BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKET NOs. UE-072300 and UG-072301

DIRECT TESTIMONY OF GLENN A. WATKINS (GAW-1T)

ON BEHALF OF

PUBLIC COUNSEL

REVISED (RED-LINED)

June 23, 2008

NON-CONFIDENTIAL

DIRECT TESTIMONY OF GLENN A. WATKINS (GAW-1T)
DOCKET NOs. UE-072300 AND UG-072301

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I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Glenn A. Watkins. My business address is James Center III, 1051 East Cary Street, Suite 601, Richmond, VA 23219.

Q: By whom are you employed and in what capacity?

A: I am a Principal and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in Richmond, Virginia.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Public Counsel Section of the Washington Attorney General's Office (Public Counsel).

Q: Please describe your professional qualifications.

A: Except for a six month period during 1987 in which I was employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have been employed by Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted marginal and embedded cost of service, rate design, cost of capital, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and have provided expert testimony in Alabama, Arizona, Georgia, Maine, Maryland, Massachusetts, Michigan, New Jersey, Illinois, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. I hold an M.B.A and B.S. in economics from Virginia Commonwealth University. I am a member of several professional organizations as well as a Certified Rate of Return Analyst. A more complete description of my education and experience is provided in Exhibit No.___ (GAW-2).

Q: What is the purpose of your testimony in this proceeding?

A: Technical Associates has been retained by Public Counsel to evaluate the accuracy and reasonableness of Puget Sound Energy's (PSE or Company) electric and natural gas class cost of service studies (CCOSS), proposed distribution of revenues by class, and residential rate designs. The purpose of my testimony, therefore, is to comment on PSE's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of the Public Counsel.

Q: Please explain how your direct testimony is structured.

A: I have separated my direct testimony into three sections: Electric Operations; Natural Gas Operations; and PSE Supplemental Filing. For each operational section, I have three subsections entitled: Class Cost of Service; Class Revenue Distribution; and, Residential Rate Design. My testimony concerning the first two sections (Electric Operations and Natural Gas Operations) is based entirely on the Company's initial filing dated December 3, 2007. I discuss the rate design implications of PSE's April 11, 2008 supplemental filing separately in the last section of my testimony.

II. ELECTRIC OPERATIONS

A. ELECTRIC COST OF SERVICE

Q: Please explain the concept of a class cost of service study (CCOSS).

A: There are two general types of cost of service studies used for public utility ratemaking: marginal cost studies and embedded, fully allocated cost studies. PSE has utilized a traditional embedded cost of service concept in this case for purposes of establishing its overall retail revenue requirement, as well as for its CCOSS. However, as I will explain later in my testimony certain aspects of the Company's electric CCOSS are premised on forward looking marginal cost principles.

Embedded cost of service studies are often referred to as fully allocated cost studies. This is because the vast majority of a public utility's plant investment serves all customers, and the majority of expenses are incurred in a joint manner such that these costs cannot be specifically attributed to any individual customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer (or group of customers), these costs are directly assigned in a CCOSS. However, the vast majority of PSE's Production, Transmission, and Distribution plant and expenses are incurred jointly to serve all (or most) customers. These joint costs are then allocated to rate classes.

It is generally recognized that to the extent possible, joint costs should be allocated to classes based on the concept of cost causation; i.e., costs are allocated based on specific factors that cause costs to be incurred by the utility. Although cost analysts generally strive to abide by the concept of cost causation to the greatest extent practical, some costs (particularly overhead costs), cannot be attributed to specific exogenous factors and must be subjectively assigned or allocated to rate classes. With regards to those costs that can be attributed to a specific factor, cost of service experts often disagree as to what is the most cost causative factor; e.g., peak demand, energy usage, number of customers, etc.

Q: How should CCOSS results be used in the ratemaking process?

A: Although there are certain principles used by all cost of service analysts, there are often significant disagreements on the specific factors that drive costs. These disagreements can and do arise as a result of the quality of data and the level of detail available from financial records. Moreover, there are often fundamental differences in opinions regarding cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Additionally, and as mentioned earlier, cost causation factors cannot be realistically ascribed to some costs such that subjective decisions are required.

In these regards, two different cost studies conducted for the same utility and time period can, and often do, yield different results. As such, regulators should consider CCOSS results as one of many tools in assigning revenue responsibility.

Q: Please explain how you proceeded with your analysis of PSE's electric CCOSS.

A: The process by which I conducted my analysis in this case was identical to how I evaluate all CCOSSs. First, I reviewed the structure and organization of the Company's CCOSS presented by PSE witness, David W. Hoff, in Exhibit No.___ (DWH-4C). Once the basic structure was understood, I reviewed the accuracy and completeness of the primary drivers (allocators) used to assign costs to rate schedules and classes. Next, I reviewed PSE's selection of allocators used to allocate specific rate base, revenue and expense accounts to customer rate classes. I then verified the accuracy of PSE's CCOSS model by replicating the results using my own computer model. Finally, I adjusted certain aspects of the Company's studies to better reflect cost causation and cost incidence by rate schedule and customer class.

Q: Did you find the Company's electric CCOSS to be mathematically accurate?

A: Yes. Perhaps the most fundamental requirement of an embedded CCOSS is that the sum of the parts (customer classes) must equal the whole (system). This is true with respect to the allocation of financial accounts, as well as the various allocation factors. Furthermore, certain costs previously allocated are carried forward for other purposes such as for the development of composite or internal allocators and for the assignment of income taxes. In all regards, I found Mr. Hoff's electric CCOSS to be mathematically accurate and I was able to replicate his results.

Q: How will you present the results of your CCOSS analyses?

A: To understand the importance and impact of each adjustment I have made to Mr. Hoff's CCOSS, I present a summary of each customer class's rate of return on rate base at current rates after each adjustment. That is, I start with a replication of Mr. Hoff's results, and subsequently present and discuss the resulting class rates of return at current rates after each of my adjustments.

Q: Please provide a summary of Mr. Hoff's CCOSS results at current rates.

A: Mr. Hoff's CCOSS generates the following rates of return on rate base at current rates. It should be noted that Mr. Hoff's electric CCOSS reflects all accounting and proforma adjustments proposed by the Company in its initial filing on December 3, 2007.

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Table 1
Replication of PSE Electric CCOSS
at Current Rates

Rate Schedule	Class	Rate of Return	Indexed ROR
7	Residential	2.87%	54%
24	Secondary Voltage <50kw	5.77%	109%
25	Secondary Voltage >50kw and <350kw	12.62%	238%
26	Secondary Voltage >350	11.33%	213%
31/35/43	Primary Voltage	6.96%	131%
40	Campus	5.73%	108%
46/49	High Voltage	4.11%	77%
449/459	Transportation	6.06%	114%
50-59	Lighting	8.69%	164%
5	Firm Resale	2.34%	44%
Total Company		5.31%	100%

1. Income Taxes

Q: Please explain your disagreements with Mr. Hoff relating to the treatment of income taxes for purposes of PSE's CCOSS.

A: As is the case for virtually all investor owned public utilities, income taxes represent a significant expense for PSE's electric operations. Although Mr. Hoff has incorporated PSE's total company electric income taxes in his CCOSS, his analysis at current rates inappropriately assigns this expense to individual classes.

It is well understood that income tax expense is based on before tax profits. However, Mr. Hoff's CCOSS analysis at current rates ignores this concept and allocates PSE's total electric income taxes to customer classes based on allocated rate base (investment). In other words, Mr. Hoff's CCOSS analysis at current rates assigns income tax expense based on the level of plant investment rather than profit contributions by customer class. Mr. Hoff's determination of each class's income tax responsibility, therefore, has nothing to do with the reality of tax incidence (revenues minus expenses), but rather is based solely on investment. Mr. Hoff's approach unrealistically assigns the same level of income tax responsibility to individual classes regardless of each class's revenues and expenses.

This allocation, or assignment, of total Company income taxes based on rate base investment significantly distorts individual class profitability at current rates and provides inaccurate information as to the adequacy, or inadequacy, of current rates.

Q: Are income taxes normally calculated or allocated for other types of financial or profitability analysis?

A: It is universally agreed that when the objective is to evaluate profitability, whether it be for a firm, a specific business unit, or single project, income tax expenses are based on the difference between revenue and deductible expenses. Allocating the total income taxes based on investment (rate base) makes no sense.

Q: Have you conducted a replication analysis of Mr. Hoff's CCOSS with a more proper determination of class income tax responsibility?

A: Yes.

Q: Please explain how you calculated electric income taxes for each class.

A: Income taxes were calculated for each class by first determining each class' earnings before interest and income taxes (EBIT). Synchronized interest expense was then determined for each class based on the allocated level of rate base. Subtracting interest from EBIT results in each class's taxable income. This taxable income amount was then multiplied by the system effective income tax rate to arrive at each class' income tax responsibility.

Q: What individual class rates of return result when Mr. Hoff's study is adjusted for a proper calculation of income taxes?

A: A summary of this CCOSS scenario is provided in Exhibit No. ___ (GAW-3). A summary comparison of class rates of return (ROR) on rate base is provided below:

Table 2
Electric CCOSS (at Current Rates)
ROR

	PSE Study		Indexed ROR	
Class	Corrected For Income Taxes	As Filed By PSE	Corrected For Income Taxes	As Filed By PSE
Residential	4.09%	2.87%	77%	54%
Secondary Sch. 24	5.54%	5.77%	104%	109%
Secondary Sch. 25	8.97%	12.62%	169%	238%
Secondary Sch. 26	8.33%	11.33%	157%	213%
Primary Sch. 31/35/43	6.14%	6.96%	115%	131%
Campus Sch. 40	5.52%	5.73%	104%	108%
High Voltage Sch 46/49	4.71%	4.11%	89%	77%
Transportation Sch. 44	5.68%	6.06%	107%	114%
Lighting	7.01%	8.69%	132%	164%
Firm Resale	3.82%	2.34%	72%	44%
Total Electric	5.31%	5.31%	100%	100%

As can be seen above, the correction to income taxes produces significantly different results for several classes. Most notably, the Residential class ROR rises from 2.87 percent (54% of the system average) to 4.09 percent (77% of system average), the Firm Resale class rises from 2.34 percent (44% of system average) to 3.82 percent (72% of system average). Rate Schedule 25 decreases from 12.62 percent (238% of system average) to 8.97 percent (169% of system average), and Rate Schedule 26 decreases from 11.33 percent (213% of system average) to 8.33 percent (157% of system average).

2. Excise Taxes and WUTC Fees

Q: Please explain your next adjustments to Mr. Hoff's electric CCOSS.

A: The next adjustments I made to Mr. Hoff's CCOSS also reflect a more accurate assignment of expenses, specifically related to WUTC filing fees, and Washington State excise taxes. Whereas each of these expenses are incurred on revenue levels, Mr. Hoff allocates them to individual classes based on gross Production, Transmission, and Distribution plant (PTDP) investment.

I separated Account No. 928 into two components and allocated PSE's proforma WUTC fees ($3,628,231) based on retail rate revenues and the remainder ($2,075,607) on the basis of Mr. Hoff's PTDP allocator. With regards to proforma Washington Excise Tax expense booked under Account 236.21, I also allocated these revenue taxes based on retail rate revenue. These adjustments to revenue-related taxes and fees, coupled with my previous adjustment to properly reflect income tax responsibility, results in the following rates of return at current rates:

Table 3
Electric CCOSS (at Current Rates)
Incorporating Income Taxes, Other Taxes and Fees
Adjustments

Class	ROR	Indexed ROR
Residential	4.22%	79%
Secondary Sch. 24	5.51%	104%
Secondary Sch. 25	8.69%	164%
Secondary Sch. 26	7.90%	149%
Primary Sch. 31/35/43	5.96%	112%
Campus Sch. 40	5.10%	96%
High Voltage Sch 46/49	4.21%	79%
Transportation Sch. 449	6.49%	122%
Lighting	7.26%	137%
Firm Resale	4.42%	83%
Total Electric	5.31%	100%

The details underlying these CCOSS results are provided in my filed workpapers.

3. Power Supply Costs

Q: How has PSE assigned generation and other power supply costs to customer classes?

A: Mr. Hoff has utilized the Peak Credit method to classify power supply costs between energy and demand. As noted on pages 10 and 11 of Mr. Hoff's direct testimony, the Peak Credit method has a "long tradition in this region" and indeed has been used in Washington State for many years by PSE, as well as other electric utilities.

Q: Please explain the conceptual basis for the Peak Credit method.

A: In general, electric utilities plan their power supply resources to meet the objective of supplying the energy (kwh) needs of its customers at the lowest total costs, subject to the constraint that enough capacity (kw) must also be available to meet peak load requirements. Because there is typically a cost tradeoff between fixed capacity costs and variable energy costs, an electric utility's power supply portfolio includes a mix of expensive fixed capacity (kw)/cheaper variable (energy) cost resources to meet annual energy requirements and less expensive fixed/more costly variable (energy) costs resources to meet peak load demands. The Peak Credit method (and other peaker methods) attempts to capture this energy/capacity tradeoff by recognizing that peak demands require only peaking generation while more efficient base and intermediate generation facilities are used to meet the annual energy requirements of customers.

As such, the Peak Credit method and other peaker methods have substantial intuitive appeal in that base load units which operate with high capacity factors are allocated on the basis of energy consumption, while peaking units, that are seldom used and only called upon during peak load periods, are allocated on peak demand in proportion to those classes contributing to the system peak load(s).

Q: Please explain how Mr. Hoff applied the Peak Credit method in this case.

A: As implied earlier, there are two components that result from the Peak Credit method: a portion of power supply classified and allocated as demand-related (kw) and a portion classified and allocated as energy-related (kwh). PSE has developed its demand/energy relationship by calculating the ratio of the costs of a hypothetical peaker unit (demand) to those of a hypothetical base load unit (energy).

Q: What do you mean by the hypothetical costs of peaker and base load units?

A: Instead of utilizing the actual costs of a particular generating unit actually in service, PSE has estimated the forward-looking capital and operating costs of a natural gas-fired simple cycle gas combustion turbine (SCCT) as a surrogate for a peaker unit and forward-looking estimates of the capital and operating costs of a combined cycle combustion turbine (CCCT) as a surrogate for a base load unit.

Q: Please continue with your explanation of Mr. Hoff's application of the Peak Credit method.

A: Of critical importance is an understanding that Mr. Hoff's cost estimates for the hypothetical SCCT and CCCT reflect estimates of both fixed capital costs and variable operating costs. Specifically, Mr. Hoff assumes the SCCT unit will be used solely for peaking purposes and operate only 75 hours per year.[1] Furthermore, Mr. Hoff assumes

[1] There are 8,760 hours in a year.

that the cost of natural gas used to run this SCCT will be purchased at a premium due to the assumed peaking nature of the unit.[2]

Q: Mr. Watkins, have you investigated the reasonableness of Mr. Hoff's assumption that the hypothetical SCCT would be used solely for peaking purposes?

A: Yes.

Q: Please explain your investigation and the reasonableness of Mr. Hoff's assumption that a SCCT will only operate for 75 hours during peak load conditions.

A: To investigate the assumption that a PSE-owned SCCT would be used only to meet peak loads, I evaluated the characteristics of PSE's dispatch of its generation, and specifically the actual dispatch of its SCCTs. In Public Counsel Data Request No. 456, I requested and was provided hourly PSE Area loads (retail plus wholesale) for the period October 1, 2005 through June 30, 2007. In addition, the hourly output of each PSE owned gas generation unit was provided in response to Public Counsel Data Request No. 457. With these two sets of data, I was able to evaluate the frequency of SCCT dispatch to serve PSE's Area loads. In other words, I was able to examine not only the number of hours in a year that PSE dispatches (utilizes) its SCCT's, but also examine each hourly SCCT dispatch relative to the PSE Area load requirements.

The period October 1, 2005 through June 30, 2007 was separated into two annual periods (October 1, 2005 through September 30, 2006, and July 1, 2006 through June 30, 2007) to enable an analysis of two complete winter seasons. PSE-owned, operated, and

[2] Because PSE's electric peak loads are in the winter and Mr. Hoff assumes this SCCT will only operate during the highest load periods of the winter, he further assumes that there will be a premium on the cost of gas for this unit because he assumes that fuel will be purchased during periods when natural gas is also in high demand.

dispatched four separate SCCTs during this study period. A summary of each unit's hours of dispatch during these two annual periods is provided below:

[Begin Confidential][3]

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(End Confidential)

Q: Please continue with your explanation of the operating characteristics of PSE's SCCT dispatch.

A: Although PSE utilizes its SCCTs significantly more than the 75 hours assumed by Mr. Hoff **[Begin Confidential]** **(**XXXXXXXXXXXXXXXXXXXXXXX) **[End Confidential]**, this by itself tells us nothing of whether these units are used primarily to meet peak period demand. Therefore, I also compared each SCCT's hourly dispatch and its coincidence with the PSE area load. In this manner, I was able to determine the extent to which PSE utilizes its SCCTs for peaking purposes.

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[3] **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX **[End Confidential].**

To avoid disagreement as to what levels of load constitutes "peak" periods, I evaluated the dispatch of PSE's SCCT's at various peak period definitions. Mr. Hoff used the highest 75 hours of peak load to develop his coincident peak demand allocators in his CCOSS, and indicated that 75 hours was selected because "[w]hile the data did not suggest a clear cut-off point, the top 75 hours have peaks that were within 90 percent of the system peak."[4]

Indeed, there are about 75 hours per year in which the PSE system load is at or above 90 percent of the annual peak load. In addition to this 90 percent of annual peak load standard, I also evaluated SCCT dispatch under more conservative definitions of "peak" demand, including hours at or above 80 percent of annual peak, 70 percent of annual peak, as well as PSE's previous standard of the highest 200 hours of peak load.

The detailed results of my analysis of PSE's utilization of its SCCTs is provided in Exhibit No. ___ (GAW-4C).

Q: Mr. Watkins, please explain what is shown in Exhibit No. ___ (GAW-4C) and your conclusions based on the data therein.

A: In Exhibit No.___(GAW-4C), I tabulate the number of hours of operation of each PSE SCCT based on my analysis of the data provided by PSE in response to Public Counsel Data Request No. 457. Specifically, this response provided the hourly generation of each of PSE's generating facilities within the period October 1, 2005 through June 30, 2007.

In undertaking my analysis of the operations of PSE's SCCTs throughout this period, I evaluated the operations of PSE's Fredonia, Frederickson and Whitehorn generating facilities. These PSE generating facilities are identified in the Company's

[4] Hoff direct testimony at p. 13, ll. 9-11.

2007 Integrated Resource Plan (IRP) as SCCTs. My analysis, therefore, consists of tabulating the hours of operations of these generating facilities to meet Area loads that are within 90 percent, 80 percent, and 70 percent of the system peak load designated in PSE's response to Public Counsel Data Request No. 456.

[Begin Confidential]

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[End Confidential]

Q: How should PSE's actual dispatch of SCCTs during off-peak hours be reflected in the Peak Credit method?

A: Given PSE's high levels of SCCT dispatch during off-peak periods, I recommend two adjustments to Mr. Hoff's Peak Credit assumptions and calculations. First, an annual utilization of [**Begin Confidential**] XXXXXXX**[End Confidential]** is clearly more appropriate than the 75 hours assumed by Mr. Hoff. This adjustment, by itself, increases the levelized cost of the SCCT unit relative to the CCCT baseload unit and increases the demand component from 26 percent to 28 percent. The second necessary adjustment is to recognize the magnitude of SCCT utilization during off-peak periods. In this regard, I recommend a 50 percent on-peak and a 50 percent off-peak SCCT utilization.

Q: Why do you recommend a 50 percent on-peak and a 50 percent off-peak utilization when PSE actually dispatches its SCCTs in a more off-peak manner?

A: [Begin Confidential] XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXX **[End Confidential]**

Q: What is the result of your two adjustments to Mr. Hoff's Peak Credit method?

A: These two adjustments result in a classification of 14 percent demand and 86 percent energy. For purposes of my CCOSS analysis, I have used a split of 15 percent demand and 85 percent energy.

Q: Do any other Washington State utilities recognize the off-peak utilization of SCCTs in their application of the Peak Credit method?

A: Yes. In its pending application before this Commission, PacifiCorp assigns 50 percent of SCCT fixed costs to off-peak hours and 50 percent to on-peak hours.[5] This 50/50 assignment reduces the ratio of peak to base load costs in the same manner that I recommend in this case.

Q: Have you reviewed the Peak Credit demand/energy classification used by PSE in previous cases?

A: Yes.

Q: What are these historical Peak Credit classifications?

A: In response to WUTC Staff Data Request No. 100, PSE provided the allocation (classification) percentages for demand and energy used in each rate case since 1982. During the period 1982 through 1989, PSE made separate demand/energy classifications for Thermal Hydro, and “Other” power supply resources. All power supply resources have been combined since the 1992 case, and the following demand/energy percentages

[5] *See WUTC v. PacifiCorp d/b/a/ Pacific Power & Light Company*, Docket No. UE-080220.

have been utilized:

Table 5
Classification Percentages

Docket No.	Energy %	Demand %
UE-921262	87%	13%
UE-011570	84%	16%
UE-040641	86%	14%
UE-060266	80%	20%
UE-072300	74%	26%

As can be seen above, my recommended 85 percent energy and 15 percent demand split is consistent with PSE's classification prior to the 2006 rate case.

Q: Earlier in your testimony you discussed PSE's use of hypothetical SCCT and CCCT generating units. How were costs developed for the hypothetical generating units?

A: Mr. Hoff forecasted the future revenue requirements for each of these two units utilizing estimated construction costs, forecasts of natural gas prices, and forecasts of other operating costs.

Q: Are these forecasted generating unit costs subject to uncertainty?

A: **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX **[End Confidential]** Of course, this involves a considerable amount of uncertainty. Furthermore, PSE's choice of which types of plants to use in their Peak Credit method is subject to uncertainty, let alone the estimated construction costs of the particular SCCT and CCCT selected for the hypothetical units. Finally, the future revenue requirement for each hypothetical unit is calculated and levelized to present value. Of critical importance to these calculations are the assumed future costs of gas, costs of capital, and capital structure. For purposes of PSE's analyses, Mr. Hoff has used the Company's proposed capital structure and proposed costs of debt and equity. Each of these parameters represents multiple uncertainties and requires assumptions that may or may not be reasonable.

Q: Did you test the reasonableness of Mr. Hoff's forecasted fuel prices and operating expenses incorporated in the calculations of generating unit costs?

A: Yes I did.

Q: Does the use of hypothetical investments, coupled with the uncertainties of future assumed cost, cause you concern as to the reasonableness of either PSE's or your own Peak Credit results?

A: Yes, they do.

Q: Were you able to test the reasonableness of the assumptions used by Mr. Hoff in his Peak Credit analysis?

A: Yes.

Q: Please explain how you tested the reasonableness of Mr. Hoff's Peak Credit input assumptions.

A: In response to Public Council Data Request No. 454, I was provided PSE's confidential computer model used to develop Mr. Hoff's proposed 26 percent demand and 74 percent energy classification of electric supply resources. I undertook the calculations of numerous scenarios with alternative future cost assumptions, including various future inflation rates, costs of gas, costs of capital, capacity factors (utilization rates), and plant investment costs. Not surprisingly, I found that the model is most sensitive to the assigned capital construction costs of the selected plants and the estimation of future gas prices. PSE's model is relatively insensitive to the other model input assumptions.

Q: Did you conduct other analyses to test the reasonableness of your recommended 15 percent demand and 85 percent energy classification of electric supply resources?

A: Yes.

Q: Please discuss these additional analyses.

A: As is true for every cost allocation methodology, the Peak Credit method is subject to conceptual and practical criticism. To test the reasonableness of my recommended 15 percent demand and 85 percent energy classification of PSE's electric supply resources, I also conducted an analysis utilizing actual PSE booked (embedded) costs. Specifically, I evaluated PSE's actual investment in each generating facility and classified each unit as demand-related (peak) or energy-related (base load). I classified PSE's steam plant (Colstrip), hydro, wind, and CCCT generating unit investments as base load energy-related and its other generating units (SCCTs) as peaking units. The details of this analysis are provided on page 1 of Exhibit No. ___ (GAW-5) and produce the following results:

Base Load (Energy) related	94.46%
Peaker (Demand) related	5.54%

Recognizing that there are some peaking capabilities of PSE's hydro units and that its combined cycle (CCCT) units do not operate at 100 percent capacity factors, I also conducted sensitivity analyses whereby I reclassified each hydro unit as 25 percent demand-related and 75 percent energy-related and reclassified each CCCT unit as 15 percent demand-related and 85 percent energy-related. This analysis produced an overall energy supply classification of 11.9 percent demand and 88.1 percent energy, as shown on page 2 of Exhibit No. ___ (GAW-5).

Based on these analyses, the diurnal and short-term peaking capabilities of certain hydro units, minimum water flow requirements, recognition of the fact that PSE meets a substantial portion of its peak load and energy requirements with purchased power (primarily hydro), and that Pacific Northwest regional wholesale market prices may dictate the dispatch of PSE's generating units at times that would otherwise be deemed inappropriate, I conclude that my adjustment to PSE's proposed 26 percent demand and 74 percent energy classification is conservatively reasonable such that a 15 percent demand and 85 percent energy is an appropriate classification of electric supply resources for CCOSS purposes.

Q: What are your CCOSS results after your adjustment to PSE's electric supply resource classification using your recommended 15 percent demand-related and 85 percent energy-related classification?

A: Building upon my earlier adjustments, the following class rates of return result from

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classifying electric supply resources as 15 percent demand and 85 percent energy:

Table 6
Electric CCOSS (at Current Rates)
Incorporating Income Taxes, Other Taxes and Fees,
and Power Supply Cost Adjustments

Class	ROR	Indexed ROR
Residential	4.67%	88%
Secondary Sch. 24	5.23%	98%
Secondary Sch. 25	8.11%	153%
Secondary Sch. 26	6.92%	130%
Primary Sch. 31/35/43	5.04%	95%
Campus Sch. 40	3.49%	66%
High Voltage Sch 46/49	2.62%	49%
Transportation Sch. 44	6.23%	117%
Lighting	7.08%	133%
Firm Resale	4.33%	82%
Total Electric	5.31%	100%

Q: Please explain your remaining adjustments to Mr. Hoff's CCOSS.

A: My last two adjustments to Mr. Hoff's electric CCOSS relate to: (1) the allocation of Salaries and Wages, which are then used to allocate certain rate base and expense accounts; and (2) the allocation of General Plant.

With regards to Salaries and Wages, Mr. Hoff grouped all labor costs into seven major categories and separately allocated each of these major categories.[6] In contrast, I have allocated Salaries and Wages associated with each individual FERC account based on the analysis of labor expenses by individual FERC account that was conducted by PSE witness, John Story and provided in his filed workpapers. As may be expected, this more detailed analysis did not produce significantly different results than those obtained by the

[6] Mr. Hoff's salaries and wages categories are: Production, Transmission, Distribution, Customer Accounts, Customer Service, and Information, General, and Sales.

more generic grouping of labor costs done by Mr. Hoff. The class rates of return obtained after a more specific allocation of Salaries and Wages (and building upon by previous CCOSS adjustments) is as follows:

Table 7
Electric CCOSS (at Current Rates)
Incorporating All Table 6 and Salaries & Wages Adjustments

Class	ROR	Indexed ROR
Residential	4.70%	88%
Secondary Sch. 24	5.24%	99%
Secondary Sch. 25	8.11%	153%
Secondary Sch. 26	6.90%	130%
Primary Sch. 31/35/43	4.86%	91%
Campus Sch. 40	3.42%	64%
High Voltage Sch 46/49	2.55%	48%
Transportation Sch. 44	6.11%	115%
Lighting	6.70%	126%
Firm Resale	4.22%	79%
Total Electric	5.31%	100%

Q: Mr. Watkins, please explain your final CCOSS adjustment which relates to the allocation of General plant.

A: Mr. Hoff allocated almost all of the Company's $282 million investment in General Plant based on Salaries and Wages.[7] Although I cannot say that Mr. Hoff's rationale and method to allocate General Plant is necessarily unreasonable since this approach is sometimes used in the industry, a more common, and in my opinion preferred, approach is to allocate General Plant based on the investment this "general" plant supports namely: Production, Transmission, and Distribution plant (PTD). As such, I have allocated all General Plant based on the composite investment in PTD plant.

[7] The exception is that Mr. Hoff allocated $1.076 million of General Plant associated with "Stores" equipment based on Production, Transmission, and Distribution Plant.

This adjustment, in conjunction with my earlier adjustment, produces my final recommended class rates of return at current rates and are summarized below:

Table 8
Electric CCOSS (at Current Rates)
Incorporating All Public Counsel Adjustments

Class	ROR	Indexed ROR
Residential	4.74%	89%
Secondary Sch. 24	5.30%	100%
Secondary Sch. 25	7.94%	149%
Secondary Sch. 26	6.71%	126%
Primary Sch. 31/35/43	4.83%	91%
Campus Sch. 40	3.34%	63%
High Voltage Sch 46/49	2.44%	46%
Transportation Sch. 44	5.83%	110%
Lighting	7.46%	140%
Firm Resale	4.06%	76%
Total Electric	5.31%	100%

The detailed output of my recommended CCOSS is provided in Exhibit No. ___ (GAW-6).

Q: Please provide a comparison of your CCOSS results to those obtained by PSE witness Hoff.

A: The following is a comparison of my recommended electric CCOSS rates of return at current rates:

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Table 9
Electric CCOSS (at Current Rates)
Comparison of Results

Class	ROR @ Current Rates Public Counsel (Watkins)	PSE (Hoff)
Residential	4.74%	2.87%
Secondary Sch. 24	5.30%	5.77%
Secondary Sch. 25	7.94%	12.62%
Secondary Sch. 26	6.71%	11.33%
Primary Sch. 31/35/43	4.83%	6.96%
Campus Sch. 40	3.34%	5.73%
High Voltage Sch 46/49	2.44%	4.11%
Transportation Sch. 44	5.83%	6.06%
Lighting	7.46%	8.69%
Firm Resale	4.06%	2.34%
Total Electric	5.31%	5.31%

B. ELECTRIC CLASS REVENUE DISTRIBUTION

Q: How did Mr. Hoff determine his proposed distribution of the Company's requested electric revenue increase to individual classes?

A: Mr. Hoff sponsors PSE's proposed class distribution of the Company requested electric revenue increase of $174.8 million. Mr. Hoff states that his proposed revenue distribution to customer classes is influenced by two "rate spread policy factors": (1) the results of his cost of service study and relationships to system parity of the customer classes; and, (2) the impact on different classes of customers of the proposed revenue spread. Mr. Hoff goes on to describe his proposed rate spread as follows:

> Based upon the parity ratios shown in the Company's cost of service study and the desire to move towards parity in a gradual manner, the Company proposes to apply the average rate increase to retail classes within 5% of parity, apply a rate increase that is 125% of the average to the rate class

that is below 95% of parity (residential class), apply a rate increase that is 75% of the average to the one class that is more than 5%, but less than 10%, above parity (Lighting), and apply an increase that is 50% of the average to the two classes that are over 10% above parity (Medium Secondary Voltage and Large Secondary Voltage). As discussed below, rates in Schedule 40 (Large Demand General Service Greater than 3 aMW) are tied to rates in the high voltage schedules such that the rate increases for that schedule are not independently determined. The wholesale for resale is moved to full parity so that there is not a cross-jurisdictional subsidy.[8]

A summary of PSE's proposed revenue increase to the CCOSS customer rate classes is shown below:

Table 10
PSE-Proposed Electric Revenue Increase[9]

Class	Amount	Percent Increase
Residential (Schedule 7)	$115,972,986	11.78%
Secondary Voltage		
Schedule 24	21,259,081	9.43%
Schedules 25/29	12,298,629	4.71%
Schedule 26	7,498,336	4.71%
Primary Voltage		
Schedules 31/35	9,378,361	9.43%
Schedule 43	1,211,431	9.43%
Campus Rate (Schedule 40)	1,947,000	5.00%
High Voltage (Schedules 46/49)	3,007,097	9.43%
Schedules 449/459	817,118	9.43%
Lighting (Schedules 50-59)	1,092,472	7.07%
Firm Resale (Schedule 5)	336,605	29.47%
Total Company	$174,819,117	9.51%

Q: Are PSE's proposed customer class revenue increases reasonable for its electric operations?

[8] Hoff direct testimony at p. 19, l. 16 through p. 20, l. 7.
[9] Exhibit No. ___ (DWH-5), page 1.

A: No, they are not.

Q: Mr. Watkins, do you have an alternative electric revenue increase Distribution to that proposed by PSE?

A: Yes. Based on the results of my CCOSS presented in Exhibit No. ___ (GAW-6) as well as a recognition of gradualism and the general interest in moving customer class rates of return toward the system rate of return, I propose the following electric revenue increase Distribution at PSE's requested level:

Table 11
Public Counsel Proposed Revenue Increase

Class	Amount	Percent Increase
Residential (Schedule 7)	$101,002,871	10.26%
Secondary Voltage		
Schedule 24	21,444,363	9.51%
Schedules 25/29	18,602,204	7.13%
Schedule 26	12,852,702	8.08%
Primary Voltage		
Schedules 31/35	9,460,097	9.51%
Schedule 43	1,221,989	9.51%
Campus Rate (Schedule 40)	4,264,090	10.94%
High Voltage (Schedules 46/49)	3,792,429	11.89%
Schedules 449/459	824,240	9.51%
Lighting (Schedules 50-59)	1,101,607	7.13%
Firm Resale (Schedule 5)	252,526	22.11%
Total Company	$174,819,117	9.51%

In formulating my proposed electric revenue increase distribution to the various customer rate classes, I started with the results of my CCOSS, which are presented in Exhibit No. ___ (GAW-6). With the results of my CCOSS as a guide, I proceeded in a similar manner as Mr. Hoff. That is, I formulated increases consistent with the CCOSS results as follows:

(1) I accepted PSE's proposal to bring Firm Resale (Schedule 5) to parity, an increase of $252,566;

(2) I increased Secondary Voltage Schedules 24, 31, 35, 43, and Transportation Schedules 449/459 at the system average increase because these customer rate classes have RORs close to the system average ROR at current rates; i.e., these classes were increased at 100% of the system average percentage increase;

(3) I increased Secondary Voltage Schedules 25/29 and Lighting Schedules 50-59 at 75% of the system average increase since each is considerably above parity;

(4) I increased Secondary Voltage Schedule 26 at 85% of the system average increase since it is also above parity, but somewhat less so than Schedules 25/29 and 50-59;

(5) I increased Campus Schedule 40 at 115% of the system average increase since it is somewhat below parity;

(6) I increased High Voltage Schedules 46/49 at 125% of the system average increase since this class was considerably below parity; and,

(7) Finally, I treated the residential customer class (Schedule 7) as the residual to "pick-up" the remainder of the revenue increase not assigned to the other customer rate classes.

My approach to the distribution of the $174.8 million overall revenue increase proposed by PSE produces an increase of 108 percent of the system average increase to the residential customer rate class. This relative increase (108% of system average) to the residential class is appropriate and reasonable since this class is currently earning slightly less than the system average rate of return (Indexed ROR of 89%).

Q: Does your proposed revenue Distribution move all classes towards rate of return parity?

A: Yes, it does. As shown below, and calculated on page 1 of Exhibit No. ___ (GAW-7), my proposed class electric revenue assignment moves all classes closer to rate of return parity:

Table 12
Indexed Rate of Return
Public Counsel CCOSS Results

Class	At Current Rates	At Public Counsel Proposed Rates
Residential (Schedule 7)	89%	93%
Secondary Voltage:		
Schedule 24	100%	100%
Schedules 25/29	149%	126%
Schedule 26	126%	118%
Primary Voltage:		
Schedules 31/35/43	91%	97%
Campus Rate (Schedule 40)	63%	91%
High Voltage (Schedules 46/49)	46%	86%
Transportation (Schedules 449/459)	110%	87%
Lighting (Schedules 50-59)	140%	117%
Firm Resale (Schedule 5)	76%	100%
Total Company	100%	100%

Q: Mr. Watkins, please provide your recommended scale back method to assign class electric revenue increases should the Commission authorize an overall revenue requirement increase less than that proposed by PSE.

A: I recommend that my customer class revenue increase distribution be scaled back in equal portions (i.e., equal percentages) should the Commission authorize an overall electric revenue increase different than that requested by PSE.

C. ELECTRIC RESIDENTIAL RATE DESIGN

1. Residential Rate Design Concepts

Q: Mr. Watkins, have you identified a common objective in PSE's electric and gas residential rate design proposals?

A: Yes. It is clear from the testimony of witnesses, David W. Hoff and Janet K. Phelps, that the primary objectives of PSE's gas and electric residential rate design proposals are to increase revenue collection associated with fixed monthly customer charges with less revenue reliance on volumetric charges.

Q: Is there a fundamental reason why PSE desires more residential revenue recognition from customer charges with less relative contributions from volumetric charges?

A: Yes. Fixed monthly customer charges represent guaranteed revenue to PSE. This guarantee of revenue obviously reduces the risk of PSE's operations and provides more assurances of net income available to shareholders.

Q: What support do Mr. Hoff and Ms. Phelps offer to justify their proposed increased reliance on fixed customer charge revenue?

A: The underlying support provided by both Mr. Hoff and Ms. Phelps is the improper notion that because many of PSE's costs are of a fixed nature, a large percentage of revenue collection should also be fixed in nature.

Q: Does PSE's proposal to increase revenue collection from fixed monthly charges comport with the economic theory of competitive markets or the actual practices of such competitive markets?

A: No. The most basic tenant of competition is that prices ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without the duplication of the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical. As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

Q: Please briefly discuss how prices are generally structured in competitive markets.

A: Economic theory tells us that efficient price signals result when prices are equal to long-run marginal costs. It is well known that, in the long-run, all costs are variable and hence, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs. Indeed, competitive market-based prices are generally structured based on usage, i.e. variable, pricing.

Q: Please explain how this theory and application of competitive pricing should be transferred to that of a regulated public utility, such as PSE.

A: Due to PSE's investment in system infrastructure, there is no debate that many of PSE's short-run costs are fixed in nature. As discussed above, efficient competitive prices are established based on long-run costs, which are entirely variable in nature.

However, marginal cost pricing only relates to efficiency. This pricing does not attempt to always address fairness or equity. From a perspective of fair and equitable pricing of a regulated monopoly's products and services, it is generally agreed that payments for a good or service should be in accordance with the benefits received. Those who receive more benefits should pay more in total than those who receive fewer benefits. With respect to electric or natural gas usage, the volume of consumption is the most direct, and perhaps best, indicator of benefits received, such that volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

The above philosophy is, and has been, the belief of economists, regulators, and the marketplace for many years. As an illustration, consider utility industry pricing in its infancy (1800s). In the beginning, customers paid a fixed monthly fee and consumed as much of the utility service/commodity as they desired (usually water). It soon became apparent that the fixed monthly fee rate schedule was inefficient and unfair. Utilities soon began metering their commodity and charging only for the amount actually consumed. In this way, consumers receiving more benefits from the utility than others paid more in total for the utility service because they used more of the commodity.

Furthermore, virtually every capital intensive industry is faced with a high percentage of fixed costs in the short-run. This includes the manufacturing and transportation industries. Prices for competitive products and services in these industries are invariably established on a volumetric basis, including those that were once regulated; e.g., airline travel and rail service.

Accordingly, Mr. Hoff and Ms. Phelps's positions, that most of PSE's fixed costs should be recovered through fixed monthly charges, in my view is incorrect since pricing should reflect long-run cost incidence wherein all costs are variable or volumetric in nature, and that users requiring more of PSE's products and services pay more than customers who use less of these products and services.

Q: Why do customer charges exist at all for public utilities?

A: The conventional wisdom in public utility pricing is that some revenues should be collected from fixed monthly charges. Although revenue stability clearly results from such pricing mechanisms, this stability in and of itself simply reduces the risk to shareholders at the expense of efficient price signals. From a practical standpoint, rates charged by public utilities are usually separated into a few classes. Within these classes, there are some customers who consume relatively small amounts of electricity or natural gas, and others that require much greater quantities of the public utility's commodity or service. Due to the incremental costs of connecting and maintaining a customer's account, the general practice is to charge a fixed monthly fee, such that small usage customers within a class provide revenue contributions to the utility to compensate for the cost of connecting and maintaining the customer's account, as well as contribute revenue based on the amount of electricity or natural gas actually used.

Q: Do PSE's tariffs contain other provisions to recognize the costs to connect new customers?

A: Yes. PSE's electric and gas tariffs each contain line extension and new customer hook-up fee schedules.[10]

Q: How are PSE's line extension and new customer fees structured?

A: For both electric and natural gas service, new customers are generally charged a connection fee based on their expected level of consumption. That is, customers that are expected to use less electricity or natural gas must pay a higher connection fee than customers with expected higher levels of usage. This pricing mechanism eliminates PSE's claim that customer charges should include the capital costs associated with connecting a new customer. I will discuss PSE's specific electric and gas connection fees later in my testimony with my explanation of residential "customer" costs and customer

[10] See Schedule 85 for PSE's electric tariff and Schedules 7 and Rule 7 for PSE's natural gas tariff.

charges for each type of new service. The purpose of this discussion is to bring to the Commission's attention the fact that the claimed desire for higher customer charges due to differences in intraclass consumption is largely already reflected in the upfront fees that small volume residential customers pay in recognition of their expected lower consumption. Therefore, higher monthly customer charges coupled with upfront connection fees represent a clear, double counting of costs to connect such customers.

2. Electric Residential Rate Design

Q: Please describe PSE's current and proposed residential electric rate structure.

A: PSE's current residential electric rate structure consists of a fixed monthly customer charge ($6.02) and an inverted, two-block energy rate. Mr. Hoff proposes to increase the monthly customer charge by approximately 50 percent, from its current level of $6.02 to a proposed rate of $9.00 per month. Base rate residential energy charges are proposed to increase from 7.4314¢/kwh to 8.5225¢/kwh (14.7%) for the first 600 kwh of monthly usage and from 9.2122¢/kwh to 10.3033¢/kwh (11.8%) for all additional energy consumption.

Q: Earlier you discussed the Company's objective to collect a higher proportion of residential revenue from fixed monthly customer charges. Did Mr. Hoff conduct any analysis of what he considered to be customer costs?

A: Yes.

Q: Do you agree with Mr. Hoff's customer cost analysis?

A: No.

Q: Please explain why you do not agree with Mr. Hoff's customer cost analysis.

A: On page 15 of Exhibit No.___ (DWH-4C), Mr. Hoff presents a summary of the results of his customer cost analysis. A closer examination of Mr. Hoff's customer cost analysis reveals that he included provisions for various capital costs, including return and depreciation, and operating and maintenance expenses. However, Mr. Hoff's analysis inappropriately includes many costs that should not be deemed customer-related for purposes of evaluating the reasonableness of residential customer charges.

Q: Please identify those capital costs that Mr. Hoff included in his customer cost analysis.

A: Mr. Hoff's analysis includes the allocated residential gross plant investments in Meters ($73.7 million), Services ($168.2 million), Distribution Line Transformers ($250.5 million), and an allocated portion of General plant ($56.9 million).

Q: Are these rate base, or capital items, appropriately included in a customer cost analysis?

A: No. Investments in Meters and Services are often included in traditional customer cost analyses. However, as mentioned earlier and as will be discussed in more detail later, PSE's customer connection fees already contain a provision for service line investments.

Mr. Hoff's inclusion of Line Transformer costs is at odds with virtually every accepted industry standard and practice. During my twenty-eight year career and practice in the area of public utility ratemaking, I have never seen a customer cost analysis that includes line transformers. Indeed, virtually every manual and text on the subject of electric cost of service properly considers line transformers as demand-related. Mr. Hoff's rationale for inclusion of transformers in this case is solely due to the fact that every distribution customer is connected to a transformer and that, once installed, transformers represent a fixed cost of providing service to the customer or group of customers connected to the transformer. Although such logic is meaningless since this notion could be extended to all distribution lines, substation equipment, and even transmission lines, the fundamental reason that transformers should not be considered customer-related is because they are sized and installed based on peak load requirements. Transformers are installed to reduce distribution voltage and are limited in capacity based on the maximum load going through each transformer. If customers were simply connected to a distribution system with no loads, there would not be a need for transformers.

Finally, Mr. Hoff has included $56.9 million in General plant in his customer cost analysis. This General plant represents the Company's investment in corporate overhead required to provide electricity sales to customers. This General overhead is needed to support PSE's electric operations which is that of selling electricity. In fact, the level of General plant included Mr. Hoff's residential customer costs includes the following gross plant amounts:

Table 13
PSE General Plant Investment
($ Millions)

Land and Land Rights	$1.6
Structure & Improvements	$23.7
Office Furniture	$14.7
Transportation Equipment	$0.6
Stores Equipment	$0.1
Tools, Shop and Garage Equipment	$0.7
Laboratory Equipment	$1.5
Power Equipment	$0.1
Communications Equipment	$13.9
Miscellaneous Equipment	$0.1

As can be seen above, the vast majority of the General plant Mr. Hoff assigns to "customers" relates to corporate office buildings, furniture, and communications equipment. Because General plant represents the overhead investment required to conduct its public service obligations of selling electricity, such costs should not be considered in a customer cost analysis for purposes of justifying fixed customer charges.

Q: What Operations and Maintenance (O&M) expenses did Mr. Hoff include in his customer cost analysis?

A: Mr. Hoff's residential customer costs analysis includes allocations for Distribution Supervision and Engineering ($0.3 million), Meters Operations Expenses ($0.9 million), Customer Installation expenses ($1.7 million), Line Transformers Maintenance expenses ($0.2 million), Meters Maintenance expenses ($0.1 million), Customer Accounting Supervision ($0.1 million), Meter Reading ($11.5 million), Customer Records & Collections expenses ($13.7 million), and a provision for Administrative and General expenses ($11.9 million).

Q: Are each of these O&M expenses properly included in a customer cost analysis?

A: No. As can be observed from their descriptions, many of the O&M costs included by Mr. Hoff represent costs that are more appropriately considered demand-related (e.g., transformer expenses) or are general overhead expenses required in order to sell electricity. Meter Reading and Customer Records & Collections expenses are properly included in Mr. Hoff's customer cost analysis.

Q. What is your overall assessment of Mr. Hoff's residential customer costs analysis?

A. Mr. Hoff's residential customer cost analysis greatly overstates those costs that should be considered in establishing a reasonable fixed monthly customer charge. Because PSE is in the business of selling electricity and not in the business of simply connecting customers, only those costs that can be directly attributed to connecting and servicing a customer's account should be included in such analysis.

Q: Please explain PSE's electric line extensions policy for residential customers.

A: Electric Tariff G, Schedule 85 contains PSE's policy regarding line extensions and connection fees for new customers. In general, customers are charged a connection fee based on the following formula:

+ Primary Voltage Lines Extension Costs
+ Secondary Voltage Lines Extension Costs
+ Exceptional Transmission & Substation Costs
- Margin Allowance
= Line Extension Cost
+ Service Line Costs
= Total Cost to Customer

These line extension costs include, at a minimum, the estimated cost to install conductors (excluding service lines) and transformers. It should be noted that the margin allowance does not include service lines meaning that customers are responsible for the costs of installing service lines to their meters. Customers are charged a non-refundable connection charge for all service line costs, as well as the line extension costs above the prescribed margin allowance. Estimated construction costs differ for underground and overhead service while the margin allowance is constant for both underground and overhead customer service.

Q: How do these new customer connection fees relate to customer charges?

A: As discussed earlier, Mr. Hoff has included the Company's allocated investment in Services and Line Transformers in his customer cost analysis. Although the Company's Schedule 85 margin allowance may be sufficient to cover the costs associated with installing new transformers (or connecting to existing facilities), all new customers are charged the costs of labor and materials to install a service line. As such, a higher customer charge as proposed by Mr. Hoff represents a double cost to new customers.

Q: Have you conducted an electric residential customer direct cost analysis applicable to PSE?

A: Yes. I have conducted a direct customer cost analysis which is provided in Exhibit No. ___ (GAW-8) and results in a monthly customer cost of $3.30 at a 10.80 percent return on equity and $3.25 at a 9.25 percent return on equity. It should be noted that my direct customer analysis does not include Services investment for the reasons noted earlier in my testimony.

Q: Mr. Watkins, have you assessed the policy implications of Mr. Hoff's proposal to increase the monthly customer charge?

A: No. Public Counsel witness, Barbara Alexander, discusses various policy implications of increasing PSE's monthly residential customer basic charge in her direct testimony.

Q: Do you have any objections to the structures of PSE's residential rates?

A: No, I do not have any objections to the general structure of PSE's residential rates. In fact, PSE's inverted block rate structure sends efficient and proper pricing signals, particularly during periods of peak demand.

Q: What is your recommendation as to residential monthly customer charges for PSE in this case?

A: Given the results of my residential monthly direct customer cost studies indicating a monthly customer cost range from $3.25 to $3.30, and in consideration of rate continuity, I recommend that the current monthly customer charge of $6.02 be maintained.

Furthermore, I recommend the $6.02 residential monthly customer charge remain at the current level regardless of the overall level in revenue requirement that may be authorized by the Commission in this case.

Q: What is your recommendation for the usage element of residential rates?

A: As I stated earlier, I am not recommending any changes to the Company's energy usage blocks; i.e., the first block is 600 kwh and the second block for all additional kwh. I do recommend, however, that the ratio of the specific charges for these two blocks be maintained, since the Company has not provided any evidence in support of changing this ratio.

As such, any increase in residential revenue authorized by the Commission should be reflected in energy charges, and these energy charges should be increased by an equal percentage.

III. NATURAL GAS OPERATIONS

A. NATURAL GAS CLASS COST OF SERVICE

Q: Mr. Watkins did PSE employ the same general procedures to conduct its natural gas CCOSS as used for its electric study?

A: Yes. PSE used the same general computer model to conduct its gas CCOSS as it did for its electric CCOSS. PSE's natural gas CCOSS was conducted and sponsored by PSE witness Janet Phelps.

Q: Were you able to replicate Ms. Phelps's CCOSS results using your own computerized model?

A: Yes.

Q: Did you find Ms. Phelps's CCOSS study to be mathematically accurate?

A: Yes. However, I did discover what appears to be a slight oversight in Ms. Phelps's calculation of class rates of return at present rates.

Q: Please explain this slight oversight.

A: Ms. Phelps's Exhibit No. ___ (JKP-5), page 1, presents a summary of PSE's gas CCOSS excluding gas costs with Line 15 showing the resulting class rates of return at current rates. In calculating these class rates of return, Ms. Phelps included certain revenue-related expenses at proposed, not current, rates and conducted her allocations based on these proforma expenses at PSE proposed rate levels.[11] In an attempt to correct for these presumed oversights, Ms. Phelps then subtracted the expenses at proposed rate levels after all allocations had been made; i.e., she backed the proposed expense levels out for summary presentation purposes but not for allocating costs to individual classes. Because Ms. Phelps's CCOSS includes numerous "internal" or composite allocators based on previous account allocations, including those erroneous expense levels at proposed rates, certain specific rate base and expense items are incorrectly allocated to classes because the allocators for the accounts include a provision for expenses at proposed rate levels.

Q: Have you corrected for this apparent oversight?

A: Yes. ~~A replication of Ms. Phelps's CCOSS, corrected to exclude those revenue dependent expenses at proposed rate levels, and is provided above:~~ <u>This minor correction results in an immaterial difference as shown below:</u>

[11] These expenses, at proposed rate levels, reflect the additional amounts resulting from the Company's proposed revenue increase and include the incremental increases to: Federal Income Taxes ($19,012,582); "Other" Taxes ($2,181,139); WUTC Fees ($113,542); and, Uncollectibles ($154,417).

~~**Table 14**~~
~~**Gas CCOSS (at Current Rates) Incorporating Expense Oversight Adjustments**~~

~~Class~~	~~PSE CCOSS As Filed~~	~~PSE CCOSS Corrected For Expense Oversights~~
~~Residential (16, 23, 53)~~	~~6.18%~~	~~6.23%~~
~~Commercial & Industrial (31, 61)~~	~~4.08%~~	~~3.55%~~
~~Large Vol. (41)~~	~~15.96%~~	~~18.74%~~
~~Interruptible (85)~~	~~19.77%~~	~~23.61%~~
~~Limited Interruptible (86)~~	~~21.97%~~	~~26.42%~~
~~Non-Exclusive Interruptible (87)~~	~~4.97%~~	~~4.69%~~
~~Transport and Contracts~~	~~10.24%~~	~~11.42%~~
~~CNG~~	~~-14.23%~~	~~-19.86%~~
~~Rentals~~	~~-9.92%~~	~~-14.35%~~
~~Total Company~~	~~5.98%~~	~~5.98%~~

Table 14
Gas CCOSS (at Current Rates) Incorporating Expense Oversight Adjustments

Class	Operating Income: PSE As Filed	Operating Income: Corrected For Expenses	Rate Base: PSE As Filed	Rate Base: Corrected For Expenses
Residential (16, 23, 53)	$56,171,759	$56,171,790	$909,282,355	$909,282,284
Commercial & Industrial (31, 61)	12,724,166	12,726,426	311,614,874	311,609,632
Large Vol. (41)	6,374,954	6,374,278	39,932,031	39,933,599
Interruptible (85)	3,096,603	3,096,217	15,663,138	15,664,036
Limited Interruptible (86)	1,798,694	1,798,520	8,187,623	8,188,026
Non-Exclusive Interruptible (87)	1,429,584	1,429,108	28,757,555	28,758,660
Transport and Contracts	1,385,521	1,385,237	13,533,683	13,534,340
CNG	<62,500>	<62,512>	439,245	439,274
Rentals	<2,180,152>	<2,180,434>	21,984,537	21,985,190
Total Company	$80,738,630	$80,738,630	$1,349,395,041	$1,349,395,041

Q: ~~**Did Ms. Phelps also inappropriately allocate class income taxes at current rates based on rate base (investment) rather than calculate income taxes for each class?**~~ **Did Ms. Phelps allocate class income taxes at current rates in the same manner as Mr. Hoff did for PSE's Electric Operations?**

A: ~~Yes.~~ No. Whereas Mr. Hoff allocated income taxes based on total rate base. Ms. Phelps utilized a different approach to allocate income taxes at current rates. Ms. Phelps allocated individual class income taxes based on each class' proportional relationship of revenues minus operating expenses (including depreciation) to total Company (gas) revenues minus operating expenses. While Ms. Phelps' method of allocating income taxes based on revenue minus operating expenses is far superior to Mr. Hoff's method, she did not reflect or consider a major income tax depreciation: interest expense. I have calculated each class's income tax responsibility consistent with the method used in my electric CCOSS.

Q: Please provide a summary of class rates of return after correcting for Ms. Phelps's improper allocation of income taxes at current rates.

A: Building upon my previous adjustment (to correct for expense levels at proposed rates) the following results are obtained:

Table 15
Gas CCOSS (at Current Rates)
Incorporating Expense Oversight
and Income Taxes Adjustments

Class	ROR
Residential (16, 23, 53)	6.13%
Commercial & Industrial (31, 61)	4.59%
Large Volume (41)	13.31%
Interruptible (85)	16.10%
Limited Interruptible (86)	17.71%
Non-Exclusive Interruptible (87)	5.24%
Transport and Contracts	9.10%
CNG	-8.85%
Rentals	-5.68%
Total Company	5.98%

1. Separate Allocation of Mains to Large Customers

Q: What methodology does Ms. Phelps use to allocate distribution Mains to the various customer classes?

A: Ms. Phelps has employed two separate allocation methods to assign Mains cost responsibility to the various customer classes. Under Ms. Phelps's approach, distribution Mains investment is first allocated to the firm portion of PSE's largest customers taking service under Rate Schedules 85, 87, 57 and Special Contracts, using one methodology, while all other customers are then assigned cost responsibility for Mains based on the Peak and Average method.

Q: Mr. Watkins, on pages 31 through 33 of her direct testimony, Ms. Phelps refers to a direct assignment of Mains plant to the largest customers who are served on Schedules 85, 87, 57, and Special Contracts. Is Ms. Phelps's reference to this "direct assignment" of Mains to PSE's largest customers the same as your reference to the separate allocation method used for certain Rate Schedules 85, 87, 57, and Special Contract customers?

A: Yes. However, it should be clearly understood that the cost responsibility assigned to these largest customers is anything but a direct assignment of Mains plant. Rather the cost responsibility assigned to these customers is the result of a separate "special" allocation procedure. Indeed, and as I will explain later in my testimony, this special allocation for PSE's largest customers involves a much higher degree of uncertainty, assumptions, and allocations than does the Peak and Average approach used to allocate Mains costs to all other PSE customers.

Q: Notwithstanding Ms. Phelps's characterization of a direct assignment of Mains plant to PSE's largest customers, do you have any concerns or criticisms of the

overall approach Ms. Phelps used to allocate PSE's investment in distribution Mains to all customer classes?

A: Yes. I have three areas of concern and criticism regarding the Company's allocation of distribution Mains. These are: (1) the special treatment (allocation) of PSE's largest customers; (2) the use of minimum monthly usages for interruptible customers in assigning the "average" portion of the Peak and Average allocation of Mains; and, (3) the Company's biased and inaccurate allocation of peak day load to individual classes based on an adjusted design day demand.

Q: Please outline the basic approach used by Ms. Phelps to conduct her special allocation of Mains to PSE's largest customers.

A: Ms. Phelps has utilized a modified version of a natural gas computer model developed for engineering analyses, known as "SynerGEE." The general concept behind PSE's special allocation is that gas flowing from the City Gate to each large customer's meter is traced given assumed load levels throughout the entire PSE distribution system. Each large customer's load is estimated over the modeled path (from the City Gate to the customer's meter) such that the customer in question is allocated costs in proportion to its estimated load relative to the total load in each of the segments of the modeled path. To estimate the customer's load contribution on various pipe segments, SynerGEE allows for the segmentation of PSE's Distribution system. The basic concept of this system segmentation can be seen schematically in my Exhibit No.___ (GAW-9) which is a reproduction of a schematic provided by PSE in response to Public Counsel Data Request No. 625. Using "Customer 6" as an example, various pipe segments are established from this customer's meter to the PSE City Gate.

Q: What concerns and criticisms do you have regarding this special allocation of Distribution Mains for PSE's largest customers?

A: I have three areas of concern regarding this approach being used for ratemaking purposes. My first two concerns are conceptual in nature, while my third involves the practical accuracy of this approach.

The first conceptual concern I have regarding PSE's special allocation method is that as a matter of regulatory ratemaking policy, all analyses should be reasonably transparent so that all assumptions, mechanics, and procedures can be explained and verified. Such is not the case with this special allocation method. Indeed, this procedure produces a black box output such that the Company has conducted analyses that require a myriad of input assumptions and calculations that cannot be verified. I will discuss some of these assumptions later under my third practical concern over this allocation approach.

My second concern is by far the most important from a ratemaking policy perspective and that is the need and/or desire to afford special discriminatory treatment to one group of customers at the expense of other customers absent any compelling reason to do so.

PSE's special allocations to its large customers "skeletonizes" the PSE Distribution system such that costs are assigned to a particular customer based on that customer's physical geographic location relative to the PSE system as a whole. In other words, the closer a customer happens to be to the City Gate, the fewer costs are assigned to this customer because this customer is only assigned costs based on the pipes upstream from its physical location. The classic analogy to this skeletonization approach is a private lane through a neighborhood, with a homeowner closer to the public road arguing that he or she should only be responsible for costs from the public road to his or her driveway and that homeowners further down the private lane should bear more cost responsibility for maintenance and upkeep of this private lane.

There are two fatal flaws with this reasoning as applied to public utility ratemaking. The first is that under such thinking the customer must assume that the distribution system was built and sited to specifically accommodate this one customer. That is, the physical pipe locations were installed to connect this one customer to the City Gate (source of supply). For example, consider Customers 4 and 6 in Exhibit No. ___ GAW-9). Under this approach, Customer 6 would be allocated fewer costs than Customer 4 (assuming they were the same size) simply because of the physical configuration of PSE's routing of Distribution Mains. If PSE rerouted any upstream Mains pipes, this customer's responsibility for costs could change dramatically.

The second fatal flaw with a skeletonization approach is that these customers receive all of the benefits of PSE's economies of scale and scope and apply these economies only to a self-serving portion of the system. Put succinctly, under this approach, selected customers are allocated per unit (average) costs that are the result of system economies but do not equitably share in all costs of the system that make these per unit (average) costs possible. Indeed, the most basic concept of a regulated utility's granted monopoly status is that societal costs and individual consumers' costs are lower with a single company servicing the collective needs of all consumers.

The concept of skeletoniztion has been addressed extensively in economic literature as well as in the Courts in the arena of anti-trust and undue price discrimination. The economic standard applied in these situations is a customer's stand-alone cost. That is, stand-alone costs are those costs that a customer would incur to design, construct, and operate a system to serve only itself, without enjoying any of the other benefits of an integrated system serving multiple customers.

Q: Please discuss your third concern which you referred to as practical in nature.

A: PSE's application of the modified SynerGEE model required a myriad of assumptions. Notwithstanding the inability to verify each of the assumptions which I discussed earlier, there are several assumptions required for this analysis that are clearly questionable as they relate to the allocation of cost responsibility.

Although Ms. Phelps claims on page 32 of her direct testimony that the SynerGEE model "was run to simulate the entire distribution system under design day conditions," the SynerGEE model itself is somewhat static in that it measures loads at particular points in time. This is of critical importance because, under a "design day" situation, loads vary throughout the day due to differences in customer demands for gas throughout the day. On such a design day, residential customer demands would increase in the morning and fall somewhat during the middle of the day as households are at work and the ambient temperature increases. Residential loads will then increase in the early evening hours and decline again later at night. Commercial loads tend to follow a similar, yet delayed diurnal pattern. As such, the PSE system load is not constant throughout the entire design day. However, the SynerGEE model requires assumed loads at all nodes. In the PSE application of the SynergGEE model, it is not known what point in time these loads are intended to represent. Nor is it known what loads are assumed to exist at each nodal end point. For example, the maximum diurnal load in a commercial/industrial area of PSE's system will peak at a different time than that for residential areas of the system. The assumptions used for these various geographic areas are critical to the ultimate costs allocated under this approach.

A second practical concern of this approach is the underlying assumption that the PSE system contains no excess capacity for future expansion or growth. Indeed, much of PSE's Distribution system was put into service many years ago when the total system loads were smaller. PSE prudently planned for this growth such that the distribution Mains particularly its trunk lines, now serve much higher demands. These demands will continue to grow as new customers are added to the PSE system. Yet the same Mains currently in service will continue to serve all customers in the future. Finally, as I will discuss later in my testimony, PSE's estimation of class contributions to design day demands are questionable at best.

To run the SynerGEE model, PSE's system must be "loaded" at a prescribed level of demand. It has been represented by PSE that this level of loading is that for PSE's design day. Because the demographics of the Company's service area vary significantly, PSE's questionable assumptions as to design day loads for particular segments of the distribution system are most suspect. In fact, Ms. Phelps developed class contributions to design day demand independently. It is my understanding that Ms. Phelps had no input as to the assumptions used to run SynerGEE for this application. Therefore, it is not known what individual loads were used in the "Special" allocation of Mains to PSE's larges gas customers, let alone whether or not they are reasonable.

Q: What is your recommendation with regards to the special allocation used to assign Mains to PSE's largest customers?

A: This special allocation should be rejected and not considered by the Commission. There is no compelling reason, other than a desired end result, to treat PSE's largest customers any differently than all other retail customers.

Q: How does your rejection of PSE's special allocation for its largest customers affect your CCOSS analysis?

A: I have treated these large customers' firm loads in the same manner as all other firm customers and incorporated these contributions to peak load directly in my Peak and Average Mains allocator.

Q: What are the CCOSS results with this adjustment?

A: Building upon my previous adjustments to Ms. Phelps's CCOSS, incorporating the Peak and Average method used to allocate Mains to all customer classes produces the following results at current rates:

Table 16
Gas CCOSS (at Current Rates)
Incorporating Expense Oversight, Income Taxes, and
Peak and Average Method Adjustments

Class	ROR
Residential	6.14%
Commercial & Industrial	4.16%
Large Volume	13.33%
Interruptible (85)	15.18%
Ltd. Interruptible (86)	17.72%
Non-Exclusive Interruptible (87)	4.80%
Transportation	9.03%
CNG	-8.85%
Rental	-5.68%
Total Company	5.98%

2. Peak and Average Classification

Q: Before continuing with your next disagreement and adjustment to PSE's CCOSS, please explain the Company's Peak and Average method further.

A: As discussed previously, and but for Ms. Phelps's special allocation of Mains to the largest customer' firm loads, the Company has utilized the Peak and Average method to allocate distribution Mains investments. As the name implies, this method allocates Mains costs partially on the basis of peak day demand and partially on the basis of average day demand (usage). It is noted that average day use is the exact same as annual throughput (usage) in relative terms. That is, class contributions to average daily use are the same as class contributions to annual use. In the application of the Peak and Average method, Ms. Phelps has elected to utilize PSE system load factors as a basis to classify this allocator between peak (demand) and average demand (throughput).[12] Ms. Phelps's load factor approach results in a distribution Mains classification of 67 percent peak day and 33 percent average day.

Q: Are there accepted ways to classify distribution Mains between Peak and Average other than the load factor approach?

A: Yes. Many utilities and cost analysts classify natural gas distribution Mains as 50 percent peak-related and 50 percent average-related. The rationale behind this 50/50 split between peak day demand and average usage (throughput) is that an equal weighting strikes a reasonable balance between the fact that a local distribution company (LDC) system is constructed and in place to serve usage requirements of customers throughout the year, yet Mains are also physically sized to meet current and future peak load requirements.

[12] Load factor is the ratio of average daily demand to peak day demand.

Q: Are there a priori ramifications of using an equal weighting of 50 percent Peak day and 50 percent Average day versus the load factor approach to classify Mains?

A: Yes. The equal weighting method invariably allocates fewer costs to low volume, low load factor customers, and more costs to large volume, high load factor customers than does the load factor approach of classifying Mains utilized by PSE.

3. Treatment of Interruptible Volumes

Q: Please explain your disagreement with Ms. Phelps as it relates to her treatment of interruptible customers for the allocation of distribution Mains.

A: Because of curtailment possibilities, there is no question that interruptible service is of a lesser quality that firm service. As a result of this lower quality of service, questions arise regarding what level of cost responsibility should be assigned interruptible customers. At one extreme is the belief that interruptible customers should not be assigned any Mains cost responsibility because the distribution system is claimed to be designed only to meet firm loads, even though these customers may use these Mains virtually every day of the year. At the other extreme is the thought that interruptible service should be treated the same as firm customers so long as there are no curtailments due to constraints of the local distribution system. That is, many natural gas LDCs have sufficient distribution system capacity to meet all loads, firm and interruptible, each and every day of the year.

To strike a balance between these two extremes, interruptible customers are usually assigned some, but not a full share, of distribution Mains costs in order to recognize the lesser quality of interruptible service. Although Ms. Phelps has assigned a minimal level of Mains-related cost responsibility to interruptible customers, her approach leans heavily towards the no cost responsibility view.

Remembering that Ms. Phelps has classified distribution Mains as 67 percent peak day related and 33 percent average day (throughput) related, she then assigned zero peak day responsibility to interruptible loads (i.e., 67% times 0% cost responsibility). With respect to the average portion of this method, Ms. Phelps did not use the average or total usage throughout the year for interruptible customers, but rather the minimum monthly usage times 12 months, i.e., (33% times [minimum monthly usage times 12 months]). In my opinion, Ms. Phelps's approach represents a clear bias with the objective to shift cost responsibility away from interruptible customers.

Consider for example that Ms. Phelps assigns 67 percent of Mains investment based on peak day demand, while interruptible loads are assumed to not have any cost responsibility for this "peak" portion of Mains. Thus, for the remaining 33 percent, she lowers interruptible customers' responsibility even more by not using annual usage, but rather minimum monthly usage times 12.

Q: What is your recommendation as to the assignment of distribution Mains cost responsibility to interruptible customers in this case?

A: Although it is common practice to utilize an equal weighting between Peak day and Average day demands, I have accepted the Company's load factor approach in this case. Furthermore, I assign no interruptible cost responsibility to the peak portion of the Peak and Average method to recognize the lower quality of non-firm service. However, I have incorporated interruptible customers' average daily usage (throughput) in the average component of the Peak and Average allocation method. In my opinion, my treatment strikes a balance between firm and interruptible customers that is more than fair to non-firm customers.

Q: Please provide a summary of class rates of return with your recommended allocation of Mains, incorporating your adjustments for interruptible customers' average, not minimum monthly usage.

A: Building upon my previous CCOSS adjustments, the following class rates of return are obtained at current rate levels:

Table 17
Gas CCOSS (at Current Rates)
Incorporating Table 16 and
Interruptible Customer Usage Adjustments

Class	ROR
Residential	6.27%
Commercial & Industrial	4.73%
Large Volume	13.97%
Interruptible (85)	11.20%
Ltd. Interruptible (86)	18.86%
Non-Exclusive Interruptible (87)	3.18%
Transportation	4.67%
CNG	-8.87%
Rental	-5.68%
Total Company	5.98%

4. Design Day versus Actual Peak Day

Q: What definition of peak day demand has PSE used for purposes of its proposed CCOSS?

A: As discussed on pages 28 through 30 of her direct testimony, Ms. Phelps has used a design day concept to measure peak day demand.

Q: Has the Commission rejected this design day concept in prior PSE rate cases?

A: Yes, that is my understanding. In previous cases, this issue has been explored in great detail. It is my understanding that this Commission has historically relied upon actual peak day volumes, rather than hypothetical design day volumes, for CCOSS purposes.

Q: Please explain how Ms. Phelps developed her design day demands for the PSE system as well as individual class contributions to this design day level.

A: Ms. Phelps started with a total PSE system design day demand and then used a top-down approach to estimate class contributions to this system design day demand.

Q: How did Ms. Phelps estimate her PSE system design day demand?

A: It is my understanding that Ms. Phelps was not responsible for the development and estimation of PSE's system design day demand. Rather, this total system estimate was provided to her by the Company's forecasting department.

Q: On pages 28 and 29 of her direct testimony, Ms. Phelps indicates that the system design day is based on 52 heating degree days, as explained in the Company's 2007 Integrated Resource Plan. Does the PSE system design day demand used by Ms. Phelps match the design day demand contained in the Company 2007 IRP?

A: No.

Q: Why not?

A: It is my understanding that the PSE system design day demand used by Ms. Phelps in this case was adjusted to reflect the test year proforma mix and level of customers.

Q: Please continue with your explanation of how Ms. Phelps developed class contributions to this adjusted system design day demand.

A: As indicated earlier, Ms. Phelps used a top-down approach, such that she started with the total system design day demand provided to her by the forecasting department, and then allocated this total system amount to individual customer classes.

Ms. Phelps's starting point was the large volume customer classes (Rate Schedules 85, 86, and 87). By utilizing their billed demand during the system peak month in 2007, Ms. Phelps assumed that these customers' demands would be the same under design day conditions as under actual, historical conditions. In other words, Ms. Phelps assumed no weather sensitivity for these customers. Next, Ms. Phelps estimated the design day demand for Commercial Schedule 50 customers (Compressed Natural Gas), incorporating a similar approach as used for Rate Schedules 85, 86, and 87 customers, except that actual average day usage during the 2007 peak month was used since there is no billing demand associated with Rate Schedule 50. After, the above classes' contributions to the design day demand were calculated, the residual (remaining) system design day load was allocated proportionally based on average daily usage in the peak month to the Residential (Rate Schedule 23) and Small Commercial/Industrial (Rate Schedule 31) classes.

Q: Does Ms. Phelps's allocation of adjusted system design day demand to individual classes produce realistic results?

A: In my opinion, no. Under Ms. Phelps's approach, she assumed that all usage above the actual 2007 amount is solely attributable to the Residential and Small Commercial/Industrial classes. While I would agree that these two customer classes tend to be the most weather sensitive, it is shortsighted to assume that other classes have virtually no weather sensitivity, particularly at an extreme design day average temperature of 13 degrees Fahrenheit.[13]

Q: Is there any evidence to suggest that large volume commercial and industrial customers have some weather sensitive characteristics in their natural gas consumption patterns?

A: Yes. As part of her filed workpapers, Ms. Phelps provided test year weather normalized monthly usages by rate class. The following are the monthly usages for the large volume user classes. Please note that I have sorted these usages from the spring to the winter:

Table 18
Weather Normalized Monthly Usage

	Rate Schedule		
Month	85	86	87
April 2007	1,394	1,478	3,134
May 2007	1,149	1,083	2,656
June 2007	849	626	2,127
July 2007	764	450	878
August 2007	798	461	1,752
September 2007	932	670	1,884
October 2006	1,307	1,324	3,035
November 2006	1,502	2,127	3,599
December 2006	1,766	2,430	4,312
January 2007	1,779	2,337	4,047
February 2007	1,612	2,018	3,611
March 2007	1,657	1,957	3,654

It is clear from the above data that a significant portion of these large volume customers' loads are weather sensitive and therefore, would increase significantly under extreme design day temperatures.

[13] PSE's design day temperature is 52 heating degree days. Heating degree days are defined as a base of 65 degrees minus the average of high and low temperature for the day. Thus, 65-52=13 degrees average daily temperature.

Q: In view of the shortcomings of Ms. Phelps's design day analysis, have you conducted an analysis of peak day demands by class?

A: Yes. In accordance with what I understand to be prior Commission practice, I have estimated class contributions to actual system peak day loads. These system peak day loads represent the average of the five highest daily send outs occurring during the most recent three years which were provided in response to Public Counsel Data Request No. 657.

Q: Please provide a comparison of the estimated system design day demand as used by Ms. Phelps to the average of the five highest actual system peak day demands during the last three years.

A: [Begin Confidential]

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[End Confidential]

Q: Please explain how you calculated individual class contributions to this actual firm peak day demand.

[14] **[Begin Confidential]**XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXX. **[End Confidential]**

A: Remembering that Ms. Phelps's assignments of design day demands to the large volume classes are based on actual test year experience, I accepted these levels since my system peak day amount is also based on actual experience. After these large volume contributions were determined, only Residential and Small Commercial/Industrial (Schedule 31) loads remained. I allocated this residual to these two classes in proportion to each class's average usage in the peak month. In other words, I used the same method as employed by Ms. Phelps to estimate class contribution to peak day demand.

Q: Please provide a comparison of Ms. Phelps's design day based on your actual peak day load factors.

A: **[Begin Confidential]** XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX XXXXXXXXX

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[**End Confidential]**

Q: Did you adjust Ms. Phelps's CCOSS to reflect actual system peak day demands?

A: Yes.

Q: Please provide a summary of CCOSS results incorporating actual system peak day loads.

A: Building upon my previous adjustments to Ms. Phelps's CCOSS, the following class rates of return results with the incorporation of actual system peak demands:

Table 23
Gas CCOSS (at Current Rates)
Incorporating All Public Counsel Adjustments

Class	ROR
Residential	6.62%
Commercial/Industrial (31)	5.01%
Large Volume (41)	10.64%
Interruptible (85)	7.44%
Limited Interruptible (86)	14.60%
Non-Exclusive Interruptible (87)	0.95%
Transportation & Contracts (57)	2.27%
CNG (50)	-8.78%
Rentals	-5.68%
Total System	5.98%

These class rates of return reflect my recommended CCOSS findings. The details of my CCOSS are provided in Exhibit No.___ (GAW-10).

B. NATURAL GAS CLASS REVENUE DISTRIBUTION

Q. How did Ms. Phelps determine her proposed distribution of PSE's requested gas revenue increase to individual customer classes?

A. Ms. Phelps discusses her proposed class distribution of the overall gas revenue increase of $56.77 million to individual customer classes beginning on page 43 of her direct testimony. Ms. Phelps states that the results of her cost of service study is the "Company's best indicator of what it costs to serve each class of customer." Accordingly, she uses these results to formulate her rate spread to customer classes. While she states the Company's long-term goal is to move customer class rates of return toward cost of service levels, Ms. Phelps indicates that moving all the way to cost-based rates in a single step would cause unreasonably large impacts on certain customers. In this regard, Ms. Phelps proposes to allocate a "relatively larger portion of the revenue increase to those classes with current parity ratios below 100 percent."

A summary of PSE's proposed revenue increase for each customer class is shown below:

Table 24
PSE Proposed Gas Revenue Increase[15]

Class	Income Amount	Percent Margin Increase
Residential	$38,682,592	17.06%
Commercial & Industrial	16,178,327	24.74%
Large Volume	127	0.00%
Interruptible	-146	0.00%
United Interruptible	-302,266	-8.53%
Non-Exclusive Interruptible	1,242,877	21.42%
Transportation & Contracts	558,839	14.27%
Compressed Natural Gas	5,074	17.54%
Rentals	404,902	5.20%
Total Company	$56,770,327	17.02%

Q. **Are PSE's proposed customer class revenue increases reasonable for its gas operations?**

A. No, they are not.

Q. **Mr. Watkins, do you have an alternative gas revenue increase distribution to that proposed by Ms. Phelps?**

A. Yes. Based on the results of my CCOSS, presented in Exhibit No.___ (GAW-10), and considering the principle of gradualism, I propose the following gas revenue increase distribution at PSE's requested overall revenue level:

[15] *See* Ms. Phelps direct testimony, Exhibit No. ___(JKP-10), page 1, columns M and N. Note that Ms. Phelps's total increase of $56,770,327 is not exactly the same as the level proposed for overall revenue requirement purposes of $56,770,922 due to Ms. Phelps' application of her proposed rates multiplied by billing determinants. This difference is attributable to Ms. Phelps's ultimate rounding of proposed distribution rates.

Table 25
Public Counsel Revenue Distribution
at PSE Proposed Gas Revenue Increase

Class	Amount	Percent Margin Increase
Residential	$36,493,752	16.10%
Commercial & Industrial	13,914,794	21.28%
Large Volume	1,168,693	8.51%
Interruptible	948,869	14.47%
Limited Interruptible	0	0.00%
Non-Exclusive Interruptible	1,383,297	23.83%
Transportation & Contracts	865,122	22.13%
Compressed Natural Gas	7,388	25.54%
Rentals	1,989,015	25.54%
Total Company	$56,770,930	17.02%

In formulating my proposed gas revenue increase distribution to the various customer classes, I began with the results of my CCOSS, which is presented in Exhibit No. ___ (GAW-10). With the results of my CCOSS as a guide, I proceeded in a similar manner as I did for PSE's electric operations. That is, I formulated increases consistent with my CCOSS results that provides for the movement to equal rates of return (parity) for all classes. My specific methodology is discussed narratively below with the actual calculation provided in Exhibit No.___ (GAW-11):

(1) I propose no increase to Limited Interruptible (Schedule 86) since this customer class exhibits the highest rate of return (14.60%) compared to the system average rate of return of 5.98% and is currently providing a ROR exceeding PSE's proposed overall ROR on rate base of 8.60%;

(2) I increased Large Volume (Schedule 41) at 50% of the system average percentage increase because this customer class has the next highest ROR (10.64%) at almost twice the system average rate of return (5.98%);

(3) I increased Interruptible (Schedule 85) at 85% of the system average percentage increase as this class's rate of return at current rates of 7.44% is also in excess of the system average rate of return of 5.98%, but below that of the 8.60% overall ROR requested by PSE;

(4) I increased Commercial & Industrial (Schedules 31 and 61) at 125% of the system average increase because this class's rate of return of 5.01% is less than the system average ROR at current rates;

(5) I increased Transportation & Contracts (Schedule 57 and Special Contracts) at 130% of the system average percentage because this class is only producing a current ROR of 2.27% and is the second lowest class rate of return compared to the system average rate of return of 5.98%;

(6) I increased Non-Exclusive Interruptible (Schedule 87) at 140% of the system average because their rate of return is even lower than for the Transportation & Contracts class;

(7) I increased both Compressed Natural Gas and Rentals at 150% of system average percentage increase since these classes are achieving the lowest rates of return at current rates of -8.78% and -5.68%, respectively; and,

(8) Finally, I treated the Residential class (Schedules 16, 23 and 53) as the residual to recover the remainder of the required revenue increase.

My recommended distribution results in an increase to the Residential class of 94.6 percent of the system average percentage increase. This relative percentage increase of 94.6 percent of system average is appropriate and reasonable since this class is currently earning somewhat in excess of the system rate of return; i.e., 6.62 percent compared to 5.98 percent.

Q. Does your proposed revenue distribution move all classes towards rate of return parity?

A. Yes. As shown below, and calculated on page 1 of Exhibit No.___ (GAW-11), my proposed class revenue assignment moves all classes closer to rate of return parity.

Table 26
Indexed ROR
at PSE Proposed Gas Revenue Increase

Class	At Current Rates	At Public Counsel Proposed Rates
Residential	111%	107%
Commercial & Industrial	84%	92%
Large Volume	178%	142%
Interruptible	124%	113%
Limited Interruptible	244%	170%
Non-Exclusive Interruptible	16%	32%
Transportation & Contracts	38%	51%
Compressed Natural Gas	-147%	-90%
Rentals	-95%	-1%
Total Company	100%	100%

Q: Mr. Watkins, please provide your recommended scale back method to assign class natural gas revenue increases should the Commission authorize an overall revenue requirement increase less than that proposed by PSE.

A: I recommend that my customer class revenue increase distribution be scaled back in equal portions (i.e., equal percentages) should the Commission authorize an overall electric revenue increase different than that requested by PSE.

C. NATURAL GAS RESIDENTIAL RATE DESIGN

Q: Please describe PSE's current and proposed residential natural gas rate structure.

A: Currently, PSE's residential natural gas base rates include a fixed monthly customer charge of $8.25, a flat delivery (distribution charge) of $0.30039/therm and a "new" customer delivery charge applicable to certain new customers ranging from $0.11/therm to $0.17/therm. Ms. Phelps proposes to increase the fixed monthly customer charge to

$18.00 (118% increase) and decrease the flat distribution charge to $0.22510 (25% decrease).

Q: Did Ms. Phelps conduct a residential customer cost analysis similar to that performed by Mr. Hoff?

A: Yes.

Q: Please comment on Ms. Phelps's residential customer cost analysis.

A: Ms. Phelps conducted an analysis that portrays the monthly residential customer cost to be $18.39. The results of Ms. Phelps's customer cost analysis is summarized on page 4 of her Exhibit No.___ (JKP-5). A closer examination of Ms. Phelps's study revealed that many costs included in her determination of the monthly $18.39 amount cannot be deemed directly customer-related. To illustrate, of the $75.2 million of Intangible plant that Ms. Phelps assigned to the residential class, $56.2 million is deemed customer-related and included in her customer cost analysis. Similarly, of the $79.2 million in total General plant assigned to the residential class, Ms. Phelps's customer cost study portrays $51.7 million to be customer-related and included in this analysis. Examples of Ms. Phelps's improper assignment of expenses to residential customer costs include all of Informational and Instructional Advertising ($0.4 million), $59.9 million in Administrative and General expenses (out of a total $80.0 million allocated to the residential class), and $0.7 million in increased Excise Tax associated with the Company's proposed rate increase. Overall, of the $909.3 million of total Rate Base allocated to the residential class, Ms. Phelps included $410.3 million as part of Residential customer costs. With respect to expenses, Ms. Phelps' CCOSS allocates

$161.1 million in total expenses (excluding income taxes) to the residential class. Of this $161.1 million, Ms. Phelps includes $98.3 million in her customer cost analysis.

In summary, Ms. Phelps has greatly overstated customer costs by including costs not required to connect customers or maintain customer accounts, but are rather general overhead costs.

Q: Please explain PSE's natural gas line extension and new customer connection policy.

A: PSE's Natural Gas Schedule 7 (Facilities Extension Standards), coupled with its Natural Gas Rule No. 7 (Extension of Distribution Facilities-Other than the Kittitas County), and sets forth the terms and pricing structure for new customer connections.

PSE's connection pricing methodology is based on a philosophy that small volume customers will utilize the Company's system less than similar, yet larger, usage customers. The Company's connection pricing method recognizes that the volume of natural gas used by small customers may not be sufficient to recover the investment required to add these customers to the system. In other words, PSE must install a service line, meter (and base) and regulator for every new customer. If a prospective customer is only planning to use natural gas, example as a decorative fireplace, this customer will not generate enough base rate (non-gas or margin) future revenue over time to justify the Company's investment. Conversely, a prospective customer who will use natural gas for space heating, hot water heating, and cooking will use substantially more gas and provide significantly more base rate revenue to PSE, thereby justifying PSE's investment to add this customer.

PSE's Rule 7 provides the formulaic cost/benefit method used to evaluate whether each new customer will or will not provide enough future revenue to recover the investment required to connect the perspective customer. If a new customer is not expected to consume enough gas (and hence, generate revenue) to justify the incremental costs to add this customer, this customer will be required to make an upfront cash contribution to PSE. Furthermore, depending on the specific differences between the expected connection costs and future revenues (i.e. benefits), the customer may pay an upfront cash contribution and agree to pay a "new customer" surcharge on gas used for a period of up to five years.

Q: What criteria are used to evaluate whether a potential customer will or will not use enough natural gas to justify the costs of connecting this customer?

A: The cost/benefit method outlined in Natural Gas Schedule 7 provides various usage allowances based on the number and type of natural gas appliances installed in a customers house. For customers who use natural gas for space heating, an allowance is given based on the square footage of the customer's home. Specific usage allowances are also given for water heaters, cooking ranges, clothes dryers, hot tubs, and fireplaces. These allowances represent the "benefits" portion of this method. Natural Gas Schedule 7 also provides a schedule of specific incremental costs considered in PSE's cost/benefit method. These costs include a flat cost per foot to extend any Mains ($40.79), a fixed cost to run a Service line ($3,026), a fixed cost for a new meter ($132), and a provision for annual Operating and Maintenance expenses ($48.00).

Q: You mentioned a surcharge imposed on certain new customers. What is the current structure and level of this surcharge?

A: Depending on the expected level of revenue shortfall from PSE's cost/benefit analysis, as well as the upfront cash contribution made by the customer, the monthly "new customer" residential surcharge imposed is either $0.115/therm or $0.17/therm for all gas consumed each month. This surcharge is in addition to the base rate distribution usage charge of $0.30039/therm and in addition to the monthly fixed customer charge of $8.25.

Q: What are the ratemaking implications of PSE's connection polices?

A: First, it is obvious that PSE recognizes customers do not connect to its gas distribution system simply for the sake of being connected. Rather, customers join the Company's system in order to consume gas. More importantly, PSE's cost/benefit methodology recognizes that expected revenue is a function of a customer's usage rather than of a customer simply being connected to the system. This realistic understanding—that revenue contributions are, and should be, a function of usage—dovetails with my earlier discussion that prices should reflect variability in usage rather than fixed per customer amounts. Such a pricing structure is not only the most efficient but also the fairest to all customers in that customers pay in relation to the level of gas consumed.

Q: If a customer is charged an up front connection fee and/or a new customer surcharge, will this customer be overcharged if fixed monthly customer charges are increased?

A: Yes. Connection fees and new customer surcharges represent a payment to PSE to compensate the Company for the costs of installing services lines and costs associated with metering and regulating equipment. If customer charges are increased or designed to also recover the costs of Services, Meters and other expenses, the customer will be double-charged: once for the connection and/or "new customer" surcharge and again for the ongoing monthly customer charge that must be paid.

Q: Is the proper solution to this double payment problem the abandonment of connection fees?

A: No. Although PSE's line extension and customer polices (Schedule 7 and Rule 7) are admittedly complicated and even perhaps self-serving to the Company, they do provide pricing and costing signals that are in the best interest of PSE and all of its customers. As I explained earlier, there is no doubt that there are circumstances in which it is neither beneficial to PSE nor its existing customers to extend service to a customer that will have little or no gas consumption.

The more appropriate solution is to maintain a pricing policy for PSE's recurring revenues that is volumetrically based and with a minimum level of customer charges.

Q: Mr. Watkins, your discussion thus far has been limited to new customers on the PSE system. Do these circumstances and concepts apply to existing customers as well?

A: Yes. First, it is well recognized that pricing should be forward looking. Therefore, recognition of how new customers affect costs and revenue collection is an important point to consider in establishing pricing policies for all customers.

Second, PSE is a relatively young and rapidly growing gas distribution company. This growth has occurred for several years and will undoubtedly continue in the foreseeable future.

Third, existing customers, like new customers, are not connected to the PSE system simply for the sake of being connected, but rather because they desire to use gas throughout the year. PSE's service lines and meters were not installed simply to enable this connection, but rather to serve as the means of enabling customers the ability to purchase or transport gas. As such, service lines are merely an extension of PSE's Distribution Mains with the primary difference being one of accounting nomenclature because service lines are typically located on customer owned property.

Q: What ramifications do these factors have on determining a reasonable fixed monthly customer charge for PSE's residential rates?

A: Given PSE's new customer connection policies and pricing methodology, the relatively young age of the PSE system, its level of growth, recognition that service lines represent an extension of distribution Mains, and most importantly, that efficient and fair pricing dictates volumetric based rates, PSE's natural gas fixed monthly customer charges should remain at their current levels regardless of any increase in overall revenue requirement authorized by this Commission.

Q: Have you conducted an analysis to determine if PSE's current residential customer charges are reasonable?

A: Yes. Similar to the direct customer cost analysis I conducted for PSE's electric operations, I have also conducted an analysis of the Company's residential gas customer costs that should be considered in evaluating the reasonableness of fixed monthly customer charges.

Q: Mr. Watkins, does your analysis include the policy implications of increasing PSE's natural gas fixed monthly customer charges?

A: No. In her direct testimony, Public Counsel witness, Barbara Alexander, discusses various potential policy implications of increasing PSE's monthly basic charge for residential gas customer.

Q: Please explain your natural gas Residential customer cost analysis.

A: Exhibit No. ___ (GAW-12) presents the results of my residential natural gas customer cost analysis.

Q: Please explain your residential natural gas customer cost analysis.

A: The direct customer costs provided on page 1 of Exhibit No.___ (GAW-12) include those rate base and expense items required for each customer connection as well as those required to maintain a customer's account. In recognition of PSE's connection fees and new customer surcharges and the concepts enumerated earlier, I have excluded Services investment from my analysis shown on page 1, and excluded all rate base items on page 2. The results of these analyses indicate a monthly customer cost in the range of $4.25 to $7.48 using PSE's requested return on equity, and $4.25 to $7.24 at a 9.25 percent cost of equity.

Q: Mr. Watkins, are there other reasonable ways to evaluate customer costs while at the same time recognize PSE's customer connection policies?

A: Yes. Considering that PSE recognizes a customer's desired use of facilities in order to consume natural gas, another reasonable method is to include the costs required to maintain a customer's account plus a provision for depreciation on the assets employed to render service. In this manner, depreciation expense represents a return of the investment to connect the customer and thus, provides for the replacement of such facilities. Profit (return) on the assets is then recovered from volumetric usage charges, which recognizes the utilization of these assets.

Q: Have you conducted an analysis such as you just described?

A: Yes. Exhibit No.___ (GAW-13) presents this analysis in which a depreciation allowance is provided for all investments required to connect a customer but excludes profit (return) for the reasons discussed. This analysis also includes all direct Operating and Maintenance expenses required to maintain a customer's account. This customer cost analysis results in a monthly customer cost of $7.23.

Q: Should the Commission authorize higher or lower revenue than that proposed by you or the Company, how should PSE's residential rates be established?

A: I recommend that PSE's current residential monthly customer charge of $8.25 be maintained regardless of the change in revenue authorized by the Commission. As such, any required change in residential revenue should be derived from the volumetric distribution charge.

IV. PSE SUPPLEMENTAL FILING

Q: Does PSE offer revised class revenue distribution proposals that incorporate the Company's supplemental request for an overall revenue requirement increase above those contained in its original December 31, 2007 filing?

A: Yes. Revised class revenue distribution proposals appear in David Hoff's prefiled supplemental testimony relating to PSE's electric operations, identified as Exhibit No.___ (DWH-8T), and in Janet Phelps's prefiled supplemental testimony concerning the Company's natural gas operations, identified as Exhibit No.___ (JKP-14T).

Q: Please explain Mr. Hoff's and Ms. Phelps's modified class revenue distribution proposals that incorporate PSE's proposed additional overall increases in requirement provided in the Supplemental testimonies of John Story.[16]

A: Mr. Hoff and Ms. Phelps both utilized the same methodologies employed in their initial filings to distribute the Company's latest proposed revenue requirement for its electric

[16] Exhibit No.___(JHS-9T) and Karl Karzmar, Exhibit No.___(KRK-7T).

and natural gas operations. I discussed Mr. Hoff's and Ms. Phelps's class revenue distribution methodologies earlier in my testimony.

Q: Do Mr. Hoff's and Ms. Phelps's supplemental testimonies effect your class revenue distribution proposals in any way?

A: No. As discussed earlier, my proposals (for purposes of the dollar amounts provided and discussed in revenue distribution) are based on the amounts PSE requested in its initial filing and provide an "apples to apples" comparison of the Company's and my proposals. Recognizing that the Commission may ultimately authorize an overall revenue requirement different than that proposed by PSE, I have provided a method by which my revenue distribution proposals should be applied to a different overall change in revenues.

Q: Does this complete your direct testimony?

A: Yes.