BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

V.

PUGET SOUND ENERGY,

Respondent.

DOCKETS UE-190529 & UG-190530 (*Consolidated*)

RESPONSE TESTIMONY OF GLENN A. WATKINS (GAW-1T)
ON BEHALF OF THE
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL,
PUBLIC COUNSEL UNIT

EXHIBIT GAW-1T

November 22, 2019

DOCKETS NOS. UE-190529 and UG-190530 (*Consolidated)*

RESPONSE TESTIMONY OF GLENN A. WATKINS

EXHIBIT GAW-1T

TABLE OF CONTENTS

DOCKETS NOS. UE-190529 and UG-190530 (*Consolidated)*

RESPONSE TESTIMONY OF GLENN A. WATKINS

EXHIBIT GAW-1T

TABLES

DOCKETS NOS. UE-190529 and UG-190530 (*Consolidated)*

RESPONSE TESTIMONY OF GLENN A. WATKINS

EXHIBIT GAW-1T

EXHIBITS LIST

Exhibit No. GAW-2:	Background & Experience Profile
Exhibit No. GAW-3C:	PSE Wind/Hydro Production during Peak Hours
Exhibit No. GAW-4C:	Assignment of Capital Costs to Hours for Probability of Dispatch
Exhibit No. GAW-5:	Assignment of Hourly Costs to Classes for Probability of Dispatch
Exhibit No. GAW-6:	PSE Probability of Dispatch Class Cost of Service Study
Exhibit No. GAW-7:	PSE Base-Intermediate-Peak Classification
Exhibit No. GAW-8:	PSE Base-Intermediate-Peak Class Cost of Service Study
Exhibit No. GAW-9:	Electric Residential Customer Cost Analysis
Exhibit No. GAW-10:	PSE Change in Mains Allocation from "Compromise" to PSE Proposed Approach
Exhibit No. GAW-11:	Natural Gas Residential Customer Cost Analysis
Exhibit No. GAW-12:	PSE Responses to Public Counsel Data Request Nos. 157, 162, 163, 164, 168, 170, and 172

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. What is your professional and educational background?

A. I am President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with an office in Hanover, Virginia. 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 39-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada. I have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. This experience includes serving as a witness for the Public Counsel Unit of the Washington State Office of the Attorney General ("Public Counsel") in several proceedings before this Commission. In addition, I have provided expert testimony before state and federal courts as well as before state legislatures. I provide a more complete description of my education and experience in Exhibit No. GAW-2.

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

A. Public Counsel retained Technical Associates 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 ("rate spread"), 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 Public Counsel.

Q. Please summarize your findings and recommendations.

A. With regard to the Company's electric operations, I have conducted alternative class cost of service studies and concluded that the Company's study provides reasonable results. While I agree with the Company's general framework concerning electric rate spread, the application of this framework is too narrowly defined such that I recommend somewhat different class revenue increases than the Company. Concerning Residential rate design, I agree with the Company to maintain the existing fixed monthly customer charge but disagree with the Company's proposal to place the entire Residential increase in the second energy block and recommend that any increase in the Residential revenue requirement be spread proportionally between the first and second energy rates.

With regard to the Company's natural gas operations, PSE proposes material changes to the manner in which distribution mains are allocated. I recommend the Commission reject these changes and recommend a somewhat different class revenue distribution than that proposed by PSE. Concerning Residential rate design, PSE proposes a fixed monthly customer charge of $11.52, while I recommend this charge be set at $11.20 per month.

Q. Please explain how your direct testimony is structured.

A. In addition to this introduction, I have separated my direct testimony into two sections: Electric Operations and Natural Gas Operations. For each operational section, I have three subsections entitled: Class Cost of Service, Class Revenue Distribution ("Rate Spread"), and Residential Rate Design. My analyses and testimony are based on the Company's initial filing dated June 20, 2019 as well as its supplemental filing and direct testimony dated September 17, 2019.

II. ELECTRIC OPERATIONS

A. Electric Cost of Service

Q. Please briefly explain the concept of a class cost of service study (CCOSS) and its purpose in a rate proceeding.

A. Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of the Washington Utilities and Transportation Commission (WUTC), PSE has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expenses are incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular 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 to that customer or group in the CCOSS. Since most of the utility's costs of providing service are jointly incurred to serve all or most customers, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although cost analysts strive to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors and must be subjectively assigned or allocated to customer rate classes. With regard to those costs which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor (e.g., peak demand, energy usage, number of customers, etc.).

Q. In your opinion, how should the results of a CCOSS be utilized 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 individual costs. These disagreements can and do arise due to the quality of data and level of detail available from financial records. There are also fundamental differences in opinions regarding the cost causation factors that should be considered to properly allocate costs to rate schedules or customer classes. Furthermore, and as mentioned previously, numerous subjective decisions are required to allocate the myriad of jointly incurred costs.

In this regard, 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 only as a guide, with the results being used as one of many tools to assign class revenue responsibility when cost causation factors cannot be realistically ascribed to certain costs.

Q. Have the higher courts opined on the usefulness of cost allocations for purposes of establishing revenue responsibility and rates?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (the predecessor to FERC), the United States Supreme Court stated:

> But whereas here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

Q. Does your opinion, and the findings of the U.S. Supreme Court, imply that cost allocations should play no role in the ratemaking process?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible approaches may produce significantly different results. In this regard, when all reasonable cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of reasonable cost allocation approaches show dramatically different results than another

[1] *Colorado Interstate Gas Co. v. Fed. Power Comm'n*, 324 U.S. 581, 65 S. Ct. 829, 89 L. Ed. 1206 (1945).

reasonable approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

Q. Before you discuss specific cost allocation methodologies, please explain how generation and production-related costs are incurred. In doing so, please explain the cost causation concepts relating to generation and production resources.

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which facilities are serving which customers. As such, production facilities are joint costs, i.e., they are used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate ("load") throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kilowatt-hour (kWh) would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that PSE experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, not all customer classes contribute in equal proportions to these varying demands placed on the generation system. Further complicating matters, the electric utility industry is unique in that there tends to be a distinct energy/capacity trade-off relating to production costs. That is, utilities generally design their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there is enough available capacity to meet peak demands.[2] The trade-off occurs between the level of fixed investment per unit of capacity kilowatt (kW) and the variable cost of producing a unit of output (kWh). Coal and nuclear units require high capital expenditures resulting in large investments per kW, whereas smaller units with higher variable production costs generally require significantly less investment per kW. Due to varying levels of demand placed on the system over the course of each day, month, and year there is a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy (i.e., its cost of service).

Therefore, as a result of the energy/capacity cost trade-off, and the fact that the service requirements of each utility are unique, many different allocation methodologies have evolved in an attempt to equitably allocate joint production costs to individual classes.

Q. Please explain.

A. Total production costs vary each hour of the year. Theoretically, energy and capacity costs should be allocated to customer classes every hour of the year. This would result in 8,760 hourly allocations. Although such an analysis is certainly possible with today's technology, hourly supply (generation) and demand (customer load) data is required to conduct such hour-by-hour analyses. While most utilities can and do record hourly production output, they often do not estimate class loads on an hourly basis (at least not for every hour of the year). With these constraints in mind, several allocation methodologies have been developed to allocate electric utility generation plant

[2] In recent years, many utilities are required to also incorporate generation facilities that reduce carbon emissions and/or utilize renewable resources in their generation portfolios that may not be the most efficient from a cost minimization perspective.

investment and attendant costs. Each of these methods has strengths and weaknesses regarding the reasonableness in reflecting cost causation.

Q. Approximately how many cost allocation methodologies exist relating to the allocation of generation plant?

A. The current National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual[3] discusses at least 13 embedded demand allocation methods, while Dr. James Bonbright notes the existence of at least 29 demand allocation methods in his treatise Principles of Public Utility Rates.[4]

Q. Please identify the common generation cost allocation methodologies.

A. Common generation cost allocation methodologies include Single Coincident Peak, Four Coincident Peak, Summer and Winter Coincident Peak, 12 Coincident Peak, Peak and Average, Average and Excess, Base-Intermediate-Peak, Probability of Dispatch, and Peak Credit (Equivalent Peaker) approach. I will discuss each of these methodologies in my testimony.

Q. Briefly discuss the strengths and weaknesses of the Single Coincident Peak methodology.

A. The basic concept underlying the Single Coincident Peak method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. As such, advocates of the Single Coincident Peak method reason that customers (or classes) should be responsible for fixed capacity costs based on their respective contributions to this peak system load. The major advantages to the Single Coincident Peak method are

---

[3] Staff Subcommittees on Electricity and Economics, Nat'l Ass'n of Regulatory Util. Comm'nrs, Electric Utility Cost Allocation Manual (1992).
[4] James C. BonBright et al., Principles of Public Utility Rates at 495 (2d ed. 1988).

that the concepts are easy to understand, the analyses required to conduct a CCOSS are relatively simple, and the data requirements are less significant than some more complex methods.

The Single Coincident Peak method has several shortcomings, however. First, and foremost, is the fact that the Single Coincident Peak method ignores the capacity/energy trade-off inherent in the electric utility industry. That is, under this method, the sole criterion for assigning 100 percent of fixed generation costs is the classes' relative contributions to load during a single hour of the year. This method does not consider, in any way, the extent to which customers use these facilities during the other 8,759 hours of the year. This may have severe consequences because a utility's planning decisions regarding the amount and type of generation capacity to build and install is predicated not only on the maximum system load, but also on how customers demand electricity throughout the year, i.e., load duration.

To illustrate, if a utility such as PSE had a peak load of 4,000 mW and its actual optimal generation mix included an assortment of coal, hydro, combined cycle, and combustion turbine units, the total cost of capacity is significantly higher than if the utility only had to consider meeting 4,000 mW for one hour of the year. This is because the utility would install the cheapest type of plant (i.e., peaker units) if it only had to consider one hour a year.

There are two other major shortcomings of the Single Coincident Peak method. First, the results produced with this method can be unstable from year to year. This is because the hour in which a utility peaks annually is largely a function of weather. Therefore, annual peak load depends on when severe weather occurs. If this occurs on a weekend or holiday, relative class contributions to the peak load will likely be significantly different than if the peak occurred during a weekday. The "free ride" problem is another major shortcoming of the Single Coincident Peak method. A summer-peaking utility that peaks at about 5:00 p.m. clearly illustrates this problem. Because street lights are not on at this time of day during summer months, this class will not be assigned any capacity costs and will, therefore, enjoy a "free ride" on the assignment of generation costs that this class requires.

Q. Briefly discuss the strengths and weaknesses of the Four Coincident Peak Method.

A. The Four Coincident Peak method is identical in concept to the Single Coincident Peak method except that the analysis relies on the peak loads during the highest four months. This method generally exhibits the same advantages and disadvantages as the Single Coincident Peak method. As a result, it is no more reasonable to use the Four Coincident Peak method versus the Single Coincident Peak method.

Q. Briefly discuss the strengths and weaknesses of the Summer and Winter Peak Method.

A. The Summer and Winter Coincident Peak method was developed because some utilities' annual peak load occurs in the summer during some years and in the winter during others. Because customers' usage and load characteristics may vary by season, the Summer and Winter Coincident Peak attempts to recognize this. This method is essentially the same as the Single Coincident Peak method except that two hours of load are considered instead of one. This method has essentially the same strengths and weaknesses as the Single Coincident Peak method, and in my opinion, is no more reasonable than the Single Coincident Peak method.

Q. Briefly discuss the strengths and weaknesses of the 12 Coincident Peak Method.

A. Arithmetically, the 12 Coincident Peak method is essentially the same as the Single Coincident Peak method except that class contributions to each monthly peak are considered. Although the Twelve Coincident Peak method bears little resemblance to how utilities design and build their systems, the results produced by this method better reflect the cost incidence of a utility's generation facilities than does the Single Coincident Peak or Four Coincident Peak methods.

Most electric utilities have distinct seasonal load patterns such that there are high system peaks during the winter and summer months, and significantly lower system peaks during the spring and autumn months. By assigning class responsibilities based on their respective contributions throughout the year, consideration is given to the fact that utilities will call on all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods. Therefore, the capacity/energy trade-off is implicitly considered to some extent under this method.

The major shortcoming of the 12 Coincident Peak method is that accurate load data is required by class throughout the year. This generally requires a utility to maintain ongoing load studies. However, once a system is in place to record class-by-class load data, the administration and maintenance of such a system is not overly cumbersome for larger utilities.

Q. Briefly discuss the strengths and weaknesses of the Peak and Average methodology.

A. The various Peak and Average methodologies rest on the premise that a utility's actual generation facilities are placed into service to meet peak load <u>and</u> serve consumers demands throughout the entire year. Hence, the Peak and Average method assigns capacity costs partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year. Although there is not universal agreement on how to measure peak demands or how the weighting between peak and average demands should be performed, most electric Peak and Average studies use class contributions to coincident-peak demand for the "peak" portion and weight the peak and average loads based on the system coincident load factor. The system load factor often represents the portion assigned based on consumption (average demand).

The major strengths of the Peak and Average method are that an attempt is made to recognize the capacity/energy trade-off in the assignment of fixed capacity costs, and that data requirements are minimal.

Although the recognition of the capacity/energy trade-off is admittedly arbitrary under the Peak and Average method, most other allocation methods also suffer some degree of arbitrariness. A potential weakness of the Peak and Average method is that a significant amount of fixed capacity investment is allocated based on energy consumption, with no recognition given to lower variable fuel costs during off-peak periods.

To illustrate this shortcoming, consider an off-peak or very high load factor class. This class consumes a constant amount of energy during the many cheaper off-peak periods. As such, this class will be assigned a significant amount of fixed capacity costs, while variable fuel costs will be assigned on a system average basis. This can result in an overburdening of costs if fuel costs vary significantly by hour. However, if the consumption patterns of the utility's various classes are such that there is little variation between class time differentiated fuel costs on an overall annual basis, the Peak and Average method can produce fair and reasonable results.

Q. Briefly discuss the strengths and weaknesses of the Average and Excess method.

A. The Average and Excess method also considers both peak demands and energy consumption throughout the year. However, the Average and Excess method is much different than the Peak and Average method in both concept and application. The Average and Excess method recognizes class load diversity within a system, such that not all classes call on the utility's resources to the same degree, at the same times. Mechanically, the Average and Excess method weights average and excess demands based on system coincident load factor. Individual class "excess" demands represent the difference between the class non-coincident peak demand and its average annual demand. The classes' "excess" demands are then summed to determine the system excess demand. Under this method, it is important to distinguish between coincident and non-coincident demands. This is because if coincident, instead of non-coincident, demands are used when calculating class excesses, the result will be the same as that achieved under the Single Coincident Peak method.

Although the Average and Excess method bears virtually no resemblance to how generation systems are designed, this method can produce fair and reasonable results for some utilities. This is because no class will receive a “free-ride” under this method, and because recognition is given to average consumption as well as to the additional costs imposed by not maintaining a perfectly constant load.

A potential shortcoming of this method is that customers that only use power during off-peak periods will be overburdened with costs. Under the Average and Excess method, off-peak customers will be assigned a higher percentage of capacity costs because their non-coincident load factor may be very low even though they call on the utility's resources only during off-peak periods. As such, unless fuel costs are time differentiated, this class will be assigned a large percentage of capacity costs and may not receive the benefits of cheaper off-peak energy costs. Another weakness of the Average and Excess method is that extensive and accurate class load data is required.

Q. Briefly discuss the strengths and weaknesses of the Base-Intermediate-Peak method.

A. The Base-Intermediate-Peak method, also known as a production stacking method, explicitly recognizes the capacity and energy tradeoff inherent with generating facilities and specifically recognizes the mix of a particular utility's resources used to serve the varying demands throughout the year. The Base-Intermediate-Peak method classifies and assigns individual generating resources based on their specific purpose and role within the utility's actual portfolio of production resources and also assigns the dollar amount of investment by type of plant such that a proper weighting of investment costs between expensive base load units relative to inexpensive peaker units is recognized within the cost allocation process.

A major strength of the Base-Intermediate-Peak method is explicit recognition of the fact that individual generating units are placed into service to meet various needs of the system. Expensive base load units with high capacity factors run constantly throughout the year to meet the energy needs of all customers. These units operate during all periods of demand including low system load as well as during peak use periods. Base load units are, therefore, classified and allocated based on their roles within the utility's portfolio of resource, i.e., energy requirements.

At the other extreme are the utility's peaker units that are designed, built, and operated only to run a few hours of the year during peak system requirements. These peaker units serve only peak loads and are, therefore, classified and allocated on peak demand.

Situated between the high capacity cost/low energy cost base load units and the low capacity cost/high energy cost peaker units are intermediate generating resources. These units may not be dispatched during the lowest periods of system load but, due to their relatively efficient energy costs, are operated during many hours of the year. Intermediate resources are classified and allocated based on their relative usage to peak capability ratios, i.e., their capacity factor.

Finally, hydro units are evaluated on a case-by-case basis. This is because there are several types of hydro generating facilities including run of the river units that run most of the time with no fuel costs, and units powered by stored water in reservoirs that operate under several environmental and hydrological constraints including flood control, downstream flow requirements, management of fisheries, and watershed replenishment. Within the constraints just noted and due to their ability to store potential energy, these units are generally dispatched on a seasonal or diurnal basis to minimize short-term energy costs and assist with peak load requirements. Pumped storage units are unique in that water is pumped up to a reservoir during off-peak hours (with low energy costs) and released during peak hours of the day. Depending on the characteristics of a unit, hydro facilities may be classified as energy-related (e.g., run of the river), peak-related (e.g., pumped storage) or a combination of energy and demand-related (traditional reservoir storage).

The weakness of the Base-Intermediate-Peak method is the same as under other methods where no recognition is given to potentially lower variable fuel costs during off-peak periods.

Q. Briefly discuss the strengths and weaknesses of the Probability of Dispatch method.

A. The Probability of Dispatch method is the most theoretically correct and most equitable method to allocate generation costs when specific data is available. Under this approach, each generation asset (plant or unit) is evaluated on an hourly basis for every hour of the year. Each generating asset's capital costs are assigned to individual hours based upon how that individual plant is dispatched or utilized. As such, investment or capital costs are distributed based on how a particular plant is actually utilized. For example, the investment costs associated with base load units, which operate almost continuously throughout the year, are spread throughout several hours of the year while the investment cost associated with individual peaker units which operate only a few hours during peak periods are assigned to only a few peak hours of the year. The hourly capacity costs for each generating asset are summed to develop hourly investments. These hourly investments are then assigned to individual rate classes based on hourly class contributions to system load. As such, the Probability of Dispatch method requires a significant amount of data such that hourly output from each generator is required as well as detailed class load studies encompassing each hour of the year (8,760 hours).

Q. Briefly discuss the strengths and weaknesses of the Peak Credit (also known as Equivalent Peaker).

A. The Peak Credit method is more commonly known as the Equivalent Peaker approach. This method combines certain aspects of traditional embedded cost methods with those used in forward-looking marginal cost studies. The Peak Credit method relies on planning information to classify individual generating units as energy or demand-related and considers the need for a mix of base load intermediate and peaking generation resources.

This method has substantial intuitive appeal in that it attempts to capture a surrogate for the marginal cost of electricity production. However, the major shortcomings of this method are that a hypothetical peaker unit must first be selected with assumed levels of investment costs, operating and fuel costs, levels of dispatch throughout a year, forecasts of future fuel and operating costs, and assumed levels of capital costs and inflation rates. As a result, the assumptions and inputs are not known with certainty and are often the source of considerable controversy.

Q. Mr. Watkins, you have discussed the strengths and weaknesses of the more common generation allocation methodologies. Are any of these methods clearly inferior in your view?

A. Yes. In my opinion, the Single Coincident Peak and seasonal Coincident Peak (such as Four Coincident Peak) methods do not reasonably reflect cost causation for integrated electric utilities because these methods totally ignore the utilization of a utility's facilities.

Consider that the methodology selected is used to allocate generation plant investment. Generation investment costs vary from a low of a few hundred dollars per kW of capacity for high operating cost (energy cost) peakers to several thousand dollars per kW for base load facilities with low operating costs. If a utility were only concerned with being able to meet peak load with no regard to operating costs, it would simply install inexpensive peakers. Under such an unrealistic system design, plant costs would be much lower than in reality, but variable operating costs (primarily fuel costs) would be astronomical and would result in a higher overall cost to serve customers. The Single Coincident Peak and seasonal Coincident Peak methods totally ignore this very important fact.

Q. What cost allocation methodology did PSE's witness Mr. Jhaveri utilize to allocate generation plant costs within his CCOSS?

A. Mr. Jhaveri utilized the long-standing approved Peak Credit method to allocate PSE's generation assets.

Q. Does Mr. Jhaveri's Peak Credit approach used in this case differ from the Peak Credit classifications in previous PSE cases?

A. In some regards, yes. As discussed on pages 10 through 12 of his direct testimony, Mr. Jhaveri's Peak Credit approach now includes the social costs of carbon within the development of the Peak Credit classification between demand and energy. This revision increased the energy/demand split from approximately 81 percent energy/19 percent demand without recognition of carbon costs to 89 percent energy/11 percent demand with recognition of carbon costs.

Q. With regard to Mr. Jhaveri's 11 percent demand-related generation costs, how did he allocate this amount to individual classes?

A. Mr. Jhaveri allocated the 11 percent demand component of generation costs based on class contributions to the average of the four highest system coincident peak demands (4-CP).

Q. Does this differ from the demand allocation used for several years?

A. Yes. Although the settlement in Docket No. UE-141368 required the use of the 4-CP method in the Company's 2017 General Rate Case, the top 75 hours of CP demands were utilized for several cases before that case.

Q. Do you agree with Mr. Jhaveri's utilization of the 4-CP method to allocate the demand component of generation plant?

A. Yes. In my opinion, when the 4-CP approach is applied with the method that separates generation costs between energy and demand, it is a reasonable approach to reflect cost causation. With regard to the prior practice of utilizing a demand allocator based on the top 75 hours of load, I agree with Mr. Jhaveri that "the use of so many hours tends to blur the lines between demand and energy."[5]

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

A. In conducting my independent analysis, I reviewed the structure and organization of the Company's CCOSS and examined 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 to specific rate base, revenue, and expense accounts. I then verified the accuracy of PSE's CCOSS model by replicating its results using my own computer model. Finally, I adjusted certain aspects of the Company's study to better reflect cost causation and cost incidence by rate schedule and customer class.

[5] Direct Testimony of Birud D. Jhaveri, Exh. BDJ-1T at 16:5-6.

Q. With regard to Mr. Jhaveri's supplemental CCOSS utilizing the peak credit method, do you have disagreements with his allocation of individual rate base or operating income accounts?

A. Yes, albeit minor. Before I discuss my specific disagreements, recall that many joint or common costs cannot be ascribed to a specific cost causation factor. This is particularly true for the Company's overhead costs, including general plant and administrative and general expenses. For example, Mr. Jhaveri allocated working capital based on total plant in service, whereas it is perhaps more common to assign working capital costs across classes based on O&M expenses. I conducted sensitivity analyses utilizing alternative allocators for various overhead and plant costs and have found no material difference in the overall results. As such, I accept Mr. Jhaveri's selection of allocators by account with the exception of those discussed below.

My first disagreement with Mr. Jhaveri's selection of allocators relates to the assignment of income taxes. With regard to Federal income taxes, Mr. Jhaveri allocated income taxes at current rates based on each class' total rate base. This calculation does not reflect an accurate portrayal of each class' contribution to profitability at current rates since income taxes are a function of current revenues minus expenses, rather than allocated rate base.[6] In conducting my analyses at current rates, I have calculated each class' income tax responsibility based on current revenues minus current expenses minus interest expense, which provides a more accurate portrayal of income tax responsibility.

[6] However, in determining individual class revenue requirements, it is acceptable to allocate income taxes to classes based on rate base since the required operating income is a direct function of allocated rate base.

This can readily be understood by evaluating a hypothetical with two classes: one class in which the calculated operating income before income taxes is exceptionally high (resulting in a high before-tax ROR) and, another in which the operating income before income taxes is exceptionally low (resulting in a low before-tax ROR). If one were to assume each class had the same level of rate base, Mr. Jhaveri would assign the same level of income tax responsibility to each class even though the low ROR class may actually have negative taxable income at current rates. Despite the difference, there is little impact in rate class parity ratios[7] as a result of our disagreement in determining the income tax responsibility.

My second disagreement relates to Mr. Jhaveri's allocation of fuel costs wherein he classified and allocated these variable costs as 11 percent demand-related and 89 percent energy-related. It is well known and universally accepted that generation fuel costs are variable in nature and are 100 percent energy-related, as these costs vary directly with the energy produced throughout the year.

[7] Parity ratio is the ratio of each class' current revenue to cost ratio divided by the system current revenue to cost ratio.

Q. In PSE's last general rate case (Docket No. UE-170033), the Company's CCOSS witness, Jon Piliaris provided rebuttal testimony (Exhibit JAP-46CT)[8] criticizing your opinion that fuel costs should be classified and allocated as 100 percent energy-related as it concerns the Company's Peak Credit CCOSS. Please respond to Mr. Piliaris' criticism.

A. First, Mr. Piliaris acknowledged that fuel costs are 100 percent energy-related wherein he stated, "While it is difficult to dispute the fact that, on a stand-alone basis, fuel is almost exclusively energy-related, ..."[9] However, Mr. Piliaris did provide his opinion as to why fuel costs should be classified and allocated as partially demand-related and partially energy-related within the context of the Peak Credit methodology.[10]

In consideration of the Company's rebuttal testimony in the last case, I agree that there is merit to this argument as it relates only to the Peak Credit methodology. However, this logic and approach does not apply to other cost allocation methods I performed for this case; i.e., Probability of Dispatch and Base-Intermediate-Peak.

As will be discussed later in my testimony, I have conducted time differentiated fuel cost analyses for of the alternative CCOSS methods I have performed for this case.

---

[8] Rebuttal Testimony of Jon A. Piliaris, Exh. JAP-46CT, *WUTC v. Puget Sound Energy* (2017) (Dockets UE-170033 & UG-170034).
[9] *Id.* at 28:17-18.
[10] *Id.*, Mr. Piliaris stated:

> [C]arving out one component of power costs for distinct and separate treatment is contrary to the theory behind, and application of, the peak credit methodology. Recall that the peak credit methodology compares the levelized cost of a peaking unit to that of a baseload unit to derive a relationship that is meant to be reflective of the proportion of overall production costs that should be considered demand-related. The levelized costs of the generic units compared include fuel expense. Therefore, fuel costs should be included among those to which the peak credit results would apply and separating these costs for unique treatment is inconsistent with the application of the methodology [29:7-15].

Q. Please explain your other disagreements with Mr. Jhaveri's selection of allocators for specific accounts.

A. My final disagreements with Mr. Jhaveri's selection of allocators for specific accounts relate to state excise taxes (Account 236.02) and WUTC fees (Account 928). These two cost items are a direct function of revenues. However, Mr. Jhaveri allocated state excise taxes at current rates based upon a close approximation of each class' revenue requirement.[11] As is the case with Mr. Jhaveri's calculation of income taxes at current rates, my disagreement is not material so long as the Commission relies upon class parity ratios instead of class RORs at current rates since the calculated state excise taxes at the Company's requested ROR is about the same under both approaches.

With regard to WUTC fees, it is my understanding that the Commission assesses these fees based on revenues. However, Mr. Jhaveri allocated this expense account based on total production, transmission, and distribution expenses. It is more appropriate to base the allocation factor on rate revenues.

Q. Do your corrections and minor disagreements with Mr. Jhaveri's Peak Credit study result in any material change to class parity ratios?

A. No. Table 1 below provides a comparison of class parity ratios under Mr. Jhaveri's supplemental CCOSS as well as that modified for the changes discussed above:

[11] Specifically, Mr. Jhaveri allocated state excise taxes at current rates based upon total O&M expense plus depreciation expense plus <u>required</u> return on rate base at the Company's proposed level.

TABLE 1
Peak Credit CCOSS Comparison
Utilizing 89% Energy/11% Demand
Parity Ratios

Rate Schedule	Class	Jhaveri Supplemental	PC Corrected
7	Residential	97%	96%
24	Secondary Voltage <50kw	105%	106%
25/29	Secondary Voltage >50kw and <350kw	106%	107%
26	Secondary Voltage >350kw	106%	107%
31	General Service-Primary	102%	103%
35	Irrigation	55%	52%
43	Interruptible Electric Schools	88%	87%
	Special Contract	99%	100%
46/49	High Voltage	106%	107%
448/449/459	Choice/Retail Wheeling/Back-Up	88%	88%
50/59	Lighting	94%	93%
5	Firm Resale	50%	47%
Total Company		100%	100%

Q. Have you conducted alternative studies that may more accurately represent the capacity and energy trade-offs exhibited in PSE's actual generation plant investment?

A. Yes. Although there is no single, or absolute, correct method to allocate joint generation costs, some methods are superior to others. As such, the results of multiple, yet reasonable, methods should be considered in evaluating class profitability as well as class revenue responsibility.

In my opinion, the Probability of Dispatch and Base-Intermediate-Peak methods more accurately reflect the capacity/energy tradeoffs that exist within an electric utility's generation-related costs. This is particularly true and important for PSE given the large amount of investment in generation provided from hydroelectric and wind facilities, as well as its investment and generation provided from the Colstrip generating units.

The importance of considering PSE's wind and hydro generation is that these types of generation are not always available to meet system load due to various constraints. For example, wind generation is only available when weather conditions allow. Similarly, hydro generation is often subject to several environmental constraints including water levels, river flow, fish and wildlife regulations, etc.

Indeed, I evaluated the amount of PSE's wind generation available at various peak periods. PSE is invariably a winter peaking utility. In response to Public Counsel Data Request Nos. 162 and 163,[12] the Company provided hourly system demands and hourly generation by unit, respectively, for 2018. During this period, wind generation operated at only a 21 percent capacity factor during the highest annual 25 hours of system peak demand. At the same time, the Company's hydro facilities only operated at about 63 percent of capacity during these 25 hours of peak demand. Exhibit No. GAW-3C contains details supporting these observations. Therefore, while the Company's wind and hydro units produced a considerable amount of energy throughout the year, these facilities cannot be fully relied upon to meet system load in any given hour.

Conversely, PSE's ownership in the Colstrip generating units provides customers with relatively inexpensive variable fuel costs such that these units are considered base load facilities. Finally, PSE owns and operates numerous gas and oil fired generating facilities including combined cycle and combustion turbine units – some of which operate on an intermediate basis, while others are generally dispatched for a few hours of the year during peak demand periods.

[12] The narrative responses to these requests are provided in my Exhibit No. GAW-12. Please note that the data provided in the attachments to these responses is extremely voluminous and are not included in Exhibit No. GAW-12.

Taking all of this into consideration, I conducted alternative CCOSS that recognize the actual configuration, dispatch, utilization, and investment of PSE's generating resources utilizing the Base-Intermediate-Peak and Probability of Dispatch methods.

1. Probability of Dispatch Method

Q. Please explain how you conducted your CCOSS utilizing the Probability of Dispatch method.

A. As discussed earlier, the Probability of Dispatch method is the most theoretically correct methodology to assign embedded (historical) generation plant investment. However, the data required to utilize this methodology is often not available because this approach requires detailed hourly output data for each generating facility as well as hourly class loads. In this case, PSE provided both of these critical data sets. As such, I was able to conduct CCOSS utilizing the Probability of Dispatch method.[13]

The first step in conducting the Probability of Dispatch method is to assign individual generating plant investments to specific hours. In accordance with the procedures set forth in the NARUC: Electric Utility Cost Allocation Manual,[14] each plant's total gross investment, accumulated depreciation, and depreciation expense was assigned pro-ratably to each hour of the year based on each respective unit's load (output) in that hour. My Exhibit No. GAW-4C[15] provides three pages of these hourly assignments. It should be noted that this exercise actually assigns costs to every hour of

[13] While it is my preference to rely upon multiple years of data in conducting Probability of Dispatch analyses (due to the possibility of abnormally mild or severe weather patterns), the Company does not have class hourly load data for 2017. Therefore, I relied exclusively upon 2018 test year data for my analysis.
[14] Staff Subcommittees on Electricity and Economics, Nat'l Ass'n of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual at 62 (1992).
[15] Glenn A. Watkins, Exh. GAW-12 at Puget Sound Energy's response to Public Counsel Data Request No 163.

the year; however, my Exhibit No. GAW-4C only encompasses several of the first hours in the test year to avoid an Exhibit exceeding 250 pages. My filed workpapers contain the details of this assignment for every hour of the test year. Page one of Exhibit No. GAW-4C provides the assignment of gross plant, while page two of this Exhibit details the assignment of each plant's depreciation reserve and page three provides details of the assignment of each plant's depreciation expense. This separate assignment between gross investment, depreciation reserve, and depreciation expense was performed due to the possibility of differences in the net book value of PSE's various generation facilities (i.e., some units may be more fully depreciated than others).

Once I determined hourly capital costs, I was able to assign these costs to individual rate classes on an hour-by-hour basis. As indicated earlier, PSE provided individual class loads for each hour of the test year in response to Public Counsel Data Request No. 162. As such, I multiplied each class' relative contribution to the total system generation load in a given hour by the hourly generation investment cost. In order to develop class responsibility for PSE's net generation plant and depreciation expense, I then summed hourly class investment and depreciation costs for all hours of the year to obtain annual amounts by class for gross plant, depreciation reserve, and depreciation expense. Exhibit No. GAW-5, which also consists of three pages, provides summaries of the hourly assignment of generation costs (gross plant, depreciation reserve, and depreciation expense) to individual rate classes. I provide the class assignment to every hour of the test year in my filed workpapers.

Q. Earlier in your testimony, you indicated that the Probability of Dispatch and Base-Intermediate-Peak methods might not properly recognize class variances in variable generation costs. Have you examined whether there are material differences in class fuel costs when analyzed on an hourly (time differentiated) basis?

A. Yes, I have. As discussed earlier, PSE provided each generation plant's hourly output during the test year. In addition, in response to Public Counsel Data Request No. 170, the Company provided annual average fuel costs (per kWh) for each plant during the test year.[16] With this data, I was able to calculate hourly fuel costs by individual generating plant based on each unit's output. I then assigned these hourly fuel costs to individual rate classes on an hour-by-hour basis based on the class hourly loads previously discussed.[17] The result of this analysis yielded similar hourly fuel costs for most classes. In this regard, the time differentiated fuel costs reflect all sources of PSE-owned generation, including wind and hydro with zero fuel costs. As a result, PSE's total fuel costs divided by total kWh is very low by industry standards (slightly less than $0.01/kWh). I provide each class' time differentiated fuel cost in Table 2 below. [18]

[16] Watkins, Exh. GAW-12.
[17] *Id.*, The class hourly loads were provided at the generation level. Each class' loads were adjusted for losses to reflect class loads at the meter as provided in response to Public Counsel Data Request No. 164.
[18] The details of this analysis are provided in my filed workpapers.

TABLE 2
PSE Test Year Class Hourly Fuel Costs

Class		At Meter Fuel Cost Per mWh	At Meter Deviation From Sys. Average
Jurisdictional:			
7	Residential	$9.24	-3%
24	Secondary <50kw	$9.78	3%
25/29	Secondary >50kw and <350kw	$9.87	4%
26	Secondary >350kw	$10.18	7%
31	General Service – Primary	$9.56	0%
35	Irrigation	$13.36	40%
43	Interruptible Electric Schools	$8.46	-11%
	Special Contract	--	--
46/49	High Voltage	$9.47	-1%
448/449//459	Choice/Retail Wheeling/Back-Up	--	--
50/59	Lighting	$10.33	8%
Non-Jurisdictional:			
5	Firm Resale	$8.09	-15%
Total		$9.52	--

In examining these time differentiated fuel costs by class, there would appear to be anomalous results for some classes at first glance. However, with further investigation, these differences can be explained and understood. Although the Lighting class is generally considered off-peak nature, this class' time differentiated fuel cost is higher than the system average. PSE's wind generation (with no fuel costs) is small to non-existent during many evening hours and the Company's hydro facilities tend to be dispatched less during these system off-peak hours. With regard to Rate Schedule 26, this class tends to use considerably more electricity in the summer months than during the winter months. Furthermore, this class tends to peak in the middle of the afternoon (before the system diurnal load increases). During periods of high Rate Schedule 26 usage, PSE tends to dispatch less hydro generation (which has zero fuel costs). As a result, the Company's generation mix during Rate Schedule 26 high use hours tends to be predominately made up with coal and natural gas units.

Q. Have you incorporated time differentiated fuel costs within your Probability of Dispatch CCOSS?

A. Yes. My CCOSS utilizing the Probability of Dispatch method incorporates the time differentiated fuel costs previously discussed.

Q. Up to this point, you have explained how you have allocated generation-related costs under the Probability of Dispatch method. Please explain how you classified and allocated transmission-related costs under the Probability of Dispatch method.

A. Since at least the early-1990s, this Commission has consistently found that transmission facilities are an extension of generation facilities in that generation facilities are often located at a long distance from customers' load centers and that transmission is simply a conduit to transmit this distant generation to retail load centers. The Commission has consistently ruled that transmission facilities should be classified as partially energy-related and partially demand-related. Traditionally, electric utilities in the State have utilized the same demand/energy classification for transmission plant as they do for generation plant. Indeed, under Mr. Jhaveri's Peak Credit method, he has classified transmission plant as 89 percent energy-related and 11 percent demand-related.[19] However, under the Probability of Dispatch method, there is no distinct energy and demand separation, or classification, per se. In order to separate my Probability of Dispatch approach from the Peak Credit approach entirely, I first split costs between classes that utilize PSE's generation resources and those transportation customers that

[19] There is a small amount of transmission plant directly-assigned to the Retail Wheeling class.

wheel power. After directly-assigning Washington Integrated Lease Facilities transmission plant to the Retail Wheeling class (in the same manner as Mr. Jhaveri), I allocated Washington and Non-Washington transmission plant consistent with the approach utilized by Mr. Jhaveri. My allocation of transmission plant (for each category) was performed on an hourly basis similar to the approach used to allocate hourly generation costs.

Q. Have you made any adjustments to class loads under your time differentiated Probability of Dispatch study?

A. Yes. I have adjusted actual Interruptible loads (Rate Schedules 43 and 46) to reasonably reflect the lesser quality of service of interruptible service compared to firm service.

Q. Please explain.

A. Although Rate Schedules 43 and 46 customers are subject to curtailment, the Company stated in response to Public Counsel Data Request No. 172 (provided in Exhibit No. GAW-12) that it has not curtailed these customers during the last three years. Therefore, the unadjusted hourly load data for these customers reflect their actual loads (which were not curtailed). Without any adjustment to these hourly loads, these rate schedules would be treated the same as firm service for cost allocation purposes. As a result, some adjustment to actual hourly loads is appropriate to reflect the fact that Interruptible service is not the same quality as firm service. To reflect the lesser quality of service of Interruptible rates, I have adjusted these rate schedule's hourly loads to zero for those hours in which the system generation load is at, or above, 90 percent of the annual system generation peak.[20]

[20] The test year annual generation jurisdictional native load system peak was 4,144 mW.

Q. Please provide a summary of the results obtained utilizing the Probability of Dispatch method.

A. The following table provides a comparison of the parity ratios obtained under the Probability of Dispatch method to those calculated under the Company's Peak Credit and my corrected Peak Credit methods:

TABLE 3
Comparison of Peak Credit and Probability of Dispatch
Parity Ratios

Rate Schedule	Class	Probability of Dispatch	Peak Credit: PSE Study	Peak Credit: PC Corrected
7	Residential	99%	97%	96%
24	Secondary Voltage <50kw	105%	105%	106%
25/29	Secondary Voltage >50kw and <350kw	105%	106%	107%
26	Secondary Voltage >350 kw	100%	106%	107%
31	General Service – Primary	98%	102%	103%
35	Irrigation	44%	55%	52%
43	Interruptible Electric Schools	85%	88%	87%
	Special Contract	98%	99%	100%
46/49	High Voltage	96%	106%	107%
448/449/459	Choice/Retail Wheeling/Back-Up	84%	88%	88%
50/59	Lighting	89%	94%	93%
5	Firm Resale	49%	50%	47%
Total Company		100%	100%	100%

While there are some differences in the parity ratios between the various studies observable in the table above, the directional relationship of these parity ratios remain the same. More specifically, these studies indicate that the Firm Resale (Rate Schedule 5) and Irrigation (Rate Schedule 35) classes are significantly below 100 percent. This indicates that rates should increase by a higher percentage for these classes compared to the system average. Equally important is the fact that these studies indicate that with the exception of the Choice/Retail Wheeling class, the remaining classes exhibit parity ratios reasonably close (within +/- 10 percent) to 100 percent.[21] My Probability of Dispatch CCOSS results are provided in Exhibit No. GAW-6.

2. Base-Intermediate-Peak Method

Q. Please explain how you conducted your CCOSS utilizing the Base-Intermediate-Peak method.

A. To reflect the capacity/energy trade-off inherent in PSE's mix of generating resources, each plant's maximum capacity (mW) and output (mWh) during the test year is required. Exhibit No. GAW-7 provides the classification between energy and demand for PSE's generation plant under the Base-Intermediate-Peak method. The Base-Intermediate-Peak method evaluates each plant based on its capacity factor and variable fuel costs to determine whether that plant operates to serve primarily energy needs throughout the year, only peak loads, or is of an intermediate type that serves both energy and peak load requirements. To illustrate, the Colstrip units are base load units in that they exhibit low running (fuel) costs per kWh. Several of the Company's gas fired combined cycle units are intermediately dispatched during periods of moderate to high peak demand since these facilities exhibit relatively low variable running costs, albeit higher than that for the Colstrip units. As shown in Exhibit No. GAW-7, the Company has five generating facilities that can be considered peaker units in that they operate with high variable running costs and are only dispatched a few hours of the year in order to meet peak load requirements. As discussed earlier, PSE has installed a considerable amount of hydro and wind generation capacity.

[21] The above studies indicate that the Choice/Retail Wheeling/Back-Up classes are somewhat below a 90 percent parity ratio threshold. However, the ratemaking implications of this rate schedule will be discussed later in my testimony.

As indicated in Exhibit No. GAW-7, the Company's base load units are classified as 100 percent energy-related. Intermediate units are classified between energy and demand depending upon each unit's actual capacity factor during the test year. Peaker units have been classified as 100 percent demand-related. In addition to those generating units, hydro and wind units have been classified as 37 percent energy and 63 percent demand and 79 percent energy and 21 percent demand, respectively. Exhibit No. GAW-3C supports this classification. When considering and weighting each unit based on its net investment, the result is a generation classification of 63.47 percent energy and 36.53 percent demand.

Q. Have you also adjusted Interruptible loads under the Base-Intermediate-Peak method to reflect the lesser quality of interruptible service compared to firm service?

A. Yes. Similar to the approach used by Mr. Jhaveri, I have included all interruptible energy usage within the energy classification and assigned no interruptible demand costs within the demand classification.

Q. Please provide a summary of the results obtained using the Base-Intermediate-Peak method.

A. The following table provides the parity ratios obtained under the Base-Intermediate-Peak method:

TABLE 4
Base-Intermediate-Peak
Parity Ratios

Rate Schedule	Class	Parity Ratio
7	Residential	95%
24	Secondary Voltage <50kw	105%
25/29	Secondary Voltage >50kw and <350kw	107%
26	Secondary Voltage >350 kw	110%
31	General Service – Primary	106%
35	Irrigation	58%
43	Interruptible Electric Schools	104%
	Special Contract	102%
46/49	High Voltage	117%
448/449/459	Choice/Retail Wheeling/Back-Up	96%
50/59	Lighting	95%
5	Firm Resale	47%
Total Company		100%

My Base-Intermediate-Peak CCOSS results are provided in Exhibit No. GAW-8.

Q. Please provide a summary of your findings and conclusions relating to CCOSS for this case.

A. The table below provides a comparison of parity ratios obtained from every CCOSS I evaluated for this proceeding. As indicated, the parity ratios tend to be fairly consistent with the Peak Credit and Probability of Dispatch approaches. Therefore, although the Peak Credit, Probability of Dispatch, and Base-Intermediate-Peak methods are all vastly different in concept, it is apparent that the results obtained by Mr. Jhaveri's Peak Credit study are within the range of reasonableness. In this regard, while it is my opinion that the Probability of Dispatch approach is the most theoretically correct approach, from a practical standpoint, the long accepted Peak Credit method produces reasonable results that are consistent with cost causation and are fair and equitable to all rate classes.

TABLE 5
Class Cost of Service Study Results
(Parity Ratios)

Class	Schedule	Peak Credit PSE As-Filed	Peak Credit PC Corrected	Probability of Dispatch	Base-Intermediate-Peak	Average All Studies
Residential	7	97%	96%	99%	95%	97%
Sec. Voltage <50kw	24	105%	106%	105%	105%	105%
Sec. Voltage >50kw <350 kw	25/29	106%	107%	105%	107%	106%
Sec. Voltage >350kw	26	106%	107%	100%	110%	106%
General Service - Primary	31	102%	103%	98%	106%	102%
Irrigation	35	55%	52%	44%	58%	52%
Interruptible Electric Schools	43	88%	87%	85%	104%	91%
Special Contract		99%	100%	98%	102%	100%
High Voltage	46/49	106%	107%	96%	117%	107%
Choice/Wheeling/Back-Up	448/449/459	88%	88%	84%	96%	89%
Lighting	50/59	94%	93%	89%	95%	93%
Firm Resale	5	50%	47%	49%	47%	48%
TOTAL		100%	100%	100%	100%	100%

B. Electric Class Revenue Distribution ("Rate Spread")

Q. What general criteria did you consider in order to establish class revenue responsibility for electric utility rates?

A. There are several criteria that should be considered in evaluating class or rate revenue responsibility. First, class cost allocation results should be considered, but as discussed in detail earlier in my testimony, CCOSS results are not surgically precise. They should only be used as a guide and as one of many tools in evaluating class revenue responsibility. Other criteria that should be considered include:

- Gradualism, wherein rates should not drastically change instantaneously.
- Rate stability, which is similar in concept to gradualism but relates to specific rate elements within a given rate structure.

- Affordability of electricity across various classes and a relative comparison of electricity prices across classes.
- Public policy concerning current economic conditions and economic development.

Because embedded class cost allocations cannot be considered surgically precise and the fact that other criteria to be considered in evaluating class revenue responsibility are clearly subjective in nature, proper class revenue distribution can be deemed more of an art than a science. As such, there is no universal mathematical methodology to apply across all utilities or all rate classes. However, most experts and regulatory commissions agree on certain broad parameters regarding class revenue increases, including movement toward allocated cost of service and maximum/minimum percentage changes across individual rate classes.

Q. Please provide a summary of the Company's proposed class revenue increases.

A. As part of its supplemental filing, the Company is requesting a total increase in revenues of $143.0 million before the $3.1 million proposed reduction in PCORC (Rider 95) resulting in a net increase in revenues of $139.9 million. The following table provides a summary of each class' current revenues, PSE's proposed increase, and PSE's proposed percentage increases:

TABLE 6
PSE Proposed Rate Spread

			PSE Proposed				
			Before Decrease to PCORC (Rider 95)				
Voltage Level	Schedule	Current Revenue ($000)	Proposed Increase ($000)	Percent Increase	Percent of System Average Increase	PCORC (Rider 95) Reduction ($000)	Net Change ($000)
		B	C				
Residential	7	$1,105,897	$84,939	7.68%	108%	($1,580)	$83,359
Secondary Voltage							
Demand <= 50 kW	24	$263,390	$20,230	7.68%	108%	$(342)	$19,888
Demand > 50 kW <= 350 kW	25/29	$270,703	$15,594	5.76%	81%	$(364)	$15,230
Demand > 350 kW	26	$160,281	$9,233	5.76%	81%	$(258)	$8,975
Total Secondary Voltage		$694,374	$45,056			($964)	$44,092
Primary Voltage							
General Service	31	$113,255	$8,699	7.68%	108%	($169)	$8,530
Irrigation	35	$268	$31	11.52%	161%	- -	$31
Interruptible Electric Schools	43	$10,687	$1,026	9.60%	134%	($12)	$1,014
Total Primary Voltage		$124,210	$9,756			($181)	$9,575
Total High Voltage	46 / 49	$40,128	$2,312	5.76%	81%	($343)	$1,969
Choice / Retail Wheeling	449 / 459	$10,114	$77	0.76%	11%	- -	$77
Special Contract	SC	$5,494	$(1,075)	-19.56%	-274%	- -	($1,075)
Lighting	50-59	$16,458	$1,580	9.60%	134%	($49)	$1,531
Total Jurisdictional Sales		$1,996,675	$142,645	7.14%	100%	($3,117)	$139,528
Firm Resale		$327	$355	108.42%		- -	$355
Total Sales		$1,997,003	$143,000	7.16%		($3,117)	$139,883

Q. What was Mr. Piliaris' method or approach to assign revenue increases to individual classes?

A. First, Mr. Piliaris allocated revenues to the Resale class at full cost of service. Next, he calculated the revenues for the new Special Contract class based upon the Commission-approved rate design for these customers.[22] With regard to the Choice/Retail Wheeling class (Rates 449/459), Mr. Piliaris increased the fixed monthly customer charge but maintained the FERC OATT transmission rates. After these three steps, Mr. Piliaris assigned smaller percentage increases to those classes who parity ratios were above 100 percent (Rates 25/29, 26, 31, and 46/49) and larger percentage increases to those classes whose parity ratios were materially lower than 100 percent (Rates 35, 43, and 50-59). Finally, the remaining classes (Rates seven, 24, and 31) received equal percentage increases based on the remaining revenue requirement.

Q. Is Mr. Piliaris' method and resulting class rate spread fair and reasonable?

A. Not entirely. While I agree with the general framework utilized by Mr. Piliaris, his recommendation is too narrowly defined. This Commission has a long-standing practice of considering not only the results of a valid CCOSS but also the principles of rate stability, gradualism, and the avoidance of rate shock.[23] With this being said, the general practice has been those classes with parity ratios +/-10 percent of unity should receive the system average percentage increase.

As shown in my previous Table 5, Rate Schedules 25/29, 26, and 46/49 have parity ratios just slightly above 100 percent (106 percent using the Company's CCOSS and 106 percent to 107 percent using the average of all CCOSS), yet, Mr. Piliaris proposes significantly smaller increases to these classes (5.76 percent compared to a jurisdictional average of 7.14 percent). Similarly, Rate Schedules 43 and 50/59 have

[22] Specifically, Mr. Piliaris reduced the fixed monthly customer charges to cost of service and increased distribution charges per the Commission-approved method.
[23] See for example, *WUTC v. PacifiCorp d/b/a/ Pac. Power & Light Co.*, Docket UE-100749, Order 06: Final Order, ¶¶315, 316 (Mar. 25, 2011).

parity ratios just slightly below 100 percent (88 percent and 94 percent using the Company's CCOSS and 91 percent and 93 percent using the average of all CCOSS), yet, he proposes materially higher percentage increases to these classes (9.60 percent compared to a jurisdictional average of 7.14 percent).

Because each of these classes parity ratios are reasonably close to unity, I recommend that all classes with the exception of Rates Choice/Retail Wheeling (46/49); Special Contract; and, Firm Resale (five), receive an equal percentage increase before recognition of the reduction to PCORC.

Q. Please provide each classes increase before recognition of the PCORC reduction.

A. The following table provides my recommended rate spread at the Company's requested revenue increase of $143.0 million:

TABLE 7

PC Proposed Rate Spread

Voltage Level	Schedule	Current Revenue ($000)	Average Parity Ratio	Accept PSE Increases	% of Remaining	Remaining Increase	All Class Increases	% Increase (Decrease)	% of Juris. Average Increase
		B							
Residential	7	$ 1,105,897	97%		100%	$80,181	$80,181	7.25%	101%
Secondary Voltage									
Demand <= 50 kW	24	$ 263,390	105%		100%	$19,097	$19,097	7.25%	101%
Demand > 50 kW <= 350 kW	25/29	$ 270,703	106%		100%	$19,627	$19,627	7.25%	101%
Demand > 350 kW	26	$ 160,281	106%		100%	$11,621	$11,621	7.25%	101%
Total Secondary Voltage		694,374				$50,344	$50,344		
Primary Voltage									
General Service	31	$ 113,255	102%		100%	$8,211	$8,211	7.25%	101%
Irrigation	35	$ 268	52%		150%	$29	$29	10.88%	152%
Interruptible Electric Schools	43	$ 10,687	91%		100%	$775	$775	7.25%	101%
Total Primary Voltage		124,210				$9,015	$9,015		
Total High Voltage	46 / 49	$ 40,128	107%		100%	$2,909	$2,909	7.25%	101%
Choice / Retail Wheeling	449 / 459	$ 10,114	89%	$77			$77	0.76%	11%
Special Contract	SC	$ 5,494	100%	($1,075)			($1,075)	-19.56%	-274%
Lighting	50-59	$ 16,458	93%		100%	$1,193	$1,193	7.25%	101%
Total Jurisdictional Sales		1,996,675		($998)		$143,643	$142,645	7.14%	
Firm Resale		$ 327	48%	$355			$355		
Total Sales		1,997,003	100%	($643)		$143,643	$143,000	7.16%	

Q. **To the extent the Commission authorizes an overall increase less than the $143.0 million requested by the Company, how should the overall increase be distributed to individual rate schedules?**

A. To the extent the Commission authorizes an overall increase less than that requested by PSE, I recommend that the change to the Special Contract and Choice/Retail Wheeling classes remain at the Company's proposed levels as these rate schedules' revenues were determined based on the Commission-approved method for Special Contracts and the

OATT rates for Choice/Retail Wheeling. All other classes' revenue increases should be reduced in proportion to my recommended rate spread.

C. Electric Rate Design

Q. Please explain PSE's current Residential rate structure.

A. Currently, PSE's Rate Schedule 7 is comprised of a fixed monthly customer charge plus an inverted two-block energy charge. Under current rates, the base monthly customer charge for single-phase service is $7.49.[24] With regard to the current inverted-block rate, there is about a $0.02 differential ($0.01896) between the first usage block (first 600 kWh) and the second usage block (above 600 kWh).

1. Customer Charges

Q. Is PSE proposing to increase the Residential fixed monthly customer charge?

A. No. The Company proposes to maintain the current Residential customer charge of $7.49 per month.

Q. Do you agree with maintaining the current customer charge of $7.49 per month?

A. Yes. In making this determination I have evaluated those direct costs required to connect and maintain a customer's account. These costs include the capital costs associated with Meters and Services as well as the O&M expenses associated with Meters, Meter Reading, and Customer Records & Collections.

Q. Has this Commission provided guidance as to the level of costs that should be considered when establishing Residential customer charges?

A. Yes. In the 2015 PacifiCorp rate case (Docket UE-140762), the Company conducted a customer cost analysis that included not only the costs mentioned above but also included

[24] The monthly customer charge for three-phase service is $17.99.

costs associated with line transformers as well as a myriad of overhead costs. Staff witness Twitchell also conducted a customer analysis that excluded several of the overhead costs included by the Company but did include the costs associated with transformers.[25] On behalf of Public Counsel, I conducted a direct customer cost analyses, which excluded the costs of transformers as well as other overhead costs.

In its Final Order, the Commission determined:

> We reject the Company's and Staff's proposals to increase significantly the basic charge to residential customers. **The Commission is not prepared to move away from the long-accepted principle that basic charges should reflect only "direct customer costs" such as meter reading and billing.** Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals. **[Emphasis added]**[26]

Q. In this case, have you conducted an electric Residential customer direct cost analysis similar to the analysis you conducted in the 2015 PacifiCorp rate case that was approved by the Commission?

A. Yes. I have conducted a direct customer cost analysis, which I present in Exhibit No. GAW-9. As shown in this Exhibit, I utilized the both Public Counsel's recommended return on equity of 8.75 percent as well as the Company's proposed return on equity of 9.80 percent. My analysis produces a direct Residential customer cost between $5.51 and $5.61 per month at the Company's requested rate of return.

[25] *WUTC v. Pac. Power & Light Co.*, Docket No. UE-140762, Order 08: Final Order at 86-87.
[26] *Id.* at 91, ¶ 216.

Q. Given your customer cost findings, could a reduction to the Residential fixed monthly customer charge be justified?

A. Yes. However, Public Counsel accepts maintaining the Residential customer charge at its current level for rate continuity.

2. Residential Energy Charges

Q. Does the Company propose any material changes to the structure of Residential energy charges?

A. With regard to maintaining a two-block inverted energy rate, the Company proposes no changes. However, Mr. Piliaris recommends that the entire increase to the Residential class be captured within the second (higher priced) energy charge rate. The following table provides a comparison of the current and PSE proposed Residential energy charges:

TABLE 8
Residential Energy Charges

	Current	PSE Proposed	Change	% Change
First 600 kWh	$0.087336	$0.087336	$0.000000	0.00%
Over 600 kWh	$0.106297	$0.125088	$0.018791	17.67%

Q. Does Mr. Piliaris provide any rationale or support for recommending that the entire Residential revenue increase be collected within the second usage block?

A. Yes. On pages 18 and 19 of his direct testimony, Mr. Piliaris provides two rationale for his proposal. First, Mr. Piliaris attempts to address concerns of lower income customers wherein these customers are often thought to use less energy than those with higher incomes. As such, Mr. Piliaris states that the Company is concerned with the overall impact of its rate proposal on the customers that can least afford it. Mr. Piliaris' second rationale is that increasing the Residential tail-block will increase the incentive for customers to conserve energy as well as for customer-owned distributed generation.

Q. Do you agree with Mr. Piliaris' proposal to only increase the second tail-block rate?

A. No. While I appreciate the Company's concern for low income customers and a proposal to offer a stronger price signal to reduce energy consumption, I have several concerns with this proposal as it affects not only low income, but all, Residential customers. PSE is a winter peaking utility and summers in the Company's service area tend to be rather mild. By implementing a very large increase in the second usage block, electric heating customers' bills during the winter months will increase considerably while there will be little, to no, increases during the non-heating months as shown in the table below:

TABLE 9
Bill Comparison Under PSE Proposed Residential Rate Design

Monthly KWH Usage	Current Rates	PSE Proposed Rates	Change	% Change
500	$50.23	$50.15	($0.08)	-0.16%
750	$74.44	$77.14	$2.70	3.63%
1000	$100.55	$107.91	$7.36	7.32%
1500	$152.76	$169.45	$16.69	10.93%
2000	$204.98	$230.99	$26.01	12.69%
2500	$257.19	$292.53	$35.34	13.74%
3000	$309.41	$354.06	$44.65	14.43%

As can be seen in the table above, Residential heating customer bills will increase substantially more during the cold winter months as usage is much larger in the winter than non-heating months. This may be particularly burdensome for low income families with less than efficient electric heating sources and inferior weatherization of their homes.

In terms of conservation, this practice does not simply mean using less of a particular resource, but rather utilizing resources in an efficient manner. Commission Staff advocated for a third Residential usage tail-block in Docket No. UE-141368 in the name of "conservation." In that case, the third block would have been priced significantly higher than the inverted second usage block. As part of the settlement in that case, PSE agreed to study the economics and feasibility of implementing an even higher third block rate. In the Company's 2017 General Rate Case (Docket No. UE-170033), PSE presented the results of the Residential avoided (incremental) cost of energy and found that this marginal cost was even lower than the current second block usage energy rate.[27]

In this case, in Public Counsel Data Request No. 157 (provided in my Exhibit No. GAW-12), I requested the Company to update its Residential avoided costs. The Company's response indicates that the incremental (avoided) cost of Residential energy is between $0.054 and $0.0578 per kWh. As such, there is no economic, conservation basis for pricing the Company's second energy block rate even higher than the current level particularly as it relates to the price differential between the first and second usage blocks.

Q. What is your recommendation regarding Residential energy rates?

A. I recommend that the authorized revenue increase to the Residential class be spread proportionally across the first and second usage blocks; i.e., each usage rate will incur the same percentage increase.

[27] Direct Testimony of Jon A. Piliaris, Exh. JAP-1T at 59, *WUTC v. Puget Sound Energy* (Jan. 13, 2017) (Dockets UE-170033 & UG-170034).

Q. With regard to the concern of making electricity affordable to all customers, particularly low income customers, do you have a recommendation?

A. Yes. In the Company's last rate case, The Energy Project's witness Shawn Collins, suggested a study to evaluate the strengths and weaknesses of maintaining a two-tiered energy rate but increasing the size of the first usage block from the current 600 kWh to 800 kWh. This structure would cover a larger portion of essential services for most households and could serve as a lifeline rate. I find merit in Mr. Collins' suggestion and recommend the Commission direct Puget Sound to study the feasibility of changing its Residential two-tiered energy block rate structure to reflect a first usage block of 800 kWh per month.

III. NATURAL GAS OPERATIONS

A. Natural Gas Cost of Service

Q. With regard to Natural Gas Distribution Companies (NGDCs), is there any aspect of class cost allocations that tends to overshadow other issues or is often controversial?

A. Yes. For virtually every NGDC, the largest single rate base item (account) is distribution mains. Furthermore, several other rate base and operating income accounts are typically allocated to classes based on the previous assignment of distribution mains. Therefore, the methods and approaches used to allocate distribution mains to classes are usually by far the most important (in terms of class rate of return [ROR] results) and tend to be the most controversial.

Q. Have you examined PSE's natural gas CCOSS sponsored by John Taylor in this case?

A. Yes.

Q. Please briefly describe the general methodology utilized by Mr. Taylor to allocate distribution mains.

A. As noted earlier, the most controversial aspect relating to natural gas cost allocation studies concerns the methodologies and approaches used to allocate distribution mains across customer classes. In this case, Mr. Taylor has continued to use the long-accepted general methodology known as the Peak & Average approach wherein distribution mains are allocated based partially on annual throughput (average day demand) and partially on peak demand. Moreover, Mr. Taylor used a system load factor of 32.23 percent to weight the allocation between average day and peak day usage.

Q. Did Mr. Taylor use the same methodology to assign distribution mains in this case as used by PSE in its recent prior rate cases?

A. No. Although Mr. Taylor characterizes the modifications he proposes in this case to be relatively minor modifications to the approach utilized by PSE for several rate cases, the reality is, Mr. Taylor's proposed new approach is materially different conceptually to that used by PSE for several rate cases and is in conflict with prior Commission Orders.

Q. Before you discuss Mr. Taylor's proposed modifications to the manner in which distribution mains are allocated in this case, please provide a brief history of issues concerning the allocation of distribution mains in Washington.

A. The issue of how distribution mains should be allocated across classes has a long history before the Washington UTC. Going back more than 30 years to a 1986 rate case involving Cascade Natural Gas (Cause No. U-86-100) and again in a 1990 rate case involving Washington Water Power Company, predecessor to Avista (Docket No. UG-901459), the Commission approved a method for allocating distribution mains, wherein mains were classified as 25 percent coincident demand-related, 25 percent non-coincident demand-related, and 50 percent commodity related.[28] In addition, demand-related costs were allocated to classes based on the three-year average of <u>actual</u> five-day sustained peak demands. Furthermore, the Commission rejected Washington Water Power Company's proposed direct assignment of distribution mains to large volume customers stating:

> Removing and directly assigning plant only for a select group of customers with lower costs is not consistent with the embedded cost class allocations underlying the rest of the company study. As described by Public Counsel on brief, direct assignment could be considered to be cost-based only if it were applied to the entire utility rather than to one customer with competitive alternatives.[29]

Q. Please continue with your history of issues concerning the allocation of distribution mains in the State of Washington.

A. In PSE's 2008 General Rate Case (Docket No. UG- 072301), the Company proposed a new method to allocate mains that relied upon an engineering software package that essentially directly-assigned mains costs to large volume customer classes. That new allocation methodology proposed by PSE was extremely contentious. However, the case was ultimately settled with a stipulated agreement to form a working group in an attempt to develop an agreed-upon methodology to allocate distribution mains. As a result, in

---

[28] *WUTC v. Cascade Natural Gas Corp.,* Cause U-86-100, Fourth Supplemental Order at 11 and *WUTC v. The Wash. Water Power Co.*, Docket UG-901459, Third Supp. Order (Mar. 9, 1992).
[29] *WUTC v. The Wash. Water Power Co.*, Docket UG-901459, Third Supp. Order at 7 (Mar. 9, 1992).

early 2009, a collaborative was formed to investigate various cost allocation methodologies relating to PSE's natural gas operations and to determine if any joint resolutions could be made by the various parties participating in the collaborative. While the 2009 collaborative did not reach agreement on a mains allocation method or even a philosophical consensus as to cost causation, each party's views were debated and clearly understood.

Then, in PSE's 2009 general rate case (Docket No. UG-090705), Company witness Janet Phelps developed what can be characterized as a "compromise" allocation methodology that considered the merits of the various positions and attempted to develop a new allocation method wherein Ms. Phelps' new methodology was: (1) consistent with cost of service principles; (2) acknowledged past Commission decisions; (3) was consistent with PSE's distribution system; (4) was fair and reasonable; and, (5) perhaps most importantly, addressed concerns raised by parties on both ends of the cost allocation spectrum.[30]

The resulting methodology introduced by Ms. Phelps on behalf of PSE in the 2009 rate case, is the method that continued through the Company's 2017 General Rate Case (Docket No. UG-170034).

[30] , Direct Testimony of Janet K. Phelps, Exh. JKP-1T, *WUTC v. Puget Sound Energy, Inc.* (May 8, 2009) (Dockets UE-090704 and UG-090705).

Q. Since the 1986 case involving Cascade Natural Gas case and the 1990 case involving Washington Water Power Company, has PSE's allocation of distribution mains materially impacted the Residential class?

A. Yes. Over the past 30-plus years, there has been a gradual, yet continual, moving of the cost of service goal line as it relates to the assignment of costs to the Residential class. In order to understand this continual movement of assigning more and more costs to the Residential class, consider the fact that the Peak and Average method approved by the Commission in 1990 classified distribution mains as 50 percent commodity and 50 percent demand.

Over the years, PSE has abandoned this classification and based the commodity/demand split based on system load factor wherein the commodity portion is now only approximately 32 percent and the demand portion is approximately 68 percent. This has a material impact on the costs assigned to the Residential class because the Residential class has a much lower load factor than Industrial customers, which means that the demand allocation factor for the Residential class is much larger than the average (commodity) allocator. This change has resulted in a significantly larger amount of mains-related costs allocated to the Residential class.

The next modification and continual assignment of additional cost responsibility to the Residential class concerns the change from using <u>actual</u> peak demands to theoretical design day demands. Because design day demands are based upon the coldest theoretical day possible, the class allocators developed using design day demands are much higher for the Residential class than those developed using actual day demands. These changes over time have further allocated more costs to the Residential class.

Finally, PSE has proposed methods that separates mains by sizes of pipe wherein large volume customer classes are not fully responsible for the costs of all distribution mains. Again, this has further increased the cost responsibility to the Residential class since fewer mains-related costs have been allocated to the large volume user classes.

Q. What new modifications are proposed by Mr. Taylor in this case relating to the allocation of distribution mains?

A. In large part, Mr. Taylor proposes to go full circle back to methods that have either been rejected by the Commission or that are contrary to the compromise approach used by PSE for several rate cases.

First, Mr. Taylor proposes to directly-assign mains costs to Special Contract customers. As noted earlier, this approach has been expressly rejected by the Commission. Second, Mr. Taylor proposes to abandon the compromise approach developed by PSE in the 2009 rate case described earlier. Specifically, Mr. Taylor proposes the following changes to the assignment of mains costs across classes:

(1) directly-assign mains to the Special Contract class;

(2) exclude the Interruptible, Limited Interruptible, and Non-Exclusive Interruptible classes from the assignment of any small mains within the "peak" portion of costs;

(3) exclude the Non-Exclusive Interruptible class from the assignment of any medium size mains within the "average" portion of costs; and,

(4) exclude the Limited Interruptible class from the assignment of any small mains within the "average" portion of costs.

The details comparing the assignment of mains costs under the old (compromise) approach and Mr. Taylor's proposed new approach are provided in my Exhibit No. GAW-10.

Q. What is the end-result of Mr. Taylor's proposed new method to assign distribution mains costs?

A. The following table provides a comparison of the assignment of distribution mains costs under the old (compromise) and Mr. Taylor's new proposed approaches:

TABLE 10
Comparison of PSE Prior & Proposed Methods To Assign Distribution Mains

Class	Old (Compromise) Method	New Method	Difference
Residential	$1,313,613,044	$1,330,244,071	$16,631,027
Comm. & Indus.	$475,502,563	$481,670,004	$6,167,441
Large Volume	$104,314,098	$106,177,959	$1,863,862
Interruptible	$51,520,800	$51,701,938	$181,137
Ltd. Interruptible	$6,276,757	$5,269,183	($1,007,574)
Non-Excl. Interruptible	$47,068,443	$40,587,804	($6,480,639)
Special Contracts	$20,009,295	$2,654,042	($17,355,253)

As can be seen above, Mr. Taylor's proposed new approach significantly shifts cost responsibility away from the Interruptible and Special Contract classes to the Firm and Small Volume classes. In particular, Mr. Taylor's new approach assigns $16.6 million more to the Residential class and $6.2 million to the Commercial & Industrial class. At the same time, his new approach assigns $17.4 million less to the Special Contract class and $6.5 million less to the Non-Exclusive Interruptible class.

Q. What is your overall assessment of the mains allocation method proposed by Mr. Taylor in this case?

A. Mr. Taylor's proposed new method is troubling and should not be accepted. As explained earlier, even under the compromise method utilized by PSE for several rate cases since 2009, the goal line for Residential and Small Commercial/Industrial cost responsibility has shifted over the years in that more and more costs have been assigned to the

Residential class due to the abandonment of the 50 percent commodity and 50 percent demand classification of distribution mains as well as the change from actual peak day demands to design day demands. While I have expressed concerns in previous cases regarding the compromise approach developed by PSE in 2009 rate case, I have acknowledged that the approach was a "compromise" of various parties' positions. In this case, Mr. Taylor proposes to move the goal line once again by assigning even more costs to the Residential and Commercial classes and significantly assigning fewer costs to the Large Interruptible and Special Contract classes.

Furthermore, there is currently a Cost of Service Rulemaking Workshop (Docket No. UG-170003) in progress wherein it is anticipated that the Commission will adopt new rules and/or policy statements concerning the approaches and methods used to allocate NGDC costs. This Workshop has been ongoing since late-2016 wherein the various stakeholders have provided significant input as to how costs should be allocated across classes. A significant amount of time and effort has been spent on the issue of how distribution mains should be allocated. Mr. Taylor's proposed approach in this case introduces a new approach that has not been mentioned or discussed at any of the Workshops during the course of this generic investigation. As such, and even though I have certain reservations over PSE's "compromise" approach to allocate distribution mains, I recommend the Commission not consider Mr. Taylor's proposed new method to allocate distribution mains and rely upon the results of the approach that has been used by PSE for the last several rate cases; i.e., the compromise method.

Q. Does Mr. Taylor's proposed new approach produce significantly different results across classes?

A. In terms of parity ratios, there is very little difference between the two methods for all classes except Special Contract. However, in evaluating class rates of return at current rates, we can see that the Commercial & Industrial class (Rates 31 and 31T) is not even producing a rate of return sufficient to cover interest costs. Furthermore, we see that Large Volume and Limited Interruptible classes are currently providing rates of return well in excess of the Company's cost of capital as shown in the table below:

TABLE 11
Comparison of Natural Gas CCOSS Results

		Parity Ratio		ROR @ Current Rates	
		Old Method	New Method	Old Method	New Method
Residential	(16, 23, 53)	107%	107%	5.73%	5.62%
Comm & Ind	(31, 31T)	82%	82%	1.04%	0.96%
Large Volume	(41, 41T)	124%	122%	9.22%	8.96%
Interruptible	(85, 85T)	109%	108%	6.30%	6.26%
Limited Interrupt.	(86, 86T)	158%	171%	16.71%	19.67%
Non-Excl. Interrupt.	(87, 87T)	75%	83%	-0.19%	1.22%
Special Contracts	(SC)	66%	171%	-1.54%	20.17%
Rentals		137%	137%	15.97%	15.97%
Total Company		100%	100%	4.55%	4.55%

B. Natural Gas Class Revenue Distribution ("Class Rate Spread")

Q. How did Mr. Taylor develop his proposed distribution of PSE's $97.9 million requested natural gas revenue increase to individual customer classes?

A. On pages 23 and 24 of his direct testimony, Mr. Taylor states that he: (1) applied the system average percentage increase to those classes with parity ratios between 90 percent and 110 percent of parity; (2) applied half of the system average percentage increase to those classes between 110 percent and 150 percent of parity; (3) proposes no increase to those classes whose parity ratios are above 150 percent; (4) applied 150 percent of the system average percentage increase to those classes with a parity ratios below 90 percent; and, (5) set the Rentals class at its allocated cost of service.[31]

Q. Please provide a summary of PSE's proposed natural gas class revenue increases.

A. The following table provides Mr. Taylor's proposed class revenue increases at the Company's requested revenue requirement:

Table 12
PSE Proposed Natural Gas Increases

Class	Current Non-Gas (Margin) Revenues ($000)	Increase ($000)	Percentage Increase in Margin Rates
Residential (Schedules 16/23/53)	$315,765	$64,777	20.5%
Comm. and Ind. (Schedules 31, 31T)	$92,797	$28,556	30.8%
Large Volume (Schedules 41, 41T)	$19,455	$1,996	10.3%
Interruptible (Schedules 85, 85T)	$8,493	$1,742	20.5%
Limited Interruptible (Schedules 86, 86T)	$1,968	--	0%
Non-Exclusive Interruptible (Schedules 87, 87T)	$4,603	$1,416	30.8%
Special Contract	$1,719	$39	2.2%
Rentals	$5,310	($645)	-12.1%
Total Company	$450,111	$97,881	21.7%

Q. Is Mr. Taylor's proposed class revenue spread reasonable?

A. Not entirely. As can be seen in Table 11, the Special Contract class parity ratios and rate of return at current rates are significantly different between the current and Mr. Taylor's new proposed methods to allocate distribution mains-related costs. Indeed, under the current compromise approach, the Special Contract class is exhibiting a negative rate of return on rate base while under his new approach, this class is producing a significantly large rate of return. This is also exhibited in this class' parity ratios of 66 percent under

[31] Direct Testimony of John D. Taylor, Exh. JDT-1T at 23-24.

the current compromise approach and 171 percent under his new approach to assign mains cost responsibility. Given this huge difference in findings for the Special Contract class and without further debating class cost allocations, I recommend that the Special Contract class receive an increase equal to the system average increase.

Next, even though the Rentals class is producing a relatively high parity ratio, I am aware that PSE is in the process of selling its rentals business. As such, I recommend no change in the Rental class' rates as compared to the reduction proposed by Mr. Taylor.

Q. Please explain and provide your recommended class revenue increases utilizing the Company's proposed overall increase of $97.9 million.

A. As noted above, I recommend the Special Contract class' revenues be increased at the system average percentage increase of 21.75 percent and that the Rentals class incur no increase in revenue responsibility. I then utilized Mr. Taylor's approach for the remaining classes. This produces the following increases by class:

TABLE 13
PC Proposed Natural Gas Rate Spread

Class	Schedule	Current Margin Revenue ($000)	Increase	% Increase (Decrease)	% of System Average Increase
Residential	16, 23, 53	$315,765	$61,559	19.50%	90%
Commercial & Industrial	31, 31T	$92,797	$30,632	33.01%	152%
Large Volume	41, 41T	$19,455	$2,141	11.00%	51%
Interruptible	85, 85T	$8,493	$1,656	19.50%	90%
Limited Interruptible	86, 86T	$1,968	$0	0.00%	0%
Non-Exclusive Interruptible	87, 87T	$ 4,603	$1,520	33.01%	152%
Contracts		$1,719	$374	21.75%	100%
Rentals	50-59	$5,310	$0	0.00%	0%
Total Company		$450,111	$97,881	21.75%	100%

Q. To the extent the Commission authorizes an overall increase less than the $97.9 million requested by the Company, how should the overall increase be distributed to individual rate schedules?

A. To the extent the Commission authorizes an overall increase less than that requested by PSE, I recommend no change to Rental revenues and that all other class revenues should be reduced in proportion to my recommended rate spread.

C. Natural Gas Residential Rate Design

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

A. Currently, PSE's Residential (Rate 23) non-gas rates include a base fixed monthly customer charge of $11.00 plus a fixed monthly charge of $0.52 associated with its Expedited Rate Filing (ERF) tariff. The Company proposes to increase the base fixed monthly customer charge to $11.52 (which would reflect the inclusion of its ERF rate) and increase its delivery charge from $0.34603 per therm to $0.44362 per therm.

Q. Have you conducted an analysis to determine if PSE's proposed Residential natural gas 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 can be considered in evaluating the reasonableness of fixed monthly customer charges.

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

A. Exhibit No. GAW-11 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 Exhibit No. GAW-11 include those rate base and expense items required for each customer connection as well as those required to maintain a customer's account. The results of my analyses indicate a monthly customer cost of $11.40 at PSE's requested 9.80 percent return on equity and $11.20 under Public Counsel's recommended 8.75 percent return on equity. In this regard, Public Counsel's recommended 8.75 percent return on equity overstates the risk and costs associated with fixed Residential customer charges as these charges reflect guaranteed revenue recovery and, therefore, have little to no risk. As a result, I have relied upon and recommend a customer cost of $11.20 per month.

Q. What are your recommendations concerning the Company's proposed Residential natural gas customer charges?

A. I recommend that the Residential customer charge be set at no more than $11.20 per month.

Q. Does this complete your testimony?

A. Yes.