EXHIBIT NO. ______ (RAF-1T)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RUSSELL A. FEINGOLD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DIRECT TESTIMONY OF RUSSELL A. FEINGOLD ON BEHALF OF PUGET SOUND ENERGY, INC.

NOVEMBER 26, 2001

PUGET SOUND ENERGY, INC.

DIRECT TESTIMONY OF RUSSELL A. FEINGOLD

I. BACKGROUND AND QUALIFICATIONS

Q: Please state your name and business address.

A: My name is Russell A. Feingold and my business address is 200 Wheeler Road, Suite 400, Burlington, Massachusetts 01803. I am employed by Navigant Consulting, Inc. ("NCI") as a Managing Director and lead its Regulation & Litigation Support Practice. I have been employed by NCI since January 1997.

Q: Please describe in more detail the business activities of NCI.

A: NCI has served the electric and natural gas industries since 1983. We offer a wide range of consulting services related to information technology, process/operations management, business strategy development, and marketing and sales designed to assist our clients in a business environment of changing regulation, increased competition and evolving technology. From an industry-wide perspective, NCI has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis and regulatory practices and policies gained through management and operating responsibilities at gas distribution, pipeline and other energy-related companies, and through a wide variety of client assignments. NCI has assisted numerous gas distribution companies located in the U.S. and Canada.

Q: What has been the nature of your work in the utility consulting field?

A: I have over 26 years of experience in the utility industry, the last 23 years of which have been in the field of utility management and economic consulting. Specializing in the gas industry, I have advised and assisted utility management, industry trade and research organizations and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, gas supply planning issues, strategic business planning, merger and acquisition analysis, corporate restructuring, new product and service development, load research studies and market planning. I have prepared and presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and several state and provincial regulatory commissions and have spoken widely on issues and activities dealing with the pricing and marketing of gas utility services.

Further background information summarizing my education, presentation of expert testimony and other industry-related activities is included in Exhibit RAF-2 to my testimony.

Q: Have you testified previously before the Washington Utilities and Transportation Commission ("the Commission")?

A: Yes, I have testified in Docket Nos. UG-950278 and UG-940814/UG-940034 on behalf of Washington Natural Gas Company on the subject of conducting allocated cost of service studies for rate design purposes and the development of costing analyses to guide the design of rates for transportation services.

II. PURPOSE

Q: For what purpose has Puget Sound Energy ("the Company") retained NCI?

A: NCI has been retained by the Company as a consultant in the area of utility costing and rate design and related regulatory matters. Specifically, I was requested by the Company to assist its staff in preparing an allocated cost of service study for its retail natural gas operations for submission in this rate proceeding.

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

A: The purpose of my testimony is to present the results of the retail natural gas cost of service study filed by the Company in this proceeding. I will also review and discuss the most important considerations in preparing a cost of service study for a local distribution company ("LDC"). Finally, I will discuss and support the underlying methodology and conceptual basis used in the Company's gas cost of service study.

III. INTRODUCTION OF THE COMPANY'S COST OF SERVICE STUDY PRESENTATION

Q: Are you sponsoring any exhibits that present the Company's cost of service study?

A: Yes, I am. The following exhibits, which were prepared under my supervision and direction, present the Company's cost of service study:

- Exhibit RAF-3 Summary of Cost Study Results
- Exhibit RAF-4 Detailed Cost Study Results
- Exhibit RAF-5 Class Load and Service Characteristics of the Company's Customers
- Exhibit RAF-6 Customer Classified Revenue Requirement
- Exhibit RAF-7 Daily Use of Jackson Prairie Storage

Q: Please describe Exhibit Nos. ___(RAF-3) and ___(RAF-4) in more detail.

A: Exhibit RAF-3 presents the following results of the Company's cost of service study:

- Earned Return Summary – Including Gas Costs
- Earned Return Summary – Excluding Gas Costs
- Revenue Requirements Summary – Including Gas Costs
- Revenue Requirements Summary – Excluding Gas Costs

- Gas Cost Sub-Report
- Cost Classifiers
- External Allocators
- Internal Allocators

Exhibit RAF-4 presents all details of the Company's proposed cost study by Federal Energy Regulatory Commission ("FERC") primary account.

Q: What was the source of the cost data analyzed in the Company's cost of service study?

A: All cost of service data have been extracted from the Company's total cost of service (i.e., total revenue requirement) contained in this filing. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company.

Q: Please describe the overall cost study considerations that you deemed appropriate to reflect in the Company's cost of service study.

A: Consistent with the approach utilized by the Company in its last gas rate proceeding, Docket No. UG-950278, a primary consideration was to derive the cost of providing transportation service across all of the Company's major customer groups. This required that I analyze the costs of moving gas on the Company's transmission and distribution (T&D) system, as well as certain costs associated with the Company's upstream supply and capacity resources. In conjunction with this analysis, it was necessary to identify and quantify the specific cost elements attributable to transportation service. This was accomplished by configuring the Company's cost of service studies in a manner that permitted the use of a "bottom-up" costing approach. Under this approach, each specific cost element attributable to transportation service was separately identified, quantified, and aggregated together for purposes of establishing a transportation cost of service level. This is in contrast to a "top-down" approach, which simply utilizes the non-gas costs of an LDC as a proxy for the cost of transportation service. Finally, the Company's cost of service study was developed in a manner to meet the transportation service costing considerations of the Commission, as delineated in its Order in Docket No. UG-940034/UG-940814.

Q: Did you make any changes to the classes of service included in the Company's cost of service study compared to the cost study submitted in its last gas rate proceeding?

A: Yes, I did. In the Company's currently filed cost of service study, I have treated as separate classes Rate 57 – Transportation Service and Rates 99/199/299 Special Contracts. In addition, I eliminated the General Service (Rates 11, 16 and 61) and Armed Forces (Rate 43) classes.

IV. FACTORS INFLUENCING THE COST ALLOCATION FRAMEWORK

Q: Please discuss the factors that you believe can influence the overall cost allocation framework utilized by an LDC.

A: In undertaking a cost of service study, the overall framework within which an LDC performs its cost study can be influenced by various factors. By overall framework, I mean the three standard steps or phases followed by a utility when performing a cost study – cost functionalization, cost classification and cost allocation. In my opinion, these factors can include: (1) the physical configuration of the LDC's gas system; (2) the availability of data within the LDC; and (3) the state regulatory policies and requirements applicable to the LDC. The physical configuration of the LDC's gas system refers to considerations such as: (1) transmission and distribution system configuration; (2) mainline pipeline functionality; and (3) system operating pressure configuration. These considerations include determining whether: (1) the distribution system is a centralized grid/single city-gate or a dispersed/multiple city-gate configuration; (2) the LDC has an integrated transmission and distribution system or a distribution-only operation; and (3) the system operates under a multiple-pressure based or a single-pressure based configuration.

With regard to data availability, the structure of the LDC's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region and the types of load data available.

State regulatory policies and requirements refers to the particular approaches used to establish utility rates in the state. For example, any specific methodological preferences or guidelines for performing cost studies or designing rates established by the state regulatory body can affect the particular cost allocation method utilized by the LDC.

Q: How do these factors relate to the specific circumstances applicable to the Company?

A: Regarding the physical configuration of the Company's gas system, it is a dispersed/multiple city-gate, integrated transmission/distribution and multi pressure-based system. The Company has detailed plant accounting records for many of its distribution-related facilities. Additionally, detailed gas supply expense data is available by specific supply and capacity resource. Finally, over the years, this Commission has expressed a preference for LDCs to utilize a costing methodology that allocates some fixed costs on the basis of annual use (or throughput) in order to reflect the fact that a gas distribution system is built to deliver gas year round.

Q: Why are these considerations relevant to conducting the Company's cost of service study?

A: As I will discuss later in my testimony, it is important to understand these considerations because they influence the overall context within which the Company's cost studies were conducted. In particular, they provided me with an indication of where I should focus my efforts for purposes of conducting a more detailed analysis of the Company's gas system design and operations, developing supporting cost data and better understanding the regulatory environment in the State of Washington as it pertains to cost of service studies and gas ratemaking issues.

V. GUIDING PRINCIPLES OF COST ALLOCATION

Q: Would you state the purpose of a cost of service study?

A: A cost of service study is an analysis of costs which attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of these studies can be utilized to determine the relative cost of service for each class and to help determine the individual class revenue requirements.

Q: Are there certain guiding principles that should be followed when performing a cost of service study?

A: Yes, there are. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of *cost causation* for purposes of allocating costs to customer groups. Cost causation addresses the question – which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

The essential element in the selection and development of a reasonable cost of service study allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all *customers* entitled to be attached to the system; (2) to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or *capacity* related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities which are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company for its sales service customers.

Q: What steps did you follow to perform the Company's cost of service studies?

A: I followed three broad steps to perform the Company's cost of service studies: (1) functionalization; (2) classification; and (3) allocation. The first step, functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. The Company's functional cost categories associated with gas service include: production, storage, transmission and distribution. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics which I previously discussed: (1) customer; (2) demand or capacity; and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs typically are allocated on customer, demand, commodity or revenue allocation factors.

Q: How does the cost analyst establish the cost and utility service relationships you previously discussed?

A: To establish these relationships, the cost analyst must analyze the Company's gas system design and operations, its accounting records and its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and "common" cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q: Please explain what you mean by the term "direct assignment."

A: The term "direct assignment" relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causative characteristics of serving individual customers or groups of customers. Therefore, in performing a cost of service study, the cost analyst seeks to maximize the amount of plant and expense directly assigned to particular customer groups to avoid the need to rely upon other more generalized allocation methods.

Direct assignments of plant and expenses to particular customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q: Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A: No, it is not. The nature of utility operations is characterized by the existence of common or joint use facilities. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, "common" allocation methods must be derived to assign or allocate the remaining costs to the customer classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q: As part of your work, did you review and analyze the Company's gas system design and operations?

A: Yes, I did. Since it is widely recognized that a utility's plant in service components provide the most direct link to a utility's gas service requirements, I initially focused my efforts on better understanding the nature and operation of the Company's gas system. This effort included review of the Company's transmission and distribution systems, the types and levels of costs incurred in connecting new customers to its distribution system, and the design and operation of the Company's winter season and gas peaking supply facilities (i.e., its underground storage and propane-air facilities). Additionally, due to the magnitude of the costs, I analyzed in detail the Company's gas supply portfolio, including the Company's mix of supply resources, its acquisition and utilization of firm pipeline contract capacities from the various pipeline suppliers serving the Company, its winter seasonal services (i.e., contract storage) and other relevant cost and operational characteristics.

Q: Please explain the most important considerations you relied upon in determining the cost allocation methodologies that were used to perform the Company's cost of service study.

A: As stated above, in order to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. Additionally, the cost analyst needs to develop data in a form that is compatible with and supportive of rate design proposals. Of further concern is the availability of data for use in developing alternative cost allocation factors. In evaluating any cost allocation methodology, it is appropriate that consideration should be given to:

1. Recognition of *cost causality*;

2. Results that are *representative* of the true costs of serving different types of customers;

3. A sound *rationale* or *theoretical basis*;

4. *Stability* of results over time;

5. Logical *consistency* and *completeness*; and

6. Ease of *implementation*.

Q: Please describe the key issues related to the allocation of demand-related costs within a cost of service study.

A: A complex part of the allocation process is the allocation of demand-related costs. Several methodologies have been used by gas utilities to develop allocation factors for the demand components of costs. In fact, it is not unusual for more than one demand cost allocation methodology to be used in a cost of service study. Despite the use of different methods to allocate demand costs, it is fair to say that three basic methodologies form the foundation for the allocation process. These three methodologies are Peak Demand Allocations, Average and Excess Demand Allocations and Non-Coincident Demand Allocations. Each of these demand allocation methodologies is discussed below.

The concept of Peak Demand Allocation is premised on the notion that investment in capacity is determined by the peak load or peak loads of the Company. Under this methodology, demand related costs are allocated to each customer class or group in proportion to the demand coincident with the system peak or peaks of that class or group. The Peak Demand Allocation process might focus on a single peak, such as the highest daily demand occurring during the test period. Other variations might include the average of several cold days, or the expected contribution to the system peak on a design day. In some instances, it may be appropriate to determine the peak demand responsibility on an hourly basis rather than a daily basis where hourly requirements dictate a company's investment in distribution facilities.

The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand related costs to the classes of service on the basis of system and class load factor characteristics. Specifically, the portion of utility facilities and related expenses required to service the average load is allocated on the basis of each class' average demand. The portion of these facilities is derived by multiplying the total demand related costs by the utility's system load factor. The remaining demand related costs are allocated to the classes based on each class' excess or unused demand (i.e., total class non-coincident demand minus average demand).

A simplified version of this methodology is the Peak and Average methodology. This cost methodology gives equivalent weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's demand-related costs on a commodity-related basis.

The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, are designed to serve local peaks which may or may not be coincident with the system peak loads. Using this methodology, demand costs are allocated on the basis of each group's or rate class' maximum demand, irrespective of the time of the system peak.

VI. REVIEW OF THE LOAD AND SERVICE CHARACTERISTICS OF THE COMPANY'S CUSTOMERS

Q: You stated earlier that the load characteristics of an LDC's customers are an important element in determining the costs incurred by the LDC in serving its customers. Have you summarized the load characteristics of the customers served by Company?

A: Yes. I have summarized the relevant load characteristics of the Company's various customer groups in Exhibit RAF-5. In reviewing this information, it is important to point out that for each class of service, the absolute and relative level of certain of these load characteristics have a direct influence on the type and level of costs incurred by the Company in serving its customers.

Q: What are the implications of class load characteristics for purposes of determining the costs to serve an LDC's customers?

A: First, annual load factor is an important indicator of how a customer utilizes an LDC's pipeline capacity. As a customer's annual load factor increases, it indicates that the customer is using the LDC's system capacity more efficiently than a lower load factor customer. In addition, peak day demand is a key element in the sizing of an LDC's facilities and in determining the level of costs incurred in serving its customers. Although the day-to-day utilization of an LDC's facilities by its customers is measured by their annual gas consumption characteristics, this measure does not have a bearing on the types and costs of facilities installed to serve customers, especially if the facility is sized to meet the specific needs of each customer (e.g., a meter, service line or regulator).

Q: Why doesn't average demand (i.e., annual gas throughput divided by 365 days) influence the incurrence of these types of fixed costs?

A: If an LDC's gas system was sized to accommodate average gas demands, it would be unable to accommodate system peak demands. That is, by sizing plant investment for peak period demands, the LDC is assured of being able to satisfy its service obligation throughout the year. From a gas engineering perspective, a peak demand design criterion should always be utilized when designing transmission and distribution systems to accommodate the gas demand requirements of the customers served from that system. As such, *cost causation* with respect to certain demand and customer related costs is unrelated to average demand characteristics. Such demand characteristics only serve as a measure of system utilization – not cost causation.

Additionally, use of average demand characteristics for the allocation of demand related costs penalizes customers that exhibit efficient gas consumption characteristics (i.e., customers with high load factors) and encourages the inefficient use of the LDC's gas system by customers with low load factors. Clearly, under-utilization of an LDC's gas system is a result that an LDC can hardly encourage, recognizing that higher system utilization will result in lower unit costs to *all* customers served by the LDC.

For the above-stated reasons, it is critical that the cost analyst carefully evaluate the degree of reliance placed upon commodity-based allocation factors, as derived from annual gas throughput volume, for purposes of allocating *fixed* demand and customer related costs of an LDC.

Q: Are these conclusions equally applicable to the Company's class load characteristics?

A: Yes, they are. These class load characteristics must be recognized within the Company's cost of service study through the proper selection and development of cost allocation factors to ensure that the resulting costs of serving its customers are reasonable.

VII. IDENTIFYING THE COSTS OF TRANSPORTATION SERVICE FOR AN LDC

Q: Please describe the preferences of the Commission for deriving the costs of transportation service, as stated in the Company's gas rate restructuring Order in Docket No. UG-940814, and how the Company accommodated those preferences in its current gas cost of service study?

A: The Commission expressed a preference for conducting a cost of service study with separate classes of service for sales and transportation service customers. In its Order, the Commission stated that, "it is essential that the cost study identify costs of gas for sales customers and the fixed and variable costs that are unique to transportation service." (Fifth Supplemental Order, mimeo at 16). Also in that Order, in commenting on the Company's analysis of the administrative costs of transportation service, the Commission indicated, ". . . that complete and accurate information on the topic, including, if needed, fact-based estimates of reasonable costs to perform functions must be provided in future proceedings."(Fifth Supplemental Order, mimeo at 24). The Company's cost of service study reflects both of these requirements in deriving the costs of transportation service.

The Company established separate classes in its cost for service study for the two customer groups that receive transportation service – Rate 57 and Rates 99/199/299 (Special Contracts). Secondly, the cost study reflects the results of a detailed analysis that identified the costs of the various administrative activities required to support transportation service. Typically these would include administrative costs associated with activities such as customer gas nominations, transport billing, gas measurement support, customer assistance and service, and gas balancing provided by the LDC.

VIII. THE METHODOLOGICAL AND CONCEPTUAL BASIS USED IN THE COMPANY'S COST OF SERVICE STUDY

Q: Please explain the reasons why the Company chose the particular cost allocation methodology utilized in its gas cost of service study.

A: The Company's proposed cost allocation methodology was chosen for the following reasons:

1. It reasonably reflects the principles deemed appropriate by this Commission in establishing a cost allocation methodology.
2. It satisfies the most important attributes considered when evaluating cost allocation methodologies.
3. It has a sound conceptual and theoretical basis.
4. It is compatible with the prevailing economics and cost structure of the energy marketplace.
5. It reflects the regulatory considerations of this Commission pertaining to cost allocation methodologies for LDCs.

The Company's proposed cost allocation methodology *only* relies upon throughput-based allocation factors, in conjunction with other appropriate allocation factors, where plant investment is deemed to be common or joint-use in nature (e.g., transmission and distribution mains). Where the Company can directly identify specific costs to serve customers, those costs are directly assigned to customers rather than having to use one or more common allocation factors to assign those costs.

Next, the Company's method recognizes the true nature and characteristics of an LDC's costs by classifying and allocating only a relatively small portion of total non-gas costs as commodity-related. This is accomplished through the use of the Company's annual system load factor to disaggregate costs between demand

and commodity classification categories. In my judgment, use of the LDC's system load factor to determine this cost split is a sound approach and provides this Commission with a rational basis to recognize both the system design characteristics of an LDC (i.e., cost incurrence principles) and system utilization concepts.

Q: How have the costs of the Company's joint use, T & D system been classified and allocated in its proposed cost of service study?

A: The Company proposes to use a "modified" Peak and Average Method, wherein the classification of costs between demand and commodity is developed based on the Company's system annual load factor that is derived on a peak day basis. This is the same demand cost allocation method adopted by the Commission in the Company's last gas rate proceeding, Docket No. UG-940814. Specifically, the Company's annual load factor based on its proposed determination of peak day demand supports the classification of 39% of the above-mentioned costs as commodity-related. Once these costs are classified, the demand-related costs are allocated to the Company's customer classes using each class' contribution to the coincident peak day demand and the commodity-related costs are allocated based on each class' annual throughput volumes.

Q: Does the modified Peak and Average method reasonably reflect the nature of a gas utility's costs and the primary system design considerations that give rise to those costs?

A: Yes, it does. It is a widely accepted principle within the utility industry that the measure of load factor is a key determinant in establishing a linkage between the gas consumption characteristics of an LDC's customers and the particular costs incurred by the LDC in serving those customers. The modified Peak and Average method directly captures this principle in the way it is applied to an LDC's cost of service and customer classes. The method is a variation of a cost allocation method that has been accepted and used by utility regulatory commissions in other states, including New Jersey, Michigan, and Pennsylvania.

In the *Gas Distribution Rate Design Manual*, published by the National Association of Regulatory Utility Commissioners ("NARUC"), it is stated at page 27 that "(t)he most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three."

It goes on to describe the Average and Peak Demand Method as follows:

> This method reflects a compromise between the coincident and non-coincident demand methods. Total demand costs are multiplied by the *system's load factor* to arrive at the capacity costs attributed to average use and are apportioned to the various customer classes on an annual volumetric basis. The remaining costs are considered to have been incurred to meet the individual peak demands of the various classes of service and are allocated on the basis of the coincident peak of each class. This method allocates cost to all classes of customers and *tempers the apportionment of costs between the high and low load factor customers*. (Emphasis added.)

Q: Please explain the method used by the Company to determine the peak day demand included in its modified Peak and Average Method?

A: The Company proposes to determine its peak day demand for cost allocation purposes using a demand level that reflects a combination of its actual historical and design day demand levels and associated weather conditions. Specifically, the peak demand level was derived based on a 50/50 weighting of the Heating Degree-Days (HDDs) experienced by the Company on the highest 3-day sustained peak over the last five years and its design day HDDs. This method results in a peak day demand for the Company of approximately 7,250,000 therms based on a 47 HDD level. The resulting demand level is reflective of the current gas usage characteristics by class experienced by the Company during its test year, the twelve months ending June 30, 2001.

Q: Why did you choose to reflect a combination of the Company's historical peak day and design day demands in the determination of its peak day for cost allocation purposes?

A: The Company chose this method to reflect a proper balancing of various conceptual, operational and regulatory considerations. In the Company's last gas rate case, much discussion occurred on the issue of peak day determination for cost allocation purposes. I was actively involved in those discussions and closely followed the process that resulted in the Commission adopting a peak determination method that was proposed by the Commission Staff based on the average of the Company's 5 highest peak days for 3 years. In my judgment, the Company's proposed method in this proceeding that uses a combination of actual peak days and its design day best accommodates the Commission's expressed preferences regarding this issue.

In its Decision in Docket No. UG-940034/UG-940814, the Commission stated that the Staff method, ". . . best considers peak usage, accounts for the usage of different classes, including actual use of interruptible customers, and reflects historical peak usage patterns." (Fifth Supplemental Order, mimeo at 8). The Commission further stated that, "The Commission Staff proposal offers the best balance among stability, validity, usage trends, and actual use during experienced weather conditions." (Fifth Supplemental Order, mimeo at 8). Nevertheless, the Commission did acknowledge that they were not convinced that the demand measure was perfect and that they believed it was preferable to use data from a longer time period to remove variations due to unusual weather and to achieve greater stability.

The Company believes its proposed peak day determination is preferable to the "5 highest peak days for 3 years" method for a number of reasons. These include:

1. It results in a relatively stable determinant of peak day demand by virtue of the longer length of time (5 years) used for capturing the Company's actual historical peak demands and the inclusion of the design day demand that provides a further stabilizing effect on the resulting peak demand level.
2. The method properly reflects actual usage trends in the peak day demands experienced by the Company because the resulting peak day allocator will change over time as the peak day usage characteristics of customers change.
3. The method appropriately captures actual peak day use by class (including interruptible customers) during experienced weather conditions and uses that information to derive a peak demand that is reflective of the current usage characteristics of its customers.
4. The method is consistent with the level of growth in customer demands for gas during peak periods and is more closely related to the change in fixed plant investment over time because of its reliance on a combination of historical peak demands and design day demand.
5. The inclusion of design day demand as one component of the method ensures that the planning and design basis for the Company's gas system resources, which the Company must rely upon in the acquisition of its upstream gas supply-related resources and in the design of its own

production, storage, transmission and distribution facilities required to service its customers, is recognized in the allocation of those same costs.

Q: Under the Company's proposed method, what were the weather conditions experienced during the 3-day sustained peak period?

A: On December 20-22, 1998, the Company experienced average daily temperatures of 20°F, 22°F, and 23°F, respectively, for a range of between 43 and 45 HDDs. The Company's current design day temperature condition is 51 HDDs.

Q: What was the level of gas demand actually experienced by the Company during the December 20-22, 1998 peak period?

A: During December 20-22, 1998, the Company experienced peak demands of 6,619,280 therms, 6,782,360 therms, and 6,607,650 therms, respectively, for an average daily demand level of 6,669,763 therms.

Q: Is the Company's estimate of peak day demand at 47 HDDs during the test year reasonable in view of the actual peak demands it experienced during the December 1998 time period?

A: Yes, I believe it is. The peak day demand proposed by the Company reflects a temperature condition that is approximately 9.3% colder than under the average daily temperature conditions during the peak of December 20-22, 1998. At 47 HDDs, the estimated peak day demand of 7,250,000 therms is only 8.7% higher than the average daily demand during December 20-22, 1998. Recognizing that more than three years have passed since that time, the combination of colder weather and a 9.2% growth rate in customers (with 95% new residential customers) clearly supports the reasonableness of the Company's current peak day demand level for cost allocation purposes.

Q: How does the Company's proposed method of determining its peak demand treat its interruptible sales and transportation service customers?

A: The method reflects a combination of the recorded level of interruptible gas sales and transportation service that was provided during its actual peak and the assumption of interruptible customers not being served on its design day. This approach results in a reduced level of interruptible service compared to the level experienced in December 1998 in recognition of the colder weather conditions (47 HDDs compared to 43 HDDs) associated with the established peak demand for cost allocation purposes.

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

A: Before classifying and allocating distribution mains, an extensive analysis of the Company's facilities serving its largest customers was performed to identify dedicated plant investment that could be directly assigned to these customers. The analysis covered all customers served under Rate Schedules 87 and 57. For each of these large customers, its location on the Company's distribution system was determined and plant investment data was compiled to develop the original cost of the distribution lines dedicated to serve the customer. For each customer, the particular main was traced upstream to its intersection with a 4-inch or larger "common" main. Based on this analysis, it was determined that most Rate 87 and 57 customers were served off of distribution mains 4 inches or larger in diameter. This conclusion led the Company to disaggregate its distribution main investment into two subgroups: (1) mains less than 4 inches in diameter and (2) mains 4 inches or greater in diameter.

Using the results of this analysis, the costs of the dedicated small diameter (less than 4 inches) facilities directly assigned to Rate 85, 87, 57 and the special contract customers were subtracted from the total mains investment for this subgroup. For mains 4 inches or greater, the plant balance was classified between demand and commodity on a system load factor basis and allocated to *all* customers based on design day demand and commodity throughput allocation factors. Mains less than 4 inches in diameter were classified in the same manner and were allocated to all customers except Rate 85, 87, 57 and special contract customers.

Q: **Why didn't the Rate 85, 87, 57 and special contract customers receive an allocated share of the costs associated with the distribution mains less than 4 inches in diameter?**

A: These customers did not cause the Company to install any downstream distribution mains on their behalf. In other words, these customers do not utilize any of the Company's downstream distribution mains to receive gas volumes at their burner-tip locations.

Q: **In conjunction with the above-described analysis of distribution mains, were there other facilities identified which exclusively served these larger customers?**

A: Yes. The actual embedded costs of service lines and industrial M&R equipment installed to serve these customers were directly assigned to the Rate 87 and 57 customers.

Q: **Please describe the special studies you conducted for purposes of allocating other distribution plant investment.**

A: Regarding the Company's major plant accounts, customer weighting factors were developed to allocate the following plant accounts: Services – Account No. 380, Meters – Account 381, Meter Installations – Account No. 382, House Regulators – Account No. 383, House Regulator Installations – Account No. 384, and Industrial Measuring & Regulating Station Equipment – Account No. 385. These weighting factors reflect any differences in the current unit costs that particular customer groups cause the Company to incur. For example, the cost of a 5/8-inch plastic service line that could serve a residential customer costs less, on a per unit basis, than the cost of a 4-inch steel service line to serve a larger industrial customer. The use of weighting factors takes these unit cost differences into account when assigning costs to these two customer classes. It should be noted that these weighting factors were used to assign costs net of the costs of facilities which were already directly assigned to specific large customers based on the special study I described earlier.

Q: How did you determine the particular type and size of facility for each plant account that should be attributed to each of the Company's customer groups?

A: Based on its historical installation and operating experience, the Company has established engineering and operational standards which enabled me to directly identify the typical size and type of service line by customer group. With regard to meters and industrial M&R station equipment, the Company was able to conduct a detailed computer analysis of data contained in its customer information system that identified the type and size of meter for each customer it serves. This analysis also was used to determine the type and size of equipment, by customer class, for house regulators and to assign the installation costs of meters and house regulators to specific customer classes.

Q: Please describe the method used to allocate reserve for depreciation and depreciation expenses.

A: These items were allocated by function in proportion to their associated plant accounts.

Q: How did the study allocate distribution-related operation and maintenance expenses?

A: In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's operation and maintenance expenses generally are thought to support the utility's corresponding plant in service accounts. That is, the existence of particular plant facilities necessitate the incurrence of cost (i.e., expenses) by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 893, Meters and House Regulator Expenses, is allocated on the same basis as its corresponding plant accounts, Account No. 381 – Meters and Account No. 383 – House Regulators. With the Company's detailed analyses supporting its assignment of plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q: How did the study allocate purchased gas expenses?

A: The Company's proposed cost of service study contains a Purchased Gas Subreport which disaggregates purchased gas costs into demand and commodity cost components to facilitate the analysis and allocation of these costs. Included in this cost category are the fixed costs of pipeline capacity, supply reservation charges, the pipeline storage costs for peaking capacity and storage capacity, and the pipeline transportation charges for peak demand and seasonal demand. The commodity related costs include contract commodity and spot market gas costs, the net cost of gas injected into and withdrawn from storage, and the associated fees for these services. The sums of the various cost components were individually allocated to the Company's customer classes according to cost responsibility (i.e., using design peak demands, winter season sales and annual sales).

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

A: Referring to the Gas Cost Sub-Report contained in Exhibit RAF-3, supply reservation charges were allocated in a manner which recognizes the reasons why the Company incurs such charges and how the various contracts fit into its overall gas supply portfolio. Reservation charges are paid by the Company to ensure that specific levels of gas supplies are available on a daily basis. For its annual contracts, although the Company is assured of supply certainty throughout the year through the payment of such charges, that certainty is most critical in the winter months and on extreme peak days. The modified Peak and Average method reflects this planning consideration by using, based on the Company's annual sales load factor, a combination of peak day demands and annual sales in deriving the allocation percentages. For winter contracts, the reservation charges were allocated on a winter seasonal basis. Firm transportation demand charges related to pipeline supplies were allocated using the modified Peak and Average method and storage-related charges were allocated on a seasonal basis. Finally, peaking supply-related charges were allocated on a peak day demand basis.

Q: How were variable or commodity-related gas costs allocated?

A: Variable gas costs were allocated on an annual sales or winter sales basis depending on the nature of each supply resource described in the listing of resources in Exhibit RAF-3.

Q: Why is it appropriate that load factor be reflected in the development of an allocation method that can be used to allocate an LDC's gas supply-related costs?

A: The optimal mix of supply and capacity related resources required to serve a particular customer or group of customers served by an LDC depends directly upon its annual load factor. For the Company, its system load factor has a direct bearing on the mix of firm gas supply and capacity resources available to serve its peak day requirements.

Q: If the Company's annual load factor increased, would its mix of firm gas supply and capacity resources change?

A: Yes, it would. The Company would in all likelihood increase its relative level of base-load resources compared to its level of seasonal and peaking resources. The modified Peak and Average method proposed by the Company recognizes load factor directly in its classification and allocation of gas supply and capacity resources.

Q: How have you computed the Company's system load factor for purposes of applying the modified Peak and Average method to the allocation of certain purchased gas expenses?

A: The modified Peak and Average method was computed using a sales load factor of 32,4% rather than a gas throughput-based load factor to appropriately exclude the Company's end-use transportation service from the calculations.

Q: How did the study allocate administrative and general expenses?

A: The study allocated these expenses on a specific account-by-account basis rather than on an aggregate basis. Specifically, administrative and general expenses of a utility typically pertain to the following expense categories: (1) labor; (2) plant; and (3) combined. In the filed cost of service studies, I was able to relate each of its administrative and general accounts to one of the above-stated categories. These categories were then used as a basis to establish an appropriate allocation factor for each account.

Q: How did the study allocate taxes other than income taxes?

A: The study allocated these expenses in a manner to reflect the specific cost causative factors associated with the Company's particular tax expense categories. Specifically, these taxes can be cost classified on the basis of the tax assessment method established for each tax category (i.e., payroll, property, revenue, sales and expenses). As a result, taxes other than income taxes of a utility typically can be grouped into the following categories: (1) labor; (2) plant; and (3) revenue. In the cost of service study, I was able to relate each of its taxes other than income taxes accounts to one of the above stated categories. These categories were then used as a basis to establish an appropriate allocation factor for each tax account.

Q: How were income taxes allocated to each customer class?

A: Income taxes were allocated to each rate class based on its income before federal income taxes. This approach made certain that the income tax assigned to each rate class reflected the proper weighting of class revenues and previously allocated expenses.

Q: Please explain how the cost elements of transportation service were derived.

A: The cost elements of transportation service were derived based on my review and evaluation of the Company's: (1) plant and operating expenses necessary to deliver gas to its transportation customers; (2) any administrative costs incurred on behalf of its transportation customers; and (3) the plant and expenses related to balancing its system throughput volumes on a daily basis.

Referring to the unit cost analysis presented in Exhibit RAF-3, all costs located under the functional categories, "Transmission" and "Distribution," excluding certain specifically identified administrative costs, comprise the Company's T & D delivery costs. The administrative costs reflected in the cost study are identified in the allocation factor section of the cost studies under the "Direct Allocators" category. These costs reflect activities including: contract administration, gas volume control (e.g., volume scheduling, gas balancing, and nominations management), gas measurement (e.g., reading and processing usage data), special billing, and customer service support.

With regard to the costs of system balancing, it was necessary to review the Company's gas supply and deliverability resources to determine the type and level of resources relied upon to accommodate system gas imbalances on a daily basis. These imbalances are created by the differences between the daily levels of gas nominated and actually consumed by both the Company's sales and transportation service customers. Based on my review of the Company's resources and discussions with staff members involved in its gas supply area, it was determined that the Jackson Prairie storage facility and its associated redelivery service accommodates the daily gas imbalances created by the Company's sales and transportation service customers.

VIII. USE OF JACKSON PRAIRIE FOR SYSTEM BALANCING

Q: At this time, is the Company proposing any methodological refinements to the allocation of Jackson Prairie storage costs for system balancing purposes?

A: Yes. The Jackson Prairie storage facility serves both seasonal supply and system balancing functions. As discussed below in more detail, the Company is proposing to more accurately reflect the use of Jackson Prairie for system balancing purposes. The Company has an obligation to customers to mitigate charges imposed by Northwest Pipeline for exceeding the three-percent tolerance band required during peak periods and on other occasions when a pipeline entitlement is imposed. As a result, the system balancing function of Jackson Prairie is a necessary, separate function of the storage facilities and should be identified separately and to the full extent of its use for this function.

Q: Please describe the method developed for use in the Company's previous system balancing study and the resulting percentage allocation.

A: The methodology employed in Docket No. UG-940814 made an assumption that transportation (customer-owned gas) and system sales imbalances would offset each other, and that actual nominations of Jackson Prairie were for supply, when they could have been for both supply and system balancing. The net pipeline imbalance (system sales and customer-owned gas) was treated as additive to the actual Jackson Prairie nominations for purposes of determining the system balancing percentage use of the storage facility. If there were no scheduled storage injections or withdrawals for a given day, the implied use of the storage facility for system balancing was 100% on that day. Likewise, if the net pipeline imbalance was less than +/- 3 percent, then there was no implied system balancing. Applying this method to the test year, the use of the Jackson Prairie facility for system balancing would be 9.36 percent.

Q. Please explain why you are recommending a refinement to this method?

A: The assumption in the previous method that allows transportation (customer-owned gas) and system sales imbalances to offset one another assumes that the Company's gas dispatching personnel would have had prior knowledge of these imbalances in order for the storage nominations during the gas day to relate only to system supply. In practice, the size and direction (short or long) of these imbalances are not known in advance of the gas day and vary randomly in the same or opposing directions throughout the gas day. The storage nominations during the gas day are a function of the day's expected system supply requirements and as a response to the imbalance conditions at the time of the nomination. The contrasting movement of the transportation and sales imbalances is illustrated in the diagram, Daily Use of Jackson Prairie, on page 1 of Exhibit RAF-7). The diagram compares these separate imbalances with the Jackson Prairie daily storage activity.

Q: Please describe the Company's proposed method for calculating the system balancing function of Jackson Prairie and the resulting allocation percentage.

A: The Company's alternative method for determining the portion of Jackson Prairie used for system balancing calculates the absolute value of the transportation (customer-owned gas) and system sales imbalances outside of the 3 percent pipeline tolerance range. The transportation and sales imbalances are not allowed to offset each other, since on any given day the respective imbalances may be tracking with or against each other. The storage facility must be dispatched to handle either condition throughout the gas day. This revised method determines the imputed sales supply use of the storage facility by subtracting the absolute value of the transportation and sales imbalances from the actual Jackson Prairie use for the gas day. In other words, what was not used to balance the system was used for system supply. The comparison of the absolute values of the transportation and supply imbalances to the actual Jackson Prairie use is illustrated on the diagram appearing on page 2 of Exhibit RAF-7. The result of the application of this revised method of determining the balancing use of Jackson Prairie storage is 19.48 percent.

Q: Do you believe that this refined method for determining the portion of Jackson Prairie dedicated to system balancing is appropriate?

A: Yes. Because it does not attribute advance knowledge of the imbalance conditions of the various elements of daily system throughput, this refined method more reasonably captures the true nature of the system balancing function of Jackson Prairie storage.

IX. RESULTS OF THE COMPANY'S COST OF SERVICE STUDY

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

A: Referring to Exhibit RAF-3, the following results at present rates are indicated:

1. The residential service rate schedules (Rate Schedules 23 and 24) exhibit the lowest rate of return of all the Company's major rate classes.
2. The firm commercial and industrial heating class exhibit a higher than average rate of return.
3. The commercial and industrial high load factor class (Rate Schedule 41) exhibits a higher than average rate of return.
4. The interruptible sales service rate schedules (Rate Schedules 85, 86, and 87) exhibit the highest rates of return of all the Company's major rate classes.
5. The transportation rate schedule (Rate Schedule 57) exhibits a higher than average rate of return.
6. The special transport contract rate schedules (Rate Schedules 99, 199, and 299) exhibit a higher than average rate of return.

Q: How can cost of service study results such as these provide guidelines for rate design?

A: Results of a cost of service study provide cost guidelines for use in evaluating class revenue levels and class rate structures. With regard to customer class revenue levels, the rate of return results show that certain rate classes are being charged rates that recover less than their indicated costs of service. Obviously, because this condition exists, rates for other customer classes provide for recovery of more than the indicated costs of serving these other rate classes. By adjusting rates in accordance with the cost study, customer class revenue levels can be brought closer in line with the indicated costs of service resulting in movement of rate class rates of return toward the system average rate of return and resulting in rates that are more in line with the cost of providing service.

Concerning cost justification of rates within each customer class, the classified costs, as allocated to each class of service in the cost study, provide cost information that can be of assistance in determining the need for changes in the relative levels of demand, customer and commodity rate block charges.

Q: Please explain how the Unit Cost Analysis presented in Exhibit RAF-3 was prepared.

A: Our computer model extracts the functionalized, classified and allocated expenses and rate base data for each class of service and applies the system average rate of return to the allocated rate base to determine the required net income. This amount is then grossed up to account for the income and general tax related revenue responsibilities. The sum of the expense related revenue requirement and the rate base related revenue requirement yield the total revenue requirement for each component of cost at the system average rate of return. The computer model makes this calculation for each of the various cost components (i.e., the customer, demand and commodity portions of the production, storage, transmission and distribution functional categories.) The summary total of these calculations is shown in Exhibit RAF-3. It should be noted that a monthly customer cost is calculated for each customer class, as well as unit commodity and demand costs.

Q: Can these unit costs analyses results be used for rate design?

A: Yes, if three part rates (i.e., customer, demand and commodity) were set at the unit cost levels, the Company's operating expenses and rate of return on investment based its most recently completed rate proceeding would be recovered. However, restructuring an LDC's rates in this manner is usually not possible because of adverse customer impact in terms of revenue allocation and the administrative burdens of three part rates, particularly for smaller customers. At best, this type of rate structure could be phased-in by the LDC over a reasonable future period of time. The unit cost analyses do provide valuable unbundled cost information for the design of portions of the tariffs. One of the most obvious applications is the use of unbundled cost information for establishing cost-based customer charges. The unit cost analysis could also be used to establish separately metered contract demand charges where the cost of demand metering can be justified.

Q: Have you prepared a more detailed analysis of the Company's customer-related costs of providing service?

A: Yes, I have. Exhibit RAF-6 provides details of the customer-related rate base and expenses, as allocated in the Company's cost of service study. Customer-related revenue requirements include operating expenses such as meter reading, customer accounting and billing, customer service, and certain distribution operating and maintenance costs, as well as the customer-classified A&G expenses. They also include the return on net rate base allowed on the Company's meters, services, and other distribution and general plant investment that have been classified as customer-related. The resulting monthly customer-related revenue requirement for the Company's residential service customers is $18.66 per customer; for C&I heating service customers, it is $34.38 per customer; for C&I high-load factor service customers, it is $425.94 per customer, and for Interruptible service (Rates 85, 86, and 87) it is $451.33, $457.07, and $554.62 per customer, respectively.

X. CONCLUDING REMARKS

Q: Do you have any concluding remarks?

A: Yes, I do. The Company must utilize a cost allocation methodology which reasonably and equitably establishes the costs of providing service to its customers, so that both the Company and its customers can be in a position to make reasoned energy-related decisions based on gas rate levels which are consistent with and representative of the prevailing economics and cost structure of the energy marketplace.

The Company continues to rely upon the modified Peak and Average methodology for use in its cost of service study. In my opinion, the methodology strikes an appropriate balance between the contrasting methodologies that can be presented by other cost analysts, while at the same time serving as a vehicle to aid the Company in the development of its proposed rates. The methodology does not abandon a throughput-based approach, but rather builds upon the most appropriate approach for the Company today. The Company's proposed cost allocation methodology *only* relies upon throughput-based allocation factors, in conjunction with other appropriate allocation factors, where plant investment is deemed to be common or joint-use in nature (e.g., transmission and distribution mains). Where the Company can directly identify specific costs to serve customers, those costs are directly assigned to customers rather than having to use one or more common allocation factors to assign those costs.

The Company's method recognizes the true nature and characteristics of an LDC's costs by classifying and allocating certain common costs through the use of the Company's annual system load factor. In my judgment, use of the Company's system load factor to determine this cost split is a sound approach and provides this Commission with a rational basis to recognize both the system design characteristics of an LDC (i.e., cost incurrence principles) and system utilization concepts.

Overall, it is my judgment that the Company's proposed cost allocation methodology will serve to implement the Commission's costing principles in *today's* gas industry environment.

Q: Mr. Feingold, does that complete your prefiled direct testimony?

A: Yes, it does.

[BA013250091]

EXHIBIT NO. ______ (RAF-2)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RUSSELL A. FEINGOLD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

PROFESSIONAL QUALIFICATIONS OF RUSSELL A. FEINGOLD ON BEHALF OF PUGET SOUND ENERGY, INC.

PUGET SOUND ENERGY, INC.

PROFESSIONAL QUALIFICATIONS OF RUSSELL A. FEINGOLD

EDUCATION

- Bachelor of Science degree in Electrical Engineering from Washington University, St. Louis.
- Master of Science degree in Financial Management from Polytechnic Institute of New York

PROFESSIONAL EMPLOYMENT

1997 – Present	Navigant Consulting, Inc. Metzler & Associates Managing Director, Regulation & Litigation Support Practice
1990 – 1997	R.J. Rudden Associates, Inc. Vice President and Director
1985 – 1990	Price Waterhouse Director, Gas Regulatory Services Public Utilities Industry Services Group
1978 – 1985	Stone & Webster Management Consultants, Inc. Executive Consultant Regulatory Services Division
1973 – 1978	Port Authority of New York and New Jersey Staff Engineer and Utility Rate Specialist Design Engineering Division

PRESENTATION OF EXPERT TESTIMONY

- Federal Energy Regulatory Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities

- Michigan Public Service Commission
- Montana Public Service Commission
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities
- New York Public Service Commission
- Ohio Public Utilities Commission
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Quebec Natural Gas Board (Canada)
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission

EDUCATIONAL AND TRAINING ACTIVITIES

- Chairman, Rate Training Subcommittee, Rate and Strategic Planning Committee of the American Gas Association
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995
- Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison, 1985 – 2001
- Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland – College Park, 1987 –1992
- Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987
- Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987
- Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress)

PUBLICATIONS AND PRESENTATIONS

- "Can a California Energy Crisis Occur Elsewhere?" American Gas Association, Rate and Strategic Issues Committee Meeting, March 2001.
- "Downstream Unbundling: Opportunities and Risks," American Gas Association, Rate and Strategic Issues Committee Meeting, April 2000.
- "Form Follows Function: Which Corporate Strategy Will Predominate in the New Millennium?" American Gas Association 1999 Workshop on Regulation and Business Strategy for Utilities in the New Millennium, August 1999

- "Total Energy Providers: Key Structural and Regulatory Issues," American Gas Association, Rate and Strategic Issues Committee Meeting, April 1999.
- "The Gas Industry: A View of the Next Decade," National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Accounts, 1998 Fall Meeting, September 1998.
- "Regulatory Responses to the Changing Gas Industry," Canadian Gas Association, 1998 Corporate Challenges Conference, September 1998
- "Trends in Performance-Based Pricing," American Gas Association Financial Analysts Conference, May 1998.
- "Unbundling – An Opportunity or Threat for Customer Care?" presented at the American Gas Association/Edison Electric Institute Customer Services Conference and Exposition, May 1998.
- "Experiences in Electric and Gas Unbundling," presented at the 1997 Indiana Energy Conference, December 1997.
- "Asset and Resource Migration Strategies," presented at the Strategic Marketing For The New Marketplace Conference sponsored by Electric Utility Consultants, Inc. and Metzler & Associates, November 1997.
- "The Status of Unbundling in the Gas Industry," presented at the American Gas Association Finance Committee, March 1997.
- Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.
- "State Regulatory Update," presented at the American Gas Association – Financial Forum, May 1995.
- "Gas Pricing Strategies and Related Rate Considerations," presented before the Rate Committee of the American Gas Association, April 1995.
- "Avoided Cost Concepts and Management Considerations," presented before the Workshop on Avoided Costs in a Post-636 Industry, sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, June 1994.
- "DSM Program Selection Under Order No. 636: Effect of Changing Gas Avoided Costs," presented before the NARUC-DOE Fifth National Integrated Resource Planning Conference, Kalispell, MT, May 1994.
- "A Review of Recent Gas IRP Activities," presented before the Rate Committee of the American Gas Association, March 1994.
- Seminar organizer and co-moderator at the American Gas Association seminar, "The Statue of Integrated Resource Planning," December 1993.
- "Industry Restructuring Issues for LDCs, presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland, 1993-1996.
- "Acquiring and Using Gas Storage Services," presented before the 8th Cogeneration and Independent Power Congress and Natural Gas Purchasing '93, June 1993.
- "Capitalizing on the New Relationships Arising Between the Various Industry Segments: Understanding How You Can Play in Today's Market," presented

before the Institute of Gas Technology's Natural Gas Markets and Marketing Conference, February 1993.

- "The Level Playing Field for Fuel Substitution (or, the Quest for the Holy Grail)," presented before the 4th Natural Gas Industry Forum – Integrated Resource Planning: The Contribution of Natural Gas, October 1992.
- "Key Methodological Considerations in Developing Gas Long-Run Avoided Costs," presented before the NARUC-DOE Fourth National Integrated Resource Planning Conference, September 1992.
- "Mega-NOPR Impacts on Transportation Arrangements for IPPs," co-presented before the 7th Cogeneration and Independent Power Congress and Natural Gas Purchasing '92, June 1992.
- "Cost Allocation in Utility Rate Proceedings," presented before the Ohio State Bar Association – Annual Convention, May 1992.
- "The Long and the Short of LRACs," presented before the Natural Gas Least-Cost Planning Conference April 1992, sponsored by Washington Gas Company and the District of Columbia Energy office.
- Seminar organizer and moderator at the American Gas Association seminar, "Integrated Resource Planning: A Primer," December 1991.
- Session organizer and moderator on integrated resource planning issues at the American Gas Association Annual Conference, October 1991.
- "Strategic Perspectives on the Rate Design Process," presented before the Executive Enterprises, Inc. conference, "Natural Gas Pricing and Rate Design in the 1990s," September 1990.
- "Distribution Company Transportation Rates," presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland 1987-1992.
- "Design of Distribution Company Gas Rates," presented before the American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin, 1985-1998.
- Seminar organizer, speaker and panel moderator at the American Gas Association seminar, "Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing," 1988-1990.
- "Local Distribution Company Bypass – Issues and Industry Responses," (Co-author) June 1989.
- "So You Think You Know Your Customers!," presented before the American Gas Association–Annual Marketing Conference, April 1990.
- "Gas Transportation Rate Considerations – A Review of Gas Transportation Practices Based on the Results of the A.G.A. Annual Pricing Strategies Survey," presented before the Rate Committee of the American Gas Association, April 1985-1991.
- "Market-Based Pricing Strategies – Targeted Rates to Meet Competition," presented before the American Gas Association Annual Marketing Conference, March 1989.

- "Gas Rate Restructuring Issues – Targeted Prices to Meet Competition," presented before the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.
- "Gas Transportation Rates – An Integral Part of a Competitive Marketplace," *American Gas Association, Financial Quarterly Review*, Summer 1987.
- "Gas Distributor Rate Design Responses to the Competitive Fuel Situation," *American Gas Association, Financial Quarterly Review*, October 1983.
- "Demand-Commodity Rates: A Second Best Response to the Competitive Fuel Situation," presented before the American Gas Association, Ratemaking Options Forum, September 1983.
- Cofounder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.
- "Current Rate and Regulatory Issues," presented before the National Fuel Gas Regulatory Seminar, July 1986.

AFFILIATIONS AND HONORS

- Financial Associate Member, American Gas Association
- Member, Institute of Electrical and Electronic Engineers
- Member, Rate and Strategic Planning Committee of the American Gas Association
- Listed in Who's Who of Emerging Leaders in America, 1989-1992

(as of September 2001)

EXHIBIT NO. ______ (RAF-3)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RUSSELL A. FEINGOLD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

EXHIBIT TO DIRECT TESTIMONY OF RUSSELL A. FEINGOLD
ON BEHALF OF PUGET SOUND ENERGY, INC.

EXHIBIT NO. ______ (RAF-4)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RUSSELL A. FEINGOLD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
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PUGET SOUND ENERGY, INC.

Respondent.

EXHIBIT TO DIRECT TESTIMONY OF RUSSELL A. FEINGOLD
ON BEHALF OF PUGET SOUND ENERGY, INC.

EXHIBIT NO. ______ (RAF-5)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RUSSELL A. FEINGOLD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

EXHIBIT TO DIRECT TESTIMONY OF RUSSELL A. FEINGOLD
ON BEHALF OF PUGET SOUND ENERGY, INC.

EXHIBIT NO. ______ (RAF-6)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RUSSELL A. FEINGOLD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

EXHIBIT TO DIRECT TESTIMONY OF RUSSELL A. FEINGOLD ON BEHALF OF PUGET SOUND ENERGY, INC.

EXHIBIT NO. ______ (RAF-7)
DOCKET NO.____________
2001 PSE RATE CASE
WITNESS: RUSSELL A. FEINGOLD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

EXHIBIT TO DIRECT TESTIMONY OF RUSSELL A. FEINGOLD
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