. Pro forma revenue is developed to ensure that the test year revenue used in calculating the revenue deficiency: (1) reflects only those price 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.

Q. Please describe the process used to develop pro forma revenue.

A. Developing pro forma revenue involves: (1) removing revenue that is not related to base rates in order to identify revenue from base price schedules; (2) making restating and pro forma adjustments to test year volume and corresponding revenue; and (3) estimating what revenue would have been had current rates been in effect throughout the test year. The Company's adjustments to test year natural gas throughput[1] for this case are summarized on page 1 of Exhibit No. ___(JKP-4), and corresponding adjustments to test year revenue are summarized on page 2 of Exhibit No. ___(JKP-4).

Column B of page 1 of Exhibit No. ___(JKP-4) shows the volume of sales and transportation for the test year ended September 2007 included in the Company's Sales of Gas report. The adjustment in column C removes revenue from discontinued propane schedules. 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

[1] Throughput, sometimes also called "sendout", is the total volume of natural gas that is delivered to customers through the system during a particular period of time.

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. PSE's income statement for a given month includes revenue from sales that were billed during that month, removes the portion of that revenue that was consumed in the previous month, and adds an estimate of revenue from sales that occurred during the calendar month but were not yet billed. In the adjustment to unbilled volume, the unbilled portion of sales was updated to reflect sales that actually took place during each calendar month, by rate schedule. The revenue related to these adjustments was calculated based on the rates that were in effect during the test year and is presented in column G of page 2 of Exhibit No. ___(JKP-4).

The weather normalization adjustment to volume presented in column E takes actual volume and adjusts it based on actual weather during the test period as compared with normal weather, as defined by heating degree days (HDD). This adjusts volume to the level it is expected to have been had weather been normal. This adjustment was made using the same method approved in the Company's last general rate case, UG-060267, and is described later in my testimony.

The migration adjustment in column F of page 1 of Exhibit No. ___(JKP-4) accounts for the movement of volume that is estimated to result from 5,289 customers migrating away from the schedules that are proposed to be closed or eliminated with the implementation of the Gas Rate Schedule Review. The net adjustment is zero therms, because there is no change in total consumption during

the test period, simply a movement of consumption away from Schedules 36, 51 and 57 when those schedules are eliminated or closed and transportation service is made available as an option on sales schedules.

Pro forma volume that reflects all of these adjustments and is used for calculating pro forma revenue is presented in column H of page 1 of Exhibit No. ___(JKP-4).

The revenue included in the test year income statement is presented in column B of page 2 of Exhibit No. ___(JKP-4). Revenue from discontinued propane schedules was removed in column C. Revenue related to municipal taxes was removed in column D. Revenue from penalty charges and revenue related to new customer rates was transferred from revenue from sales to other operating revenue in column E. Revenue related to conservation, the low income program, and Schedule 106 (the amortization of deferred gas supply costs) was removed in column F, because the revenue requirement for these programs is addressed through separate tariff schedules that directly pass the costs through to customers. The entries in column G correspond to those in column D of page 1, and reflect out of period adjustments to sales volume and related revenue as well as the unbilled revenue adjustment. The out-of-period adjustment corrects revenue associated with billing corrections by moving the consumption and related revenue from the period in which they were corrected into the period in which they should have been billed. The unbilled revenue adjustment adjusts for the fact that customers' bills are issued throughout the month and do not correspond to calendar months. PSE's income statement for a given month includes revenue

from sales that were billed during that month, removes the portion of that revenue that was consumed in the previous month, and adds an estimate of revenue from sales that occurred during the calendar month but were not yet billed. In the adjustment to unbilled revenue, the unbilled portion of sales was updated to reflect sales that actually took place during each calendar month, by rate schedule, and the related revenue was calculated based on the rates that were in effect during the test year.

The adjustment for January 2007 rates in column H increases test year revenue to include revenue collected as a result of the rate increase that was implemented pursuant to the Company's 2006 general rate case, Docket No. UG-060267 et al. In this adjustment, revenue from sales for the October 1, 2006 through January 12, 2007 period was increased to reflect the rates that were implemented on January 13, 2007. The adjustment for October 2007 rates in column I reflects the implementation of new gas rates on October 1, 2007. Both of these adjustments restate revenue as if current rates had been in effect throughout the test year.

The weather normalization adjusts revenue based on weather normalized gas volumes presented on page 1 of Exhibit No. ___(JKP-4) and rates in effect October 1, 2007.

The migration adjustment in column K accounts for the difference in revenue that is estimated to result from customers migrating away from the schedules that are proposed to be eliminated or closed. For each customer assumed to migrate as a

result of schedule eliminations and closures, revenue under existing rates was calculated on the customer's current schedule and the schedule to which the customer is expected to migrate. These amounts were summed across all 5,289 customers assumed to migrate. The migration adjustment is the difference between what those customers pay on their current schedules and what they would pay after they migrate to another schedule, at existing rates. It is an estimate of revenue that will be lost (excluding municipal taxes and schedules that have been excluded from the analysis) if customers migrate to the schedules to which they are expected to migrate. For Schedules 36, 51 and 57 the adjustment is negative because customers will leave the schedules. This negative adjustment is partially offset by the positive adjustments on Schedules 31, 41, 85 and 87, the schedules to which the customers will be migrating. The net effect of all of the adjustments to all schedules is -$2,218,411. The negative nature of the adjustment indicates that under existing rates, the proposed migration is expected to result in lower bills for these customers. The volume and revenue adjustments are provided in more detail on page 3 of Exhibit No.___(JKP-4).

The adjustment in column L adjusts Schedule 101 gas revenues to reflect the change to the revenue adjustment factor ("RAF") proposed in this case.

Finally, the Everett Delta adjustment to other operating revenue, as discussed in the prefiled direct testimony of Mr. Karl Karzmar, Exhibit No. ___(KRK-1T), is presented in column M of page 2.

Q. Does the Company's gas cost of service and rate design implement the Company's weather normalization methodology, as approved in the last general rate case?

A. Yes. The cost of service and the rate design reflect the proforma adjustment of energy sales. This adjustment decreased test year therms because the test year was colder than normal.

Q. Please describe how the weather normalization is calculated

A. The test year proforma delivered loads by schedule shown in column H of page 1 of Exhibit No. ___(JKP-4) have been adjusted for, and thus include -22,765,733 therms of temperature adjustment. The system level temperature adjustment in Exhibit No. ___(JKP-4) was calculated in total and allocated to each of the applicable schedules by month based on the Company's temperature adjustment methodology presented in the 2006 general rate case. The Commission expressed satisfaction with the Company's weather normalization analysis in that docket. *See* Docket Nos. UE-060266 and UG-060267, Order No. 08, ¶ 163.

Q. Please describe how the Company normalized the test year system level delivered load in this case.

A. As was done in the 2006 case, PSE used weather sensitivity coefficients based on actual load data and actual temperature Sea-Tac International Airport ("Sea-Tac") to adjust system level delivered load (Firm, Interruptible and Transport) for

weather. PSE's "normal" weather dataset was developed using data reported at Sea-Tac over the 30-year period from 1977 through 2006 by calculating daily heating degree days ("HDDs") using two base temperatures (45 and 65 degrees). The actual HDDs were calculated using the average of the 24 hourly temperatures compared against the base temperature. The amount of weather adjustment was calculated by taking the weather sensitivity coefficients and multiplying it by the difference between the actual and normal HDDs. This process was done for each base HDD that appeared in the model.

Q. How did the Company use temperature normalized gas load to calculate the load adjustment that should be made to various customer classes (rate schedules) related to weather effects?

A. Also as was done in the 2006 case, PSE examined monthly usage patterns of all of the Company's gas rate classes to identify which rate classes are weather sensitive. This analysis identified the following rate schedules (classes) as being temperature sensitive: Schedule 23 (Residential), Schedule 31, (Commercial, Industrial), Schedule 36 (Commercial), Schedule 51 (Commercial), Schedules 85 (Commercial), Schedule 86 (Commercial) Schedule 87 (Commercial), Schedule 57 (Commercial) and Schedule 99 (Commercial) The Company next developed linear regression equations to characterize the relationship between temperature and load for each of the above weather sensitive rate schedules. The amount of weather adjustment of system level delivered load was then allocated to each of

the applicable schedules by taking the percentage share of each schedule's weather adjustment to total weather adjustment for all schedules as calculated by the rate schedule normalization equations, and then multiplying the system load temperature adjustment by these percentage shares.

Q. What were the results of this process?

A. Applying the process described above to the test year delivered load of 1,110,572,519 therms resulted in a total weather adjustment of -22,765,733 therms. Because the test year was colder than normal, this adjustment resulted in a proforma delivered system load that is smaller than actual load delivered during the test year.

With regard to rate schedule normalization, when the system temperature adjustment was allocated to the rate schedules, the loads of all of the temperature sensitive schedules were reduced. The residential schedules represented 68 percent of the total weather adjustment, decreasing by 15,500,668 therms.

Q. What is the impact of the weather normalization on revenue for the test year?

A. The reduction to volume had the effect of decreasing pro forma revenue by $24,484,890, as shown on page 2 of Exhibit No. ___(JKP-4).

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Q. Why have you included the migration adjustment in pro forma revenue?

A. The test year revenue requirement is established based on the schedules on which customers were served during the test year, adjusted for known and measurable changes. If a customer is expected to move from the schedule on which he was served during the test year due to the elimination of the schedule, that movement must be accounted for and revenues adjusted accordingly. If the movement is to a schedule on which the customer would pay lower rates, the lower bills represent a margin shortfall unless the migration adjustment is made.

Q. What is the Company's resulting pro forma revenue?

A. Total pro forma revenue for the test year of $1,068,194,798 is presented in column O. The gas cost of $697,020,806 associated with this revenue is presented in column Q.

IV. COST OF SERVICE PRINCIPLES

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

A. The purpose of a cost of service study is to apportion the Company's total cost of service, or revenue requirement, to the respective customer classes. This cost analysis then provides guidance for the determination of the revenue responsibility for the individual customer classes.

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Q. What are the guiding principles of cost of service analysis?

A. Cost causation is the fundamental principle of cost of service analysis. The question that must be answered is: which customer or group of customers causes the utility to incur particular types of costs? To answer this question, a connection must be made between customer requirements and usage characteristics, and costs incurred to meet those requirements.

Some components of the revenue requirement can be directly assigned to specific customers or customer classes because those costs are incurred solely for the benefit of those customers. For example, certain portions of the Company's mains are dedicated to specific large customers; the costs related to these mains are directly assigned to the appropriate customer classes because those costs are incurred only for their benefit. Costs that are incurred for the benefit of all customers are allocated to the customer classes on the basis of common usage-related or customer-related characteristics.

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 three primary tasks: (1) to provide distribution services to *customers* entitled to be served by the system; (2) to serve peak day *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 either 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 or individual

customers' peak demands. 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 different 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 can be directly assigned to a 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.

V. PSE'S NATURAL GAS COST OF SERVICE STUDY

A. Overview of the Company's Proposed Gas Cost of Service Study

Q. Is the methodology employed in the Company's cost of service study for its natural gas service in this case consistent with its cost of service study in the Company's last general rate case?

A. Yes. The Company has conducted the cost of service study in this case consistent with the methodology used in its last general rate case, UE-060266 and UG-060267. Because the Company proposes to offer transportation service as an option on five of its sales schedules instead of having a single transportation schedule for customers of all sizes and load characteristics, transportation no longer appears as a separate rate class in the cost of service study. The costs that are unique to transportation service have been identified, directly assigned to the schedules where transportation customers are expected to migrate when the proposed changes to schedules are made, and tracked within the cost of service study. In addition, the allocation of costs reflects the assumed migration of customers from Schedule 51 to Schedule 31 and from Schedule 36 to Schedules 31 and 41. In terms of cost allocation, this case is consistent with the last case.

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Q. Why did the Company assume the migration of customers in the cost of service analysis?

A. A pro forma adjustment to revenue for the test year was made, which affects the Company's revenue requirement. For the cost of service study to be consistent with the revenue requirement, it was necessary to include the migration adjustment in the cost of service study.

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 Purchased Gas Adjustment ("PGA") mechanism passes through the changes in commodity costs. This means that the focus in natural gas general rate cases is on 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.

Summary schedules for the cost of service scenario without gas costs appear in Exhibit No. ___(JKP-5), and summary schedules for the cost of service scenario with gas costs appear in Exhibit No. ___(JKP-6). Supporting detailed output from the study is included in Exhibit Nos. ___(JKP-7, 8 and 9).

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

A. The Company is using the Navigant Consulting, Inc. Cost of Service Model. This is the same model that was used in the Company's 2006 general rate case and that is used for the electric cost of service study in the present case.

B. <u>Classification and Allocation of Distribution Main Costs</u>

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

A. The investment in distribution mains is a demand-related cost, and the Company used the peak and average method for allocating this portion of its demand-related costs, consistent with previous general rate cases. 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 peak demand and how much would be allocated based on average demand or average annual throughput.

Q. How were the peak demand and system load factor developed?

A. The Company used the system design day as 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] The system peak demand was estimated using regression equations based on 52 HDD and weather normalized volumes for the test period. The system load factor was calculated based on this estimate of peak demand and weather normalized annual volume. 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. This resulted in these costs being allocated 33 percent on average demand and 67 percent on peak 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).

Q. Why did you use the Company's design day peak demand to allocate demand-related costs instead of using actual peak 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. These are:

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

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

indicator of cost causation than historical peak demands.

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

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

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 is obligated to provide reliable service, and customers expect that reliability, especially during cold weather. Peak-hour demand is a key element in the sizing of the Company's facilities and in determining the level of costs incurred in serving its customers, because the Company designs its system to meet a peak hour load during cold weather. Although the day-to-day utilization of the Company's facilities by its customers is measured by their annual gas consumption, this measure does not have a bearing on the types and costs of specific facilities installed to serve specific customers. This is due to the significant differences between peak flows, which the system must be designed for, and the average annual gas consumption. If the system were designed based on average annual loads, it would be a much smaller system and would not be able to meet customers' peak demands.

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Q. Why does design day peak provide a more stable estimate of peak?

A. Historical 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 is used, cost allocation depends 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. This could result in greater volatility of cost assignments from one cost study to the next. The design day standard is a stable determinant of planned capacity.

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

A. 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 as described above. This resulted in $ 340.5 million, or 33 percent, of plant to be allocated based on average demand and $692.7 million, or 67 percent, to be allocated based on peak demand.

2. The 67 percent to be allocated based on peak demand was divided into a portion to be directly assigned to the largest customers, who are served on Schedules 85, 87, 57 and special contracts, and all other customers. The directly assigned portion to be assigned to customers on Schedules 85, 87, 57 and special contracts was identified based on a flow analysis that was conducted using the Company's planning tool, SynerGEE.

3. The 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 33 percent based on average demand was allocated to all classes based on total or minimum energy requirements for the test year. For customers on Schedules 85, 87, 57 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.

Q. How was the directly assigned portion of the distribution mains determined?

A. The Company uses the SynerGEE model in its gas planning activities to help predict the pressures in the system under varying conditions and to determine when capacity constraints are reaching a point where corrective action is required. The model was run to simulate the entire distribution system under design day conditions, which meant that all interruptible loads were curtailed. The analysis determined the path through the system that gas would follow from the gate stations to each customer on Schedules 85, 87, 57 and special contracts. This analysis was combined with information on the size, type and footage of main currently in place to provide equivalent footage of main by size and type that would be used to serve the customers being studied under design day conditions. For these large customers that usage was their firm contract demand only. Equivalent footage represents the segments of pipe through which gas flows to serve a given customer, and reflects the fact that only a portion of the gas flowing through any given segment may actually be used to serve the specific customer rather than other customers. For example, if only one percent of the gas flowing through a given segment is used to serve the specific customer being studied, the

length of that segment is adjusted to reflect that customer's usage in equivalent footage.

This data on equivalent main used to serve large customers was assigned a dollar value using data on the original cost of mains, brought forward to 2007 dollars, to identify the original cost of the distribution mains dedicated to serve the customer in design day conditions. The relationship between the cost of main used to serve those customers and the original cost of all main, also expressed in 2007 dollars, was applied to test year plant in service to determine the size of the direct assignment.

Q. Why was minimum volume used for the Schedule 85, 87, 57 and special contract customers to allocate the average demand portion of costs?

A. The peak and average cost allocation method reflects a balancing of two concepts. The first is that the size of plant in place is determined based on the Company's obligation to meet design day peak demands rather than the volume of throughput delivered through the system over time. The second concept is that the Company uses the system year round to deliver volume to customers. The peak and average method uses both of these concepts in allocating costs to the various customer classes. The flow analysis described above identified that portion of the system used to serve the firm component of customer loads served on interruptible schedules on a design day peak, but it does not reflect those customers' use of the system on an ongoing basis. To be consistent in applying the peak and average

concept to all customers, the large interruptible customers should be assigned some costs based on volume. However, an interruptible therm is of lower value to customers than a firm therm, because interruptible therms can be curtailed, forcing the customer to change its operations. So use of annual volume to determine these customers' share of average demand costs would allocate too much cost to these customers. The use of minimum volume for the large customers reflects the inferior value to the customer of interruptible volume as compared to firm volume.

Q. How was the minimum volume calculated?

A. For each customer on Schedules 85, 87, 57 and special contracts, monthly volumes for a one year period were examined. For each customer, the month where the smallest volume was used was identified. This month's volume was multiplied by 12 to determine the annual minimum volume. These customer-level results were summed by rate schedule to determine the minimum volume by schedule.

C. Classification and Allocation of Other Plant Costs

Q. Were other facilities identified that could be directly assigned to larger customers?

A. Yes. The Company conducted an analysis to identify the cost of customer service lines in Federal Energy Regulatory Commission ("FERC") Account 380 that are

dedicated to customers on Rate Schedules 85, 87, 57 and special contracts. This portion of plant in Account 380 was directly assigned to these customers, and the remainder was allocated to all other customers 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 383-384), 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 did the study allocate distribution-related operation and maintenance expenses?

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

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D. Classification and Allocation of Purchased Gas Expenses

Q. How did the study allocate purchased gas expenses?

A. The Company's study classifies purchased gas costs into two components: demand and variable. Variable costs include interstate pipeline transportation variable costs, gas supply contract commodity, spot market gas costs, the net cost of gas injected into and withdrawn from storage, and the associated volumetric-based fees for these services. Demand-related costs include interstate pipeline demand charges, leased underground storage (Clay Basin and Jackson Prairie) and liquefied natural gas storage service LS-1 demand charges, and fixed charges related to gas supply contracts.

The various demand and variable cost components of the gas supply portfolio were allocated to the Company's customer classes according to annual sales volumes, winter sales volumes, and design peak demand allocation factors, as well as composite allocation factors composed of design peak demands, winter season sales and annual sales. The composite allocators, which are designed to reflect the Company's current resources, were used to allocate Jackson Prairie storage costs and related TF-2 pipeline costs, and TF-1 pipeline capacity.

The components of the Company's gas costs and the allocation factors used to allocate those costs are provided in Exhibit No. ___(JKP-8).

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Q. Please describe the methods used to allocate fixed demand-related gas costs.

A. The reservation charges associated with winter firm and peaking supply contracts were classified as demand costs and allocated on a winter season and peak day basis, respectively. Interstate pipeline transportation demand costs (TF-1) were allocated on the basis of a composite allocation factor that represents the proportionate year-round, winter season and system peak requirements served by the underlying pipeline capacity. The Company used annual, winter and peak pipeline capacity percentage requirements to weight the applicable customer usage characteristics, that is, the class-by-class contributions to annual sales, winter season sales, and the system peak day, and applied the result to the various pipeline demand charges in the Company's supply portfolio. Pipeline transportation (TF-2) demand charges related to the delivery of liquefied natural gas storage withdrawals to the Company's city gates were allocated using the design day peak. Clay Basin storage costs were allocated based on winter sales volumes. The portion of Jackson Prairie storage costs and related pipeline transportation (TF-2) demand charges not related to balancing (78%) were allocated on a weighted winter season and day peak basis. Finally, the portion of Jackson Prairie demand charges related to its balancing function (22%) was allocated to all classes on a system average throughput basis.

Q. How were the variable gas costs allocated?

A. All variable gas supply costs were classified as commodity costs. Peaking

supply-related charges were allocated on a peak day basis. Pipeline variable costs related to Jackson Prairie storage delivery (TF-2) were allocated using a composite allocator consistent with the allocation of fixed costs related to Jackson Prairie. Storage withdrawal and injection costs were allocated on the basis of winter sales. Interstate pipeline commodity costs (TF-1) were allocated on the basis of a composite allocation factor that represents the proportionate year-round, winter season and system peak requirements served by the underlying pipeline capacity. The rest of the variable costs related to purchased gas supplies or pipeline fuel use charges were allocated on the basis of annual gas sales, with the exception of those costs related to Jackson Prairie balancing, which were allocated on system average throughput (including transportation volumes).

E. Classification and Allocation of Administrative and General Expenses

Q. How did the study allocate administrative and general expenses and income taxes to each customer class?

A. Administrative and general ("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 expense, were allocated based on revenue. All other A&G costs, which are related to the overall operation and maintenance of the utility, were allocated based on operation and

maintenance expenses.

Q. What other approaches to its cost of service study has the Company used in the last five years?

A. As indicated earlier in my testimony, the proposed cost of service study is consistent with the study proposed in the 2006 general rate case, which is the basis for the rates that were implemented as a result of that case and that are currently in place. The differences between the current method and the method used prior to 2006 are the following:

- 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 in 2006 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 A&G expenses starting with the 2006 case. In the old method, half of certain A&G accounts were allocated based on O&M expense and the other half of those accounts were allocated based on system throughput, rather than the entire account being allocated on either O&M or revenue.

- Beginning in the 2006 case, 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). In the old method, average weather conditions during five observed peak days over a three year period were assumed in the estimation of the peak for cost allocation purposes.

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F. Results of the Cost of Service Study

1. Parity ratios

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

A. The parity ratios under current rates, excluding gas costs, are summarized in the following table. The parity ratio 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 as Exhibit No. ___(JKP-5) at 1, line 36.

Rate Class	Parity Ratio
Total System	100%
Residential (Schedules 23, 16, 53)	101%
Commercial & Industrial (Schedules 31, 61)	89%
Large Volume (Schedule 41)	156%
Interruptible (Schedule 85)	172%
Limited Interruptible (Schedule 86)	187%
Non-exclusive Interruptible (Schedule 87)	92%
Transportation (Schedule 57) and Special Contracts	122%
Compressed Natural Gas (Schedule 50)	21%
Rentals (Schedules 71, 72, 74)	69%

2. Fixed customer costs versus current customer charges

Q. Have you prepared an analysis of the Company's costs to provide different types of customers with natural gas service, even if a customer within a particular customer class were to use little to no gas?

A. Yes, I have. The unit cost analysis on page 4 of Exhibit No. ___(JKP-5) presents the customer costs on a unit cost basis. Customer-related costs include operating expenses such as meter reading, customer accounting and billing, customer service, and certain distribution operating and maintenance costs, as well as related A&G expenses. It is not unusual from a cost of service perspective to include a customer-related component of distribution mains in customer costs. However, PSE has not defined these as customer costs in this case. If a portion of distribution mains had been included, the customer costs would be higher than those presented in Exhibit No. ___(JKP-5). In other words, the basic cost to provide service to customers set forth in Exhibit No. ___(JKP-5) and in the table below actually understates the costs of providing such service.

The following table compares the Company's current monthly basic charges to what the monthly basic charges would be if they included all costs defined in the Company's study to be customer related.

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Class	Schedule	Current Basic Charge	Cost-Based Basic Charge
Residential	23	$8.25	$18.39
Commercial & Industrial General Service	31	$17.50	$68.59
Commercial & Industrial Large Volume	41	$80.00	$143.52
Propane	53	$8.25	$18.39
Interruptible	85	$500.00	$1,117.97
Limited Interruptible	86	$100.00	$193.01
Non-exclusive Interruptible	87	$500.00	$1,777.73
Transportation and Special Contracts	57	$800.00	$1,786.00
Compressed Natural Gas	50	$150.00	$1,692.92

VI. RATE SPREAD AND RATE DESIGN PRINCIPLES

Q. What rate design and rate spread principles should be followed in developing rates?

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).

VII. RATE SPREAD AND RATE DESIGN

A. Overview of Rate Spread and Rate Design and Their Relation to the Cost of Service Study

Q. How do the cost of service study results relate to rate spread and rate design?

A. The cost of service study is the Company's best indicator of what it costs to serve each class of customer. The parity ratios presented on page 1 of 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. As a result, some classes essentially subsidize other classes. In addition, the Company's earned return varies by customer class. By adjusting rate spread, class members can be brought closer to paying the costs that the Company actually incurs to serve the class. When such adjustment is combined with adjustments to rate design, class revenues can be brought closer to cost of service levels, and class level rates of return can be brought closer to the system average rate of return.

B. Summary of the Company's Proposed Rate Spread and Rate Design

Q. How does the Company propose to allocate the rate increase to the customer classes?

A. PSE's long-term goal is to move its rates toward cost of service levels for each class, but to move all the way to cost based rates in a single step would cause

larger impacts on certain customers than may be reasonable. The Company proposes to allocate a relatively larger portion of the revenue increase to those classes with current parity ratios below 100 percent. The proposed revenue allocation by rate class is presented on page 1 of Exhibit No. ___(JKP-10) and is summarized in the following table:

Customer Class	Schedule	Parity Ratio[1]	Proposed Rate Increase[2]
Residential	23	101%	5.7%
Commercial & Industrial	31, 61	89%	6.9%
Large Volume	41	156%	0.0%
Compressed Natural Gas	50	21%	4.0%
Interruptible	85	172%	0.0%
Limited Interruptible	86	187%	-1.8%
Non Exclusive Interruptible	87	92%	3.6%
Transportation [3]	57	122%	23.9%
Rentals	71, 72, 74	69%	5.2%
System Total / Average		100%	5.3%

[1]At existing rates

[2]Including gas costs except Schedule 57

[3]Parity ratio includes special contracts, increase does not

Q. Why does the Company propose a rate decrease for Schedule 86?

A. Cost of service results indicate that Schedule 86 rates are well above cost of service levels. In addition, the average rate for Schedule 86 customers is high relative to the rates charged firm customers of similar size on Schedule 41. Given

this disparity, increasing Schedule 86 rates is not justified. In addition, PSE has received complaints from Schedule 86 customers that their rates are high relative to the rates of firm customers.

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 4 of Exhibit No. ___(JKP-5) serves as a guide to the appropriate levels of the demand, commodity, and customer charges for each customer class.

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

A. Yes. The revised tariffs are presented in Exhibit No. ___(JKP-13).

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

A. The Company proposes the following changes:

1) Elimination of Schedules 36 and 51.

2) The addition of a transportation option on Schedules 31, 41, 85, 86 and 87.

3) Closure of Schedule 57 and termination of Schedule 57 at the end of 2012.

4) Increases to all of its basic charges.

5) An increase to the delivery demand charge from $0.70 to $1.50 for

Schedule 41 customers, and a reduction in the volumetric delivery charges for these customers.

6) An increase to the minimum delivery charge for Schedule 41 customers.

7) Changes to the delivery and demand charges to produce revenues consistent with each class's revenue requirement.

C. Increasing the Basic Charges to Better Recover Fixed Costs

Q. Why does the Company propose to raise basic charges?

A. Under PSE's current natural gas tariff schedules, PSE relies on volumetric, or per therm, rates to recover a large portion of its costs, but many costs do not vary based on the volume of gas sold. Instead, they vary based on either capacity or the number of customers on the Company's system. PSE incurs these costs for each customer whether that customer purchases gas or not. Many of PSE's capital and operating costs are related to meeting design peak demand or providing service to customers, regardless of the volume of gas customers purchase. For example, in the residential class prior to any rate changes, 71 percent of margin revenue is derived from volumetric, or per therm, charges. In contrast, less than one percent of the Company's distribution cost is related to the volume of gas the Company sells or transports. Yet most revenue is derived from volumetric rates. Because of this, the Company's revenue stream is vulnerable to changes in customer usage patterns, weather, and conservation efforts. A major concern of the Company is this continuing practice of recovering fixed costs through volumetric rates – not only customer costs but demand costs as well.

Increasing the basic charge starts to address the need to recover fixed costs through fixed charges. Even with the proposed increases in customer charges, a large portion of fixed costs will continue to be recovered through volumetric rates. The proposed basic charges reflect the need to make the Company's rate structure more consistent with its cost structure.

Q. To what levels do you propose to adjust the basic charges?

A. The Company's current and proposed basic charges are summarized in the following table, along with the cost-based rates indicated by the cost of service study.

Class	Schedule	Current Basic Charge	Cost-Based Basic Charge	Proposed Basic Charge
Residential	23	$8.25	$18.39	$18.00
Commercial & Industrial General Service	31	$17.50	$68.59	$60.00
Commercial & Industrial Large Volume Sales	41	$80.00	$143.52	$120.00
Propane	53	$8.25	$18.39	$18.00
Interruptible Sales	85	$500.00	$1,117.97	$750.00
Limited Interruptible Sales	86	$100.00	$193.01	$175.00
Non-exclusive Interruptible Sales	87	$500.00	$1,777.73	$750.00
Transportation	57	$800.00	$1,786.00	$1,050.00
Compressed Natural Gas	50	$150.00	$1,692.92	$300.00

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

A. Exhibit No. ___(JKP-11) contains a comparison of basic charges and percentile rankings for residential service from 214 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 ("AGA"). 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 $1.00 per month at the City of Corpus Christi to $24.62 per month at Missouri Gas Energy. The average basic charge is $9.28 per month. By comparison, PSE's current residential basic charge of $8.25 per month is only 89 percent of the average basic charge and is in the 44th percentile of the 214 companies. In other words, 56 percent of the other distribution companies in the country have residential basic charges higher than PSE's charge. Exhibit No.___(JKP-11) indicates that utilities in Washington State have among the lowest residential basic charges in the nation.

Q. Are there customer benefits to higher basic charges?

A. Please see the prefiled direct testimony of Mr. David Hoff, Exhibit No. ___(DWH-1T) for a detailed discussion of these benefits.

D. Additional Rate Schedule Comments

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

A. The Company's analysis in this case showed that the adjustment to the rates in Schedules 101 and 106 for revenue sensitive items should be changed from the current 1.04569 to 1.04508. The proposed Schedule 101 and 106 tariff sheets reflect this change.

VIII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.